APPENDIX: METHODOLOGY & INPUT DATA

CUMULATIVE HEALTH AND CLIMATE BENEFIT ANALYSIS

Our cumulative health and climate benefit methodology draws upon the approach described in the Building Back Better: Investing in a Resilient Recovery for Washington State report. The public health benefits are estimated based on statewide averages while a social cost of carbon estimate is used for climate benefits. These broad and averaged levels of aggregation are not granular enough to capture finer scale impacts, which can vary dramatically based on population density and proximity to pollution sources.[1] All of the case studies except Charging Infrastructure had sufficient detail of avoided fuel consumption to determine overall climate and statewide health benefits.

The cumulative health modeling approach requires the following steps:

1. Following the Building Back Better methodology, Reduced-Complexity Models (RCM) were relied upon for pollutant-specific, monetized damages associated with each fuel and sector to estimate annual mortality from pollution.[2,3] This RCM-based approach allows us to estimate the public health damages associated with emitting a ton of toxic criteria pollutants ($PM_{2.5}$, SO_2, NO_x, VOCs, or NH_3). Publicly available data from the Center for Air, Climate, and Energy Solutions (CACES) was used, which includes three different RCMs to estimate public health damages per unit of pollution. State-level CACES data was used for these estimates. The RCMs estimate the link between local air pollution levels, population exposures, physical health and environmental effects, and monetary damages.
2. The monetized damages per unit of air pollution are based on the EPA's estimates for the value of statistical life (VSL) which is $9.4 million in year 2020 dollars. The CACES model provides geographic resolution on sources of pollution but not for the location of mortality impacts. As RCMs capture the downwind effects of pollution, some of the health impacts may be happening outside of the state. Combining the CACES estimates and VSL provides the dollars in health damages per ton of each toxic criteria pollutant emitted in the state.
3. Based on the case-study specific research, we determine the ratio of each of the toxic criteria pollutants to the amount of greenhouse gas (GHG) pollution, yielding tons of toxic criteria pollutant per ton of GHG.
4. Based on this ratio of emissions determined in (3) and the damages per ton of toxic criteria pollutant determined in (1) and (2), the monetized health damages associated with each ton of GHG emission ($/$tCO_2e$) are determined. With our model estimates of GHG reduction, the monetized health damages can be converted into a time-series of total damages ($). The total damages include avoided damages from fuel consumption less the increased damages from electricity consumption. Electricity consumption is assigned the statewide average determined for the Building Back Better report: negative $16/$tCO_2e$.

The climate benefits are based on an estimate of the social cost of carbon ($52/$tCO_2e$) by the U.S. Interagency Working Group and adjusted to 2020 dollars.[4] The annual GHG reductions are discounted to NPV and then scaled by this fixed dollar multiplier to determine the annual, discounted climate benefits.

ADDITIONAL METRICS & INPUTS

AVOIDED GHG EMISSIONS

The avoided GHG emissions are based on case-study specific estimates of the difference in volume and types of fuel consumed by the lower emissions technology relative to the baseline technology. These estimates are dependent on both the fuel consumption estimates specific to each case study, and the emissions intensities of the fuels being used. Emissions intensity factors include tCO_2e per gallon of fuel consumed and gCO_2e per kWh of electricity consumed.

For the emissions reductions, climate benefits, and public health benefits, we consider only the "tank-to-wheel" emissions and not the full life-cycle (or "well-to-wheel") emissions. For Clean Fuel Standard (CFS) impacts (fuel prices and credit value), the emissions intensities are scaled to the full well-to-wheel values based on the defined scope of the CFS program.

EMISSIONS INTENSITIES

Emissions intensities evolve over time, unless otherwise noted for a specific case study, based on:

- CFS requirements (decrease in tCO_2e/gallon "well-to-wheel" emissions intensities of fuel to 10% in 2031-2033 and a 20% cap in 2038 and beyond), and;
- CETA requirements for electricity supply, dependent on the utility provider, of no coal by 2025, GHG-neutral by 2030 where program compliance is modeled as zero-emissions electricity, and 100% GHG-free without any offsetting by 2045.

The following **emissions intensities for fuels** are used as starting values prior to implementation or compliance with the CFS or CETA:

- Diesel fuel (ferry electrification, drayage trucks, motor coaches, cargo-handling equipment): 0.01007 to 0.01015 tCO_2e/gallon for tank-to-wheel and 0.1351 to 0.1362 tCO_2e/gallon for CFS related calculations for well-to-wheel life-cycle.
- Gasoline fuel (passenger vehicles): 0.008573 tCO_2e/gallon for tank-to-wheel and 0.0115 tCO_2e/gallon for CFS related well-to-wheel life-cycle emissions intensities.
- Marine Gas Oil (shore power): 694 gCO_2e/kWh of auxiliary engine output based on data from the 2016 Puget Sound Maritime Emissions Inventory and global warming potentials of 28 tCO_2e for methane and 265 tCO_2e for N2O (personal communication with NWSA staff). For CFS related calculations, the emissions factor was scaled by the same amount as for diesel ferries for a 931 gCO_2e/kWh well-to-wheel emissions factor.

