Advancing Zero-Emission Fuels in Washington's Shipping Sector

Roadmap to 2050

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About RMI

RMI is an independent nonprofit, founded in 1982 as Rocky Mountain Institute, that transforms global energy systems through market-driven solutions to align with a 1.5°C future and secure a clean, prosperous, zero-carbon future for all. We work in the world's most critical geographies and engage businesses, policymakers, communities, and NGOs to identify and scale energy system interventions that will cut climate pollution at least 50 percent by 2030. RMI has offices in Basalt and Boulder, Colorado; New York City; Oakland, California; Washington, D.C.; Abuja, Nigeria; and Beijing.

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Executive Summary

In pursuit of ambitious state decarbonization goals, the Washington State Department of Commerce has identified renewable fuels made from clean hydrogen as an essential solution, especially in hard-to-electrify sectors such as shipping and aviation.[1] Washington ports and regional maritime stakeholders have also demonstrated a strong ambition to advance shipping-specific decarbonization initiatives, given regulatory pressures from the International Maritime Organization (IMO) and the availability of robust hydrogen production subsidies in the United States this decade.

International shipping cannot be fully decarbonized without the adoption of zero- or near-zero-emission fuels (ZEFs) by ocean-going vessels (OGVs), and this transition has already begun at ports around the world.[i] This report defines ZEFs as fuels that achieve at least a 90% reduction in greenhouse gas (GHG) emissions relative to traditional fossil bunker fuel on an entire life-cycle emissions basis. Although fuels offering partial emissions reductions are also being deployed and will continue to play a part in shipping's energy transition, it is imperative for planning and investment in ZEFs and related infrastructure to accelerate this decade if ZEF deployment is to scale up to reach industry decarbonization by midcentury.

Washington must plan for the deployment of ZEFs in the state to ensure the continued relevance and growth of the shipping sector in the region, and to reach international and state decarbonization goals. Washington ports provide a vital gateway to international trade between the United States and Asia, as well as an essential source of domestic economic activity and jobs.

This roadmap study, *Advancing Zero-Emission Fuels in Washington's Shipping Sector*, was conducted to provide insights for policymakers, industry stakeholders, and other relevant partners into feasible pathways for catalyzing deployment of zero-emissions shipping fuels by 2030 and fully decarbonizing shipping fuel for OGVs calling at Washington ports by 2050, in accordance with IMO targets. This study focuses on fuel demand for all ocean-going vessels, including cruise ships, and the "shipping sector" and "shipping fuels" as used in this report should be understood to include cruise vessels and their fuels, which play an important role in the region's maritime ecosystem. The analysis provides insights into the feasibility of several ZEFs, derived from green electrolytic hydrogen (e-fuels) or sustainable biomass feedstocks (biofuels), by assessing the fuels based on emissions reductions, delivered cost, scalability, and technological readiness between now and 2050.

Key Findings

- By 2030, Washington ports should bunker ZEFs equivalent in energy to approximately 100,000–200,000 tons of VLSFO (very low sulfur fuel oil — an incumbent marine fossil fuel) to align with the IMO's ZEF-adoption targets and commence a fuel transition that will ensure the continued growth of the state's maritime sector.

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i "Zero- or near-zero-emission fuels" reflects the terminology used in IMO's 2023 revised greenhouse gas (GHG) emissions reduction strategy for global shipping, specifically in reference to 2030 adoption targets. Although the IMO has not yet defined a threshold for zero- or near-zero-emission fuels, this report uses a threshold of at least 90% GHG emissions reduction relative to a traditional fossil fuel baseline of 91.16g CO_2e/MJ on an entire life-cycle emissions basis (or a well-to-wake emissions basis).

- The Ports of Seattle, Tacoma, and the Northwest Seaport Alliance are already working to catalyze this ZEF demand, conducting green-corridor feasibility studies that could stimulate ZEF demand capable of displacing 100,000–200,000 tons of VLSFO by 2030 if successful. The PNW-Alaska Green Cruise Corridor has selected (e- or bio-) methanol as a target fuel.

- The investment in port storage and bunkering infrastructure required to meet this scale of ZEF demand in 2030 using (e- or bio-) methanol is estimated at about $20 million for methanol storage and an additional $25 million for a methanol bunker vessel. Aligning early investment efforts around a single ZEF is important in this early stage of the maritime energy transition, when costs are highest and demand is lowest.

- ZEFs capable of providing at least 90% emissions reductions *and* a credible path to meeting a significant scale of global shipping demand include e-fuels derived from low-carbon electrolytic hydrogen (including but not limited to e-methanol, e-ammonia, and e-liquefied natural gas, or e-LNG). Second-generation biofuels derived from sustainable biomass feedstocks (including but not limited to bio-methanol and bio-LNG) can also reduce emissions in the short- to medium-term. However, actual emissions reductions depend on well-to-wake (WtW) life-cycle analysis looking at feedstock source, production process, and (especially in the case of e-LNG and bio-LNG) leakage rates across the supply chain.

- Dual-fuel vessels capable of running on ZEFs such as methanol or ammonia are commercially available and already operating today. The global orderbook[ii] for methanol vessels, in particular, represents a potential demand in 2030 greater than expected supply.

E-Fuels

E-fuels are expected to be cheapest to produce where renewable resources, especially wind resources, are strongest. The Inflation Reduction Act (IRA) tax credits have helped make high-wind regions of the United States some of the least-cost production locations in the world. This study uses a high-wind site in North Dakota as representative of low-cost hydrogen production locations prevalent in the middle of the country, roughly between North Dakota and the Oklahoma Panhandle (the US Wind Belt). Some comparable wind resources can also be found in Montana.

- E-fuels made in the US Wind Belt (using new, co-located wind and solar resources) are expected to be approximately 1.5 times the cost of incumbent shipping fuel in 2030 (on an energy-equivalent basis), including IRA tax credits.[iii] When the cost of transporting fuels to Washington ports is included, the delivered cost is approximately 2.5 times the cost of incumbent shipping fuel.

- E-fuel production costs in Washington in 2030 are expected to be more than double production costs in the US Wind Belt and about 3.5 times the cost of incumbent shipping fuel, including IRA tax credits. Delivered fuel costs (including cost of transport to the Port of Seattle) are about 50% higher for Washington production than for US Wind Belt production.

ii The term "global orderbook" refers to all vessels on order that have not been delivered to the global fleet; this report relies on DNV's Alternative Fuel Insights platform for global orderbook data.

iii The IRA introduced the Clean Electricity Production Tax Credit (45Y), which awards up to $33/MWh of renewable electricity production; and the Clean Hydrogen Production Tax Credit (45V), which awards up to $3/kg of hydrogen produced. The hydrogen production must meet three main pillars: incrementality, deliverability, and temporal matching, discussed in the *Candidate Zero-Emission Fuels* section of this report.

- Actors across the fuel supply chain, from off-takers to ports to the State of Washington, may place some additional value on production close to ports or in-state (due to supply-chain stability, energy security, local job creation, and economic development considerations). However, high production costs in Washington indicate that a large share of demand should be met by out-of-state imports to reach a least-cost energy system.

- Local electrolytic production on the scale of Washington's fuel demand will require significant increases in the scale and pace of renewable capacity deployment and transmission expansion in the Pacific Northwest region, raising feasibility challenges.

- Carbon capture on Washington's existing pulp and paper mills and biomass power plants could provide a significant supply of biogenic CO_2 feedstock. Global biogenic CO_2 supply constraints may challenge ultimate scalability unless direct air capture (DAC) becomes an economically feasible source of biogenic CO_2 supply.

- E-LNG requires very low leakage rates in upstream, midstream, and onboard combustion to achieve greater than 90% emissions reduction. Recent reports suggest current US leakage rates are often high enough to substantially reduce climate benefit.

Biofuels

Biofuel costs vary widely, depending on feedstock type, feedstock transport distance, and production process. Conventional biofuels (such as biodiesel) derived from FOG feedstocks (fats, oils, and grease, such as used cooking oil, soybean oil, and animal tallow) cannot scale to meet significant shares of global maritime demand because of limited global FOG feedstocks, and most conventional biofuels offer only partial emissions reductions. As a result, conventional biofuels such as biodiesel and other fuels made from FOG feedstocks are outside the scope of the present study, although it should be noted that biodiesel is being deployed today to achieve partial emissions reductions and will continue to play a part in the maritime fuel transition.

In contrast, non-lipid second-generation biofuels (such as bio-methanol and bio-LNG) derived from agricultural waste, forestry waste, and municipal waste can potentially offer increased scalability and emissions reductions.

- Sustainable and scalable biofuels are expected to be 1.5 to 4 times the cost of incumbent shipping fuel in 2030, depending on the cost of the biomass feedstock and the conversion process.

- Washington is rich in forestry, agricultural, and municipal waste feedstocks, but using these feedstocks to produce biofuels for shipping will require robust investment in new production technologies that are currently at early stages of commercial deployment, including gasification, fast pyrolysis, and hydrothermal liquefaction, as well as new infrastructure and logistical solutions for biomass collection and preprocessing.

- Commercial deployment of second-generation biofuels production facilities is very limited. A lucrative incentive ecosystem supporting conventional biofuels has limited appetite for investment in second-generation technologies, given the attractive business case and incentive landscape for more commercially mature technologies, as well as the lack of clear or widespread product differentiation between conventional and second-generation biofuels from the perspective of off-takers.

- Most existing federal and state policies funnel biofuels to road transport and aviation and exclude OGVs.
- Competition across end-use sectors for limited sustainable biomass will likely present challenges to scaling second-generation biofuel deployment in the shipping sector. Sectors such as aviation, plastics, and carbon sequestration will vie for significant shares of the sustainable biomass potential.
- Bio-LNG requires very low leakage rates in upstream, midstream, and onboard combustion to achieve more than 90% emissions reduction; recent reports suggest current US leakage rates are often high enough to substantially reduce climate benefit.

Policy Recommendations

This study examined the existing policy landscape affecting the shipping sector in Washington and sought to identify potential state policy levers that could effectively accelerate ZEF. From the perspective of state policymakers and regulators, having an impact on an international industry whose operations extend beyond state borders faces clear challenges and limitations. Still, we identified impactful policy mechanisms within state jurisdiction. The analysis focused on policies that can: incentivize ZEF deployment for OGVs (demand side) rather than solely fuel production (supply side); incentivize ZEFs that have potential to decarbonize a significant share of shipping energy demand, rather than fuels facing near-term feedstock constraints (e.g., fuels made from FOG feedstocks); creatively leverage a constrained state budget; and prioritize environmental justice in port transition. Given these criteria, three policy recommendations have been identified as high-impact objectives for Washington State to advance decarbonization of shipping fuel:

- Make it easier for ZEFs to generate credits in Washington's Clean Fuel Standard (CFS) by accelerating the timeline to Tier 1 pathway approval for ZEFs. Include a cap on the use of conventional and FOG-based biofuels for credit generation to prevent problematic lock-in of infrastructure and supply chains for fuels facing significant feedstock constraints.
- Implement a targeted incentive mechanism that helps close the final cost gap between fossil maritime fuels and ZEFs (regardless of where they are produced). This could take the form of a tax credit for fuel off-takers, a sales and use tax incentive, or a more targeted program such as a contract-for-difference mechanism for clean maritime fuel.
- Invest in port transition planning and implementation, especially improvements in the permitting and regulatory processes for new storage and bunkering infrastructure, and investments in workforce training and upskilling. These policies must encourage collaboration with state and federal permitting agencies while keeping port communities and maritime workers at the forefront. The state must also seek to take advantage of the numerous federal programs that help cover up-front costs of infrastructure and workforce investments.

Maritime Fuel Demand

Baseline Demand

Establishing a baseline for incumbent fuel demand is important when estimating the potential scale and growth of ZEF demand in the coming years and decades.

The maritime sector can be divided roughly into OGVs (large vessels such as container ships, bulk carriers, car carriers, and cruises) and harbor craft (generally smaller vessels limited to ports and coastal waters, including tugs, barges, ferries, fishing boats, and excursion vessels). The scope of this study is limited to OGVs, which are responsible for most of the maritime sector's energy demand. Current harbor craft demand in Washington is estimated at approximately 200,000 tons per year of diesel equivalent fuel.[2] OGVs rely on various liquid fossil fuels collectively referred to as bunker fuel, and average bunker fuel sales in Washington are approximately 1.75 million tons per year, or roughly 9 to 10 times harbor craft demand.[3]

OGVs and harbor craft also require different decarbonization solutions for many vessel types, depending on vessel type, meaning only a portion of harbor craft demand will likely adopt the ZEFs under consideration for OGVs. For instance, many harbor crafts will be capable of being electrified or using hydrogen directly in a fuel cell, whereas electrification and direct-hydrogen use are not practicable or feasible for OGVs' transoceanic voyages.

Early-adoption of ZEFs will be driven primarily by OGVs, as evidenced by the global OGV orderbook for vessels capable of running on potential ZEFs such as (e- or bio-) methanol and ammonia, compared with the very limited production of commercial harbor craft vessels using these fuels. Although development of a ZEF supply chain to serve OGVs might benefit some harbor craft vessel types, harbor craft are unlikely to be drivers of ZEF production or deployment and unlikely to constitute a large share of demand.

