# Estimating the Breakeven Cost of Delivered Electricity To Charge Class 8 Electric Tractors

Jesse Bennett, Partha Mishra, Eric Miller,
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**Technical Report**
NREL/TP-5400-82092
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## NOTICE

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*Cover Photo by Dennis Schroeder: NREL 31855.*

# Errata

This report, originally published in October 2022, has been revised in December 2022 to provide clarification on a few parts of the executive summary based on feedback from DOE that came after the report was published. This includes details on the naming structure for each scenario with a footnote at the bottom of Table ES1 directing the reader to Table 1 for more details on how each scenario was developed. There is also clarification statement at the bottom of page v that highlights the process for including a wide range of parameters for this analysis that are incorporated into each of the scenarios.

# Acknowledgments

The authors wish to thank the U.S. Department of Energy Vehicle Technologies Office, and Lee Slezak and Jacob Ward in particular, for their support of the 1+MW and depot charging analysis projects that led to the development of en route and depot charging demand for Class 8 tractors. The 1+MW effort for en route charging has further supported the development of the Electric Vehicle Infrastructure – Energy Estimation and Site Optimization tool (EVI-EnSite). The authors would also like to thank the Hydrogen and Fuel Cell Technologies Office for their continued support of the Hydrogen Financial Analysis Scenario Tool (H2FAST) over the years. This tool is the foundation for the Electric Vehicle Infrastructure – Financial Analysis Scenario Tool (EVI-FAST), which is used to evaluate the different charging station scenarios.

The authors would also like to recognize the substantial contributions for this work from the 21st Century Truck Partnership (21CTP), Electrification Technical Team, Charging Infrastructure Working Group. The working group consists of 21CTP members from vehicle manufacturers and government representatives, as well as invited utility and fueling service providers. This report is the culmination of over a year of discussions on the approach for developing travel profiles, modeling vehicle adoption, and determining the site infrastructure and grid infrastructure upgrades that form the key inputs to this analysis. All aspects of this work have been developed and reviewed by this team. The authors would especially like to thank the following members for their significant contributions: Mark Kosowski and Dan Bowermaster (Electric Power Research Institute), Michael Potter and Ian Sutherland (General Motors), Jordan Smith (Southern California Edison), Tom Canada (Southern Company), and Lucy Lu (Ford).

# Executive Summary

As electrification of transportation expands, it is important for owners and operators of class 8 tractors to understand the wide range of impacts that may result from this momentous change. These considerations include operational implications, such as energy requirements and charging power needs as well as financial impacts such as the initial capital investments and operational and maintenance costs. This study considers, under a select number of specific scenarios, how all these factors can be accounted for and summarized in a breakeven cost to charge class 8 tractors. There are a total of 20 scenarios considered in this study that account for a range of varying parameters such as site utilization, installation costs, distribution upgrades, and a select number of utility rates. These scenarios are intended to be illustrative of the process to estimate these costs and are not intended to be representative of all possible charging station configurations and rate options. The scenarios were selected to identify potential impact from variations in these parameters but are not bounding assumptions.

The results present a possible breakeven cost to charge class 8 tractors as observed from a station operator, which could be a fleet manager operating a private depot with electric vehicle supply equipment (EVSE) specifically for their fleet, or a charge service provider with EVSE available for public use. The breakeven cost to charge is determined by NREL's EVI-FAST as the price at which an operator would need to sell electricity to receive the internal rate of return specified as input parameters to the analysis in Section 3.4. The intent of these results is to present the full scope of what is required to support the charging of class 8 tactors and the cost to provide that service. However, the actual price to charge may be different due to variations in the cost and utilization factors, as well as market influences and business practices. The breakeven cost to charge under each scenario, as defined in Table 1, are presented in Table ES1. The results for each of these scenarios were considered under two electric utility rate structures as defined in Table 6 and were selected to represent a rate with relatively low and high demand charges with an inversely related shift in energy charges to present the impacts from variations in each rate element.

**Table ES1. Summary of Breakeven Cost to Charge by Scenario and Rate Structure**

| Scenario | EVSE Unit Power (kW) | Site Charging Capacity (MW) | Initial Capital Investment ($M) | Breakeven Cost with Rate 1 ($/kWh) | Breakeven Cost with Rate 2 ($/kWh) |
|---|---|---|---|---|---|
| DLL | 50 | 0.95 | $0.8 | $0.21 | $0.26 |
| DLH | 50 | 0.95 | $1.3 | $0.22 | $0.27 |
| DHL | 150 | 3.6 | $4.7 | $0.17 | $0.21 |
| DHH | 150 | 3.6 | $7.8 | $0.19 | $0.23 |
| TLL | 150 | 1.5 | $1.6 | $0.23 | $0.27 |
| TLH | 150 | 1.5 | $2.3 | $0.25 | $0.30 |
| THL | 150 | 1.5 | $1.6 | $0.20 | $0.24 |
| THH | 150 | 1.5 | $2.3 | $0.22 | $0.26 |
| ELL-kW* | 150 | 1.4 | $1.4 | $0.23 | $0.19 |

| Scenario | EVSE Unit Power (kW) | Site Charging Capacity (MW) | Initial Capital Investment ($M) | Breakeven Cost with Rate 1 ($/kWh) | Breakeven Cost with Rate 2 ($/kWh) |
|---|---|---|---|---|---|
| ELL-MW* | 3,000 | 21 | $13 | $0.27 | $0.38 |
| EHL-kW* | 150 | 3.9 | $4.1 | $0.22 | $0.18 |
| EHL-MW* | 3,000 | 42 | $25 | $0.18 | $0.23 |

*ELL and EHL scenarios simulate both kW and MW EVSE at a single site

** See Table 1 for detailed scenario descriptions (**D**epot, **T**ravel Center, **E**n Route), (**L**ow and **H**igh Utilization) and (**L**ow and **H**igh Install Costs)

These results, present a range of charging costs from as low as $0.17/kWh to as high as $0.38/kWh. This wide range of costs represents the wide range of station scenarios and cost parameter considerations used in this study but should not be interpreted as the upper and lower bounds of what is possible. These results present how variations in demand charges, station utilization, as well as the installation and upgrades resulting from site peak demand influence the breakeven cost to charge. An example of these impacts would be a comparison between the results for DHH and DLH. Although DHH has significantly higher initial capital investment than DLH, the increased utilization in DHH results in a lower breakeven cost to charge. However, it is clear from both these scenarios that a higher demand charge, even when coupled with a relatively lower energy charge, will increase the breakeven cost to charge.

Therefore, while these results cover multiple possible scenarios and the potential breakeven cost to charge class 8 tractors, it should be noted that each site will have specific considerations resulting in different values for the breakeven cost to charge. This report outlines the process used to estimate the breakeven cost to charge by establishing parameters for each scenario, as outlined in Appendix B, which were the key inputs to NREL's EVI-FAST tool, which generated the results presented throughout this report and are summarized in Appendix C. This process provides a framework to consider site-specific and use-case specific parameters; in particular: utilization rate, installation costs, and utility rate, that will be critical in understanding the breakeven cost to charge electric vehicles.

## List of Acronyms

| | |
|---|---|
| 21CTP | 21st Century Truck Partnership |
| EVI-EnSite | Electric Vehicle Infrastructure – Energy Estimation and Site Optimization tool |
| EVI-FAST | Electric Vehicle Infrastructure – Financial Analysis Scenario Tool |
| EVSE | electric vehicle supply equipment |
| NREL | National Renewable Energy Laboratory |
| SOC | state of charge |

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# 1 Introduction

As vehicle electrification expands from the light-duty sector to include larger commercial medium- and heavy-duty vehicles, businesses need to decide if electrification is appropriate for their fleets. A key factor in this decision will be the total cost of ownership for on-road electric Class 8 tractors compared to their combustion counterparts. Total cost of ownership will be most influenced by the cost fleets incur to charge these vehicles (Hunter et al. 2021). Most light-duty fleet applications are best served by AC Level 2 charging defined by the SAE International J1772 standard (Bennett et al. 2019). As outlined in this study, Class 8 tractors use more energy than light-duty vehicles. Additionally, Class 8 vehicles are driven to fulfill specific vocations, such as freight hauling, meaning that they spend more time driving and must adhere to a stricter schedule compared to passenger vehicles. Larger vehicles used in commercial applications are much more likely than light-duty vehicles to rely on high-power DC charging technologies to meet their operational requirements. Without sufficient utilization (e.g., low early-market charging demands), installing and operating these high-power chargers increases the cost of charging per unit of energy (Borlaug et al. 2020).

This report examines the breakeven cost of electricity for electric Class 8 tractor charging to address its importance in the total cost of ownership for the operation of an electrified fleet and to account for the inherent differences of higher-power charging. The breakeven cost to charge is determined by NREL's Electric Vehicle Infrastructure – Financial Analysis Scenario Tool (EVI-FAST) (NREL 2022) and defined as the price at which an operator would need to sell electricity to receive the internal rate of return specified as input parameters to the analysis in Section 3.4. To understand the possible cost of delivered energy, given the stated assumptions—in this report the breakeven cost—to charge electric tractors, this study followed an analysis framework, outlined in Figure 1, that considers a wide range of factors to estimate the breakeven cost to charge at various station types. This requires an estimation of electric vehicle adoption trajectories and analysis of real-world fleet data to assess energy needs of heavy-duty electric tractors and to determine expected charging station demand over time. Station demand informs the level of electric vehicle supply equipment (EVSE) deployment that is necessary at each station type, as well as the site utilization and anticipated load profiles. Then, by accounting for a wide range of capital investments, operating costs, and other expenses, a breakeven cost of energy is determined.

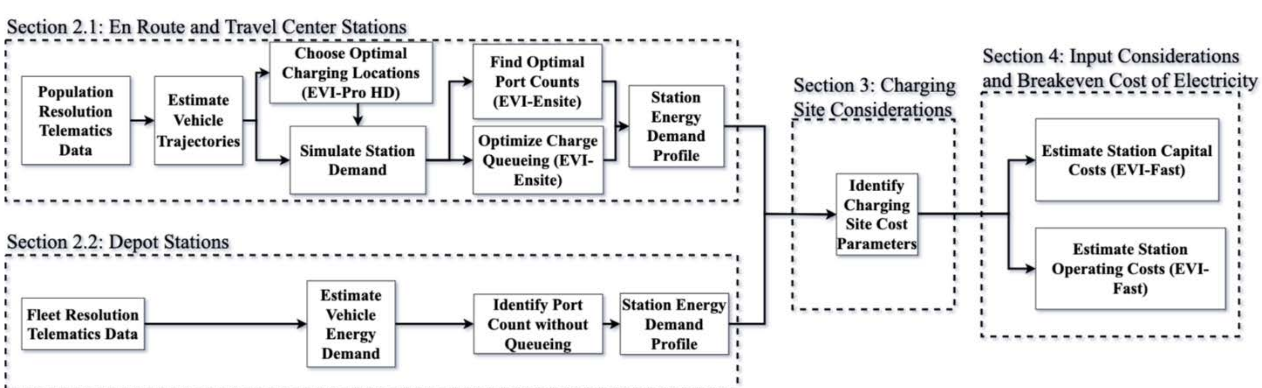



**Figure 1. Analysis framework**

This framework is applied to multiple scenarios accounting for a wide range of applications and situations. The scenarios are primarily defined by the station type, which includes private depots, travel centers, and en route locations. Depot-based operations include vehicle charging that occurs primarily at privately owned facilities, sometimes referred to as "behind the fence" charging. It is assumed that depot charging will occur during longer dwell periods and the EVSE will be owned and managed by the fleet owner for the vehicles that regularly dwell at these locations. This contrasts with travel centers and en route locations, which are public stations offering charging services to heavy-duty vehicles. While it is likely that public charging locations will also serve medium- and light-duty vehicles, these additional loads are not modeled in this study. Like depots, travel centers in this study serve the charging need of vehicles with long dwell times during driver rest periods, and therefore provide EVSE with a similarly low charging power. However, some drivers will require stations designed to serve shorter dwell periods to immediately complete their trip, thus requiring the use of EVSE with up to 3 MW of power (Mishra et al. 2020).

The en route locations in this study serve a broader range of charging needs, offering high-powered EVSE for short dwell periods and low-power EVSE for long dwell periods, and require much larger grid interconnections (10 MW or more). These sites are considered separately from travel centers, as they are likely to be placed at locations where the grid has sufficient capacity and installation costs are lowest to mitigate upfront capital investments. Each of these location types will be the basis for a series of scenarios considered throughout this study. Table 1 outlines each of the scenarios, defined by location type, station utilization, and installation costs, with a corresponding abbreviation for each. Station utilization refers to how often the EVSE at the location is in use and is explored in Section 2. Installation costs, explored in Section 3, are the capital expenses incurred to develop a charging location, including items such as the EVSE, site infrastructure, and utility upgrades. It should be noted that while the depot and travel center scenarios have both low and high installation cost considerations, the two en route scenarios only consider low installation costs. These scenarios are both considered low-cost installs as it is assumed that the en route sites would be built in locations where installation costs are lower given the significant grid capacity available.