In the baseline fuel consumption case, we adjust toxic air pollutants in proportion to the reduction in GHG emissions as a simplifying assumption. In most cases, the reduction in criteria pollutants does not simply match the reduction in GHG emissions and is dependent on the lower GHG fuel in question. That determination was beyond the scope of the analysis in this report, but is an important consideration

Electricity emissions intensities for three representative service areas and utilities are used:

- Seattle City Light (shore power, a portion of ferry electrification, drayage trucks, a portion of cargo-handling equipment) is near-zero (0-12 gCO_2e/kWh) electricity. There is limited to no impact from CETA on this electricity supply.
- Tacoma Power (some of the cargo-handling equipment) is near-zero (0-5 gCO_2e/kWh). There is limited to no impact from CETA on this electricity.
- Puget Sound Energy (PSE) (a portion of ferry electrification, drayage trucks, motor coaches, passenger vehicles) starts at nearly 400 gCO_2e/kWh based on the 2020 fuel mix published in June 2021.[5] Under CETA, emissions drop to net-zero by 2030. In 2025, under the CETA requirement of no coal generation, we assume all coal-based electricity is replaced by natural gas-based electricity at least until net-zero requirements start in 2030. Based on the 2019 Department of Commerce Fuel Mix Disclosure report estimates of emissions intensity for coal and natural gas electricity and the relative share of each in the PSE mix, we estimate emissions from 2025 through 2029 to be 52% of the baseline, or just over 200 gCO_2e/kWh.[6]

FUEL PRICES

Baseline liquid fuel prices are projected for each case study, covering several different fuel types with some overlap of methodology across case studies.

- **Ferry System Electrification:** A methodology was developed for the original Mukilteo-Clinton Life Cycle Cost Analysis study based on a historic relationship of 1.375 times the Brent Crude Oil price.[7] In the original analysis, the diesel cost projection was based on the US Energy Information Agency's (EIA) 2017 Annual Energy Outlook. For this study, we updated the fuel price projection to match the 2021 Annual Energy Outlook using the same multiplier of 1.375. Underlying diesel prices are projected to rise from $1.80 per gallon in 2023 to $3.11 per gallon in 2050.[8]
- **Shore Power:** Uses the relative increase in fuel cost from Electric Ferries from an initial MGO price of $598/metric ton for MGO 0.1% for Seattle.[9]
- **Other case studies:** The Washington State Department of Commerce's Carbon Tax Assessment Model (CTAM) version 4.2[10] was used as the starting point for transportation diesel and gasoline prices. CTAM 4.2 is based on EIA AEO 2020 data. We updated the baseline fuel prices in CTAM 4.2 by the ratio of "Pacific Region" diesel and gasoline prices in AEO 2021 to the prices in AEO 2020.
    - Baseline diesel prices (in 2021 USD) start at $2.84/gallon in 2022 and rise to $4.09/gallon in 2030, $4.35/gallon in 2040, and $4.51/gallon in 2050.
    - Baseline gasoline prices (in 2021 USD) start at $2.67/gallon in 2022 and rise to $3.61/gallon in 2030, $3.93/gallon in 2040, and $4.08/gallon in 2050

Fuel costs are adjusted upwards on the basis of two programs that price carbon based on the emissions or emissions intensity of fuels: the Climate Commitment Act (CCA) and the Clean Fuel Standard (CFS).

- **Clean Fuel Standard** compliance costs and credits are based on well-to-wheel life-cycle emissions of fuel: the required percentage reduction in emissions intensity of the fuel multiplied by the emissions intensity of the fuel on a life cycle basis multiplied by per unit credit costs.[11]
- **Climate Commitment Act** compliance costs rely on the $/tCO_2e$ average allowance auction price from the June 2021 revised fiscal note through 2040 times the "tank to wheel" emissions factors. After 2040, the compliance costs are modeled to increase $5/tCO_2e$ annually through the final year in which the program is authorized to exist, 2055.

Combined compliance costs are projected to add $0.24 to a gallon of diesel in 2023, rising to $1.00 per gallon in 2039 and $1.33 per gallon by 2050. For a gallon of gasoline, the compliance costs project to add $0.20 per gallon in 2023, rising to $1.01 per gallon by 2046 and $1.12 per gallon by 2050.

ELECTRICITY COSTS

Baseline electricity costs

There is wide variability in assumed electricity prices based on the range of end-uses, rate structures, and utilities. Main factors in this variability include the electric utility providing power, the type of service (e.g. residential or commercial), and the impact of demand charges based on the maximum capacity or power draw (in kilowatts, kW) required.

The greatest projected variability occurs within the ferry electrification study. Demand charges (monthly charges per kW of maximum capacity required) factor heavily if required during the "peak hours". As the ferries run throughout the day, sustaining capacity during peak times is necessary. We provide some additional details about electricity rates for each case study in the next section of this Appendix. Here, we outline initial electricity rates and provide some information about how those rates are assumed to evolve over time, including through the impact of CETA on electricity prices.

For ferry electrification, each route (but not all boats) is expected to be at least partially electrified by 2026. As a relevant point of reference, we report the average assumed electricity prices in 2026 along each route:

- Seattle-Bainbridge: 9.1 cents/kWh in Seattle, 7.5 cents/kWh in Bainbridge
- Mukilteo-Clinton: 15.2 cents/kWh in Clinton (one-side charging)
- Seattle-Bremerton: 27.9 cents/kWh in Seattle, 21.9 cents/kWh in Bremerton
- Kingston: 9.9 cents/kWh for the initial JMII-class retrofit, 6.9 cents/kWh for subsequent 144-class new builds (one-side charging).