ZEF Demand

This study examines the potential for Washington ports to become ZEF bunkering hubs, physically storing ZEFs near ports and serving OGVs seeking to use these fuels. Although shipping decarbonization is expected to benefit from certification mechanisms, such as a book and claim system that allows emissions reductions achieved on one voyage to be certified and purchased by different cargo owners (thereby creating a broader marketplace for "green shipping"),[iv] ZEFs such as methanol and ammonia still must be physically stored at global ports and deployed in ships for the sector to decarbonize. In the early stages of ZEF deployment (around 2030), there likely will be competition among global ports for limited ZEF supply, making concerted planning and action on the part of ports and other local stakeholders essential for securing supply.

iv See the collaboration of RMI, the Maersk Mc-Kinney Møller Center for Zero Carbon Shipping, and Hapag-Lloyd on piloting a maritime book and claim system: "Maritime Book and Claim System Advances Pilot Study to Support First Movers in Zero-Emissions Shipping," April 16, 2024, **https://rmi.org/press-release/maritime-book-and-claim-system-advances-pilot-study-to-support-first-movers-in-zero-emissions-shipping/**.

The benefits of being a first-mover port include: ensuring continued global competitiveness of Washington ports, building up low-carbon fuel supply chains that can benefit other local industries and the region's economic development more broadly, and the potential for Washington ports to gain market share as shipowners and shipping's customers face increasing regulatory pressures. The fuel cost analysis in the following section includes estimated ZEF production costs in different global production regions, as well as estimated costs to transport ZEFs to the Ports of Seattle and Tacoma, in light of these ports' ambition to provide ZEF for green shipping corridors and other first movers.

Candidate Zero-Emissions Fuels

This study evaluates e-fuels derived from electrolytic hydrogen, and biofuels derived from sustainable biomass feedstocks.[v] Although there are many maritime fuels with the potential to offer partial emissions reductions, this study focuses solely on ZEFs capable of providing at least 90% reduction of greenhouse gas (GHG) emissions on a life-cycle emissions basis, relative to incumbent bunker fuel.[vi] This is not to dismiss fuels offering more partial emissions reductions, which are also playing a role in shipping's energy transition. Rather, this study seeks to highlight the importance of near-term investment in fuels and fuel supply chains that can offer near total decarbonization potential so that the shipping sector can meet the IMO target of net-zero shipping by 2050. These investments are already being seen among first-mover vessel operators and fuel producers. (See the *Commercial Readiness* section below)

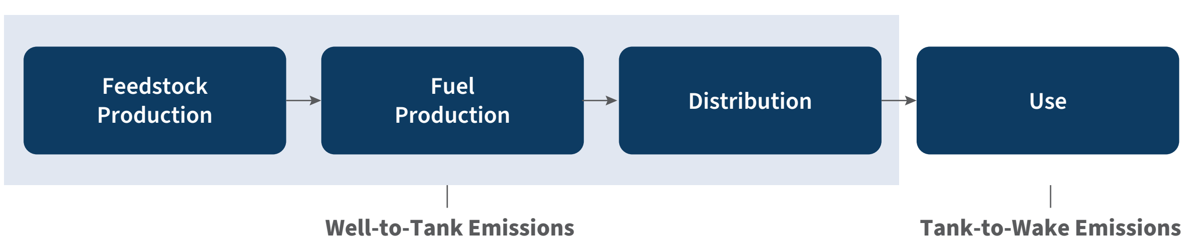
GHG emissions reduction potential should be assessed on a WtW basis (i.e., an entire life-cycle emissions basis). This includes upstream emissions from feedstock production and fuel production processes; midstream emissions from the transport, delivery, and storage of fuel; and downstream emissions from onboard fuel combustion or use in a fuel cell (see Exhibit 1).

The next section examines various potential zero-emission e-fuels and biofuels across the following metrics:

- **Emissions:** potential for GHG reduction measured on a WtW basis, and challenges to achieving the 90% ZEF threshold
- **Scalability:** feedstock requirements for and constraints on producing fuel at the scale of maritime demand
- **Cost:** production and transport costs, delivered costs to Washington ports, and cost drivers over time
- **Commercial readiness:** technological challenges to deployment of vessels, fuel production plants, and transport, storage, and bunkering infrastructure

Exhibit 1 Well-to-Wake Emissions

WELL-TO-WAKE EMISSIONS



RMI Graphic. Source: International Council on Clean Transportation

v Not considered in this report are direct use of hydrogen as a shipping fuel, as well as electrification using batteries, because both solutions have feasibility challenges stemming from low energy density, making them ill-suited to the long voyages of OGVs.

vi This report uses an incumbent fuel baseline GHG emissions intensity of 91.16 gCO_2/MJ, in alignment with FuelEU Maritime regulations.

E-Fuels

E-fuels are synthetic fuels whose principal feedstock is electrolytic hydrogen derived from renewable electricity. E-fuels such as e-methanol and e-LNG also require a biogenic CO_2 feedstock, meaning CO_2 released and captured during the chemical conversion of biomass (rather than CO_2 captured from the combustion of a fossil fuel). E-ammonia, in contrast, does not require any CO_2 feedstock.

This report examines e-methanol, e-ammonia, and e-LNG but focuses more closely on e-methanol and e-ammonia because of uncertainty around the extent of e-LNG's current and future WtW emissions reduction potential, as described in the emissions section below. E-methanol, e-ammonia, and e-LNG have all generated significant investments across the shipping value chain in the first half of this decade, including new vessels, fuel production projects, and infrastructure assets.

Emissions

WtW emissions of any e-fuel depend largely on the source of electricity used to make electrolytic hydrogen. Carbon-free electricity from renewables can result in e-fuels with more than 90% emissions reduction relative to VLSFO.

In the United States, the federal incentive for low-carbon hydrogen production (45V) requires that the renewable electricity used for electrolysis meet further criteria, often referred to as the "three pillars" of incrementality, deliverability, and temporal matching. The goal of requiring the three pillars is to ensure that production of renewable fuels remains compatible with the primary decarbonization strategy of widespread electrification of buildings and transport (in other words, that large increases in electricity demand for fuels production do not inadvertently inhibit the ability of electric utilities to meet other essential electricity demands with clean electricity). The requirements of the three pillars are:

- **Incrementality:** Clean electricity used for hydrogen production must come from a generation asset that began operating within three years of the hydrogen production facility's commercial operation date.
- **Deliverability:** Clean electricity used for hydrogen production must be generated at a plant in the same US Department of Energy (DOE) Grid Congestion Zone as the hydrogen production facility.
- **Temporal matching:** Clean electricity used for hydrogen production must be generated in the same hour in which it is used by the hydrogen production plant starting in 2028 (or in the same year before 2028).

In Washington, almost all electricity generated from existing hydroelectric generation does not meet the three-pillars criteria of incrementality.[vii] The EU regulatory regime also uses a version of the three-pillars methodology to evaluate the emissions intensity of hydrogen production.

The simplest path to three-pillars compliance is the construction of new renewable assets, co-located with and dedicated to the hydrogen production project (i.e., behind-the-meter renewables). When a hydrogen production project uses grid electricity for some or all of its electricity needs, compliance with the three pillars is expected to be achieved through the purchase of hourly energy attribute credits (EACs). Hourly-

vii Initial draft regulations released by the U.S. Department of the Treasury and the Internal Revenue Service have proposed that 5% of existing carbon-free electricity generation (including existing hydroelectric) be exempt for the incrementality pillar, and thus eligible for the 45V tax credit if the generation satisfies the temporal and geographic requirements. Five percent of annual hydroelectric generation in Washington is approximately 5–6 TWh, or enough electricity for 100,000 tons of hydrogen per year.

EACs track and certify the hour in which a unit of electricity is produced, as well as the location and vintage of the generation asset that produced it, enabling the creation of a marketplace for clean electricity on an hourly basis.

Whether e-fuels rely on hydrogen made with dedicated, behind-the-meter renewables, or on the procurement of hourly-EACs certifying the carbon intensity of grid electricity, they require new deployments of zero-carbon electricity generation to yield WtW emissions reduction potentials greater than 90% relative to incumbent bunker fuel.

Biogenic CO_2

In addition to these requirements concerning the carbon intensity of electrolytic hydrogen, near-zero-emissions e-methanol and e-LNG require a biogenic CO_2 feedstock. Using CO_2 captured from non-biogenic sources, such as power plants, cement plants, or refineries, will increase WtW emissions. E-fuels must also use biogenic CO_2 to comply with EU regulations, and likely with forthcoming IMO regulations. Major sources of biogenic CO_2 emissions in Washington are pulp and paper mills and biomass power plants. Using this CO_2 for local e-fuel production requires deploying carbon capture on these facilities and transporting the CO_2 to the site of e-fuel production. Direct Air Capture (DAC) is also a potential future source of biogenic CO_2 but was outside the scope of this study.

Methane Leakage

E-LNG faces additional challenges around measuring and mitigating methane leakage across the fuel supply chain as well as onboard methane slip (leakage into the atmosphere of uncombusted fuel).

LNG is methane (i.e., natural gas or fossil gas) that has been cooled and liquefied to achieve a higher volumetric energy density, allowing it to be more effectively stored, transported, and used as a shipping fuel. When methane is produced from electrolytic hydrogen, it is sometimes termed e-methane (or synthetic methane) and, when liquefied, e-LNG. Like fossil LNG, e-LNG requires very low rates of methane leakage across the supply chain, as well as very low levels of onboard methane slip to achieve significant emissions mitigation.

Recent studies conducted by the International Council on Clean Transportation conclude that onboard methane slip varies significantly across engine types and that one of the most popular engine types (a low-pressure injection, dual-fuel four-stroke engine, used in more than 300 LNG vessels operating today) has the highest rate of methane slip, at an average rate of about 6%.[4] This is approximately double the rates of methane slip assumed by the EU and IMO for LNG engines. At these rates of methane slip, the WtW reduction potential of e-LNG is estimated at approximately a 70% reduction relative to VLSFO on a 100-year timescale and only a 25% reduction on a 20-year timescale.[viii] (Notably, fossil LNG has no emissions benefits at these levels of methane slip and can actually increase emissions relative to VLSFO.[5])

viii Emissions are often measured using GWP100 (global warming potential on a 100-year timescale) and GWP20 (global warming potential on a 20-year timescale). Methane has a shorter atmospheric life span than CO_2 but a more powerful warming impact during that lifetime, yielding a higher GWP20. Thus, GWP20 reflects the powerful near-term climate impacts of methane slip on a 20-year time horizon.

E-methane produced from electrolytic hydrogen is chemically identical to fossil methane and would use existing natural gas pipeline infrastructure and liquefaction facilities, both of which result in some level of leakage. Recent studies based on novel satellite imaging techniques indicate that average US methane leakage rates are roughly three times previous industry and government estimates, with midstream leakage accounting for 18% to 57% of leakage, depending on the regions analyzed.[6] Thus, quantifying the true emissions reduction potential of e-LNG is dependent upon advances in monitoring, reporting, and verification (MRV) of methane leakage across the supply chain, and of methane slip onboard vessels. If current levels of methane leakage and onboard methane slip are not significantly reduced and quantified through robust MRV, e-LNG will not achieve the GHG-emissions reduction required to qualify as a ZEF. (The same is true of bio-LNG, as discussed in the subsequent “Biofuels” section.)

Scalability

The primary constraints on the scalability of electrolytic hydrogen production are related to the pace with which clean electricity generation capacity can be deployed. But the availability of the primary resources (land on which to site renewables, and water for electrolysis) is not expected to constrain potential production. (This contrasts with sustainable biomass feedstocks required for biofuel production, which do face binding constraints on potential feedstock supply relative to global demand.)

Challenges around the pace and scale of renewable electricity deployment are significant in Washington, compared with other potential global production locations. The pace of renewable deployment in Washington must rise significantly to meet the increased electricity demand required to decarbonize sectors such as transportation and buildings, even before e-fuel production is considered.