**Table 1. Definition of Scenario Names**

| Scenario Name | Location Type | Utilization Rate | Install Cost |
|---|---|---|---|
| DLL | Depot | Low | Low |
| DLH | Depot | Low | High |
| DHL | Depot | High | Low |
| DHH | Depot | High | High |
| TLL | Travel Center | Low | Low |
| TLH | Travel Center | Low | High |
| THL | Travel Center | High | Low |
| THH | Travel Center | High | High |
| ELL | En Route | Low | Low |
| EHL | En Route | High | Low |

# 2 Station Siting and Load Analyses

This section provides background on the methodologies used to simulate charging demand, locate charging stations, and produce site-specific load profiles for the three station types considered in this study—en route, travel center, and private depot.

## 2.1 En Route and Travel Center Stations

### 2.1.1 Identifying Charging Locations

High-power charging at the megawatt level enables the electrification of Class 8 regional and long-haul tractors by ensuring that drivers can complete their existing routes without excessive delay (Mishra et al. 2020). Through the use of high power levels, such as 3 MW, electric tractor batteries can be fully charged at a duration approaching the time it takes to refuel a typical diesel tractor. Installing infrastructure capable of such high-power charging will be expensive but crucial to meeting the operational requirements of regional and long-haul tractors. In this work, we review conventional Class 8 tractor travel data (Fleet DNA) and select charging locations in a coordinated, intelligent manner whereby Class 8 regional and long-haul travel can be electrified by a minimal set of high-power charging locations. Generating such a set of stations is known as a maximal covering set problem. In this problem, each vehicle can only be converted from diesel to electric if, over the course of its existing route, a set of charging stations exist so that it never needs to exceed the range of its onboard battery without having the opportunity to charge. This constraint is central to the underlying linear program, whose details can be found in Mishra et al. (2022) but are omitted here for brevity. Note that this approach does not consider modification to the travel route or alternate freight movement strategies. The linear program seeks to maximize the number of miles driven by electric tractors given a fixed budget of high-power en route charging stations with one or more charging dispensers (EVSE). The parameters of this optimization are the range of the vehicle in miles and the number of stations that can be built. This report focuses on vehicles with a range of 450 miles with an additional buffer of 50 miles. Correspondingly, the optimum set of stations is collated in a data set that we call R450, containing station schedules where vehicle range is 450 miles.

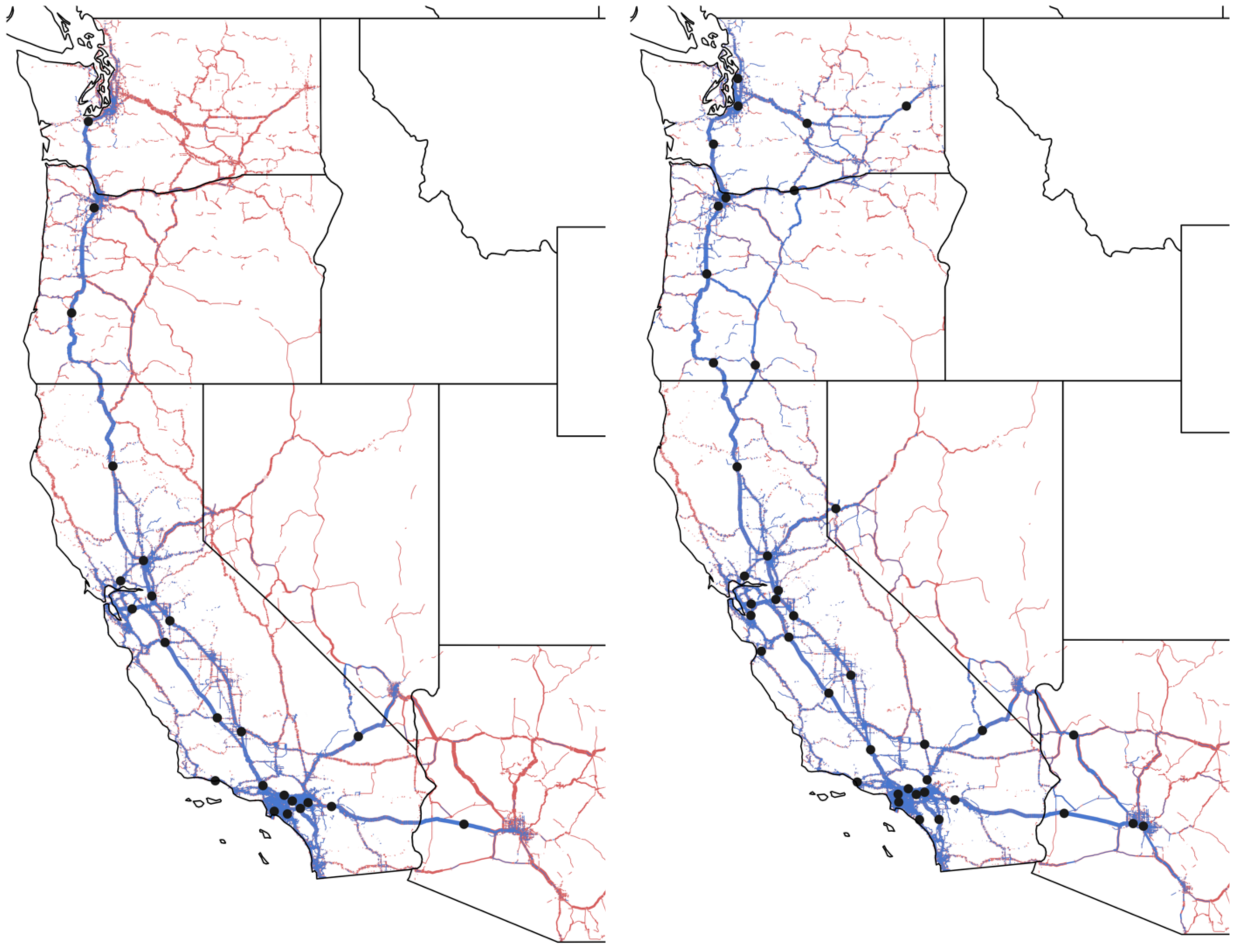


**Figure 2. Electrified driving (blue lines) increases as the number of en route charging locations (black dots) increases for the R450 case (vehicles have 450 miles of driving range on one charge)**

Additionally, opportunities are identified where vehicles may be able to charge at reduced power levels, on the order of kilowatts (kW) rather than megawatts (MW). These locations include fleet depots, warehouses, truck stops, and rest areas. These kilowatt-level charging locations are identified by manually inspecting areas where trucks stop for 4 or more hours. If, by review of satellite imagery and land use data, the tractor appears to be stopped at a depot, warehouse, rest area, or truck stop, then it was eligible to charge at reduced power. The inclusion of kilowatt-level charging locations increases the use cases where tractors could be electrified, as a result of a more robust charging network. This increase in tractor electrification also increases the number of tractors electrified per megawatt-level charging station, but the effect is minimal in the current data set, as there are few vehicles with use cases requiring access to public kilowatt-level charging. Although the electrification impact is still small, the number of vehicles that can operate charging only at depots grows significantly as the range of the vehicles increases from 300 to 450 miles. Figure 3 shows the distribution of longest trip distances, as defined by driving segments terminated by a dwell period exceeding four hours, and the cumulative percent of the trucks in the R450 data set that could be electrified without megawatt-scale charging as a function of usable battery range, assuming adequate coverage of kilowatt-level chargers and no change to existing operations.

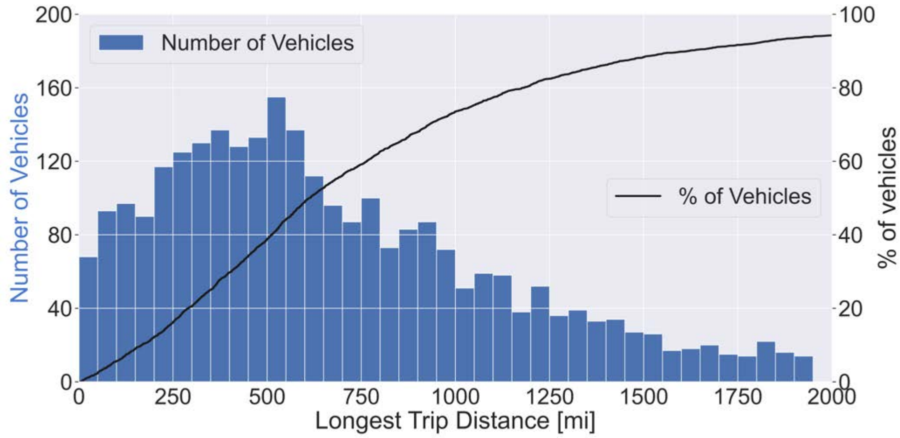



**Figure 3. Count of longest trips throughout the vehicles within the R450 data set**

### *2.1.2 Vehicle Adoption Scenarios*

The use of en route megawatt-level public charging stations, and thus the breakeven cost of charging, will be dependent on how quickly the fleet adopts electric vehicles. The HDStock model is used to estimate the number of vehicles in use by powertrain and size class based on total sales, sales share by powertrain, and age-specific scrappage rates. HDStock was developed for the Vehicle Technologies Office Analysis Program and is updated and calibrated annually to the U.S. Energy Information Administration's latest Annual Energy Outlook. For this study, HDStock was used to analyze two scenarios of Class 8 tractor electric vehicle adoption. A low adoption scenario was developed by linearly extrapolating Bloomberg New Energy Finance's Electric Vehicle Outlook 2020, which projects those electric vehicles could reach 10% of global heavy commercial vehicle sales by 2040. The high scenario is developed as a "what-if" scenario where the California Advanced Clean Trucks regulation's mandate for zero-emission vehicle sales (California Air Resources Board 2019) is assumed at the national level, with electric vehicle sales achieving 30% market share by 2030. This scenario extrapolates beyond the California mandate for tractors, which is capped at 40%, to reach 80% of sales by 2040. The sales share assumptions and resulting estimates of electric vehicles as a percent of in-use stock are shown in Figure 4. These scenarios are intended to provide bounding conditions for the analysis to evaluate the impact of the adoption rate on the breakeven cost of electricity at public charging sites and is not intended to forecast adoption.

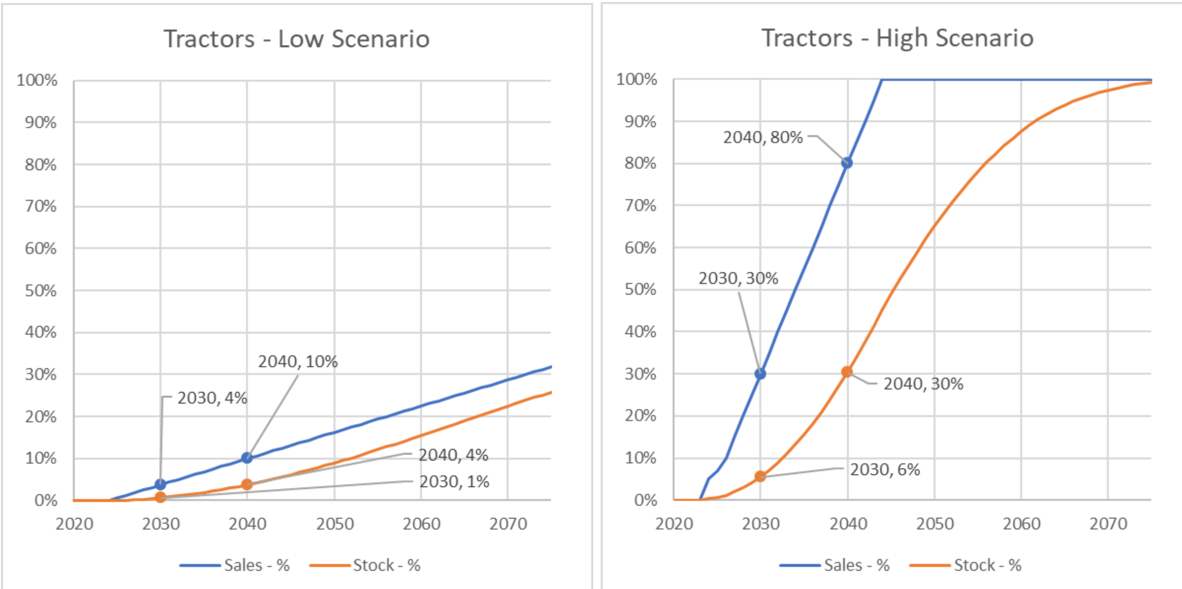



**Figure 4. Low and high national adoption scenarios of Class 8 tractors**

### 2.1.3 Generating Station Schedules

Station demand schedules were generated using a Monte Carlo simulation method using the optimal set of stations and conventional vehicle travel data. The vehicle trajectories and station locations are used to estimate a vehicle's state of charge (SOC) through an agent-based simulation approach by accounting for energy use by the vehicle's route of travel and charge events when it passes a station. The probability that a driver will stop at the station increases as the projected vehicle SOC decreases, reflecting driver preference for fewer recharging stops. This decision process is executed iteratively for each vehicle until it has driven its entire route and is valuable in reducing infrastructure and operating costs of truck charging by minimizing the number of stations. Driver preference for kilowatt-level charging is also reflected in this simulation to avoid excessive use of higher power chargers with a likely higher cost of energy. Drivers will forgo charging at other stations along their route if they are able to reach a kilowatt-level charger on their current charge and similarly will only partially charge at a megawatt-level station if they know that they will be stopping at a kilowatt-level station.