Initial electricity rates for the other case studies are as follows:

- Shore Power: 10.9 cents/kWh in Seattle City Light (SCL) service territory based on rate structure and anticipated capacity demand charges (personal communication, NWSA staff);
- Drayage Trucks: 8.2 cents/kWh in the near-zero carbon scenario (SCL) based on medium commercial customers (50 to 999 kW capacity)[12] and 7.6 cents/kWh in Puget Sound Energy (PSE) service territory based on average rates across secondary, large demand and primary large demand commercial customers.[13]
- Motor Coaches: 8.2 cents/kWh based on PSE rates as in the Drayage Truck study but with a cost-premium based on 5% of electricity demand being met by more expensive public charging.
- Passenger Vehicles: 15.7 cents/kWh (PSE) based on PSE residential rates at a 15% share of electricity demand being met by more expensive public charging.[14]
- Cargo-Handling Equipment: 7 cents/kWh for both Tacoma and Seattle.[15]

Baseline electricity cost increases are derived mainly from the ferry electrification life cycle Seattle-Bremerton route which projects a 2.4% increase in the Seattle (SCL) rate and a 3.0% increase in the Bremerton (PSE) rate by 2026, increasing to 8.9% and 11.3%, respectively, by 2050.[16] These rate increases are applied, on the basis of PSE as the service provider or not, throughout the other case studies. The other ferry routes have rate increases more consistent with their corresponding life cycle cost analysis studies.

Clean Energy Transformation Act (CETA) Impact on electricity costs

Previous research by the Low Carbon Prosperity Institute evaluated the projected cost increases associated with CETA compliance.[17] The compliance costs are expected to primarily impact investor-owned utilities (IOUs) rather than other utilities, including public utilities like Seattle City Light and Tacoma Power, due to the heavier reliance on fossil-fuel generation in their current generation mix. In modeling price increases for electric power throughout the case studies, we use the low and high cost increase projections from that research of a 4% increase in 2025 as coal-generation is fully eliminated, a 21% to 32% increase by 2030 for net-zero electricity, and a 24% to 39% increase by 2045 for a 99% emissions-free power supply.[18]

ADDITIONAL CASE STUDY DETAILS

In this section we report on additional assumptions that are in addition to or in adjustment to the key assumptions earlier in the report and appendix.

FERRY SYSTEM ELECTRIFICATION

The Ferry System Electrification case studies rely heavily on the initial Life Cycle Cost Analysis reports for the individual routes as well as the subsequent 2040 System Electrification Plan.

Public Health Impacts

Public health multipliers ($/t$CO_2$e) were derived from Table C.2 of the 2016 Puget Sound Maritime Emissions Inventory for Tier 1 (JMII retrofit) and Tier 4 (new builds of Olympic and 144-class vessels) engines sized 3,701+ kW.[19] The ratio of air pollutants and CO_2 was put into the methodology for public health benefits described at the beginning of the Appendix to determine the public health benefit multipliers for the two engine tiers.

Annual Electricity Demand

The electricity demand and annual percentage reduction in fuel consumption as originally reported in route-specific LCCA and related studies were adjusted for more recent information from the 2040 System Electrification Plan (SEP), based on the annual reduction in diesel consumption as follows:

- Seattle-Bainbridge: 95.3% reduction in LCCA study adjusted to 90.5% reduction in SEP;
- Mukilteo-Clinton: 95.55% reduction in LCCA adjusted to 95.7% reduction in SEP;
- Edmonds-Kingston:
  - For the Puyallup JMII retrofit, a 95.3% reduction in LCCA adjusted to a 78.4% reduction in the SEP;
  - For new 144-class builds, a 95.7% reduction as indicated in the SEP;
- Seattle-Bremerton: 94.2% reduction in LCCA adjusted to 84.5% reduction in SEP, due to a scaled down battery system (10 MWh rather than 12 MWh);
- HEO Relief Vessel: Average of the Mukilteo-Clinton and Seattle-Bremerton routes based on the SEP, for a total of 90.1%.
- Annual diesel reductions for the limited number of years without shore power range (Seattle-Bainbridge and Edmonds-Kingston routes only) are 13.3% to 13.5% based on estimates reported in the SEP.

Electricity Prices

In addition to the electricity price metrics described above, the following route-specific adjustments were made:

- Baseline Seattle-Bainbridge electricity prices, before accounting for any impact of CETA, were held constant. This is consistent with the original LCCA which projected a less than 1% increase in total electricity costs at each terminal between 2022 and 2059.
- Kingston baseline electricity prices were similarly held constant based on the original LCCA which showed a less than 1% change in electricity costs. The LCCA electricity costs were adjusted to reflect the SEP updates with charging occurring only at the Kingston terminal.
- Clinton electricity costs in the corresponding LCCA were projected to increase steadily and substantially over the base year (2018) costs: a 3.1% increase by 2023, 15% increase by 2050, and 32% increase by the final year of new vessel operation, 2086.