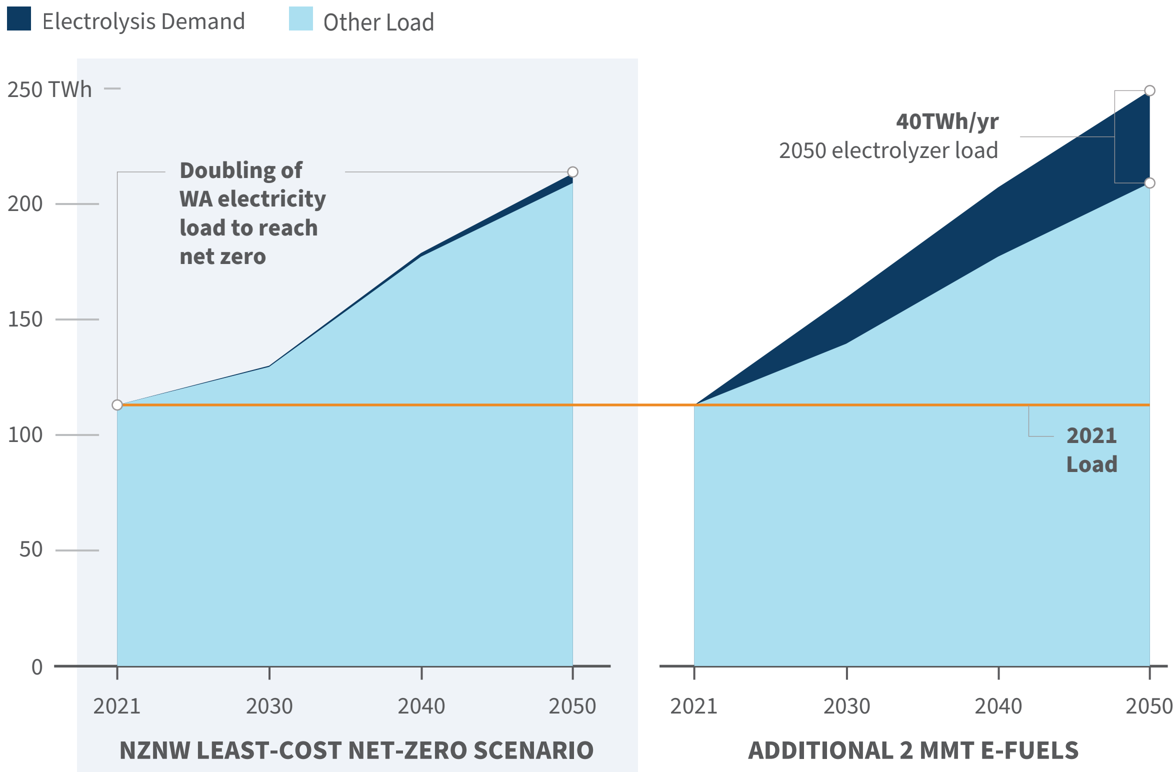
Energy system modeling conducted for the study *Net Zero Northwest: Technical and Economic Pathways to 2050* found that the least-cost decarbonization pathway for the region will nearly double Washington’s current electricity load by 2050 (from 113 terawatt-hours [TWh] per year to 213 TWh per year), mostly because of the needs of electrified road transport and buildings.[7] In the NZNW study’s least-cost scenario, electrolytic hydrogen production accounts for less than 2% of Washington’s electricity demand in 2050, and less than 90,000 tons of electrolytic hydrogen is produced in-state by 2050. In this scenario, most hydrogen and e-fuels are imported from high-wind regions outside of Washington, such as Montana.

To meet a large share of Washington’s hydrogen and e-fuel demand with local production would require even greater electricity load growth and the deployment of significantly more low-carbon electricity capacity at a more rapid pace. To illustrate this challenge, satisfying approximately 2 million tons of annual maritime fuel demand with e-fuel production in Washington would require an estimated additional 40 TWh per year of electricity — 35% of Washington’s current annual electricity demand, and a nearly 20% load increase above NZNW’s least-cost scenario (see Exhibit 2, next page). This does not account for fuel demand in other sectors with even greater demand, such as aviation.

The NZNW study also models a “local clean fuels” scenario in which all hydrogen and e-fuel demand must be produced in the state where it is used. This scenario requires more than 170 TWh solely for Washington’s electrolytic hydrogen production and a total annual electricity demand of 365 TWh — more than three times the state’s current demand — which the study authors note is “unlikely to be a feasible pathway for Washington.”[8]

Scalability of e-methanol and e-LNG also depends on availability of biogenic CO_2 supply. The primary sources of existing biogenic CO_2 potential in Washington State are pulp and paper mills and biomass power

Exhibit 2 Impact of In-State E-Fuel Production on Electricity Load Growth Over Time



RMI Graphic. Source: *Net Zero Northwest Technical and Eeconomic Pathways to 2050* and RMI analysis

plants, where CO_2 emissions from biomass combustion can be captured. These sources emit approximately 5.5 million tons of biogenic CO_2 per year, enough for about 4 million tons of e-methanol production. This quantity of e-fuels is sufficient to satisfy all of Washington's bunker fuel demand. However, shipping will also face competition from other sectors for biogenic CO_2 supply.

Access to Washington's biogenic CO_2 feedstocks requires the deployment of carbon capture infrastructure on existing pulp and paper mills and biomass power plants. It will also require infrastructure to transport CO_2 to the e-fuel production location. Eventually, DAC may offer a biogenic CO_2 source that is infinitely scalable; however, the cost per ton of CO_2 from DAC is currently an order of magnitude greater than the sources described above, and DAC was not included in the scope of this study.

Cost: Washington Production

The production costs of e-fuels are highly dependent on the cost of electrolyzers, the cost of carbon-free electricity needed to operate the electrolyzers, and the electrolyzer utilization rate (or load factor) that can be achieved with that electricity. Increasing the capacity at which electrolyzers operate throughout the year (i.e., load factor) can lower hydrogen costs by increasing hydrogen yield achieved from the same piece of equipment. However, increasing the load factor inevitably increases the average cost of electricity needed to operate the electrolyzer because doing so requires deploying more dedicated renewable assets, more storage, or procuring more hourly-EACs in hours when they are increasingly scarce and costly. Even grid-connected projects are not likely to operate at 100% load factor (that is, at maximum capacity 24 hours per day, seven days per week) because it is unlikely that 45V-qualifying electricity and the associated EACs will be available every hour of the year.

RMI conducted cost modeling for this study using a linear optimization model to determine least-cost project configurations for a given region, based on location-specific hourly wind and solar production profiles. For a more detailed explanation of modeling methodologies and cost assumptions, see the *Technical Appendix*.

The IRA's hydrogen production tax credit (45V), which lasts through 2032, has made the United States one of the lowest-cost production countries in the world. The analysis finds that the delivered cost of e-fuels produced in high-wind regions such as the US Wind Belt in 2030 and delivered to the Port of Seattle or Tacoma is approximately 2.5 times the cost of incumbent VLSFO, while the delivered cost of e-fuels produced locally in Washington is approximately 3.5 to 4 times the cost of VLSFO.

As discussed in the *Emissions* section above, the zero-carbon electricity needed for electrolytic hydrogen production can be supplied either through dedicated renewables co-located with electrolyzers (behind the meter) or through grid electricity and EAC procurement. Techno-economic analysis, industry feedback, and announced projects to date indicate that grid-connected production in Washington is more economic than behind-the-meter production in Washington. Average industrial electricity rates in Washington are between $45/megawatt-hour (MWh) and $65/MWh, depending on the utility district, while the average national rate is approximately $83/MWh.[9]

The digital infrastructure, marketplace, and operational framework needed to implement hourly-EACs are being developed by private and public entities. In the absence of a developed EAC marketplace with price visibility, the cost of EAC procurement must be estimated. The estimate is based on historic market dynamics for existing renewable energy certificates, projections of available hourly-EAC supply in the Pacific Northwest, projections of renewable capacity additions in the region, and projections of EAC demand in the region from hydrogen producers and other corporate buyers.

Renewables developers with large asset portfolios are well positioned to offer long-term contracts for hourly-EACs aggregated from generation assets across their generation portfolios, which can provide the long-term de-risking necessary for hydrogen production projects in the absence of a developed spot market. This is the approach modeled for grid-connected projects in Washington.

Based on this methodology, the levelized cost of hydrogen production in 2030 in Washington is estimated at approximately $4.25/kg, including the application of the 45V tax credit. This figure is based on an estimated average all-in electricity cost of $70/MWh for grid electricity and EACs, enabling an estimated electrolyzer utilization rate of 70%. This yields a delivered e-methanol cost of approximately $1,250/ton and a delivered e-ammonia cost of approximately $1,150/ton. When compared with the cost of incumbent fuel oil on an energy-equivalent basis,[ix] e-fuels produced in Washington are projected to be approximately 3.5 to 4 times the cost of the fossil incumbent in 2030.[x]

ix Different fuels store different amounts of energy in a given volume because of their chemical properties. In this analysis, we compare different fuel prices by energy content, not volume, to ensure an apples-to-apples comparison. For example, 1 ton of VLSFO contains the same energy as 2.06 tons of methanol or 2.2 tons of ammonia.

x This assumes the fossil incumbent is VLSFO, at a cost of $680/ton at the Port of Seattle, based on a three-year rolling average. Marine gas oil three-year rolling average is approximately $760/ton.

Cost: Out-of-State and Global Production

The market for ZEF is a global one, with first-mover global shipping companies purchasing ZEF today where it is available at a competitive price. ZEF does not necessarily need to be produced close to its deployment. Our analysis shows that achieving the lowest production cost is most important for achieving the lowest delivered cost and that high transport costs can be offset by the significantly lower costs achievable in high-wind and solar regions. Ultimately, vessel owners and bunkering companies procuring ZEFs will deploy these fuels where they make the most sense from an economic and operational perspective, which can be influenced by first-mover efforts such as green corridors and port readiness to bunker specific fuel types.

These findings build on recent studies of the Pacific Northwest's decarbonization pathways — including the Washington State Department of Commerce's recent *Green Electrolytic Hydrogen and Renewable Fuels* report, which indicates that satisfying much of Washington's hydrogen demand with imports from states with better wind resources, such as Montana, will be significantly cheaper than relying entirely on in-state production.[10] Because the market for shipping fuel is a global one, the geographic boundary for comparing e-fuel production costs can likewise be global.

To gain more insights into the share of transport costs in final delivered cost, this analysis models e-fuel production and transport to the Ports of Seattle and Tacoma from two locations with exceptional wind resources — the US Wind Belt (modeled here in North Dakota, with a wind capacity factor of 43%); and Magallanes, Chile, with a wind capacity factor of 61%. The analysis models behind-the-meter hydrogen production in each location (i.e., no grid connection) because the high-wind capacity factors in each region, coupled with solar, allow electrolyzers to reach high utilization without relying on grid electricity. Both regions are the sites of announced e-methanol production projects.

The North Dakota scenario assumes delivery via rail and truck, much the way ethanol is delivered to the West Coast today from Midwest production locations. The Midwest also has a large potential supply of biogenic CO_2 from ethanol facilities, and carbon capture on ethanol facilities is expected to be one of the cheapest sources of biogenic CO_2.

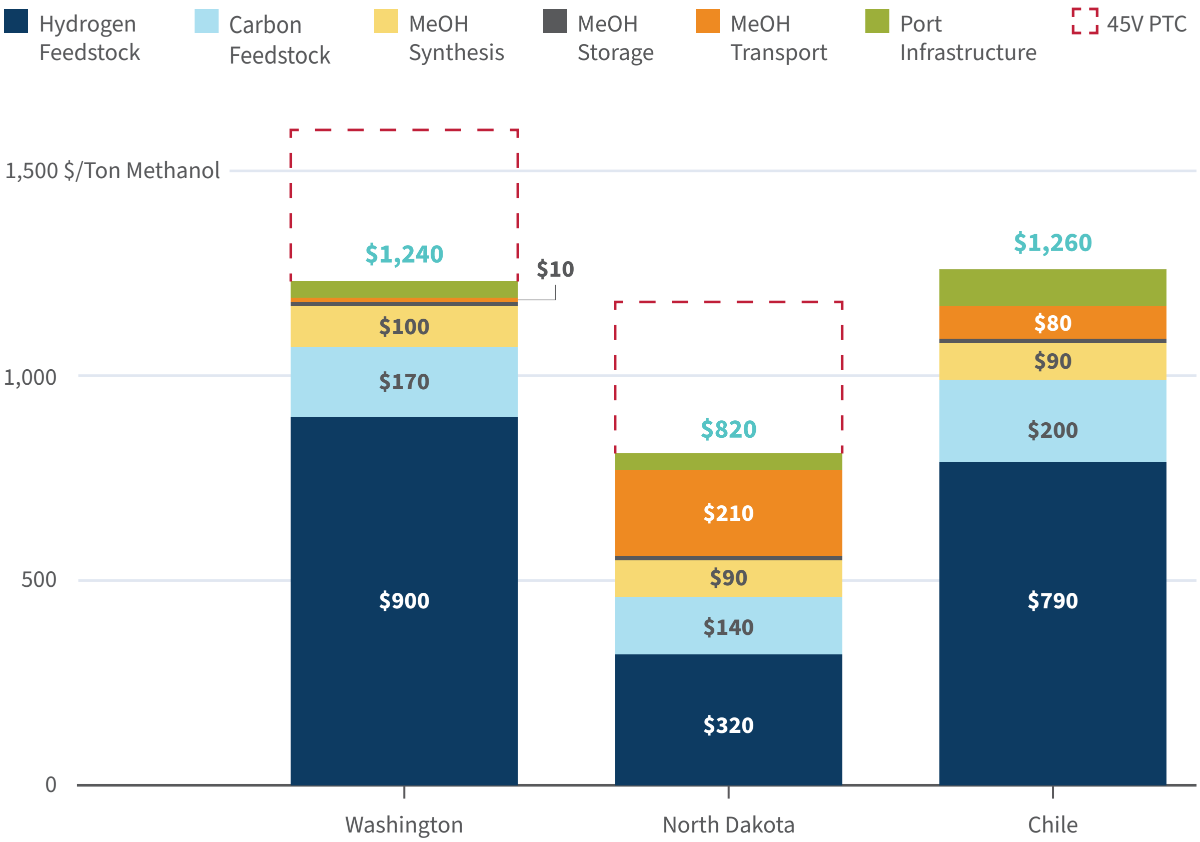
The Chile scenario assumes transport via very large methanol or ammonia tanker, providing high-level comparison of land versus maritime transport costs, as well as comparison between production locations with and without the 45V tax credit.

2030 Cost Results

The analysis indicates that in 2030 the least-cost production location analyzed is the US Wind Belt (North Dakota), which achieves a hydrogen production cost of approximately $2.20/kg (compared with Chile's $4.20/kg) after the hydrogen production tax credit (45V) and the clean electricity production tax credit (45Y). E-methanol production cost is modeled at approximately $560/ton, and the delivered cost of e-methanol to the Port of Seattle is approximately $820/ton, or about 2.5 times the cost of VLSFO on an energy-equivalent basis.