This method was oversampled by changing the vehicle range, initial SOC, and start time randomly to simulate a larger fleet. Since the size of the data set used in this study is estimated to be slightly greater than 2% of the national Class 8 trucking fleet, vehicle charging is oversampled nine times to obtain charging scenarios for 20% of the national fleet. The aggregate of these many individual driver decisions is a schedule of charging demand for each station, which includes the arrival time and charge energy required every time a vehicle stops at that location.

Demand schedules are combined when a kilowatt-level station is located within 5 miles of a megawatt-level station to reflect the role that megawatt-level stations will likely fulfill as en route locations where drivers also rest as mandated by law.

### 2.1.4 Station Load Analyses

The station schedules generated are analyzed for station design requirements and resultant station load profiles using the National Renewable Energy Laboratory's (NREL's) Electric Vehicle Infrastructure – Energy Estimation and Site Optimization tool (EVI-EnSite) (NREL 2021). Figure 5 shows a schematic of how EVI-EnSite emulates station operation and what kind of input data and processes are involved to model such behavior. The tool uses an agent-based modeling approach where the vehicles and a station are defined by a set of respective properties. For a vehicle, these defining properties are its battery capacity, arrival time, initial SOC, final desired SOC or energy demand, and a charge acceptance curve. Arrival time and initial SOC can be stochastic parameters, but in this study, deterministic data are used by preprocessing the station schedules. The charge acceptance curve of a vehicle, which is a map between SOC and maximum charging power of the battery pack and is chemistry-dependent, is used as a proxy to emulate more complex control algorithms of a battery management system. By using the charge acceptance curve, EVI-EnSite ensures that the battery charging power is limited by either the port power capacity or the battery management system control action.

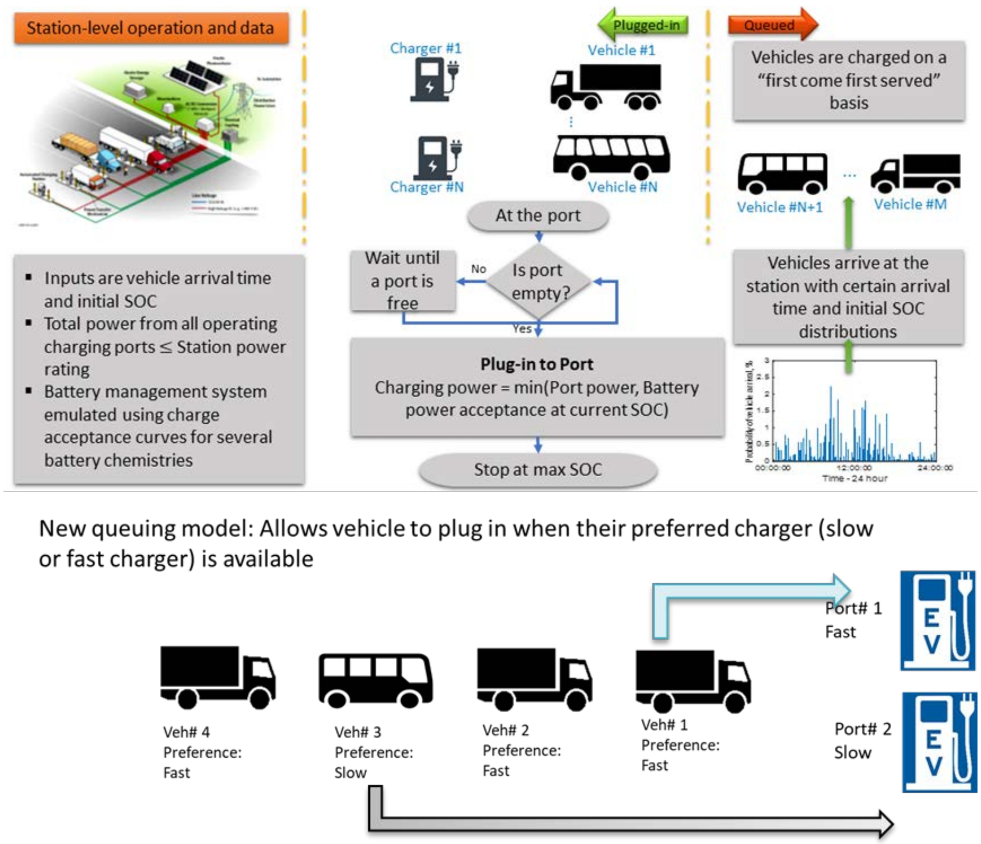



**Figure 5. EVI-EnSite: An agent-based charging station modeling and analysis tool to investigate operational behavior**

A station, on the other hand, is defined by the number of charging ports, port capacity, and the station capacity. When a vehicle arrives at the station, it is either plugged into a charging port if a desired port is empty or queued if all the ports are occupied. Charging is complete when the battery pack SOC reaches a predefined maximum value or a requested level of energy is added to the pack. Using the generated station schedules, we simulate the station operation over a period of 4 weeks at a time step of 1 minute. After the simulation is complete, several station performance metrics and data are calculated, including station peak and average power demand, charging energy needs by port type, and average and maximum charging and waiting time. Since this report focuses on a public charging setup, we simulated uncoordinated, first-come, first-served charging operation at the station.

#### 2.1.4.1 Station Analysis and Representative Stations

This section presents a discussion on downselecting representative stations from the station schedules, preprocessing the data for EVI-EnSite analysis, and the underlying assumptions in this study. Out of the 1,514 identified locations in the R450 data set, 169 locations are identified as en route locations, meaning vehicles primarily charge at megawatt-scale (defined as 3 MW EVSE for this report), short-dwell-period ports with some options to charge at kilowatt-scale (defined as 50 kW and 150 kW EVSE for this report), long-dwell-period ports. Of the remainder, 1,133 locations are identified as depot locations, which are analyzed separately, and 212 locations qualify as travel centers that can host kilowatt-level, long-dwell-period charging ports.

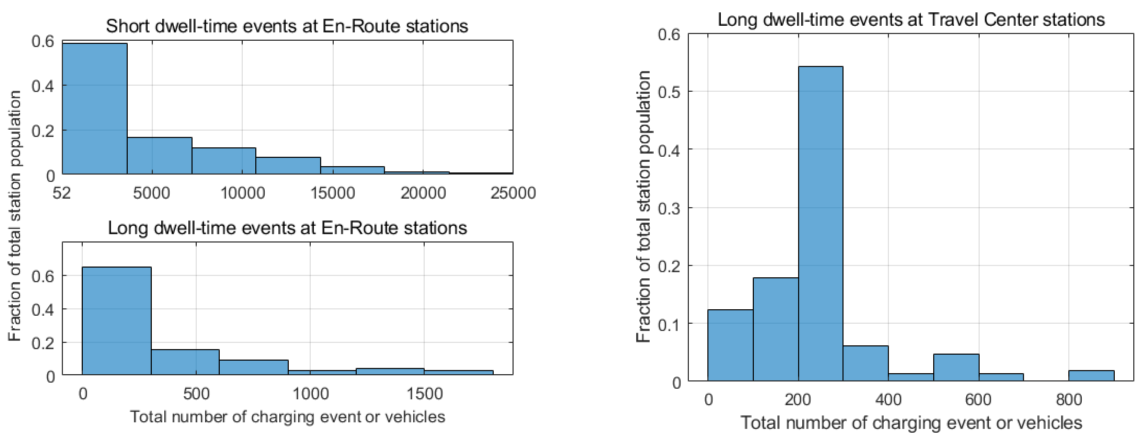



**Figure 6. Distribution of total charging events or vehicles in (left) en route and (right) travel center stations**

Figure 6 shows a probability distribution of the total number of charging events or vehicles over a 28-day period at the identified en route and travel center locations undergoing short- or long-dwell-time charging events. These figures are for the entire population of each type of station and indicate the fraction of the station population across the charging network that might see a given range of total charging events. Note that this distribution is evaluated for a scenario with 20% of vehicle stock electrified, which would occur at different years depending on the vehicle adoption scenario (see Figure 4). We selected stations closest to the median and 80$^{th}$ percentile, as well as median and 95$^{th}$ percentile, of the total vehicles from the en route data and travel center data, respectively, as representative stations with mid and high utilization (Table 2).

**Table 2. Median and 80th/95th Percentile Number of Charging Events or Vehicles at Different Types of Stations Over a 28-Day Period**

| Station Type | Type of Charging | Median | 80th/95th Percentile |
|---|---|---|---|
| En route | Short dwell | 2,063 | 6,839 |
| | Long dwell | 170 | 559 |
| Travel center | Long dwell | 281 | 561 |

#### 2.1.4.2 Simulation Assumptions

The station schedules contain information about vehicle charging need in terms of miles because the vehicle schedules are generated using vehicle telematics data. Some assumptions are made to convert these data in miles to an equivalent energy value, and thus make them compatible with EVI-EnSite's inputs. Specifically, the following assumptions/preprocessing are made:

1. For the R450 data set, total vehicle ranges are lumped into a 250-mile range for vehicles with travel distances less than 200 miles, which allows for a 50-mile buffer, and into a 500-mile range for vehicles with travel distances greater than or equal to 200 miles. This allows us to assume a total battery pack capacity for different vehicles.
2. These ranges and required miles to charge are converted to energy (in kilowatt-hours) by using a suitable energy consumption value. For earlier adoption scenarios, assuming 2% of the national stock is electrified, we assume an on-road energy consumption of 2.1 kWh/mile, and 1.8 kWh/mile for later adoptions.
3. En route stations are assumed to have charging ports with capacities of 3 MW, such as the power capabilities available in the MCS Standard (Tetik, n.d.), for short-dwell-time charging and 150 kW for long-dwell-time charging. Travel center stations have only 150-kW chargers.
4. Finally, we assume that vehicles in the lower adoption scenario have a charge acceptance curve based on the constant current, constant voltage charging protocol rated at a C-rate of 1.5C, whereas at higher adoption level, the rating is increased to 3C. Figure 7 shows example charge acceptance curves with the two C-rates (lower and higher adoption scenario) for a 250-mile-range vehicle (corresponding battery sizes of 525 and 450 kWh at lower and higher adoption scenarios, respectively to reflect the efficiency differences).

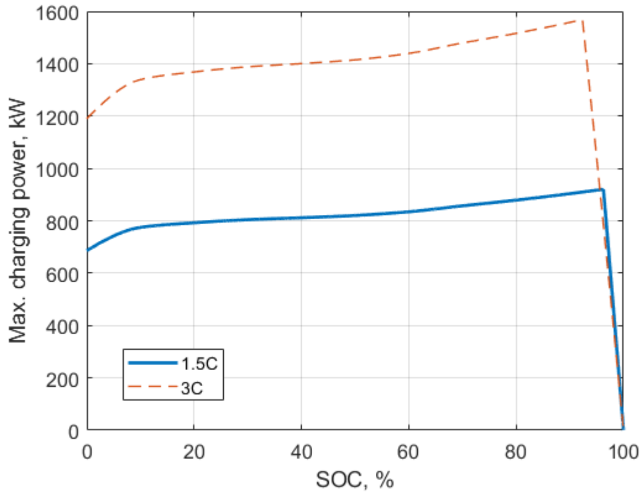
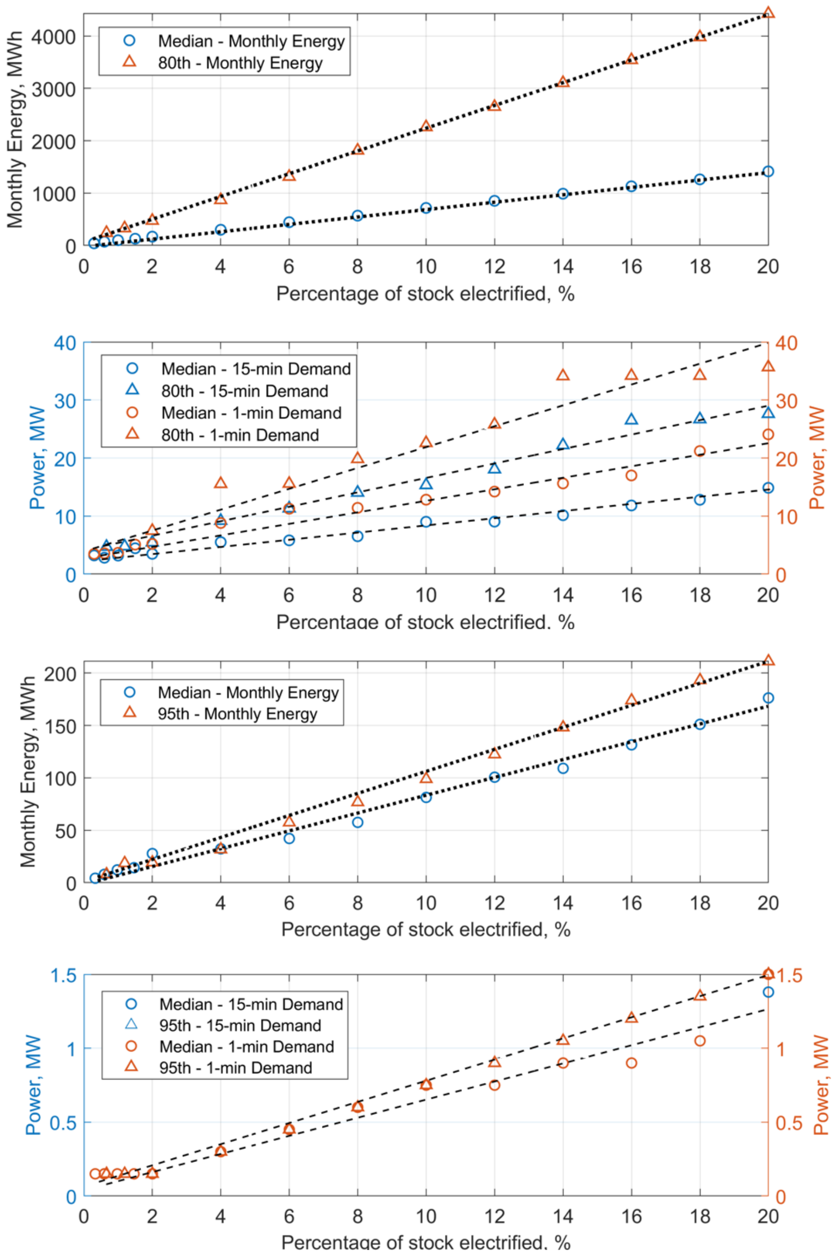