Terminal and Vessel Capital Costs

Terminal and vessel capital costs track the 2040 SEP forecasts. The terminal costs for each route in the case study include the total project costs from Table 5 (page 88) plus the total utility cost in Table 3 (page 84) of the 2040 SEP appendices.

Vessel conversion costs are adjusted from the LCCA estimates for the following routes:

- Two Olympic Class vessels on the Mukilteo-Clinton route, based on larger battery systems to meet system redundancy as described in the 2040 SEP (10 MWh instead of 3.2 MWh). The cost premium for each new ferry is increased from $4.7 million to $7.1 million based on a 2023 battery-cost estimate of $349/kWh taken from the LCCA.
- The additional Olympic class vessel (relief service) and the 144-class vessels (Edmonds-Kingston) were projected at the same total cost premium as the Seattle-Bremerton vessels, but adjusted to lower costs due to the battery system being installed at a later date when battery costs per kWh are anticipated to be lower.

The SEP calls for a smaller battery system, 10 MWh, than the originally planned 12 MWh on the Seattle-Bremerton route. However, no cost decrease was tracked to account for the smaller battery system.

Battery replacements are a major ongoing cost for these routes and are dependent on size and usage characteristics. Based on the original LCCA and battery engineering studies, along with any updated information from the 2040 SEP, the following battery replacement rates were assumed:

- Seattle-Bainbridge: every 4 years
- Mukilteo-Clinton: every 10 years
- Seattle-Bremerton: every 4 years
- Edmond-Kingston: every 5 years (JMII retrofit), every 9 years (144-class)
- HEO Relief vessel: every 10 years

Operational Days

Operational days were scaled by starting from the LCCA and 2040 SEP assumption and filling out operational time from relief vessels to ensure full system capacity is achieved. Annual fuel consumption is adjusted where necessary to align with the number of operational days. The following operational days per year were assumed:

- Seattle-Bainbridge with 365 days/year run-time by the retrofitted JMII class Wenatchee and Tacoma vessels. This reflects full service, although it would likely be filled with service by the retrofit Puyallup vessel during out-of-service windows for the Wenatchee and Tacoma.
- All non-relief HEO (Seattle-Bremerton and Mukilteo-Clinton) and 144-class (Edmonds-Kingston) new builds are assumed to operate 313 days per year, with the Puyallup filling gaps in service for the three 144-class vessels (156 days per year, starting in 2031) and the HEO relief vessel filling gaps in service on the Mukilteo-Clinton and Seattle-Bremerton routes (208 days per year).
- The Puyallup is assumed to run 208 days per year initially before shifting to a relief vessel role in 2031.

Sensitivity Analysis

We conducted a light sensitivity analysis on the ferry system electrification case study by adjusting some of the key model assumptions. These include:

- A pessimistic scenario where the present value discounting rate is set to 8% rather than 4%, PSE electricity is held at 2020 emissions rates with no cost discounting, shore power projects in Seattle, Bainbridge, and Kingston lag new vessels by 4 years rather than 2, and there are no additional diesel price impacts from the CFS or CCA programs
- An optimistic scenario where baseline diesel fuel prices are 20% higher leading to increased fuel cost savings ($2.40/gallon in 2023, $5.06/gallon in 2050), PSE emissions are treated as zero from the beginning of the project through use of Green-Up purchase premiums, terminal electrification costs do not include any contingency costs (following total project costs from Table 5 on page 88 of the SEP 2040 Appendices), and CETA impacts on electricity costs follow the “low” (21% price increase by 2030 and 24% price increase by 2045) rather than “high” (32% and 39% respectively) cost increases.

The range of cumulative outcomes from this simple sensitivity analysis (presented from optimistic to to pessimistic) is:

- 4.5 MtCO_2e to 2.5 MtCO_2e avoided
- $530 million to $220 million in NPV Public Health and Climate Benefits
- -$290 million to $140 million in NPV costs
- -$180 / t$CO_2$e to $320 / t$CO_2$e in NPV abatement costs
- Net benefits surpass net costs between 2031 and 2043

SHORE POWER

Our T-18 Shore Power case study was built upon an initial modeling calculation provided by the NWSA. The average shore duration (32 hours, with 30 hours drawing power), total power draw (34.7 MWh), and average auxiliary load (1,139 kW) were based on data shared by the NWSA in this initial calculation and via personal communication. Additional assumptions provided from initial NWSA data collection and analysis, which were subsequently reviewed for this report include:

- Seattle City Light Large General Service electricity rates, with two-thirds of power demand during peak service hours (6AM to 10PM), leading to a power cost per vessel call of $3,735 initially, rising to $4,021 after 30 years
- The total estimated budget includes $27.6 million in capital costs plus $1 million in planning costs according to NWSA Clean Air Strategy Implementation Plan Documents[20]
- Tier 0 through Tier 3 emissions for NO_x, $PM_{2.5}$, and VOC were provided from NWSA via personal communication. These were translated by our methodology into the following public health multipliers:
  - Tier 0: $361/t$CO_2$e (initial 20% share of shore power vessel calls, declining 2% per year for 10 years)
  - Tier 1: $323/t$CO_2$e (initial 65% share declining 2% per year starting in 2030)
  - Tier 2: $298/t$CO_2$e (initial 15% share declining 1% per year starting in 2040)
  - Tier 3: $148//t$CO_2$e (initial 0% share, increasing at the rate that Tier 0, 1, and 2 share decrease).