The North Dakota scenario also has the highest transport costs, as transport via rail and truck over long distances is more expensive than transport via tanker. Despite transport costs roughly 20 times higher in the North Dakota scenario than in the Washington scenario, North Dakota's low production cost more than offsets increased transport costs. Delivered cost in the Washington scenario is over 50% higher than delivered cost in the North Dakota scenario in 2030.

Exhibit 3 2030 Delivered Cost of E-Methanol to the Port of Seattle



RMI Graphic. Source: RMI analysis

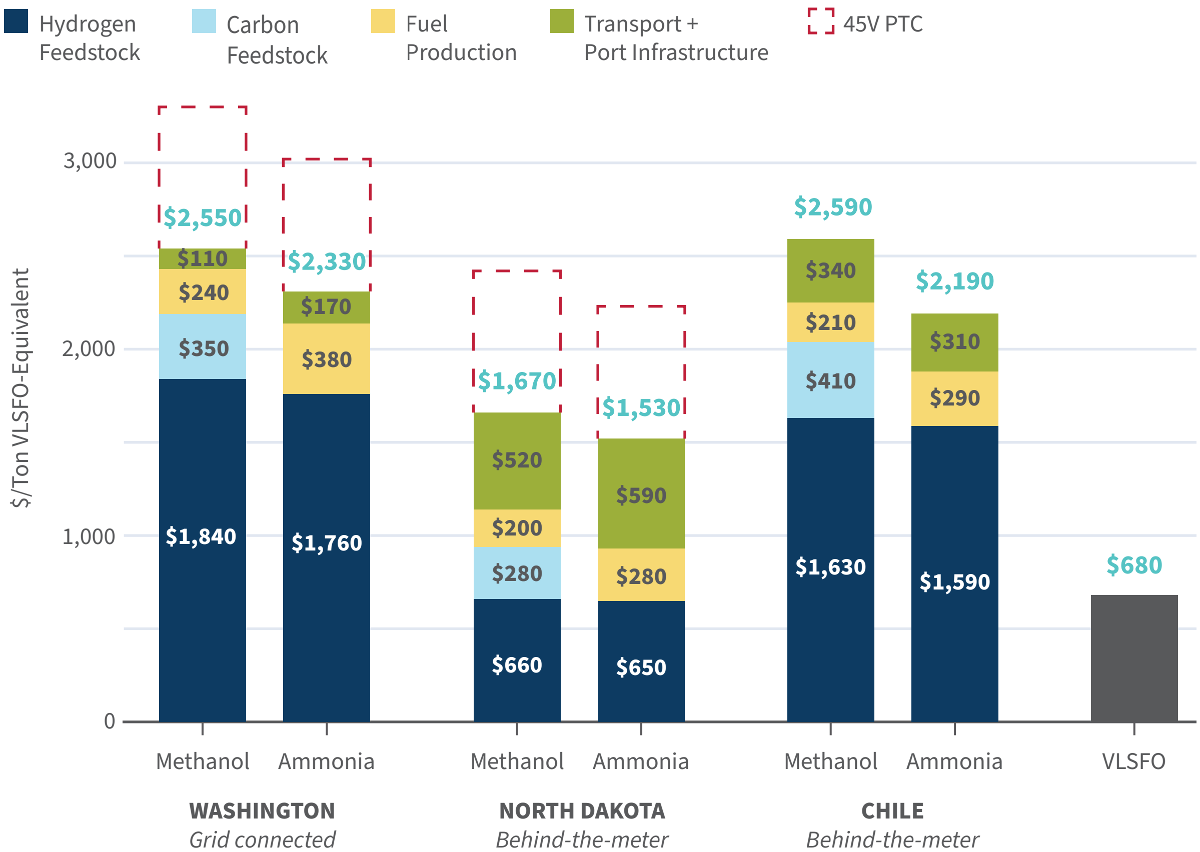
Chile does not benefit from the US subsidy on hydrogen production or renewable energy production; Chile's unsubsidized hydrogen production cost is slightly lower than Washington's subsidized production cost. The additional cost of transport (both of the final fuel to the Pacific Northwest and of the CO_2 feedstock to a remote production site) drives delivered cost higher than that of Washington's local production.

Comparing transport costs in the North Dakota and Chile scenarios, it is notable that transport from the southern tip of Chile is about one-third the cost of transport from the Midwest, despite being more than six times the distance. This demonstrates the extent of the cost savings achievable from moving e-fuels by tanker compared with rail or truck. The cost of moving ammonia by truck is about six times the cost of moving methanol by truck, but ammonia truck transport still makes up a very small share of total delivered cost in the Washington case, as the transport distance assumed is only 50 miles (based on the distance between Centralia and the Port of Tacoma). Rail transport and tanker transport costs do not vary significantly between ammonia and methanol. For both fuels, pipeline transport has the potential to achieve even lower transport costs on a $/ton basis if high throughput is achieved (spreading the large capital investment over a large quantity of fuel), but pipeline transport was not modeled for this study.[xi]

xi Emissions associated with transport of e-fuels to Washington were not quantified for this study; these emissions are expected to be small compared to WtW emissions of incumbent fuels, but are an important consideration in future life-cycle emissions accounting.

Exhibit 4 shows the delivered costs of e-methanol and e-ammonia in 2030 on an energy-equivalent basis with VLSFO to allow for an apples-to-apples comparison across fuel types.[xii]

Exhibit 4 2030 Cost of Delivered E-Fuel by Region



RMI Graphic. Source: RMI analysis

Long-Term Cost Trends

The analysis also examines expected production costs of new production projects in 2040, after the expiration of the 45V tax credits (see Exhibit 5, next page). Scenarios for 2040 also reflect anticipated cost declines for electrolyzers and renewables. The result is that, although unsubsidized production costs fall by about 15%, delivered costs still rise meaningfully due to the expiration of the tax credit.

The US Wind Belt remains the least-cost scenario, with a production cost over 40% lower than Washington's and a delivered cost more than 25% lower. The expiration of the tax credit also makes distant high-wind locations such as Chile significantly more cost-competitive than Washington.

xii Assumes energy gravimetric density of VLSFO is 2.05 times methanol and 2.16 times ammonia.

Exhibit 5 Cost of Delivered E-Methanol by Region: 2030, 2040

RMI Graphic. Source: RMI analysis

It is important to note that 2040 production cost projections are not necessarily reflective of the fuel price to off-takers. Production projects are modeled as 30-year assets, with the 45V tax credit levelized over the lifetime of the project to yield a steady production cost. Thus, a project beginning operation in 2030 that achieves the 2030 production cost can produce hydrogen at that levelized cost for the lifetime of the plant. The 45V tax credit expires in 2032. Any qualifying hydrogen production facility that begins construction before 2032 is eligible to receive the $3/kg tax credit for the first 10 years of its operations. The most likely outcome is a surge in the project pipeline at the beginning of the decade, with many projects beginning construction between 2030 and 2032, when costs are lowest, and commencing commercial operation in the first half of the decade. The complex supply and demand fluctuations emerging from this environment will influence the price paid by off-takers of e-fuels in 2040. For this reason, the 2040 scenarios modeled in Exhibit 5 can provide insights into the impacts of technology cost declines and 45V expiration on the levelized production cost for new e-fuel production projects in 2040 but are not necessarily indicative of a customer-facing fuel price because we expect supply and demand to increase, which makes price predictions uncertain.

Commercial Readiness

E-methanol has a higher technological readiness than e-ammonia, but large-scale fuel production projects for both fuels have been announced globally, and vessels capable of running on e-methanol have already hit the water and are calling at the Port of Seattle.

As of June 2024, DNV reports 33 methanol dual-fuel vessels in operation and over 240 on the global order book to be delivered between now and 2028, the majority being container ships.[11] Dual-fuel methanol ships have two separate fuel tanks, one for incumbent bunker fuel and one for methanol, allowing them to use either fuel and to switch almost instantly between fuel types. This design enables vessel owners to invest in new zero-emission assets without having to rely purely on zero-emission fuel to operate them. Methanol vessel availability is not expected to be a barrier to accelerating green shipping, given that fuel demand from methanol vessels already on the orderbook for delivery this decade will likely outstrip 2030 supply projections.

Ammonia vessels and ammonia engines are less commercially advanced. The world's first ammonia-fueled vessel (*Fortescue Green Pioneer*) completed its first ammonia fuel trial in Singapore in March 2023.[12] DNV reports 19 other dual-fuel ammonia vessels on the orderbook through 2027, most of which are bulk carriers and tankers. Given the much smaller number of vessels on order compared with methanol and the fact that ammonia is expected to be produced in significant quantities as a means of transporting low-carbon hydrogen to regions seeking clean energy imports (e.g., EU and East Asia), ammonia vessels should not see the same degree of competition for global fuel supply as methanol vessels.

Methanol and ammonia have each been shipped as cargo in tankers for many decades, and the infrastructure for storing the chemicals safely near ports is mature and well established. Many ammonia and methanol terminals in the United States are situated along the Gulf Coast, where there is high demand from the chemicals industry. On the Pacific Coast, the sole methanol terminal is in Vancouver, Canada. With minimal adjustments, conventional methanol terminals could potentially serve as reload hubs for methanol bunker vessels or barges. However, the suitability of these terminals for directly bunkering methanol-fueled ships must be assessed individually. Ammonia terminals are located at the Ports of Stockton, California, and Portland, Oregon, where they receive imports of anhydrous ammonia for use in fertilizer production. The practicality of using these inland ammonia terminals for direct bunkering of ammonia-fueled ships is limited, compared with coastal ports.

Although moving methanol and ammonia as cargo is well established, combusting them as fuel onboard vessels raises novel safety and technological considerations. The higher toxicity of ammonia compared with methanol or existing fossil bunker fuels requires increased attention to risk mitigation and safety protocols to ensure workforce safety. Many feasibility and hazard identification studies have been conducted to pave the way for safe ammonia bunkering, most notably at the Port of Singapore.[13]

E-methanol has a higher technological readiness than e-ammonia, but large-scale fuel production projects for both fuels have been announced globally, and vessels capable of running on e-methanol have already hit the water and are calling at the Port of Seattle.

Biofuels

Biofuel is an umbrella term encompassing a wide variety of fuels and production processes derived from a biomass feedstock. The most common biofuel used in OGVs today is FAME (fatty acid methyl ester) biodiesel, most of which is blended in some ratio with conventional fuel oil. However, small quantities of pure biodiesel (B100) are used as well. Feedstocks for conventional biofuels (most notably FOGs) are very limited relative to the scale of maritime fuel demand. As a result, conventional biofuels such as biodiesel or B100 were excluded from the scope of the present study.

This study examines bio-methanol and bio-LNG made from more scalable second-generation waste feedstocks such as forestry residues, agricultural resides, and municipal wastes. Deployments of these fuels are limited to pilots and first-mover efforts, but the fuels are commercially available in limited quantities.

Emissions

The WtW emissions of a given biofuel — whether bio-methanol, bio-LNG, or some other biofuel — depend on many factors, including type of biomass feedstock, feedstock cultivation practices used, feedstock collection and transport method, and the fuel production process and associated energy use. Quantifying a specific feedstock's contribution to a fuel's carbon intensity involves a complex life-cycle analysis, considering changes in land use triggered by increased feedstock cultivation (e.g., indirect land-use change). Biodiesel produced from soybean oil in one region, for example, and from canola oil in another region, can yield radically different WtW emissions. However, feedstocks derived from wastes — whether agricultural waste, forestry waste, or municipal waste — are generally required to achieve greater than 90% WtW emissions reductions, whereas seed oils can generally only offer partial emissions reductions.

Bio-LNG faces the same challenges as e-LNG in terms of quantifying and mitigating emissions from methane leakage and onboard methane slip. (See the e-fuels *Emissions* section above.) Current levels of on-board methane slip and methane leakage during midstream transport and liquefaction have the potential to significantly reduce climate benefits and prevent bio-LNG from achieving the 90% reduction threshold. In the case of bio-LNG derived from anaerobic digestion, leakage due to poor design and management of feedstock and digestate storage units has historically been underestimated and can be a significant contributor to overall emissions.[14]

Scalability

Incumbent, or conventional, biofuels such as B100 are typically made from FOG feedstocks. However, most of these feedstocks are already being used for road transport and aviation fuel (e.g., HEFA jet fuel),[xiii] and conventional biofuels cannot reach the scale of ultimate maritime demand. Shifting these feedstocks away from road transport could increase the amount of B100 available to the shipping sector, but biodiesel is still not expected to offer a viable path to full decarbonization of shipping.

Second-generation biofuels produced from forestry waste, agricultural waste, and municipal wastes can potentially meet much larger shares of maritime demand. However, many end-use sectors will be

xiii HEFA, or hydrotreated esters and fatty acids, are vegetable oils, waste oils, or fats refined into sustainable aviation fuel (SAF) through a process that uses hydrogen (hydrogenation).

competing for limited quantities of sustainable biomass, and there is unlikely to be enough sustainable potential to meet all demand.[15] Demand sectors include existing materials uses (e.g., timber, and pulp and paper mills) as well as new uses for which there are limited decarbonization alternatives, such as plastics feedstocks and jet fuel.