**Figure 7. Example of charge acceptance curves for a vehicle with 250-mile range**

### 2.1.4.3 En Route and Travel Center Loads

Station operation is simulated using the assumptions and scenarios delineated in earlier sections, focusing specifically on the R450 data set. The objectives of the simulation were to understand the infrastructure needs and utilization of a representative station as more electrified vehicles are adopted in the national stock. We analyzed electrified vehicle adoption scenarios up to 20% of the national stock for the en route and travel center stations at fixed stock points for both station scenarios (median and 80$^{th}$ percentile). The high and low utilization cases are chosen from these two stations, median and 80$^{th}$ percentile, respectively, and their utilization ramps reflect the power and energy at each station for the given low and high adoption rates in Figure 4. Figure 8 shows how energy demand and power loads change for these stations as a function of the stock adoption rate. It is important to note, specifically for the en route stations, that the difference between 15-min averaged power demand and 1-min power demand increases as adoption increases. This is because with increased adoption of high-C-rate vehicles, the average charging power over 1-min intervals may capture higher portions of the charging curve than would be observed over the average of a 15-min interval . In other words, charge events of less than 15 min result in lower power demand when averaged over a longer 15-min time window.



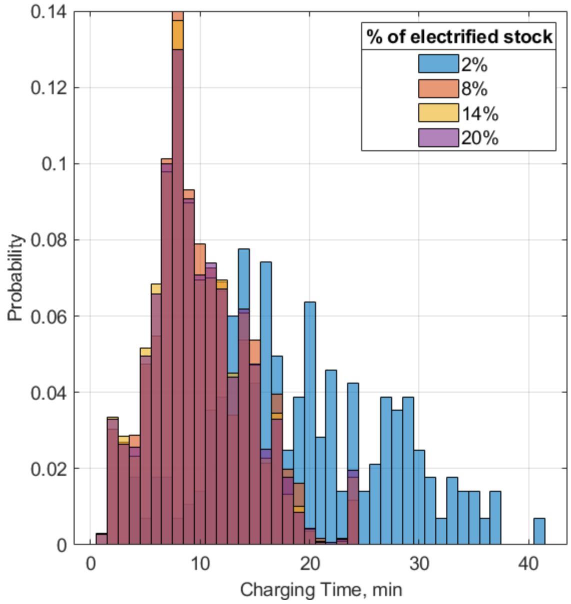

(Top) Monthly energy demand and peak power (averaged over 15-min and 1-min windows) as a function of percentage of electrified stock in en route stations. Results are for the previously identified median and 80th percentile stations.

(Bottom) Monthly energy demand and peak power (averaged over 15-min and 1-min windows) as a function of percentage of electrified stock in travel center stations. Results are for the previously identified median and 95th percentile stations.

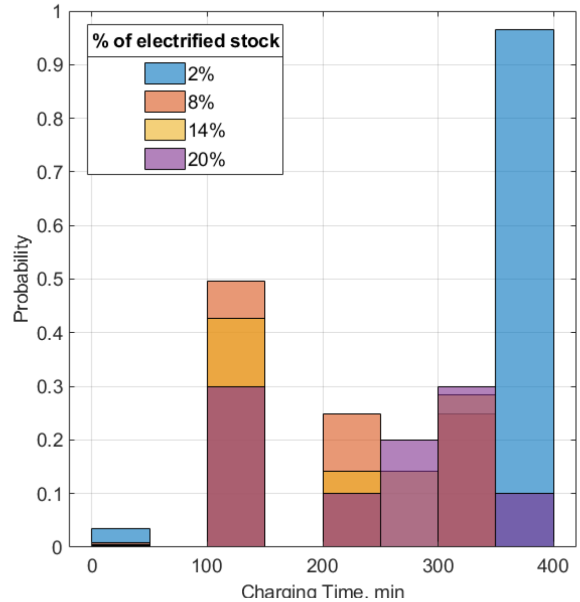
**Figure 8. Energy and power demands in en route and travel center stations**

Figure 9 shows the distribution of resultant charging times for (a) vehicles charging at MW-scale ports in en route stations and (b) vehicles charging at kW-scale ports in travel centers at the median representative stations of each. The different colored bars represent vehicles at different adoption levels (2%, 8%, 14%, and 20% of the electrified stock). Figure 9a specifically shows how the assumption of 3 MW capacity ports and vehicle maturity at higher adoption level (that allows for 3C charging rates) can result in average charging times of 10 mins for the trucks in the R450 data set. With higher BEV adoption, the charging time distribution for megawatt-scale charging at en-route stations moves towards a 10-min median value from an 18-min median value at 2% adoption. For the travel center station, charging times are much higher than the 15-

min averaging window; hence, the differences between 15-min and 1-min power demands are minimal.




(a) Distribution of charging time in megawatt-scale ports at the median en route station.




(b) Distribution of charging time in kilowatt-scale ports at the median travel center station.

**Figure 9. Distribution of charging times in median stations**

The low adoption scenarios in Section 2.1.2 combined with the site-level load profiles, through the use of NREL's EVI-EnSite tool, for median stations at fixed adoption levels throughout the travel center and en route scenarios create the long-term utilization metrics for the low-utilization scenarios (e.g., TLL, ELL). Similarly, the high utilization scenarios (e.g., THL, EHL) have been developed using the 80$^{th}$/95$^{th}$ percentile stations and load profiles from Section 2.1.2. The site peak demand, long-term utilization, and demand ramp for the travel center and en route scenarios are summarized in Table 3. Additionally, each of these stations is simulated with a peak utilization of 20% due to coincident need for charging resulting in queing at higher utilization rates. The energy and demand changes throughout the operation of a station are used in Section 4 to calculate the breakeven cost of electricity. The kilowatt- and megawatt-level charging at the en route stations have been separated in this analysis to allow for individual analysis at the same location in these scenarios.

**Table 3. Station Utilization Parameters for Travel Center and En Route Scenarios from EVI-EnSite**

| Scenario | EVSE Power (kW) | EVSE Count | EVSE Capacity (MW) | Site Peak Demand (MW) | Long-Term Utilization | Demand Ramp (years) |
|---|---|---|---|---|---|---|
| TLL, TLH | 150 | 10 | 1.50 | 1.76 | 20% | 18 |
| THL THH | 150 | 10 | 1.50 | 1.76 | 20% | 12 |
| ELL-kW* | 150 | 9 | 1.35 | ~ | 11% | 10 |
| ELL-MW* | 3,000 | 7 | 21.0 | 10.0 | 6% | 10 |
| EHL-kW* | 150 | 26 | 3.90 | ~ | 10% | 15 |
| EHL-MW* | 3,000 | 14 | 42.0 | 20.0 | 10% | 15 |

*ELL and EHL scenarios simulate both kW and MW EVSE at a single site

## 2.2 Depot Stations

Considerations for vehicle energy needs, site design, and utilization at depot stations will differ from public en route and travel center locations. This is due to several factors, including the constraints and relative certainty of energy demand in fleet operations, as well as an understanding of utilization ramp as a result of electrification planning.

### 2.2.1 Depot Operations

Battery electric short-haul trucks, characterized by routes <200 miles (Federal Highway Administration 1997), may be able to perform most of their charging while off-shift and parked at one (or several) private depot locations. Depot charging has several advantages over public stations, including increased convenience and reliability and the opportunity to lower breakeven charging cost by participating in managed charging programs, such as in Southern California Edison (2019). This analysis leverages a recent study by Borlaug et al. (2021) to model the charging demands and daily depot load profiles of two real-world conventional heavy-duty delivery fleets in NREL's Fleet DNA database (NREL 2020). The first is a warehouse delivery fleet, averaging 83 miles/vehicle-day; the second is a food delivery fleet averaging 123 miles/vehicle-day (see Appendix A). These fleets are further summarized in Table 4 and Borlaug et al. (2021).

**Table 4. Summary of Short-Haul Delivery Fleets in the Depot Analysis**

| Fleet Vocation | Vehicles | Vehicle Days | Operating Range | Daily Vehicle Miles Traveled | Daily Off-Shift Dwell Hours |
|---|---|---|---|---|---|
| Warehouse delivery | 9 | 111 | ≤50 miles | 83 | 15.0 |
| Food delivery | 21 | 325 | ≤100 miles | 123 | 13.8 |

### 2.2.2 Depot Load Profiles and EVSE Requirements

Fleet charging behaviors are modeled under the following assumptions:

1. Operating schedules from conventional trucks do not change due to electrification.

2. Short-haul battery electric trucks have an average energy consumption rate of 2.35 kWh/mile, determined through 21st Century Truck Partnership (21CTP) expert elicitation
3. Trucks are able to charge without queuing—i.e., fleet operators purchase and install as much EVSE as needed to ensure that a port is available upon arrival at the depot.
4. Charging is unmanaged—i.e., trucks are charged as soon as possible after a shift ends until either the battery is fully charged or a subsequent shift begins, and at a rate determined by the energy demands and off-shift dwell times of a particular fleet (50-kW DC and 150-kW DC for the warehouse delivery and food delivery fleets, respectively).
5. Trucks are charged at constant power with no tapering given the low (<0.5) C-rates modeled.
6. Trucks are unavailable to charge for 15 min immediately preceding or following a shift, accounting for the time taken to plug and unplug the vehicle.

For further information on how fleet charging demand profiles are produced in this study, refer to Borlaug et al. (2021).

The typical fleet size for tractors operating out of a common depot location is inferred from 2013 vehicle registration data (IHS Markit 2013). We find in these data that most inferred depot locations (~95%) have five or fewer tractor registrations and that nearly all locations (>99%) have 100 or fewer registrations. When disaggregating by the two fleet vocations considered in this study (i.e., "Food Processing & Distribution" and "General Freight"), the average fleet size per depot increases, with ~5% of locations having fleets of 25 to 100 tractors (Figure 10). However, the likelihood of a location having >100 tractors is rare (<1%). Thus, for this study we consider fleet sizes of 20 to 50 tractors operating out of a single depot, reflecting the size of fleets that have already publicly announced plans to electrify their facilities (Shroeder 2021; Bollier 2021) while ensuring fleet sizes are realistic.

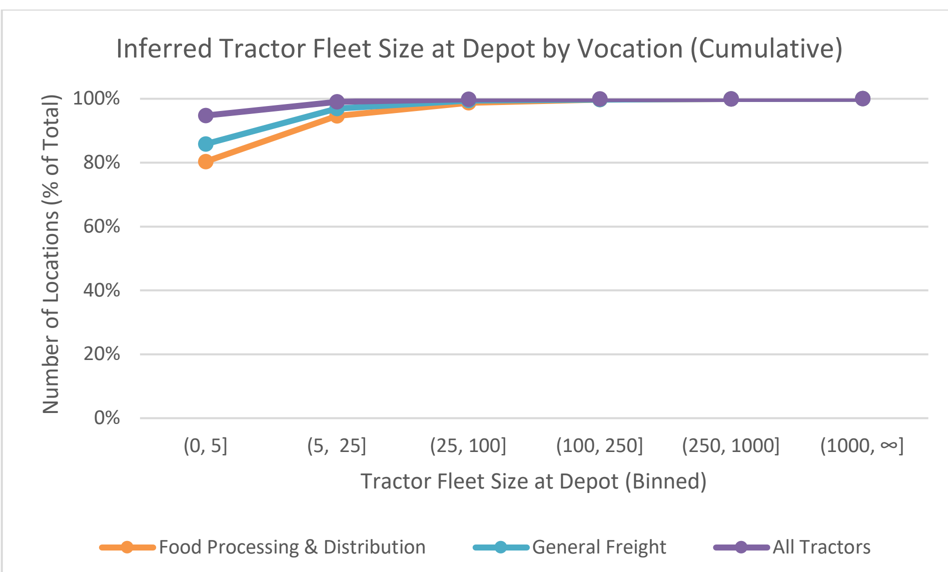



**Figure 10. National distribution of tractor fleet size for depots inferred from vehicle registration data**

Table 5 summarizes the site energy demands for the four depot charging scenarios modeled in this study. The two low utilization scenarios (DLL and DLH) are derived from the simulated charging demands of 20 warehouse delivery tractors operating from a single depot, and the high utilization scenarios (DHL and DHH) are based on the food delivery fleet charging demand with 50 tractors. The EVSE port counts are sized to allow port sharing due to staggered vehicle schedules but do not allow for queuing. In contrast to the publicly available en route and travel center site scenarios where charging demand is dependent on widespread fleet electrification, the demand ramp-up period for private depot charging is just 2 years, representing a case of rapid fleet turnover due to favorable economics or other factors.