In addition to the vessel turnover assumptions, which are based on our general assumptions of long-lived infrastructure turnover, we also assume the trend will be to a greater share of vessels using shore power when docked. We assume an increase from the starting point of 197 calls/year (out of 398 calls at T-18) by 5 calls/year. Under this assumption, 86% of vessel calls use shore power at the end of the 30 year project life.

DRAYAGE TRUCKS

The new diesel truck purchase cost estimate of $180,126 per truck, the new electric truck purchase cost estimate of $290,194 per truck, and the per truck charging infrastructure costs of $68,698 were based on a CARB Draft Advanced Clean Trucks Total Cost of Ownership Discussion Document Appendix H.[21] Capital costs for the new electric trucks were assumed to be financed with a 0% down-payment and three-year, 3% financing plan. This is representative of a typical automobile loan and repayment schedule. Financing a new purchase is a normal practice according to the industry partners we collaborated with.

The model we developed spans a range of operational and maintenance costs for diesel and electric drayage trucks. As the diesel case involves replacement of older trucks, we assume the high range of maintenance costs for the diesel trucks ($0.19/mile) versus the mid-range for new electric trucks ($0.098/mile).[22]

An Energy Economy/Efficiency Ratio (EER) is needed to determine the relative fuel consumption compared to a diesel truck. An equation developed by CARB and corresponding to the average drayage truck speed shown in that CARB documentation (13 mph) was used to estimate an EER of 4.83.[23] The baseline diesel truck fuel economy estimate was 7 mpg.[24] Combining the EER and the baseline diesel truck efficiency results in an estimated fuel economy for the electric truck of 0.90 miles/kWh.

While we assumed an electricity rate of $0.075/kWh for PSE and $0.0815/kWh for SCL based on their current rate values for commercial customers and uncertainty about peak versus off-peak charging,[25,26] the greater demand charge for peak fueling (for SCL: $4/kW capacity peak versus $0.028/kW capacity for off-peak) provides a major incentive to fuel off-peak to the extent possible. Determining how/whether this would impact NWSA's operations and charging schedule is dependent on many factors that are beyond the scope of this report, so we refrain from speculation about the relative peak vs off-peak mix here.

ON-ROAD VEHICLE MODEL DEVELOPMENT

Newly developed companion modeling tools for the motor coaches and passenger vehicles case studies provide an adaptable, flexible, and highly useful model for investigating various vehicle classes, models, and incentive programs. These tools offer perspectives that are both relevant to and adjustable for program managers, policy-makers, fleet operators, and individuals.

The model interface and calculations are layered on top of a CARB benefits modeling tool.[27] In this specific case, the model basis is the Benefits Calculator Tool for the Low Carbon Transportation Program On-Road Consumer-Based Incentive Projects under the "On-Road Consumer-Based Incentives" Project Type.

Standard inputs to the original CARB model include vehicle classes, technology (e.g. battery electric vehicle or hybrid), baseline fuel type, VMT, and quantification period for the technology. Standard outputs include a fuel economy summary, criteria pollutant emissions factors (both well-to-wheel and tank-to-wheel - including exhaust, brake, and tire), annual and lifetime emissions benefits based on fixed emission intensities, fuel reduction, and fuel cost savings based on fixed fuel costs.

Our model layers additional metrics and assesses dynamic rather than fixed inputs (e.g. fuel costs and emissions intensities). The following additional metrics are built onto the original CARB tool:

- Time-evolving and program-specific emissions intensities and fuel costs
- Monetized estimates of public health and climate benefits
- Vehicle maintenance cost savings
- NPV accounting and the ability to incorporate multi-year vehicle financing, and
- The potential credit revenues associated with the clean fuel standard

On the front end of the model, we provide toggles for the following inputs and assumptions:

- Vehicle Description (fuel type, vehicle class, model year and model year replaced, lifetime miles driven, lifetime, mpg of baseline vehicle from model database or by user preference)
- Financing Parameters (% down, financed years, finance rate)
- Fuel and efficiency characteristics (energy efficiency ratio or EER of electric to combustion engine vehicle dependent on average vehicle speed, inclusion of various program costs on fuel prices, share of charging at private [home] facility, maintenance savings per mile)
- Baseline use-case and per-vehicle cost-premiums

We are refining several advanced capabilities for different use-cases that can tailor model usefulness to specific end-user goals and priorities. The focus of these capabilities is on:

- Investigating the impact of per vehicle incentive pricing on near, medium, and long-term ownership costs. This capability allows breakeven points and timeframes to be easily evaluated and readily displayed, both with and without clean fuel standard credits factored in. Such a perspective is useful for individuals, fleet purchasers, and those structuring incentive programs and funding allocations. This can be used to interrogate various combinations of vehicle type, vehicle cost premium, and vehicle incentive prices that result in desired breakeven cost timeframes, and also translate these to abatement costs ($/t$CO_2$e).
- An Incentive Framework module that allows the targeted payback period to be adjusted and allows the user to define whether CFS credits are factored in as part of the incentive.
- Program impacts and attribution, based on a user-defined share of program funding that directly correlates vehicle purchase decisions or uptake. Given user-defined funding size and allocation, the overall funding impact can be evaluated including the number of vehicles, the emissions reductions and abatement costs attributable to the program, and the NPV climate and public health benefits attributable to the funding.