Sustainable biomass can also be a low-cost source of carbon removal, through methods such as direct biomass storage (e.g., burial), or pyrolysis and storage (e.g., biochar burial). This raises the potential for carbon removal regimes to compete directly with liquid fuels for biomass feedstocks; a future carbon tax could potentially make sustainable biomass more lucrative to sequester than to convert into liquid fuels. This fundamental competition, and the potentially superior climate benefits of biochar sequestration, are acknowledged by recent reports on Washington biomass potential from Washington State University and the Pacific Northwest National Laboratory.[16] Regardless of the role of biomass in carbon removal, competition across end uses will eventually create a supply-constrained landscape that will likely drive up the cost of biomass feedstocks as the energy transition progresses.

The technical potential of sustainable biomass in Washington State is estimated at roughly 70 million to 95 million tons per year, including municipal wastes, agricultural residues (mostly wheat straw), forestry residues, and plantation forestry.[17] The share of the technical potential that can economically be used for biofuel production ultimately depends on the market price of the specific biomass feedstock, including the cost of collection and preprocessing. The market price varies significantly across different types of feedstocks and is strongly influenced by the level of competition for the feedstock. Biomass collection and preprocessing become more costly the more geographically dispersed the biomass feedstock and the farther the feedstock from the biorefinery site. Recent analyses estimate the current economic potential of sustainable biomass in Washington at 20 million tons per year, with a threshold of roughly $35 per dry ton of biomass.[18] This is insufficient to decarbonize all of Washington's current shipping and aviation demand, which is estimated to require 30 million to 50 million tons of biomass.[xiv]

As the market for ZEFs matures, and the willingness of vessel owners and cargo owners to pay higher prices for ZEFs becomes better established, the economically feasible threshold for biomass feedstock will rise. However, market prices may also rise because of increased competition for feedstocks in an environment of increasing regulatory pressure to decarbonize.

Commercial deployment of biofuel production projects using second-generation feedstocks is nascent. The US government established policies to stimulate second-generation biofuel production in 2007, but investment and production volumes have not reached modest program targets.[19] Scaling second-generation biofuel production from Washington's sustainable biomass feedstocks requires robust investment in new production technologies at early stages of commercial deployment, including Fischer-Tropsch gasification, fast pyrolysis, and hydrothermal liquefaction, as well as infrastructure and operations for biomass collection and preprocessing.

A forthcoming study from NREL and the US Department of Transportation Volpe Center examines potential maritime biofuel production in Washington, including detailed cost modeling of methanol synthesis of woody biomass feedstocks, Fischer-Tropsch gasification of woody biomass feedstocks, and hydrothermal

xiv The shipping estimate assumes conversion efficiency of approximately 40% to 60% yield of bio-methanol per ton of dry lignocellulosic biomass, via gasification + methanol synthesis. The aviation estimate assumes approximately 20% total biofuel yield per ton of dry lignocellulosic biomass via gasification + Fischer Tropsch, with the resulting biofuel product slate being approximately 60% to 70% SAF. Biomass required will vary depending on many factors, including biomass feedstock type, biomass conversion process, and product slate optimization.

liquefaction of sludge (municipal wet waste), and delivery to the Port of Seattle. Further study of the ability of locally produced ZEFs made from waste feedstocks to compete with global least-cost ZEFs is recommended.

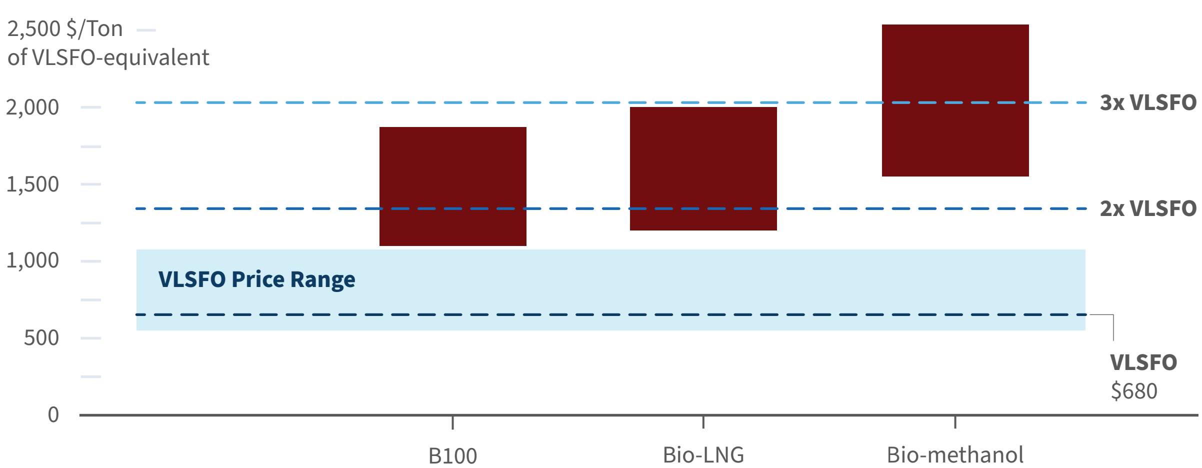
Ultimately, industry players investing in such biomass conversion technologies will target production of the fuels that are most incentivized by policy landscapes domestically and internationally, and by market dynamics in each sector that yield a willingness to pay for a premium, low-carbon product. Today, various federal and state policies in the United States and around the world incentivize the production of tens of millions of tons of biofuels for road transport. Whether the planet's limited quantities of sustainable biomass feedstock are used to create shipping fuel depends on the strength of policy and market drivers in the shipping sector relative to other sectors such as aviation, plastics, carbon removal, and road transport.

Cost

Biofuel cost projections are based on techno-economic analyses and recently published studies of second-generation biofuel production pathways, as well as feedback and input from industry stakeholders and fuel producers.

Although the e-fuel analyses include cost projections to 2050 based on projected learning curves and cost declines for electrolyzers and renewables, this approach is less suited to biofuel production. The ability to predict biofuel production costs over a long time horizon is limited by many factors, including the wide spectrum of potential production technologies and plant configurations, the nature of biofuel production plants being less "modular" and "repeatable" than electrolyzer manufacturing, uncertainty around the pace and extent to which competition for feedstocks will drive up feedstock prices, and uncertainty around the timeline of first-mover investments in production assets without the near-term forcing function of the IRA tax credits.

Exhibit 6 **Current Global Production Cost Ranges for 3 Biofuels**



Note: VLSFO price represents global 3-year rolling average, sourced from Ship & Bunker;
B100 price represents US Retail 3-year rolling average, sourced from EIA;
Bio-LNG and Bio-methanol prices sourced from literature review and industry surveys.

RMI Graphic. Source: RMI analysis

In 2030, bio-methanol and bio-LNG are expected to be between two and four times the cost of incumbent VLSFO (on an energy-equivalent basis). Major cost drivers include feedstock cost, feedstock transport distance, and facility scale and capital expenditures requirements. More bio-LNG is generally expected to be available, and at a lower cost, than bio-methanol this decade, largely because of bio-LNG's ability to share existing LNG infrastructure, including natural gas pipelines, liquefaction facilities, portside LNG storage, and LNG bunkering vessels. Bio-methane is produced globally in greater quantities today than bio-methanol. Landfill gas and biogas from anaerobic digesters are two of the most common sources today of bio-methane, much of which is combusted for on-site power generation or directed toward renewable natural gas (RNG) production. With appropriate policies or market signals, these production facilities could be used to produce bio-LNG for shipping.

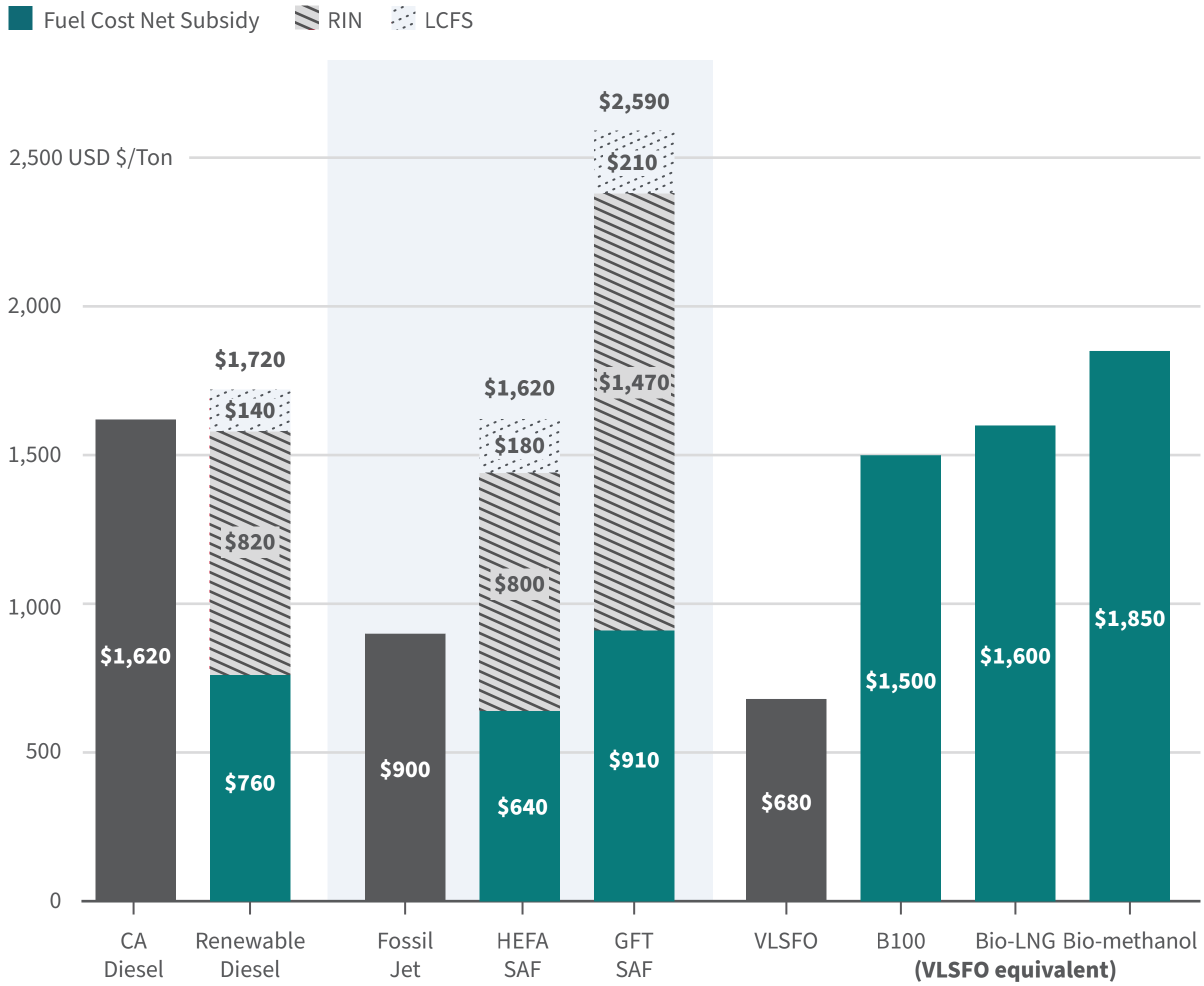
However, greater supply and lower costs in the near term do not necessarily indicate greater supply and lower costs in the medium to long term, as indicated by recent studies.[20] We expect bio-methanol costs to fall below bio-LNG costs because of several factors:

- Liquefaction of bio-methane to yield bio-LNG adds cost and energy to the production process, which is not required for bio-methanol.
- Bio-LNG is more expensive than bio-methanol to store and transport.
- As distances between feedstock and natural gas pipelines increase, bio-LNG cost will increase, further constraining supply relative to demand.
- The potential for methane leakage to affect WtW emissions introduces increased risk associated with regulatory compliance.

Like e-fuels, the cost of biofuels is heavily influenced by federal, state, and international policies. In the US context, the production costs of conventional biofuels have been heavily subsidized by the federal Renewable Fuel Standard (RFS) and state clean fuel standards (such as the California Low Carbon Fuel Standard [LCFS] and, more recently, the CFS in Washington) for many years. The impact of these subsidies today is that renewable diesel and HEFA jet fuel (both made from FOGs) can reach production costs lower than the price of the fossil incumbent (see Exhibit 7). Maritime fuel for OGVs is currently excluded from both the RFS and the LCFS; the Washington CFS allows marine fuels to opt in to generate CFS credits, but only LNG currently has a defined credit-generating pathway.

> **Many sectors will be competing for limited quantities of sustainable biomass, and there is unlikely to be enough sustainable potential to meet all demand. Demand sectors include existing materials uses, aviation, plastics feedstocks, and biomass-based carbon removal.**

Exhibit 7 Impact of RFS and LCFS Subsidies on Biofuel Production Costs



RMI Graphic. Source: RMI analysis

This environment has led to rapid expansion of production infrastructure for renewable diesel and HEFA. Although a larger incentive exists under the RFS for cellulosic biofuels (or, roughly, second-generation biofuels) than for conventional biofuels, this has been insufficient to stimulate the desired investment in the less commercially mature production infrastructure.

Although making shipping fuels eligible for the RFS and state clean fuel standards could lower their cost and increase biofuel deployment in shipping, the current policy incentive environment might do little to stimulate investment in more scalable second-generation biofuels, given the lower risk profile and generous margins available for conventional biofuels. For this reason, we recommend integrating maritime fuels into the CFS with a cap on the number of credits that can be generated from conventional biofuels using FOG feedstocks (see *Policy Recommendations*).