**Table 5. Station Utilization Parameters for Depot Scenarios**

| Scenario | EVSE Power (kW) | EVSE Count | EVSE Capacity (MW) | Site Peak Demand (MW) | Long-Term Utilization | Demand Ramp (years) |
|---|---|---|---|---|---|---|
| DLL, DLH | 50 | 19 | 0.95 | 1.11 | 18% | 2 |
| DHL, DHH | 150 | 24 | 3.60 | 4.23 | 19% | 2 |

# 3 Input Cost Considerations

Charging station designs associated with each of the developed scenarios are critical in understanding the costs associated with site development and operation to determine the breakeven cost of charging. Installation costs, including the EVSE unit, installation, and utility upgrades, will reflect key capital investments that will be incurred. However, there are many other considerations such as utility rates, operating expenses, and station improvements that must be accounted for throughout the life of the station. In order for a station to recoup the costs of these investments, these initial costs must be amortized across all anticipated charging, which is dependent on the station utilization.

All of these considerations will be combined using NREL's EVI-FAST (NREL 2022) to determine the breakeven cost of charging under various scenarios. EVI-FAST provides analysis on the financial considerations, including capital expenditures, loan and investor considerations, and site operations and maintenance to estimate the breakeven cost to charge electric vehicles. The tool uses generally accepted accounting principles to provide a wide range of results. The charging cost breakdown outlines the details and contributing factors associated with the breakeven cost to charge. The site utilization by year outlines the average annual EVSE utilization rate as a factor of time. This helps to explain the results from the annual cost of goods sold, which is represented in dollars per kilowatt-hour and presented in real dollars as referenced from the first year of the analysis (2025 for this study). Each of these results helps to explain in more detail the breakeven cost to charge and is a factor of the input parameters outlined in the following sections.

## 3.1 Utility Rate Structures

One of the most crucial elements impacting the breakeven cost to charge is the electric utility rate structure. Utility rates vary based on different factors such as geographic region, location or customer type, service voltage, and interconnection level. For this study, two rate structures were identified in agreement with the 21CTP infrastructure working group that were informed by an

NREL rate study (McLaren, Mullendore, and Gagnon 2017) and a rate report from Edison Electric Institute (2020). They are defined by an energy charge, demand charge, and annual interconnection fee. As outlined in Table 6, Rate 1 has a relatively average energy charge coupled with a relatively low demand charge, whereas Rate 2 has a relatively low energy charge and average demand charge. Each rate also includes a $1,890 annual interconnection fee. These rates are not intended to be representative of average rates in low- and high-cost regions or customer conditions, but instead have been chosen to identify sensible rate structures that can be used to provide insight into sensitivity of changes in energy and demand charges on the breakeven cost to charge.

**Table 6. Rate Structures**

| Rate | Energy Charge ($/kWh) | Demand Charge ($/kW/month) | Interconnection Fee ($/year) |
|---|---|---|---|
| Rate 1 | $0.065 | $5 | $1,890 |
| Rate 2 | $0.030 | $15 | $1,890 |

## 3.2 EVSE Costs

One of the most critical expenses regarding the installation of a charging station is the unit cost of the EVSE itself. The cost of these units as represented in dollars per kilowatt were developed in agreement with the 21CTP infrastructure working group as informed by market analysis performed by the Electric Power Research Institute and a report developed by Gladstein, Neandross & Associates (GNA) for megawatt charging (GNA 2021) and a report by BNEF (Fisher 2020) for kilowatt charging. To account for variability in these costs, ranges were determined for each EVSE power level—50 kW, 150 kW, and 3 MW—with the low installation cost scenarios accounting for the lower end of the range and the high installation cost scenario accounting for the higher end of the range. These costs are outlined for each scenario in Table 7, detailing the EVSE unit cost and total site costs for all EVSE.

**Table 7. EVSE Costs for Each Scenario**

| Scenario | EVSE Unit Power (kW) | EVSE Unit Count | EVSE Cost ($/kW) | EVSE Unit Cost ($/unit) | Total EVSE Capacity (MW/site) | Site Total EVSE Cost ($K) |
|---|---|---|---|---|---|---|
| DLL | 50 | 19 | $382.90 | $19,145 | 0.95 | $363.8 |
| DLH | 50 | 19 | $519.40 | $25,970 | 0.95 | $493.4 |
| DHL | 150 | 24 | $299.72 | $44,958 | 3.60 | $1,079 |
| DHH | 150 | 24 | $415.68 | $62,352 | 3.60 | $1,496 |
| TLL | 150 | 10 | $299.72 | $44,958 | 1.50 | $449.6 |
| TLH | 150 | 10 | $415.68 | $62,352 | 1.50 | $623.5 |
| THL | 150 | 10 | $299.72 | $44,958 | 1.50 | $449.6 |
| THH | 150 | 10 | $415.68 | $62,352 | 1.50 | $623.5 |
| ELL-kW* | 150 | 9 | $299.72 | $44,958 | 1.35 | $404.6 |

| Scenario | EVSE Unit Power (kW) | EVSE Unit Count | EVSE Cost ($/kW) | EVSE Unit Cost ($/unit) | Total EVSE Capacity (MW/site) | Site Total EVSE Cost ($K) |
|---|---|---|---|---|---|---|
| ELL-MW* | 3,000 | 7 | $300.00 | $900,000 | 21.0 | $6,300 |
| EHL-kW* | 150 | 26 | $299.72 | $44,958 | 3.90 | $1,169 |
| EHL-MW* | 3,000 | 14 | $300.00 | $900,000 | 42.0 | $12,600 |

*ELL and EHL scenarios simulate both kW and MW EVSE at a single site

In order to facilitate the installation of EVSE units, the site costs must account for the land requirements for site equipment (Black & Veatch, n.d.), parking, and traffic flow, as well as the regular maintenance of EVSE including both hardware repairs and the network connection costs necessary for transaction processing. These maintenance costs were agreed upon by the 21CTP infrastructure working group and informed by a report from GNA (GNA 2021). The rent and land requirements for these costs were developed in consultation with real estate experts and site layout designs developed within the 21CTP infrastructure working group. The variability in land rent was accounted for through variations between low and high installation cost scenarios, as detailed in Table 8. Additionally, the assumption was made for depot scenarios that land required to park vehicles was an expense associated with regular fleet operations and was therefore not included in the financial analysis.

**Table 8. EVSE Maintenance and Land Costs for Each Scenario**

| Scenario | EVSE Unit Power (kW) | EVSE Count | EVSE Maintenance ($/year) | Land Required (acres) | Land Rent ($K/year) |
|---|---|---|---|---|---|
| DLL | 50 | 19 | $60,800 | 1.2 | N/A |
| DLH | 50 | 19 | $60,800 | 1.2 | N/A |
| DHL | 150 | 24 | $76,800 | 2.1 | N/A |
| DHH | 150 | 24 | $76,800 | 2.1 | N/A |
| TLL | 150 | 10 | $32,000 | 0.8 | $20.0 |
| TLH | 150 | 10 | $32,000 | 0.8 | $20.0 |
| THL | 150 | 10 | $32,000 | 0.8 | $20.0 |
| THH | 150 | 10 | $32,000 | 0.8 | $20.0 |
| ELL-kW | 150 | 9 | $28,800 | 0.5 | $12.5 |
| ELL-MW | 3,000 | 7 | $22,400 | 0.5 | $12.5 |
| EHL-kW | 150 | 26 | $83,200 | 1.5 | $37.5 |
| EHL-MW | 3,000 | 14 | $44,800 | 1.0 | $25.0 |

**ELL and EHL scenarios simulate both kW and MW EVSE at a single site*

## 3.3 Installation and Utility Upgrade Costs

The costs associated with installing EVSE can at times be as expensive, if not more so, than the units themselves. For the purposes of this study the team made assumptions on the installation costs for each station configuration, included all wiring, conduit, protection, and other facility equipment upgrades, as well as construction costs such as trenching that may be required. Put simply, this metric captures all of the installation and construction costs—with the exception of the EVSE unit—for everything on the charging station side of the utility meter. Many of the station configurations have a high (Scenario names: "xxH") install cost scenario, and a low (Scenario names: "xxL") install cost scenario to reflect the range of possible installation costs for a given station configuration. These metrics are presented in Table 9 and were developed in agreement with the 21CTP infrastructure working group as informed by the International Energy Agency's *Global EV Outlook 2021* (International Energy Agency 2021) and a report developed by GNA (GNA 2021).

**Table 9. EVSE Installation Costs for Each Scenario**

| Scenario | EVSE Unit Power (kW) | Install Cost ($/kW) | EVSE Install ($/unit) | EVSE Capacity (MW/site) | Site Install Cost ($K) |
|---|---|---|---|---|---|
| DLL | 50 | $420.00 | $21,000 | 0.95 | $399.0 |
| DLH | 50 | $750.00 | $37,500 | 0.95 | $712.5 |
| DHL | 150 | $750.00 | $112,500 | 3.60 | $2,700 |
| DHH | 150 | $1,080.00 | $162,000 | 3.60 | $3,888 |
| TLL | 150 | $750.00 | $112,500 | 1.50 | $1,125 |
| TLH | 150 | $1,080.00 | $162,000 | 1.50 | $1,620 |
| THL | 150 | $750.00 | $112,500 | 1.50 | $1,125 |
| THH | 150 | $1,080.00 | $162,000 | 1.50 | $1,620 |
| ELL-kW | 150 | $750.00 | $112,500 | 1.35 | $1,013 |
| ELL-MW | 3,000 | $65.00 | $195,000 | 21.0 | $1,365 |
| EHL-kW | 150 | $750.00 | $112,500 | 3.90 | $2,925 |
| EHL-MW | 3,000 | $65.00 | $195,000 | 42.0 | $2,730 |

*ELL and EHL scenarios simulate both kW and MW EVSE at a single site

In addition to all the installation costs on the facility side of the electric meter, many charging stations will also have EVSE capacity that requires upgrades to equipment on the utility side of the meter. Similar to the installation costs, many of the station configurations have a high (Scenario names: "xxH") utility upgrade cost scenario, and a low (Scenario names: "xxL") utility upgrade cost scenario to reflect the range of possible upgrades that may be required for a given station configuration. The utility upgrade costs outlined in Table 10 were agreed upon by the 21CTP infrastructure working group as informed by reports from GNA (GNA 2021) and Black & Veatch (Black & Veatch 2019). The level of utility upgrades required to support interconnection to the grid varied by the site's peak demand. For both the depot and travel center scenarios, the site peak demand is greater than the EVSE capacity to account for the losses associated with the EVSE and distribution transformer, as outlined in Section 3.4. As a result, the necessary grid upgrades included new service drops, distribution transformer upgrades, and, for the larger sites (4.23 MW for DHL and DHH), the costs associated with a reconductoring of the main feeder line. Each of these costs is incurred by all the EVSE and equally distributed across the dispensed energy from each port. There is some uncertainty associated with these costs, and therefore a range of upgrade costs was determined with the lower end of the range applying to low installation cost scenarios and the upper end of the range associated with high installation cost scenarios. Although these costs are sometimes covered completely or at least in part by the utility, this study assumes that all upgrade costs would be covered by the facility and recouped over the equipment's expected life.

Unlike the depot and travel center scenarios, the en route scenarios include both fast (3-MW) and slow (150-kW) EVSE. As a result of a large number of EVSE per site and the high power levels of the fast chargers, a peak demand determined by summing the EVSE capacity would exceed reasonable interconnection levels. The en route scenario site peak demands are determined by considering the coincident load of the megawatt-level charging as discussed in Section 2. Therefore, this study uses a 10-MW site demand for the low utilization scenario and 20 MW for the high utilization scenario. Due to the amount of capacity required to support these stations, a facility-owned substation would need to interconnect to a utility's sub-transmission system (typically operating at a minimum of 34 kV). This ensures the utility would have the capacity needed to serve this large load and would depend on the facility to install a substation including the necessary disconnect switches, breakers, switchgear, and power transformers that would likely cost a facility somewhere between \$5 million and \$10 million. It is assumed that the costs associated with this large demand (all substation and demand charge costs) would be fully recouped through the fast (3-MW) EVSE. These scenarios are both considered low-cost installs as it is assumed that the en route sites would have flexibility to choose locations where costs are lower. There are likely rural locations with long-distance upgrades or urban location with stringent siting requirements that might result in higher install costs for a load of this magnitude.