MOTOR COACHES

The modeling tool used for this case study has a wide-range of applicability, extending upon a tool originally developed by CARB.[28] The maintenance cost savings are our "mid" case estimate ($0.14/mile) of an electric versus diesel motor coach, which are based on the difference (diesel minus electric) in average maintenance of Class 8 tractor and Class 4 parcel delivery savings from Table 5 of an NREL report (high maintenance cost scenarios).[29] We use the "high" estimate from that report as our "mid" case for this case study, as it is substantially below private industry estimates we received ($0.27/mile), which can be used as the "high" maintenance savings assumption in the model.

The cost premium for accessing public charging infrastructure is assumed to be 2.1 times the home-base charging cost, based on a relative per unit cost of $0.19 for public charging versus $0.09 for home-base charging. This assumption is contained within the original CARB model and tracked through relative to retail electricity costs in our model. The motor coaches are assumed to receive 5% of the energy needs from public charging.

PASSENGER VEHICLES

The overarching modeling tool and approach follows that of the motor coach study, but is adjusted for gasoline as the baseline fuel along with different vehicle types and characteristics. In the passenger vehicle scenarios, we assume that 15% of the annual energy needs are satisfied by public charging at the higher cost rate described in the motor coach assumptions above. Maintenance savings are assumed to be $0.013 per mile for a new electric vehicle relative to a new gasoline vehicle. This is based on the "low" maintenance savings taken from the motor coach methodology.

CHARGING INFRASTRUCTURE: PRELIMINARY NEEDS ASSESSMENT

Charging infrastructure needs assessments are unique in that they include only upfront costs and do not attempt to quantify return on investment or additional emissions reductions. Emissions reductions are assigned at the vehicle level rather than at the charger or charging network level. Therefore, these cost estimates represent a conservative estimate by not including ongoing revenue streams that partially or fully offset upfront costs.

Passenger Vehicles

The Charging Infrastructure needs for passenger vehicles are determined based on three pieces of information:

- The State Energy Strategy forecasting of 1 million light-duy EVs by 2030 and 2.3 million light-duty EVs by 2035[30]
- Previously completed EV charging needs assessments in California and Oregon for a similar scale of EV uptake[31]
- A range of per-charging port installation costs for publicly available infrastructure: $650/kW at the low-end for a shared-public charger in 2020 (forecast to decline slowly to $533/kW by 2050),[32] $9,322 cost per L2 connection, and $102,914 cost per fast-charging connection based on CEC data[33]

Combining the charging needs (one fast-charger for every 71 [OR] to 200 [CA] vehicles and one Level 2 charger for every 7 [CA] to 21 [OR] vehicles) with the estimates of charging port costs gives a range of $500 to $1,800 in public charging infrastructure costs per vehicle.

For the lower-end of the range, we assume, based on our interpretation of the NREL No Place Like Home study (see Figure 10 of main report), that roughly 25% of the EV population will be reliant on public charging. This is roughly the share without home charging access at between 25% ("Existing Electrical Access") and 100% ("Enhanced Electrical Access (w/ parking behavior mod)"). As we are conservatively assuming in the Passenger Vehicle study that each vehicle purchased is accompanied by a new Level 2 home charger at substantial capital cost, additional charging infrastructure costs associated with public charging concentrate on the public charging needs for the remaining 25% of the vehicle population. We assume that all Level 2 charging needs within this vehicle population are met by 10 kW capacity chargers at $650/kW. We assume a split in fast-chargers between 150 kW (60% of fast-chargers) and 350 kW (40% of fast-chargers), also at $650/kW.

Despite the different prioritization of level 2 versus fast-charging in the Oregon and California assessments, the total costs range is driven mostly by the per kW installation costs rather than the relative preference for type of charging station. For example, at the lower installation costs from the MJ Bradley report, the relative cost range is $500 to $700 per vehicle. At the higher installation costs from the CEC report, the relative cost range is essentially the same ($1,800 to the nearest hundred).

Based on these calculations, total capital costs are $0.5 to $1.8 billion for a vehicle population of 1 million by 2030. As the vehicle population increasingly converts to electric for a total of 2.3 million by 2035, total capital costs grow to $1.1 to $4.2 billion by 2035.

Medium and Heavy-Duty Vehicles (MHDV)

The Charging Infrastructure needs for MHDVs are based on scaling to 50% of current miles traveled by those vehicle classes. The cost-methodology and range is documented in the case study chapter. Because we are assuming large infrastructure costs within the MHDV case studies, and subsequently estimating some scaling of those for overall magnitude (Table 16 of the main report), the estimates here are not treated as additional to those costs. Rather, they are illustrative of the charging infrastructure cost premium, separate from the vehicle cost premium, and of the scale of investment needed for an even more ambitious charging infrastructure rollout than projected in Table 16 and across a wider range of vehicle types than the two MHDV case studies in this report.