Commercial Readiness

Conventional FAME biodiesel production is commercially mature, with millions of tons produced in the United States annually, most of it used in road transport. Use of pure FAME biodiesel (B100) as a maritime fuel is less commercially advanced, but B100 is increasingly available at select ports.

Commercial deployments of second-generation biofuel production projects have mostly been limited to pilot and demonstration scale projects, with some of the first commercial-scale gasification and fast pyrolysis projects beginning operation between 2023 and 2025. A.P. Møller-Maersk reports partnerships with at least six global bio-methanol producers in China and the Americas. Most of these producers have commercial production targets beginning in 2025 or 2026.

Bio-methane production from anaerobic digestion is commercially mature, but much of current production is small-scale, disaggregated, and used for on-site power or road fuels. Making this source of bio-methane commercially available to the shipping sector in the form of bio-LNG requires more large-scale and concentrated operations. Producing more sustainable and scalable second-generation biofuels in Washington will necessitate robust investment in more large-scale facilities regardless of technology type, as well as new feedstock aggregation and preprocessing facilities.

Because bio-methanol and e-methanol are chemically identical, the commercial readiness of dual-fuel methanol vessels and methanol infrastructure at ports is the same for e-methanol and bio-methanol.

Similarly, bio-LNG is chemically identical to fossil LNG, and bio-LNG can be used in existing LNG vessels and infrastructure. LNG vessels and LNG infrastructure are commercially mature, having benefited from the explosive growth of the global LNG trade over the past two decades. Today, there are more than 500 LNG vessels in operation globally, and more than 500 on the global orderbook for delivery by 2028.[21]

In Washington, there is one LNG facility, at the Port of Tacoma, operated by Puget Sound Energy. The LNG facility holds approximately 14,000 tons of LNG (or 8 million gallons), 75% of which is dedicated solely to long-term seasonal storage for Puget Sound Energy's utility customers (i.e., residential and commercial users of natural gas). The remaining storage is available for maritime fuel, and the facility currently supplies about 1,500 tons per week, or 75,000 tons per year, of LNG to two roll-on/roll-off LNG vessels owned and operated by TOTE Maritime Alaska. The remaining LNG capacity is enough to supply between one and four OGVs per month. Additionally, three LNG bunker vessels are operating in waterways around the Ports of Vancouver and Victoria.

Although the commercial readiness of the liquefaction, transport, and storage infrastructure for LNG is relatively mature, using these assets for low-carbon bio-LNG will require the use of comprehensive certification mechanisms. Registries and certification systems with robust chain-of-custody protocols must enable bio-LNG and fossil LNG to be blended in the same pipeline or storage tank without their environmental attributes being double-counted by multiple parties — an issue that has had an impact on certification mechanisms across many sectors in the past.

ZEF Adoption Targets

This roadmap uses three demand-side scenarios to present the range of potential shipping fuel demand in Washington through 2050, as well as three fuel-transition scenarios with varying levels of ambition for ZEF adoption as a percentage of total demand. Pairing demand-side scenarios with fuel-transition scenarios yields a quantitative target for ZEF bunkered at Washington ports in 2030, 2040, and 2050 (see Exhibit 8).

Exhibit 8 **ZEF Adoption Target Methodology**

1. **Energy Demand Scenarios**
   Model year over year (YoY) change in total energy demand from liquid fuels at Washington ports, considering growth in global trade, ability of WA to maintain market share, efficiency improvements, and potential decline in fossil fuel demand (declining tanker trade)

2. **Fuel Transition Scenarios**
   Model targets for zero-emission fuel adoption at Washington ports, based on IMO decarbonization targets

3. **Calculate ZEF Demand**
   Pair Energy Demand Scenario with Fuel Transition Scenario to yield Washington ports' demand for zero emission fuel by decade

RMI Graphic. Source: RMI analysis

Energy demand forecasts for the shipping sector are informed by key metrics such as projected changes in societal factors such as gross domestic product, population, and trade; efficiency improvements in vessel technology and operations/logistics; and projected declines in the maritime transport of fossil commodities (tanker trade).[22] The roadmap uses the pre-Covid baseline for bunker fuel sales in Washington of 1.75 million tons per year (see *Maritime Fuel Demand*). The demand scenarios are described in Exhibit 9 (see next page).

Fuel-transition scenarios (see Exhibit 10) are based on IMO GHG-reduction goals, which target a percentage of shipping's energy demand to be met by ZEFs in 2030, and overall GHG emissions reductions in 2040 and 2050 (see Maritime Fuels Policy Analysis). Washington's "ambitious" fuel-transition scenario is based on the IMO's "striving for" targets, while the "moderate" fuel-transition scenario is based on the IMO's "at least" targets. Both reach net zero by 2050, but the pace of the transition is slower in the moderate scenario, which may affect Washington's ability to win greater market share. The "delayed action" fuel-transition scenario does not achieve the IMO's net zero by 2050 target and is meant to represent a scenario in which Washington does not become a significant bunkering hub for zero-emissions fuels, and fuel demand and trade flows decline.

Exhibit 9 Shipping Energy Demand Scenarios

Demand Scenario	Energy Demand	Description
Strong Growth	+1% CAGR	Models 1% average annual growth in maritime fuel demand (on energy equivalent basis) at Washington ports, representing scenario in which overall growth in shipping demand is strong through 2050, and Washington ports gain market share.
Steady Demand	2050 demand roughly equivalent to current baseline	Models 0.1% annual growth in maritime fuel demand at Washington ports for all cargo types except tanker vessels, whose share of fuel demand declines annually by 3%, reflecting recent global demand forecasts released by DNV and Maersk Mc-Kinney Moller Center for Zero Carbon Shipping (MMMCZCS) taking into account efficiency improvements and declining fossil commodity demand to 2050.
Declining Demand	–0.2% CAGR	Models -0.2% average annual decline in maritime fuel demand at Washington ports, representing scenario in which total global shipping energy demand declines slightly (-0.35% CAGR), and Washington ports lose market share due to competition from larger and more strategically placed ports for bunkering future fuels.

RMI Graphic. Source: RMI analysis

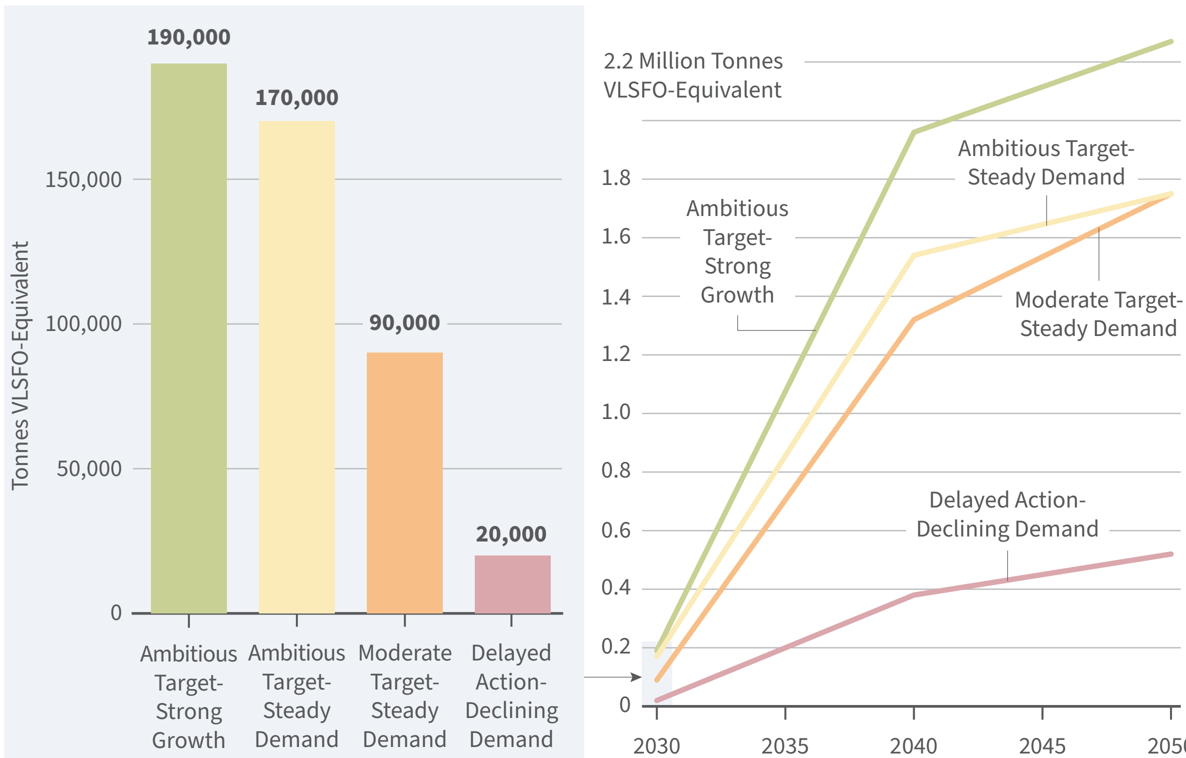
Exhibit 10 ZEF Demand Scenarios

Zero E	Description	2030	2040	2050
Ambitious Targets (Bunkering Hub)	IMO "striving for" targets. Represents scenario in which PNW becomes bunkering hub for future fuels, winning ZEF market share in supply-constrained environment by readying ports for large-scale methanol bunkering, implementing successful first-mover green corridors, and rolling out policies to help mitigate green fuel premium.	ZEFs= 10% energy demand	70% GHG reduction	Net Zero
Moderate Targets	IMO "at least" targets. Represents scenario in which shipping reaches net-zero ghg emissions by 2050 in accordance with IMO minimum targets, but early growth is slower due to limited global fuel supply in the 2030s.	ZEFs = 5% energy demand	60% GHG reduction	Net Zero
Delayed Action	Represents scenario in which shipping does not reach net-zero by 2050 and PNW does not become bunkering hub for future fuels; paired with "declining market share" demand scenario	ZEFs= 1% energy demand	ZEFs= 20% energy demand	ZEFs= 50% energy demand

RMI Graphic. Source: RMI analysis

The results of paired demand and fuel-transition scenarios can be seen in Exhibit 11. In scenarios where fuel demand does not decline and IMO targets are reached, the demand in 2030 is between 90,000 and 190,000 tons of VLSFO-equivalent ZEF. (If this demand were to be satisfied by e-methanol, for instance, this would be equivalent to 180,000–380,000 tons of e-methanol.)

Exhibit 11 2030 ZEF Demand and Washington's ZEF Adoption Trajectory by Scenario



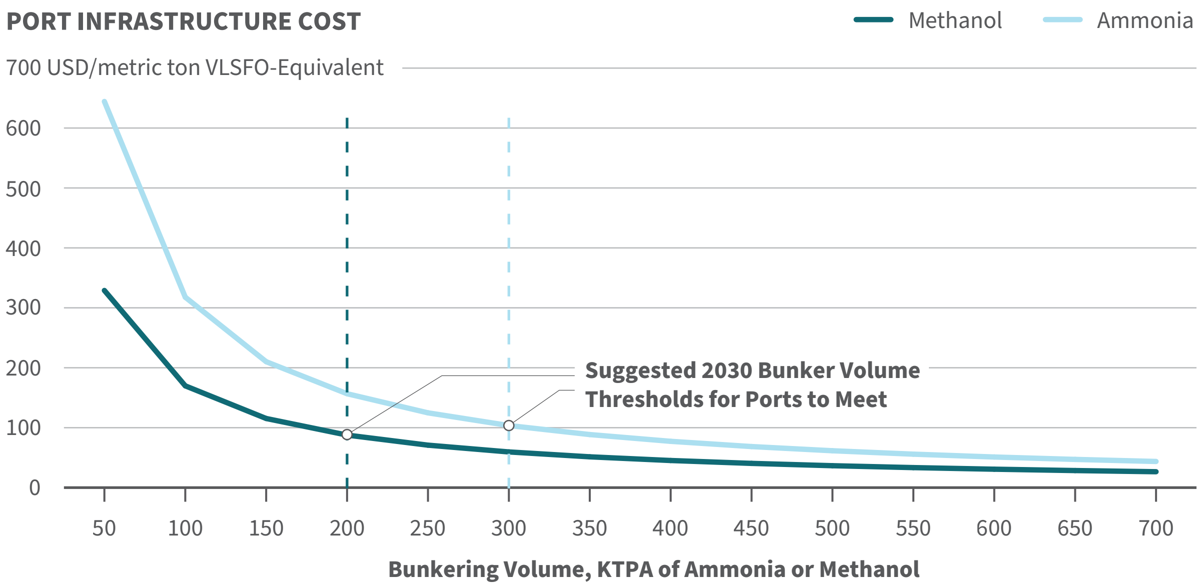
RMI Graphic. Source: RMI analysis

To catalyze and plan for this early ZEF demand, the Ports of Seattle and Tacoma are engaged in three green-corridor feasibility studies (having already completed the pre-feasibility phase): a green cruise corridor between the Pacific Northwest and Alaska, a trans-Pacific car-carrier corridor, and a trans-Pacific container corridor. The corridor studies involve close collaboration among fuel producers, vessel owners, and cargo owners to quantify fuel demand and related investments and develop approaches to corridor implementation.