**Table 10. Utility Upgrade Costs for Each Scenario**

| Scenario | EVSE Unit Power (kW) | EVSE Capacity (MW/site) | Site Peak Demand (MW) | Utility Upgrade Costs ($K) |
|---|---|---|---|---|
| DLL | 50 | 0.95 | 1.11 | 50.0 |
| DLH | 50 | 0.95 | 1.11 | 60.0 |
| DHL | 150 | 3.60 | 4.23 | 945 |
| DHH | 150 | 3.60 | 4.23 | 2,445 |
| TLL | 150 | 1.50 | 1.8 | 50.0 |
| TLH | 150 | 1.50 | 1.8 | 60.0 |
| THL | 150 | 1.50 | 1.8 | 50.0 |
| THH | 150 | 1.50 | 1.8 | 60.0 |
| ELL-kW* | 150 | 1.35 | N/A | N/A |
| ELL-MW* | 3,000 | 21.0 | 10.0 | 5,000 |
| EHL-kW* | 150 | 3.90 | N/A | N/A |
| EHL-MW* | 3,000 | 42.0 | 20.0 | 10,000 |

*ELL and EHL scenarios simulate both kW and MW EVSE at a single site

## 3.4 Other Financial Parameters

There are many other financial parameters that must be considered as part of the EVI-FAST analysis in addition to the key capital upgrades, operational costs, and maintenance costs outlined in the preceding sections. These parameters, as defined in Table 11, were developed in conjunction with the 21CTP infrastructure working group and the developers of EVI-FAST to ensure compliance with generally accepted accounting principles and industry standard practices.

The most notable of these metrics are the operational life of the EVSE, life of the service equipment, and efficiency. The electrical service equipment, including equipment on the facility and utility side of the meter, are assumed to operate for 40 years, except for EVSE, which is assumed to have an operating life of 10 years. These assumptions led to a 40-year simulation of a single charging station from 2025 through 2065 in which new EVSE costs were incurred after every 10 years of operation. Throughout this 40-year period, inflation is assumed to occur at an annual rate of 1.9%, while the energy costs, including energy charges, demand charges, and interconnection fees, increase at an annual rate of 1.43% as informed by the *Annual Energy Outlook 2021* from the U.S. Energy Information Administration (2021). Additionally, the 85% combined operational efficiency of the EVSE and distribution transformer increased the site peak demand, relative to the EVSE capacity, by a factor of 1.176 for both depot and travel center scenarios. This efficiency results in an increase in both energy and demand charges as seen by the utility's primary voltage meter. The efficiencies accounted for in this study consider low-frequency transformer conversion in addition to the EVSE conversion and there could be improvements with future high-frequency transformer and EVSE technologies.

**Table 11. EVI-FAST Parameters**

| Parameter | Assumptions |
| --- | --- |
| Period of analysis | 2025–2065 |
| Oper42ational life: EVSE | 10 years |
| Operational life: service equipment | 40 years |
| Operational efficiency (transformer/EVSE losses) | 85% |
| Inflation rate | 1.90% |
| Electricity cost escalation rate | 1.43% |
| Credit card transaction fee (% of sales)[a] | 2.50% |
| Sales tax (% of sales)[a] | 2.25% |
| Administrative expense (% of sales)[a] | 0.50% |
| Total tax rate (state, federal, local)[a] | 25.74% |
| Capital gains tax[a] | 15% |
| Depreciation type | MACRS[b] |
| Depreciation period | 5 years |
| Leveraged after tax nominal discount rate | 8.00% |
| Debt/equity financing | 1.5 |
| Debt interest rate | 4.00% |

[a] Parameters associated with the sale of a good and therefore do not apply to depot scenarios

[b] Modified accelerated cost recovery system.

# 4 Breakeven Cost of Charging

The key deliverable of this study is to estimate the breakeven cost of delivered electricity to charge Class 8 electric vehicles, under a specific set of scenarios. The results in Table 12 represent the breakeven cost to charge Class 8 vehicles under several possible scenarios with the assumptions outlined in Section 3. The actual price to charge may be different due to variations in the cost and utilization factors, as well as market influences and business practices. Detailed analysis and discussion of these results are presented in Sections 4.1, 4.2, and 4.3.

**Table 12. Breakeven Cost of Delivered Electricity for Each Scenario**

| Scenario | EVSE Unit Power (kW) | Breakeven Cost Rate 1 ($/kWh) | Breakeven Cost Rate 2 ($/kWh) |
|---|---|---|---|
| DLL | 50 | $0.21 | $0.26 |
| DLH | 50 | $0.22 | $0.27 |
| DHL | 150 | $0.17 | $0.21 |
| DHH | 150 | $0.19 | $0.23 |
| TLL | 150 | $0.23 | $0.27 |
| TLH | 150 | $0.25 | $0.30 |
| THL | 150 | $0.20 | $0.24 |
| THH | 150 | $0.22 | $0.26 |
| ELL-kW* | 150 | $0.23 | $0.19 |
| ELL-MW* | 3,000 | $0.27 | $0.38 |
| EHL-kW* | 150 | $0.22 | $0.18 |
| EHL-MW* | 3,000 | $0.18 | $0.23 |

*ELL and EHL scenarios simulate both kW and MW EVSE at a single site

## 4.1 Depot Results

Fleets that heavily rely on long-dwell depot parking at their own facilities will have reliable predictions regarding EVSE utilization. Charging at these private parking facilities will likely be predictable but have lower utilization rates than public stations in a mature electric vehicle market. The utilization ramp for these sites was assumed to only occur over a 2-year period due to the predictable nature of fleet electrification within a depot (EVSE installations account for 2 years of electric vehicle acquisitions). The depot results also omit the cost of land because this is already a factor in fleet depot operations, and the potential for a marginal increase in land space is assumed to be a small impact. Further, parameters associated with the sale of a good are omitted because there are no financial transactions taking place in the depot.

The cost of electricity, however, is a strong contributing factor in the breakeven cost to charge vehicles. This can be seen by comparing the results between two scenarios where the only parameter modification is in the utility rate. Figure 11 presents the results for DHL Rate 1 and

Figure 12 presents the results for DHL Rate 2. While nearly every element of the breakeven cost for each scenario is identical, there is a significant difference in the final price of $0.04/kWh. This is purely a factor of the differences in the electricity costs. The lower price is associated with Rate 1 (energy charge: $0.06/kWh, demand charge: $5/kW) and the higher price is associated with Rate 2 (energy charge: $0.035/kWh, demand charge: $15/kW), suggesting that for depots with this utilization level, demand charges play a large factor.

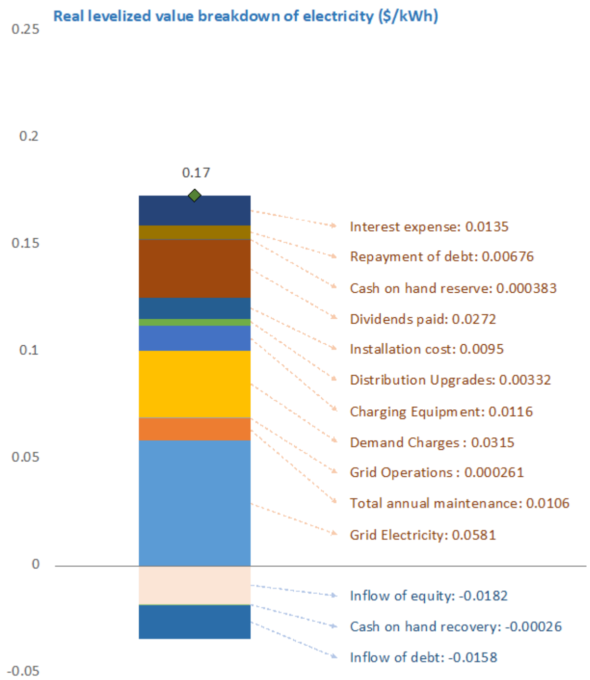



**Figure 11. DHL Rate 1 charging cost breakdown**

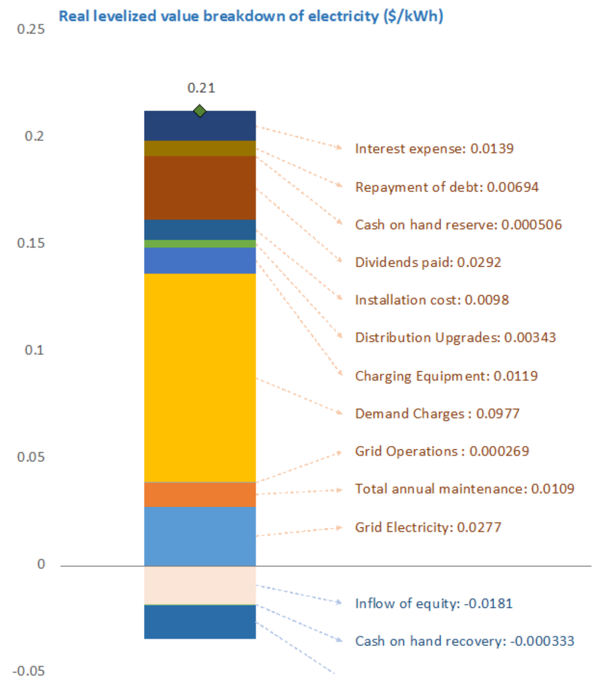



**Figure 12. DHL Rate 2 charging cost breakdown**

## 4.2 Travel Center Results

In addition to depot operations, many fleets will also rely on public infrastructure to provide their vehicles with the energy they need. For charge sessions with more than 4 hours of vehicle dwell, travel centers with 150-kW EVSE will serve the energy needs of many different vehicles but will be subject to a longer utilization ramp due to the dependence on public demand. These stations will likely be deployed in a wide range of locations that are predetermined based on existing structures or businesses. Therefore, in addition to variable utilization ramps, this analysis also considered varying installation costs to account for the uncertainty of nearby electrical service capacity.

The demand ramp for these stations under both high and low utilization scenarios was determined by the analysis in Section 2. Unlike the depot scenarios, the station designs were held constant across all travel center scenarios, with each location offering 10 EVSE providing up to 150 kW of charging power. The station utilization in each of these scenarios increases until the point at which they are occupied 20% of the time. This assumption was agreed upon by the 21CTP Team and represents the point at which point queuing would likely occur and a neighboring station would be built to serve the increasing demand. As displayed in Figure 13, the high utilization scenarios reach this point in the year 2037 (operating year 12), while the slower demand ramp for the low utilization scenarios reaches peak utilization in 2043 (operating year 18). Note that the differences in these demand ramps are primarily driven by the vehicle adoption scenarios (see Section 2.1.2).

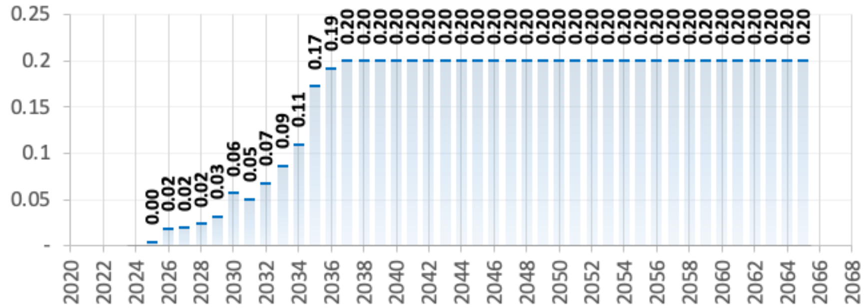


Figure 13. THL and THH site utilization by year

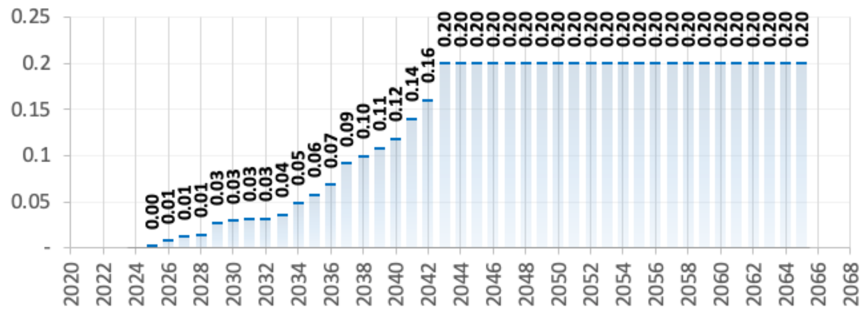


Figure 14. TLL and TLH site utilization by year

In order to understand how the utilization ramp impacts the breakeven cost to charge, it is important to consider the average cost of goods sold each year. Figure 15 displays the THL Rate 1 scenario average cost of goods (electricity) sold each year in real 2025 dollars (not adjusted for inflation). Observing the inverse relationship between the demand utilization and cost of goods sold helps to understand how the final breakeven cost to charge ($0.20/kWh in 2025$ and indicated with the horizontal dashed line) is estimated. Figure 16 displays the TLL Rate 1 scenario and helps display how the EVSE reinvestments every 10 years, which temporarily increase the cost of goods sold, also impact the breakeven cost to charge ($0.29/kWh in 2025$).