The cost range of $1.8 to $9.2 billion is based on the following assumptions of fleet size and infrastructure cost range, assuming 50% of each vehicle class is electrified.[34,35]

- Class 2b: 283,257 vehicles at $5,000 to $20,000 per vehicle infrastructure costs
- Bus, class 3-8: 11,908 vehicles at $10,000 to $20,000 per vehicle infrastructure costs
- Work and freight,class 3-8: 199,343 vehicles at $6,000 to $40,000 per vehicle infrastructure costs
- Combination Truck, class 7-8: 45,109 vehicles at $20,000 to $100,000 per vehicle infrastructure costs

CARGO HANDLING EQUIPMENT

The Cargo Handling Equipment case study utilizes the Clean Off-Road Equipment Voucher Incentive Project (CORE) calculator tool as a starting point, with additional model capabilities and sensitivities built upon that platform. The following assumptions, based in large-part on documents provided by and other personal communication with NWSA staff, are used for input into the CORE calculator tool developed under the CARB California Climate Investments Program:[36]

- First year of operation: 2024 for all equipment types;
- Equipment lifetime:
  - Terminal Tractor: 12 years
  - Top Straddler: 15 years
  - Straddle Carrier: 15 years
  - RTG, retrofit: 20 years
  - RTG, new: 30 years
- Baseline equipment replacement is year 2005 for all except for terminal tractors which are assumed to be year 2009 models
- Baseline engine horsepower:
  - Terminal Tractor: 190 horsepower
  - Top Straddler: 360 horsepower
  - Straddle Carrier: 370 horsepower
  - RTGs, retrofit and new: 900 horsepower

- Baseline annual fuel consumption:
  - Terminal Tractor: 3,000 gallons
  - Top Straddler: 9,000 gallons
  - Straddle Carrier: 9,000 gallons
  - RTGs, retrofit and new: 15,080 gallons (due to model logic and flow, this value is equivalent to the avoided fuel consumption, with the low-carbon equipment set to 0 fuel consumption).[37]
- Total capital costs per piece of electric or hybrid equipment are derived from initial cost estimates provided by the NWSA based mainly on CHE demo projects and assessments at other west coast ports.
  - Terminal Tractor: $450,000
  - Top Straddler: $2,267,000
  - Straddle Carrier: $2,833,333
  - RTG, retrofit: $500,000
  - RTG, new: $1,417,500
- Avoided future diesel equipment replacement costs (halfway through new equipment lifetime) are scaled as a percentage of the electric or hybrid equipment to align with initial cost estimates provided by NWSA:
  - Terminal Tractor: $100,000
  - Top Straddler: $566,750
  - Straddle Carrier: $708,333
  - RTG, retrofit: $1,300,000
  - RTG, new: $1,304,100
- Future baseline diesel equipment replacement, efficiency gain versus existing equipment is assumed to be 25% for all equipment
- Future baseline diesel equipment reduction in toxic criteria pollution relative to existing equipment is assumed to be a 75% reduction in all cases
- Maintenance cost savings are calculated per hour of run-time, and are estimated to be the following:
  - Terminal Tractor: $7.22/hour
  - Top Straddler: $8.70/hour
  - Straddle Carrier: $8.70/hour
  - RTG, retrofit: no maintenance savings for hybrid models

APPENDIX FOOTNOTES

[1] Goodkind, A. L., Tessum, C. W., Coggins, J. S., Hill, J. D., & Marshall, J. D. (2019). Fine-scale damage estimates of particulate matter air pollution reveal opportunities for location-specific mitigation of emissions. Proceedings of the National Academy of Sciences, 116(18), 8775-8780. t.ly/xrq0

[2] Reduced Complexity Models are commonly used tools to screen for public health impacts from air pollution. They use geographic data on population density, wind patterns, and point source behavior to estimate the health impacts from pollution. For more details on RCMs used in this study, see CACES.us.

[3] Kurman-Faber, J., Tempest, K., & Wincele, R. (2020). Building Back Better: Investing in a Resilient Recovery for Washington State. Low Carbon Prosperity Institute. t.ly/Wick1

[4] Interagency Working Group on Social Cost of Greenhouse Gases, 2016 (t.ly/U4mo). Other studies project the social cost of carbon could be as high as \$417 per tCO_2e as reported in the 2020 Building Back Better report (t.ly/Wick1)

[5] PSE's 2020 Greenhouse Gas Inventory Appendix Table 7 reports Total Firm & Non-Firm Contracts Purchases & PSE Generated value of 20,839,813,847 kWh and 8,260,552 tCO_2e (link to PDF of inventory: www.pse.com/-/media/PDFs/GHG_Inventory_2020.pdf?modified=20210624214457).

[6] Fuel mix disclosure. (2022, January 12). Washington State Dept. of Commerce. t.ly/gvye

[7] Page 10 of: Elliot Bay Design Group. OLYMPIC CLASS Hybrid Life Cycle Cost Analysis. February 28, 2019. PDF received by personal communication with Vigor.

[8] There is no price adder assumed for the 10% biodiesel blend that WSF is already using.

[9] Oil Monster North America Bunker Fuel Prices (t.ly/kxKX), accessed on 10/15/2021

[10] Carbon tax assessment model. (2021, February 25). Washington State Dept. of Commerce. t.ly/VbRZ

[11] Percentage reductions in emissions intensity increase by 0.5% in 2023 and 2024, 1% per year in 2025-2027, 1.5% per year in 2028-2031 to a total of 10%. Starting in 2034, percentage reductions increase by 2% per year until a total 20% reduction is reached in 2038 and held at 20% moving forward. Emissions intensities are on a life-cycle basis and are described in the preceding section. Compliance and credit costs are assumed to start at \$175/tCO_2e in 2023 based on recent price points in California and Oregon, and assumed to decrease by \$5/tCO_2e per year to a floor of \$50/tCO_2e starting in 2043.