Although the demand analyses from these studies are not yet complete, high-level assumptions about route distances in each geography, vessel deployment by 2032 (four to five per corridor), and fuel burn, yield a total demand across the three corridors of 100,000—200,000 tons of VLSFO-equivalent. If the green corridors are successful, they will be sufficient to hit the moderate, or even ambitious, roadmap targets. The intent of green corridors is to stimulate first-mover ZEF offtake and deployment that serves as the foundation for further ZEF uptake; green-corridor demand should not be seen as a total demand forecast.

Robust initial ZEF demand is important for achieving economies of scale for port infrastructure costs (portside storage and bunkering). At low levels of demand, the necessary infrastructure investments are spread across relatively few customers, increasing the role of infrastructure costs for overall fuel costs. A recent RMI report identifies approximate thresholds at which the share of infrastructure costs begin to plateau. The suggested demand thresholds (see Exhibit 12) are approximately 200,000 tons per year for methanol or 300,000 tons per year for ammonia (ammonia being more expensive to bunker). At demand levels below these thresholds, the infrastructure cost component of the fuel begins to increase rapidly. At the threshold of 200,000 tons per year of methanol demand, total storage infrastructure investment is expected to be about a $20 million (see Exhibit 12), or $45 million if a bunker vessel is also purchased.[23]

Exhibit 12 2030 ZEF Demand and Washington's ZEF Adoption Trajectory by Scenario



Note: Last-mile costs are significantly smaller once a certain bunker volume is reached.

RMI Graphic. Source: Source: RMI *Oceans of Opportunity Report* 2024

The aggressive ZEF target scenarios are consistent with surpassing these thresholds, although the moderate target-steady growth scenario does not surpass them. For instance, if the moderate target of 90,000 tons of VLSFO-equivalent is met exclusively by methanol, this will yield approximately 185,000 tons per year of methanol, or 10% below the recommended minimum demand threshold for infrastructure investment. If met exclusively by ammonia, the result is approximately 195,000 tons of ammonia, or 35% below the infrastructure threshold. The more ZEF demand can coalesce around a single fuel in the near term, the lower the infrastructure cost component of total fuel cost will be. This is not to say that ZEF uptake must be limited to a single "winning" fuel between now and 2050, but that early efforts, when fuel costs are highest and total demand is lowest, should coalesce around a single ZEF to achieve lowest cost. The PNW-Alaska Green Cruise Corridor—the most advanced green corridor in the region—has identified (e- or bio-) methanol as the target fuel, making this a promising fuel around which to coalesce early investments.

Maritime Fuels Policy Analysis

Existing Policy Landscape

To understand how Washington State policy might incentivize sustainable maritime fuel uptake, it is important to understand the broader policy landscape. The maritime industry is, by necessity, an international industry; policies across jurisdictions must coordinate to prevent asset stranding and service disruption.

The broadest coordinator of shipping policy is the International Maritime Organization (IMO), which is a United Nations specialized agency that sets norms, protocols, and coordinates policy across the world. The IMO agreed to the following international decarbonization targets:[24]

- Adoption by 2030 of zero or near-zero-emission fuels equivalent to 5% (striving for 10%) of global shipping's total energy use
- Reduction by 2040 of 70% to 80% of global shipping's GHG emissions, relative to a 2008 baseline
- Net-zero emissions by 2050

The IMO is currently working to establish the specific binding regulations and policies through which these targets will be implemented. Although measures such the Carbon Intensity Index help track and enforce progress by mandating reporting of a vessel's emissions intensity per cargo-carrying capacity and nautical mile, national governments must still adopt the conventions and amendments introducing such measures. Therefore, the enforcement of IMO targets ultimately depends on member states' adoption of IMO measures in their own national laws.

On the level of national and regional policy, the EU has the most advanced regulatory environment for shipping emissions. The FuelEU Maritime Regulation, part of the ambitious Fit for 55 package, sets stringent emissions standards for ships operating within EU ports.[25] The regulation mandates a progressive decrease in the GHG intensity of maritime fuels, aiming for an 80% reduction by 2050. To encourage compliance, financial penalties are imposed on ships that exceed WtW emissions requirements. Additionally, the EU incentivizes the adoption of renewable fuels of non-biological origin (RFNBOs), which comprise clean hydrogen and e-fuels, promoting a shift toward fuels with high-decarbonization potential.

In contrast, maritime fuel is noticeably absent from nearly all large-scale decarbonization incentivization schemas in the United States. Keystone climate programs, such as the federal RFS, the 45Z Clean Fuel Production Tax Credit, the California LCFS, and the Oregon Clean Fuels Program explicitly exclude maritime fuel.[26] Under the Washington CFS, maritime fuel may opt in to generate credits; however, the program is only accepting these *de novo* Tier 2 applications after October 1, 2024. [27,xv]

xv A Tier 2 pathway is used for less common fuels or fuels that have variable production pathways. A Tier 2 application often requires more information and detailed analysis than a Tier 1 pathway. Tier 1 pathways are used for well-understood fuels with established production processes like corn ethanol or biodiesel.

The result of maritime fuel's exclusion from these programs is that feedstocks that can be used to make different fuel types are funneled toward uses that generate revenues under these programs, including renewable diesel for road transport and SAF. This draw toward fuel supply chains for other sectors is especially problematic for feedstocks with limited total supply potential. Feedstocks such as FOGs that are used in HEFA pathways as well as other traditional biofuel feedstocks (corn, sugarcane, and palm oil) used in ethanol and alcohol-to-jet pathways can only scale so far and will eventually have greater demand than supply.

Policy Parameters to Incentivize Maritime ZEF

Given the existing landscape, there are firm parameters around policies that Washington State should pursue to incentivize the uptake of clean maritime fuel at local ports:

1. **Policies must be within a state's jurisdiction but should have the potential to affect an international industry.**

Washington is limited in what it may pursue by the United States' system of federalism, which allows a state certain powers to legislate within its borders but circumscribes its ability to regulate interstate and international commerce and trade. Successful policies must fall within state powers, incentivize change in the shipping industry, and align with the broader maritime landscape to maintain coordination.

2. **Policies should target the demand side and incentivize use of sustainable, scalable fuels over conventional biofuels that do not have the potential to decarbonize a significant share of shipping's total energy demand.**

Given that importing zero-emission maritime fuels from other states is necessary for achieving a least-cost energy system, policy should ideally target the demand side of the fuel equation. When incentivizing fuel deployment, it is important that fuels being incentivized represent a true path to sector decarbonization, rather than locking in assets across the value chain that cannot ultimately help the shipping sector reach its 2050 goal. Feedstocks for conventional biofuels are in high demand across the country and face a hard limit on total global supply. Therefore, policy should ideally target e-fuels and, where necessary, second-generation biofuels that will experience less competition than first-generation biofuels.

3. **Policies should aim to help close the price gap between incumbent fossil fuels and ZEFs while remaining fiscally viable.**

One of the greatest barriers to clean fuel uptake is the higher cost of ZEFs compared with conventional fuels (i.e., the green premium), as well as the competitive disadvantage that shipping experiences relative to SAF. Uncertainty around future fuel prices can prevent shipping companies from signing long-term offtake contracts necessary to advance ZEF production projects and secure ZEF supply. Policies that can mitigate this price gap between traditional fuels and ZEFs will have the greatest impact on catalyzing ZEF uptake. At the same time, state budgets are not infinite, and any fiscal output from the state must be creatively leveraged to maximize returns.

4. **Policies must prepare local ports for an efficient and just transition.**

Preparing a port or private fuel terminal to store and dispense new fuel types will require a broad array of supportive policies. These policies are essential pieces of incentivizing and facilitating clean fuel uptake in

Washington and will need to accompany any financial or market incentivization. These policies may include infrastructural or regulatory support and policies aimed at supporting port communities and maritime workers through the transition, as well as streamlining the process to construct new infrastructure needed to support ZEF. Policies must integrate community outreach, education, and support for people who live close to port infrastructure.

Policy Recommendations

Given these parameters, three primary policy recommendations arise. Together, these policies create a robust framework that guides the shift toward a decarbonized maritime sector while remaining within state jurisdiction and budgetary constraints and keeping climate justice for the maritime workforce and local communities at the forefront.

1. **Make it easier for ZEFs to generate credits in Washington's Clean Fuel Standard (CFS) by accelerating the timeline to Tier 1 pathway approval for ZEFs. Include a cap on the use of biofuels with limited scaling potential (such as FOG-based fuels) to stimulate next-generation infrastructure.**

Washington has already taken the first step toward creating a regulatory pathway for maritime fuels under its CFS program, but simplifying maritime fuel pathways could further incentivize clean fuel uptake. Currently, maritime fuels (ranging from LNG to e-methanol to biofuels) are considered a Tier 2 fuel pathway application. The program is not accepting de novo Tier 2 fuel pathway applications until October 1, 2024. Tier 2 applications under CFS programs are essentially bespoke pathway applications that fuel producers pursue. The applications can include public comment and may require additional documentation and verification for approval.

Tier 1 applications are generally used for well-established technologies with documented emissions profiles and are typically approved more easily. Washington should look to create Tier 1 pathways for target maritime fuels as soon as enough information is available on their performance. This will increase the ease with which fuel producers can generate credits. This process will also necessitate close collaboration with industry in order to better understand all impacts that greater CFS opt-in might have on industry—likely via multiple comment periods and feedback on proposed fuel pathways.

However, other CFS programs have seen biofuel-based credits flood the market and depress credit prices. Program operators have expressed concern that allowing maritime fuel to generate credits but not deficits would exacerbate this issue. To avoid this, a limit should be placed on the number of credits fuel producers may generate via conventional biofuels, FOG-based biofuels, and other biofuels facing significant feedstock constraints, as a percentage of total generated credits. This has the benefit of pushing the maritime industry toward ZEFs without subjecting the industry to CFS deficit obligations, avoiding lock-in of infrastructure and supply chains for conventional biofuels and FOG-based biofuels that face feedstock constraints, and preventing a sudden flood of credits into the CFS market as next-generation fuel types are less prevalent in the industry.

Furthermore, CFS programs are market based and, therefore, low-cost to the state. They can even bring in state revenue from registration fees that can be put back into supporting the maritime transition. One drawback is that this type of policy targets the fuel producer or importer rather than the off-taker (i.e., fuel purchaser), though some portion of the burden is typically integrated into the final fuel sales price, satisfying the second policy parameter outlined above.

2. **Implement a targeted subsidy program that helps close the final price gap between e-fuels and traditional maritime fuels.**

The green premium on clean maritime fuels is the most significant barrier to uptake. To close the gap, the state will need to be prepared to allocate some of its budget toward supporting fuel purchasers. Both programs outlined below creatively leverage state funds to support fuel demand and can be structured to only have an impact on ZEFs.

The first option — and the more common choice — is an investment tax credit (ITC) or a sales and use tax credit, for fuel purchasers. This type of tax credit for purchasers of maritime fuels can specifically target preferred fuel types and emissions requirements. State-level programs can be offered on a first-come, first-serve basis, and the amount of credit per gallon can be designed to be worth more for cleaner fuels, imitating the structure of many IRA credits. A benefit of this type of program is state institutional knowledge of implementing tax credits. A drawback is that a tax credit cannot flex with the price of clean maritime fuels, so if fuel prices rise drastically, then the credit impact may diminish drastically as well.

The second option is a contract for difference (CfD). A CfD is a financial arrangement between two parties in which a buyer receives or gives payments based on the difference between the current market price and a predetermined strike price for a specified commodity. In this case, the state would allocate seed money to a fund; if the market price for clean fuels is higher than the strike price, then the state would cover the difference until the fund is depleted. If the market price is lower than the strike price, the fuel buyer pays the difference into the CfD fund. In this way, a CfD can flex with the price of the fuel, fully covering the buyers' risk, and can replenish itself if prices fall.

These programs are especially useful in fluctuating markets. Some drawbacks are that there is less precedence for this kind of state program. In the United States, New York's Index Offshore Renewable Energy Certificate represents one precedent for a state CfD.[28] The United Kingdom has also used a CfD for offshore wind, and the Netherlands has done so for renewable energy.[29] The European Hydrogen Bank is currently running a similar program for hydrogen production using an auction mechanism to allow prospective hydrogen producers to bid for the minimum subsidy needed to advance their projects.[30]

3. **Invest in port transition planning and implementation to support the deployment of ZEFs and related infrastructure, using federal dollars where possible.**

There are many smaller pieces that need to come together to prepare a port to store and dispense new fuel types. Although Washington ports have not historically owned and operated fuel storage and bunkering assets, they can play a pivotal role in connecting and galvanizing the greater ecosystem around a shared vision of decarbonization and the fuel transition.

Port infrastructure and workforce preparations are essential pieces of incentivizing and facilitating ZEF uptake in the Pacific Northwest but are more diffuse and piecemeal than broad programs such as a CFS program or a tax credit. These infrastructural, regulatory, and workforce pieces can be passed in one large package of bills or can be implemented more slowly. These support policies may include (but are not limited to):

- Fast-tracking state-level permitting requests from ports for modernization decarbonization projects and new bunkering infrastructure and collaborating with external permitting bodies (including US Coast Guard, EPA, and others) to prevent duplication of permitting efforts.

- Establishing a lead agency for permitting all maritime fuel infrastructural projects in the state and ensuring that this lead agency has sufficient staff with the technical expertise to assess such projects for permit approval. Establishing programs with local trade schools and community colleges to upskill and reskill maritime workers to work with future fuels.

- Establishing programs with local trade schools and community colleges to upskill and reskill maritime workers to work with future fuels.

- Working with ports to assess regulatory gaps and support development of new protocols.