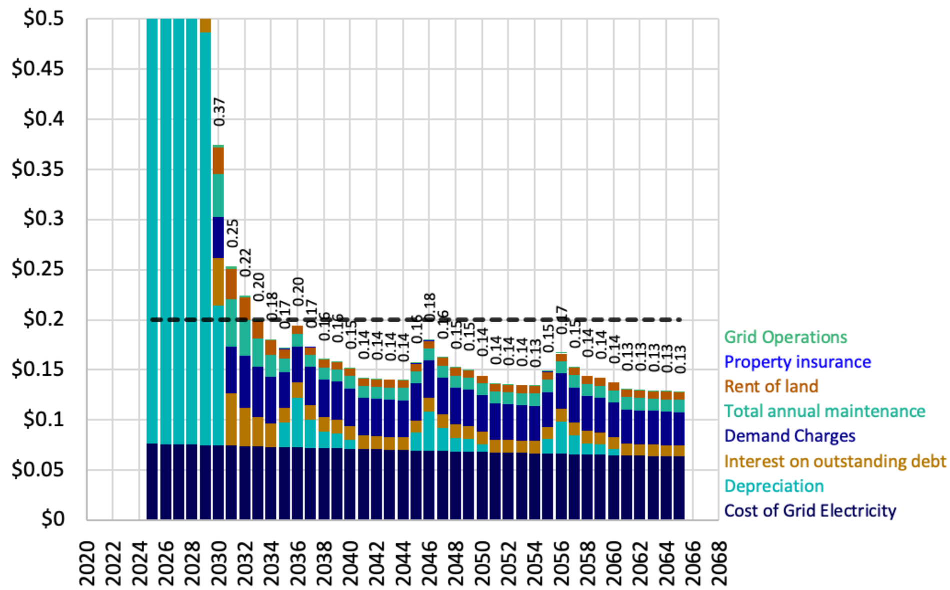



**Figure 15. THL Rate 1 annual cost of goods sold ($/kWh) in real 2025 dollars**

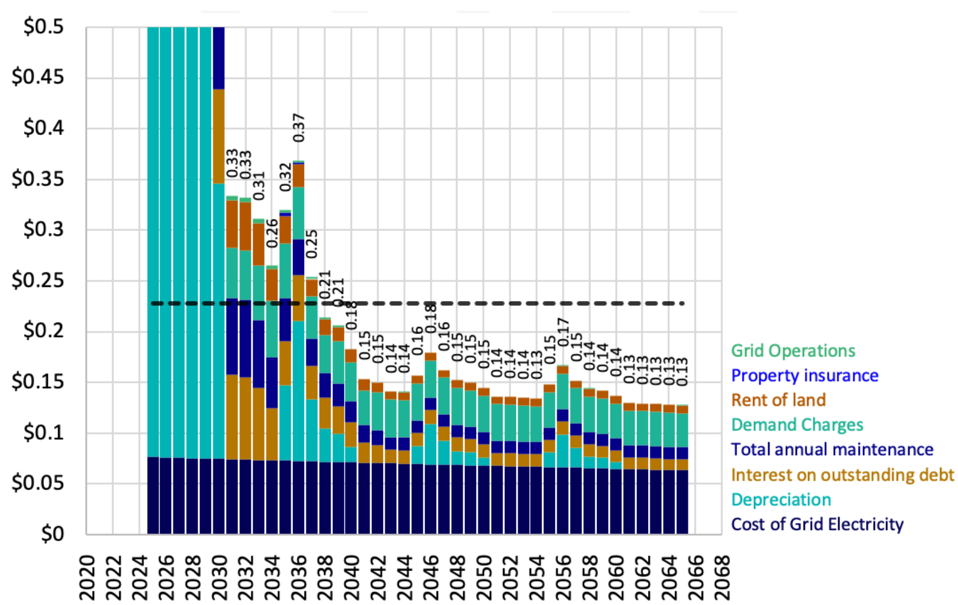



**Figure 16. TLL Rate 1 annual cost of goods sold ($/kWh) in real 2025 dollars**

## 4.3 En Route Results

Many public stations offering en route charging will likely have EVSE with a mix of power capabilities. For en route stations in this study offering the highest-power EVSE (3 MW) for vehicles with short dwell periods, it is assumed there would be the option for vehicles with longer dwell periods to charge from lower-power stations (150 kW). The EVSE breakdown and utilization for each of these stations is outlined in Section 2.1, with EVI-FAST results presented in Figure 17, Figure 18, Figure 19, and Figure 20. While the utility upgrade costs in both of the en route scenarios are completely covered by megawatt-level charging, the breakeven costs for each scenario show that is not the largest contributing factor to the breakeven cost.

While there is a lot of variability between all four figures, the most interesting result is the relationship between the kilowatt- and megawatt-level chargers within each scenario. The EHL-MW Rate 1 results in Figure 17 present a lower breakeven cost to charge than the EHL-kW Rate 1 from the same station in Figure 18. However, the relationship between the kilowatt- and megawatt-level EVSE breakeven cost is the opposite in the ELL scenario, as represented in Figure 19 and Figure 20. This is likely influenced by the differences between variable and fixed cost distributions. For example, the EHL Rate 1 scenario likely has a lower cost for the megawatt-level EVSE compared to the kilowatt-level EVSE because the higher utilization rates (as a factor of percent of time) result in a much larger amount of energy being dispensed from the megawatt-level EVSE. This means that, although there are more expenses that must be covered by the megawatt-level EVSE, there is such a disproportionate amount of energy dispensed from those ports that the initial capital investments have little impact on the breakeven cost. This is most notable where the EHL-MW and EHL-kW installation costs are both very similar ($2.7 and $2.9 million, respectively), but this portion of total breakeven cost has a much lower impact on the EHL-MW scenario than the EHL-kW scenario ($0.002/kWh and $0.019/kWh, respectively).

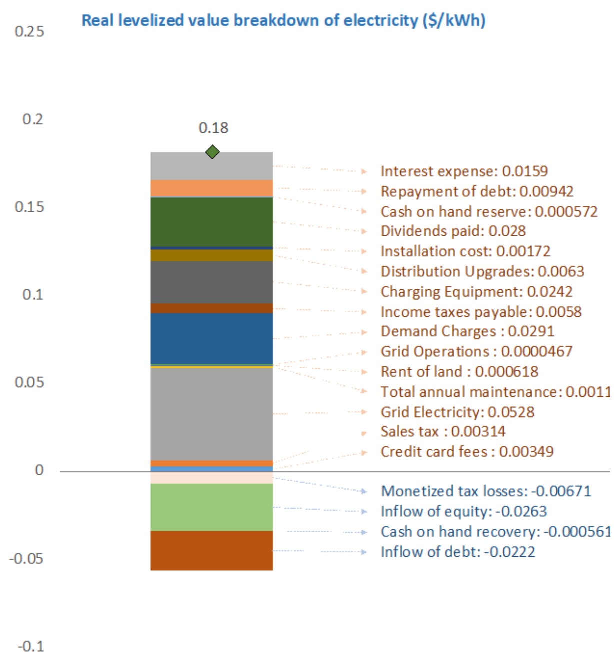



**Figure 17. EHL-MW Rate 1 charging cost breakdown**

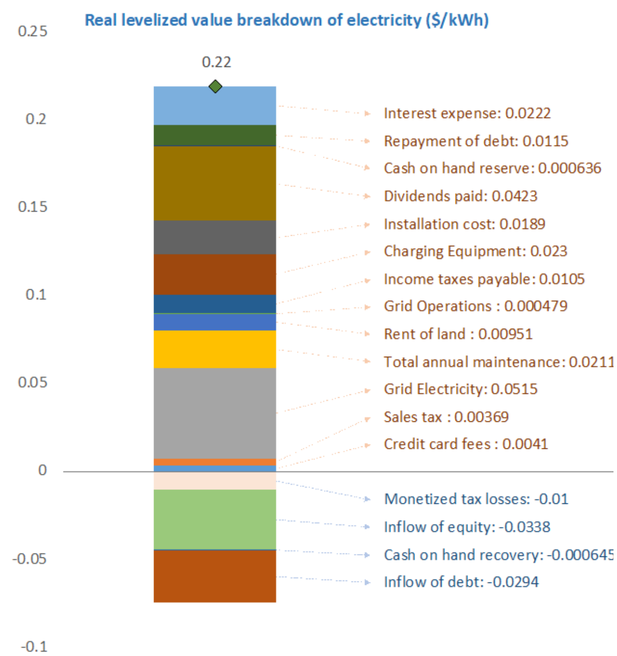



**Figure 18. EHL-kW Rate 1 charging cost breakdown**

This relationship between the megawatt- and kilowatt-level EVSE is more predictable in the ELL Rate 2 Scenario, with the megawatt-level EVSE resulting in a much higher breakeven cost, as shown in Figure 19 and Figure 20. The higher demand charges in Rate 2 present a significant impact on the megawatt-level EVSE breakeven cost. This is emphasized by the low utilization in the ELL scenario that focuses the impact of those demand charges over less dispensed energy. However, note that in this scenario the kilowatt-level EVSE is not impacted by these demand charges, which are fully recouped by the megawatt-level EVSE, but does benefit from the associated lower electricity rate results with a lower breakeven cost to charge. This assumption in the analysis is intended to represent an incentivization for vehicles to charge at lower power levels. The results show how both utilization rates and utility rates can have a significant impact. Lower utilization rates concentrate the impact of the initial investment due to the smaller amount of dispensed energy, while lower utility rates can reduce the breakeven cost to charge regardless of utilization.

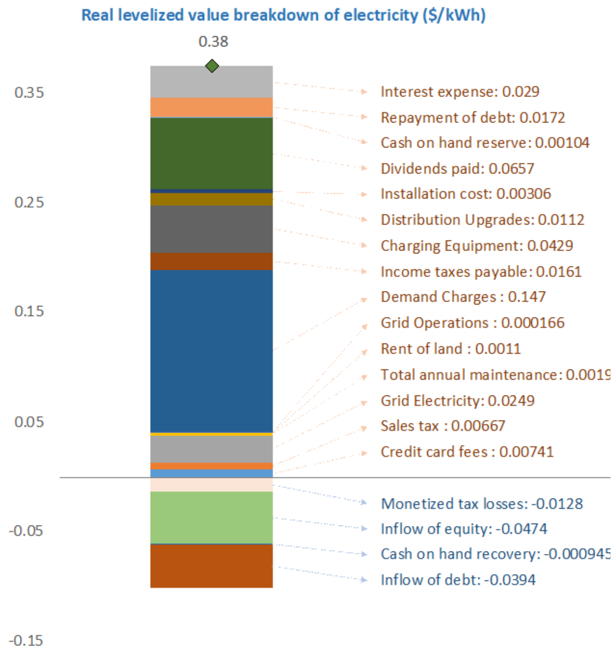



Figure 19. ELL-MW Rate 2 charging cost breakdown

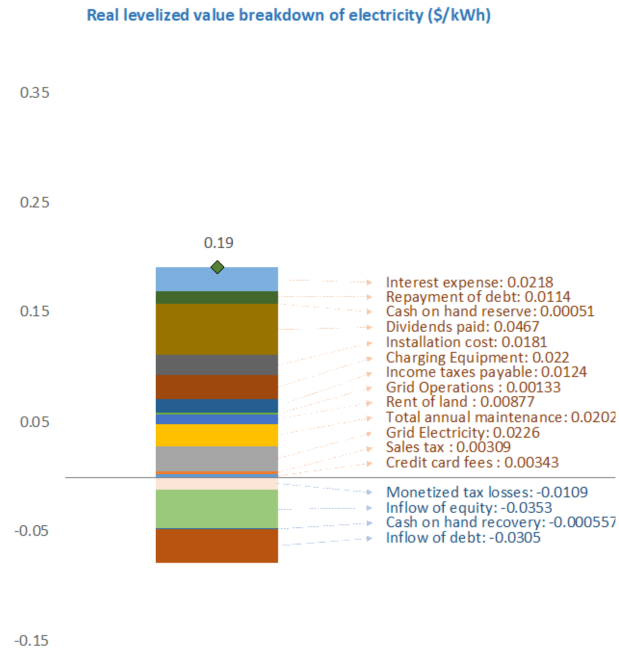



Figure 20. ELL-kW Rate 2 charging cost breakdown

# 5 Conclusion

This study investigates an approach to identify the breakeven cost to charge Class 8 tractors through an analysis of three charging scenarios and site types—private depot, travel center, and en route—with a process that uses vehicle travel data to develop site utilization characteristics considering vehicle arrival statistics and a site-level infrastructure deployment considering dwell time to determine charging power. The approach allows for the charging price to include cost associated with the capital investment to develop as well as the operational cost to maintain each site. These life cycle costs allow for the analysis to determine the sensitivity of several factors that contribute to a levelized price for charging at the sites.