[12] Business rates - City light. (2022). seattle.gov. Retrieved January 28, 2022, from t.ly/WjON.

[13] Downloadable PDF with rates available at: t.ly/IPpy

[14] Ibid. But for residential rates.

[15] These rates are close to the rates for commercial or industrial customers, but do not fully take into account potential demand charges (\$ / kW of capacity). Depending on capacity requirements and peak versus off-peak usage characteristics, the electricity rates could be higher, in closer alignment to the Shore Power electricity rates.

[16] Elliot Bay Design Group. OLYMPIC CLASS Hybrid Life Cycle Cost Analysis, Seattle-Bremerton Route. October 28, 2019. PDF received by personal communication with Vigor

[17] Tempest, K. (2019, March 27). Analysis of 100% clean bill (SB 5116) cost cap – Low carbon prosperity institute. Low Carbon Prosperity Institute. t.ly/QHZi

[18] Cost increases are capped at 99% GHG-free power supply as the our projections for cleaning the last 1% are highly volatile and potentially substantially greater. Cost increases are phased in incrementally starting in 2028 to meet 2030 requirements and starting in 2043 to meet 2045 requirements.

[19] 2016 Puget Sound maritime air emissions inventory. (revised 2018, October). Puget Sound Maritime Air Forum. t.ly/yp8b

[20] The full implementation plan can be found at the NWSA webpage: t.ly/hOZA

[21] Table 18. Appendix H Draft Advanced Clean Trucks Total Cost of Ownership Discussion Document. (2019). California Air Resources Board. t.ly/JDQW

[22] Hunter, C., Penev, M., Reznicek, E., Lustbader, J., Birky, A., & Zhang, C. (2021). Spatial and temporal analysis of the total cost of ownership for class 8 tractors and class 4 parcel delivery trucks. t.ly/lsx4

[23] CARB. Battery-Electric Truck and Bus Energy Efficiency Compared to Conventional Diesel Vehicles t.ly/KAQm

[24] Table 18. Appendix H Draft Advanced Clean Trucks Total Cost of Ownership Discussion Document. (2019). California Air Resources Board. t.ly/JDQW

[25] 2022-01-01 ELECTRIC PRICE SUMMARY for Residential & Commercial/Industrial Customers. (January 1, 2022). Puget Sound Energy. Retrieved January 24, 2022, from t.ly/fu1m

[26] Seattle City Light. (n.d.). Business rates - Seattle, Renton, and King County Businesses. Seattle.gov. Retrieved January 24, 2022, from t.ly/aEQq

[27] The full range of quantification methodologies and tools can be found at: t.ly/dXDc

[28] Draft On-Road Consumer-Based Incentive Draft Calculator Tool. (n.d.). California Air Resources Board. Retrieved October 28, 2021, from t.ly/CX4x

[29] Hunter, C., Penev, M., Reznicek, E., Lustbader, J., Birky, A., & Zhang, C. (2021). Spatial and temporal analysis of the total cost of ownership for class 8 tractors and class 4 parcel delivery trucks. t.ly/lsx4

[30] 2021 State Energy Strategy. (2021, October 22). Washington State Department of Commerce. t.ly/1qaFL

[31] Oregon's Transportation Electrification Infrastructure Needs Assessment (t.ly/pizM) and California's Electric Vehicle Charging Infrastructure Assessment - AB 2127 (t.ly/OMOf)

[32] Lowell, D., Saha, A., Freeman, M., MacNair, D., Seamonds, D., & Langlois, T. (2021). Clean Trucks Analysis: Costs & Benefits of State-Level Policies to Require No- and Low-Emission Trucks. MJ Bradley and Associates. t.ly/fGfi

[33] Alexander, M., Crisostomo, N., Krell, W., Lu, J., & Ramesh, R. (2021). Electric vehicle charging infrastructure assessment - AB 2127. California Energy Commission. t.ly/MbOq

[34] Lowell, D., Saha, A., Freeman, M., MacNair, D., Seamonds, D., & Langlois, T. (2021). Clean Trucks Analysis: Costs & Benefits of State-Level Policies to Require No- and Low-Emission Trucks. MJ Bradley and Associates. t.ly/fGfi

[35] As described for the Motor Coach case study, this range is based generally off of Low: MJ Bradley projected charging needs (t.ly/fGfi) for a transit bus (50 kW home-depot charging, 20% at 500 kW public charging) with \$650-\$700/kW infrastructure costs; High: California Energy Commission DC-Fast Charging costs per station (t.ly/zkZY) with an assumed 0.87 chargers required per vehicle (more than one vehicle shares a single charger, on average).

[36] California quantification methodologies and calculator tools are accessible at: t.ly/sXTj

[37] The 58% reduction is based on technology specification estimates EPA's Verified Technologies for SmartWay and Clean Diesel MJ EcoPower Hybrid Systems, Inc.—EcoCrane Hybrid System t.ly/56KD