- Applying for federal support to help finance new port infrastructure that can store and dispense new fuel types and offering state-level ZEF port storage and bunkering infrastructure grants.

- Using federal dollars to support training and apprenticeship programs for port workers.

- The state and the port may also explore more creative options, such as port logistics policies that favor lower-emissions ships, and labeling goods that arrive at port on cleaner ships to educate the final consumer.

Some of these policies, especially those related to new infrastructure, can require large capital expenditures. This analysis estimates the total infrastructure investment for storage of 200,000 tons of annual methanol demand at approximately $20 million dollars. For projects on this scale, it is recommended to take advantage of federal grant, loan, and cost-share programs.

For example, the Port Infrastructure Development Program may be applied to the purchase of zero-emissions mobile equipment, equipment that serves zero-emissions mobile equipment, and deployment support activities, including workforce training.[31] There is $2.25 billion available in 2022–2026, and the grant reopens annually. The US Environmental Protection Agency Clean Ports grant program also offers up to $3 million for planning and implementation efforts for port decarbonization projects. For workforce support, the Critical Sector Job Quality Grant aims to improve job quality in key sectors through industry-led, worker-centered strategies built through labor-management partnerships.[32] For support deploying capital expenditures toward infrastructural updates, the RAISE, Mega, and INFRA grants can all be deployed to ports.[33] The Loan Programs Office's State Energy Financing Institution (SEFI) loans and Energy Infrastructure Reinvestment loans may also apply, depending on the precise nature of the project.[34] Washington already has one institution that is certified by the DOE as a SEFI institution, the Washington State Housing Finance Commission, which might provide institutional knowledge to help qualify another institution as a SEFI geared specifically toward port improvement.[35]

Although it is unlikely that one industrial site would qualify for all these programs, the federal government has dollars set aside for state-level projects that aim to decarbonize the heavy sectors. As ports and other stakeholders embark on capital expenditures–intensive ZEF infrastructure projects, stakeholders should explore avenues for federal support.

Conclusion

The strong ambition among Washington stakeholders across the shipping value chain has created a momentous opportunity for Washington to position itself as a leader in shipping decarbonization by becoming one of the first ZEF bunkering hubs in the nation. This is an opportunity not just to reduce emissions, but to drive sustainable growth in Washington's shipping sector and to contribute to the state's broader economic competitiveness and development. Investment in ZEF infrastructure this decade is essential for the shipping sector to meet international decarbonization goals, and for Washington to secure its role as a key player in an emerging market.

Although global shipping's future fuel mix will likely include multiple ZEFs and no single fuel is identified as the optimal "winner" in Washington, this study does highlight the benefit of early investments in ZEF infrastructure coalescing around a single ZEF. The identification of e-methanol or bio-methanol as the target fuel for the Pacific Northwest–Alaska Cruise Corridor makes this a promising fuel choice.

The economic challenges associated with ZEF production in Washington, especially compared with high-wind regions in the United States, such as Montana and the US Wind Belt, necessitate a balanced approach that combines local production with strategic imports. ZEFs are expected to be between two and three times the cost of conventional fossil fuels in 2030, requiring innovative market and policy mechanisms to catalyze uptake.

The policy recommendations in this report advocate for a multifaceted approach that includes streamlining ZEFs into the Washington CFS, implementing a targeted demand-side subsidy such as a sales and use tax credit to bridge the cost gap between ZEFs and fossil fuels, and investing in comprehensive port transition plans such as ZEF storage infrastructure and workforce training.

As the state continues to make progress on planning ZEF deployment and decarbonizing the shipping sector, further study will be needed across several essential topics, including but not limited to:

- the interplay between OGV fuel demand and harbor craft energy demand, and the impacts of the OGV fuel transition on harbor craft operators
- the relative health and safety risks of various ZEFs, relative to incumbent fuels, on Washington's maritime workers, surrounding communities, and marine ecosystems
- the opportunities and the challenges presented by ZEF deployment for advancing workforce equity concerns and local communities' environmental justice goals

A successful approach will not only facilitate the adoption of ZEFs, but also ensure that the transition is equitable and beneficial to port communities and workers. The collaborative efforts of policymakers, industry stakeholders, and community partners will be essential in achieving these ambitious targets, ensuring a resilient and sustainable future for Washington's shipping industry.

Technical Appendix

This appendix provides high-level descriptions of modeling methodologies and assumptions conducted for this study, including the most significant technical and cost assumptions. Additional smaller-impact cost or operational assumptions are not included in this report for simplicity.

Hydrogen Cost Modeling (Off-Grid)

RMI modeled off-grid electrolytic hydrogen production costs using a proprietary linear optimization model. This is the approach used to model production costs in the US Wind Belt scenario and the Chile scenario. This model is strictly for non-grid-connected projects, relying on new co-located wind and solar capacity deployment (e.g., behind-the-meter renewables). The model optimizes for the lowest total project capital expenditures to achieve an annual and hourly hydrogen production target (input constraint), solving for: wind and solar capacity, electrolyzer capacity, and hydrogen storage size, using location-specific hourly renewable production profiles. The model's chief output is a levelized cost of hydrogen over the lifetime of the plant, based on project finance assumptions and including applicable tax credits and depreciation schedules (see Exhibit A1).

Exhibit A1 Off-Grid Levelized Cost of Hydrogen Model Assumptions

45V and 45Y subsidies considered if the fuel is produced in the US (45Z not considered)

Assumption	2030	2040	Source
Wind installed capital expenditures (capex)	$1,096/kW	$855/kW	RMI assumption, based on National Renewable Energy Laboratory (NREL) Annual Technology Baseline (2023) and stakeholder interviews
Solar installed capex	$750/kW	$595/kW	RMI assumption, based on NREL Annual Technology Baseline (2023) and stakeholder interviews
Electrolyzer capex (stack + balance of plant [BoP])	$660/kW	$493/kW	RMI assumption, based on stakeholder interviews and DOE's "Pathways to Commercial Liftoff: Clean Hydrogen" (2023)
Indirect electrolyzer capex (engineering, procurement, and construction [EPC], permitting, etc.)	$390/kW	$322/kW	RMI assumption, based on stakeholder interviews and DOE's "Pathways to Commercial Liftoff: Clean Hydrogen" (2023)
Electrolyzer energy requirement	53 kWh/kg	50 kWh/kg	RMI assumption

Assumption	2030	2040	Source
Hydrogen storage capex	$0.40–$0.70/kg for pipeline, depending on storage size		RMI assumption, adapted from DOE's "System Level Analysis of Hydrogen Storage Options" (2019) and BloombergNEF's "Hydrogen: Economics of Storage" (2019)
Weighted average cost of capital (WACC)	7.8%	7.8%	RMI assumption
Plant life	30 years	30 years	RMI assumption

RMI Graphic. Source: RMI analysis

Hydrogen Cost Modeling (Grid-Connected, Washington)

To estimate production costs in Washington State, RMI modeled grid-connected electrolytic hydrogen production rather than off-grid production, for the following reasons:

1. Low wind and solar capacity factors in Washington relative to other US locations yielded higher production costs for off-grid than for grid-connected.

2. Lower industrial electricity rates in Washington, relative to other US locations, make Washington a comparatively attractive place to use grid electricity, assuming the availability of hourly-EACs needed to qualify for the 45V tax credit.

3. Most production projects included in the Washington Hydrogen Hub DOE application are believed to be pursuing grid-connected projects, and stakeholder validation indicated that grid-connected was the more frequently considered production pathway in the region.

As discussed in the report, qualifying for the 45V production tax credit when using grid electricity requires hourly matching of electrolyzer operations with availability of three pillars–compliant, low-carbon electricity. This is assumed to be accomplished through the purchase of hourly-EACs that certify the temporal and locational characteristics of the electricity, as well as the power plant vintage. The average all-in electricity cost including grid electricity and EAC procurement is included in Exhibit A2 (see next page).

Exhibit A2 Washington Grid-Connected Levelized Cost of Hydrogen Assumptions

Full 45V subsidy included, assuming projects comply with three-pillars requirements through purchase of hourly-EACs

Assumption	2030	2040	Source
Average all-in electricity cost (grid electricity + hourly-EAC procurement)	$70/MWh	$70/MWh	RMI assumption
Electrolyzer load factor	70%	70%	RMI assumption
Electrolyzer capex (stack + BoP)	$660/kW	$493/kW	RMI assumption, based on stakeholder interviews and DOE's "Pathways to Commercial Liftoff: Clean Hydrogen" (2023)
Indirect electrolyzer capex (EPC, permitting, etc.)	$390/kW	$322/kW	RMI assumption, based on stakeholder interviews and DOE's "Pathways to Commercial Liftoff: Clean Hydrogen" (2023)
Electrolyzer energy requirement	53 kWh/kg	50 kWh/kg	RMI assumption
Hydrogen (H2) storage capex (assumes H2 pipeline)	$0.40–$0.70/kg for pipeline, depending on storage size		RMI assumption, adapted from DOE's "System Level Analysis of Hydrogen Storage Options" (2019) and BloombergNEF's "Hydrogen: Economics of Storage" (2019)
WACC	7.8%	7.8%	RMI assumption
Plant life	30 years	30 years	RMI assumption

RMI Graphic. Source: RMI analysis

E-Fuel Cost Modeling

Exhibit A3 Levelized Cost of E-Ammonia Assumptions

Assumption	Value	Source
Overall capex	$611/ton ammonia	RMI assumption based on Fasihi et al., "Global Potential of Green Ammonia Based on Hybrid PV-Wind Power Plants" (2021) and Nayak-Luke et al., "Techno-Economic Aspects of Production, Storage and Distribution of Ammonia" (2021)
Electricity consumption	719 kWh/year	Cesaro et al., "Ammonia to Power: Forecasting the Levelized Cost of Electricity from Green Ammonia in Largescale Power Plants" (2020)
Operating expenditures (opex)	4% of capex	Lloyd's Register and University Maritime Advisory Services' (UMAS) "Fuel Production Cost Estimates and Assumptions" (2019)

RMI Graphic. Source: RMI analysis

Exhibit A4 Levelized Cost of E-Methanol Assumptions

Assumption	Value	Source
Capex	\$263–\$562/ton MeOH, depending on size of plant	Nyári, "Techno-economic Feasibility Study of a Methanol Plant Using Carbon Dioxide and Hydrogen" (2018)
Fixed opex	4% of capex	Lloyd's Register and UMAS' "Fuel Production Cost Estimates and Assumptions" (2019)
Electricity requirement	216 kWh/ton MeOH	Lloyd's Register & UMAS' "Fuel Production Cost Estimates and Assumptions" (2019)
Cost of delivered CO2: Washington scenario	\$100/ton CO2	RMI assumption, based on literature review and stakeholder feedback; assumes carbon capture on pulp and paper mill, and CO2 transport distance <100 miles
Cost of delivered CO2: US Wind Belt scenario	\$80/ton CO2	RMI assumption based on literature review and stakeholder feedback; Assumes carbon capture on ethanol plant, and CO2 transport <100 miles
Cost of delivered CO2: Chile scenario	\$120/ton CO2	RMI assumption based on literature review and stakeholder feedback; assumes bioenergy with carbon capture and storage, and CO2 transport >1,000 miles via ship

RMI Graphic. Source: RMI analysis

Exhibit A5 Storage (at the Production Site) Cost Assumptions

Assumption	Ammonia	Methanol	Source
Capex	\$843–\$1,418/ ton NH3	\$417–\$614/ton MeOH	RMI assumption, based on HyDelta, "Technical Analysis of Hydrogen Supply Chains" (2022) and Nayak-Luke et al., "Techno-Economic Aspects of Production, Storage and Distribution of Ammonia" (2021)
Opex	3% of capex	0.60% capex	HyDelta, "Technical Analysis of Hydrogen Supply Chains" (2022) and Lloyd's Register and UMAS' "Fuel Production Cost Estimates and Assumptions" (2019)
Tank utilization	80%		RMI assumption, based on industry feedback and validation
Maximum frequency of tank usage	20 times/year		RMI assumption, based on industry feedback and validation

RMI Graphic. Source: RMI analysis

Exhibit A6 Transportation Cost Assumptions

Assumption	Ammonia	Methanol	Source
Via rail	$0.095/ ton-km	$0.095/ ton-km	RMI assumption, based on industry feedback and validation
Via truck	$0.143/ ton-km	$0.143/ ton-km	RMI assumption, based on industry feedback and validation

RMI Graphic. Source: RMI analysis

Exhibit A7 Portside Cost Assumptions

Assumption	Ammonia	Methanol	Source
Portside storage			
Capex	$1,265/ton NH3	$548/ton MeOH	RMI assumption, based on HyDelta, “Technical Analysis of Hydrogen Supply Chains” (2022) and Nayak-Luke et al., “Techno-Economic Aspects of Production, Storage and Distribution of Ammonia” (2021)
Opex	3% of capex	0.60% of capex	HyDelta, “Technical Analysis of Hydrogen Supply Chains” (2022); Lloyd’s Register and UMAS’ “Fuel Production Cost Estimates and Assumptions” (2019)
Bunker vessel (based on a chemical carrier powered by VLSFO)			
Capex	$25 million/bunker vessel		Industry experts
Bunkering crew and other operational costs	$8,000/day		Industry experts
Size	12,000 tons NH3/MeOH		RMI assumption
Bunker vessel utilization	60%		Industry experts

RMI Graphic. Source: RMI analysis

Endnotes

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