There are many different factors that influence the breakeven cost to charge Class 8 tractors. This analysis has accounted for factors such as regional differences in utility rates, grid upgrade practices, and future EV adoption. With these factors, the preceding analysis has developed a large range of results with the lowest price at $0.17/kWh for kilowatt-scale charging at a depot with high utilization, low installation cost, and a utility rate with an average energy charge—$0.065/kWh—coupled with a relatively low demand charge—$5/kW (DHL, Rate 1). This is in contrast to the highest price at $0.38/kWh for megawatt-scale charging at an en route site with low utilization, low installation cost, and a rate with a relatively low energy charge—$0.030/kWh—and average demand charge—$15/kW (ELL-MW, Rate 2).

It is apparent from the results that varying the assumptions leading to the contributing factors can result in a significant difference in the price to charge a Class 8 tractor. As a result, the most precise analysis on the cost to charge a class 8 tractor will account for geographic considerations and local conditions. This may be achieved through the use of NREL's EVI-FAST tool with the assumptions from this analysis updated as necessary. Some of these considerations, such as accounting for the land cost to support supply equipment at depot locations, could increase the price to charge. However, this analysis assumes all of the distribution upgrades are paid for by the facility and assuming there is a cost sharing between the facility and utility will reduce the cost to charge. In addition to these factors, this analysis concluded that one of the most significant impacts to the price to charge was variations in the electricity rates and accounting for local energy charges and demand charges will also impact the price to charge.

While site operators may have little influence over the options of utility rates at charging sites, they can reduce the breakeven cost by choosing locations with higher expected utilization. However, this may present challenges when considering that some locations may be necessary for providing coverage in a charging network and for scenarios with lower fleet adoption, which reduce the overall utilization. Nevertheless, utilization rates can have a significant impact on the incumbent costs that constitute the breakeven cost. These costs are typically fixed investments that have varying impacts on the final breakeven cost. This variability will depend on the site utilization and is inversely related to the amount of energy that will be dispensed over a given period. Sites with higher utilization will be less impacted by these costs because their effect will be distributed across more dispensed energy.

Furthermore, given the range in breakeven costs to charge, a determination of an average price of electricity for a total cost of ownership analysis should consider the framework presented here to determine cost for the given charging scenario(s) and that the operation of the Class 8 tractor will determine the frequency of charging in each scenario. For example, the breakeven costs of $0.17/kWh for kilowatt-scale charging (DHL, Rate 1) and $0.38/kWh for megawatt-scale charging (ELL-MW, Rate 2), when applied directly to a simplified on-road energy consumption of 1.8 to 2.1 kWh/mile assumption, would result in a range of $0.31 to $0.80/mile for the price of charging electricity. This assumes all charging occurs at a single location type and uses an average on-road consumption, which is unrealistic. Even for a specific vocation, analysis should be based on factors such as regional differences in utility rates, grid upgrade practices, and fleet adoption. Further, the analysis will need to consider that the on-road energy consumption may also be influenced by factors such as regional differences, vehicle routing, and operational practices. However, deployment in vocations that predominantly leverage depot charging scenarios may mitigate some of the uncertainty in these factors through independent adoption decisions that can lead to higher utilization of a charging site that is chosen with lower install costs.

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# Appendix A. Daily Short-Haul Tractor Fleet Distributions for Depot Charging Scenario

Figure A-1 shows daily vehicle miles traveled (VMT) and off-shift dwell-time distributions for the two short-haul fleets considered in the depot charging scenario of this study. For the warehouse delivery fleet, the maximum daily vehicle miles traveled is well within the expected range of battery electric trucks coming to market, at 194 miles/day. The maximum daily vehicle miles traveled is considerably greater for the food delivery fleet (546 miles); however, most vehicle days require <300 miles (89%) and nearly all require <500 miles (99%). In both fleets, trucks have ample opportunity for depot charging, with an average of 15 and 13.8 off-shift dwell hours per day for the warehouse and food delivery fleets, respectively.

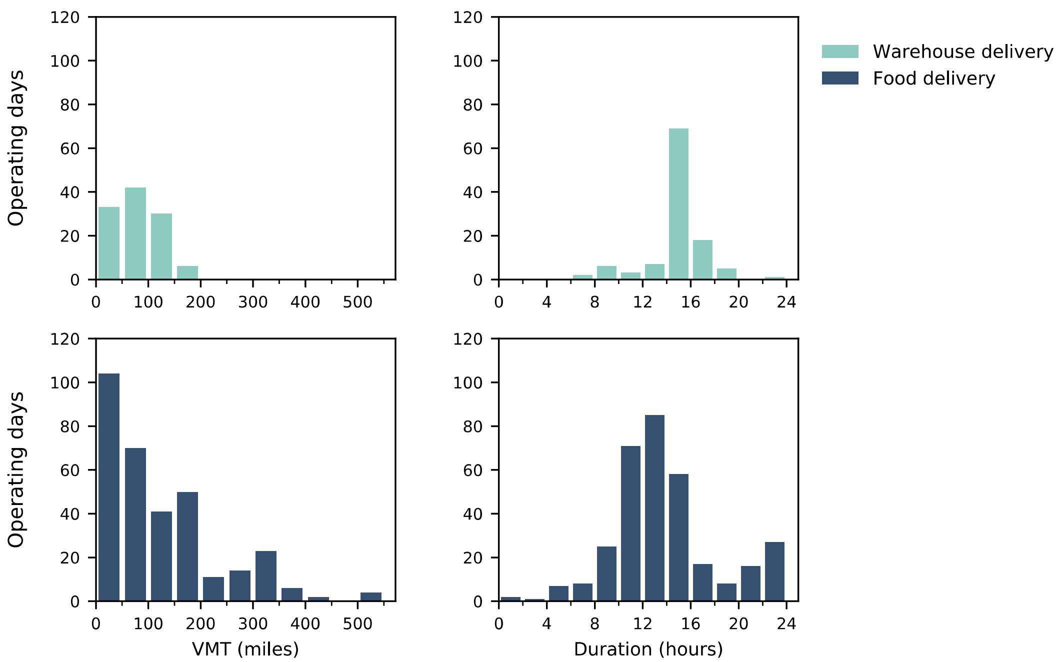


**Figure A-1. Daily driving distances (left) and daily off-shift dwell durations (right) for the fleets studied. The daily off-shift dwell duration indicates the maximum available time window for charging.**

# Appendix B. EVI-FAST Parameters

| EVI-FAST Parameter | DHL | DLL | DHH | DLH |
|---|---|---|---|---|
| EVSE Unit Power (kW) | 150 | 50 | 150 | 50 |
| EVSE Unit Quantity | 24 | 19 | 24 | 19 |
| EVSE Site Capacity (kW) | 3,600 | 950 | 3,600 | 950 |
| Peak Demand (kW) | 4,234 | 1,117 | 4,234 | 1117 |
| Unit Pricing ($/kW) | $ 300 | $ 383 | $ 416 | $ 519 |
| Charging Equipment Cost ($/unit) | $ 1,078,992 | $ 363,755 | $ 1,496,448 | $ 493,430 |
| Distribution Upgrades ($) | $ 945,000 | $ 50,000 | $ 2,445,000 | $ 60,000 |
| Installation Price ($/kW) | $ 750 | $ 420 | $ 1,080 | $ 750 |
| On-Site Installation Cost ($) | $ 2,700,000 | $ 399,000 | $ 3,888,000 | $ 712,500 |
| Annual Maintenance Cost ($/year) | $ 76,800 | $ 60,800 | $ 76,800 | $ 60,800 |
| Utilization | | | | |
| Operational Life (EVSE) | 10 | 10 | 10 | 10 |
| Operational Life (Service Equipment) | 40 | 40 | 40 | 40 |
| Installation time (months) | 9 | 3 | 12 | 3 |
| Electricity Consumption Rate (kWh/kWh) | 1.176 | 1.176 | 1.176 | 1.176 |
| Demand ramp-up (years) | 2 | 2 | 2 | 2 |
| Long-term Nominal Utilization | 19.4% | 17.6% | 19.4% | 17.6% |
| Operating Expenses | | | | |
| Energy charges ($/kWh) | $0.065/$0.030 | $0.03 - $0.065 | $0.03 - $0.065 | $0.03 - $0.065 |
| Demand charges ($/kW) | $5/$15 | $5/$15 | $5/$15 | $5/$15 |
| Grid Operations/Service ($/year) | $ 1,890 | $ 1,890 | $ 1,890 | $ 1,890 |
| Land Requirements (acres) | 2.10 | 1.20 | 2.10 | 1.20 |
| Land costs ($/acre/yr) | $ - | $ - | $ - | $ - |

**Figure B-1. Depot parameter summary**

| EVI-FAST Parameter | THL | TLL | THH | TLH |
|---|---|---|---|---|
| EVSE Unit Power (kW) | 150 | 150 | 150 | 150 |
| EVSE Unit Quantity | 10 | 10 | 10 | 10 |
| EVSE Site Capacity (kW) | 1,500 | 1,500 | 1,500 | 1,500 |
| Peak Demand (kW) | 1,764 | 1,764 | 1,764 | 1,764 |
| Unit Pricing ($/kW) | $ 300 | $ 300 | $ 416 | $ 416 |
| Charging Equipment Cost ($/unit) | $ 449,580 | $ 449,580 | $ 623,520 | $ 623,520 |
| Distribution Upgrades ($) | $ 50,000 | $ 50,000 | $ 60,000 | $ 60,000 |
| Installation Price ($/kW) | $ 750 | $ 750 | $ 1,080 | $ 1,080 |
| On-Site Installation Cost ($) | $ 1,125,000 | $ 1,125,000 | $ 1,620,000 | $ 1,620,000 |
| Annual Maintenance Cost ($/year) | $ 32,000 | $ 32,000 | $ 32,000 | $ 32,000 |
| Utilization | | | | |
| Operational Life (EVSE) | 10 | 10 | 10 | 10 |
| Operational Life (Service Equipment) | 40 | 40 | 40 | 40 |
| Installation time (months) | 6 | 6 | 9 | 9 |
| Electricity Consumption Rate (kWh/kWh) | 1.176 | 1.176 | 1.176 | 1.176 |
| Demand ramp-up (years) | 12 | 18 | 12 | 18 |
| Long-term Nominal Utilization | 20.0% | 20.0% | 20.0% | 20.0% |
| Operating Expenses | | | | |
| Energy charges ($/kWh) | $0.065/$0.030 | $0.03 - $0.065 | $0.03 - $0.065 | $0.03 - $0.065 |
| Demand charges ($/kW) | $5/$15 | $5/$15 | $5/$15 | $5/$15 |
| Grid Operations/Service ($/year) | $ 1,890 | $ 1,890 | $ 1,890 | $ 1,890 |
| Land Requirements (acres) | 0.80 | 0.80 | 0.80 | 0.80 |
| Land costs ($/acre/yr) | $ 20,000 | $ 20,000 | $ 20,000 | $ 20,000 |

**Figure B-2. Travel center parameter summary**

| EVI-FAST Parameter | EHL-MW | EHL-kW | ELL-MW | ELL-kW |
|---|---|---|---|---|
| EVSE Unit Power (kW) | 3,000 | 150 | 3,000 | 150 |
| EVSE Unit Quantity | 14 | 26 | 7 | 9 |
| EVSE Site Capacity (kW) | 42,000 | 3,900 | 21,000 | 1,350 |
| Peak Demand (kW) | 20,000 | - | 10,000 | - |
| Unit Pricing ($/kW) | $ 300 | $ 300 | $ 300 | $ 300 |
| Charging Equipment Cost ($/unit) | $ 12,600,000 | $ 1,168,908 | $ 6,300,000 | $ 404,622 |
| Distribution Upgrades ($) | $ 10,000,000 | $ - | $ 5,000,000 | $ - |
| Installation Price ($/kW) | $ 65 | $ 750 | $ 65 | $ 750 |
| On-Site Installation Cost ($) | $ 2,730,000 | $ 2,925,000 | $ 1,365,000 | $ 1,012,500 |
| Annual Maintenance Cost ($/year) | $ 44,800 | $ 83,200 | $ 22,400 | $ 28,800 |
| Utilization | | | | |
| Operational Life (EVSE) | 10 | 10 | 10 | 10 |
| Operational Life (Service Equipment) | 40 | 40 | 40 | 40 |
| Installation time (months) | 12 | 12 | 9 | 9 |
| Electricity Consumption Rate (kWh/kWh) | 1.176 | 1.176 | 1.176 | 1.176 |
| Demand ramp-up (years) | 10 | 10 | 15 | 15 |
| Long-term Nominal Utilization | 9.5% | 9.8% | 6.1% | 10.7% |
| Operating Expenses | | | | |
| Energy charges ($/kWh) | $0.065/$0.030 | $0.03 - $0.065 | $0.03 - $0.065 | $0.03 - $0.065 |
| Demand charges ($/kW) | $5/$15 | $5/$15 | $5/$15 | $5/$15 |
| Grid Operations/Service ($/year) | $ 1,890 | $ 1,890 | $ 1,890 | $ 1,890 |
| Land Requirements (acres) | 1.00 | 1.50 | 0.50 | 0.50 |
| Land costs ($/acre/yr) | $ 25,000 | $ 37,500 | $ 12,500 | $ 12,500 |

**Figure B-3. En route parameter summary**

# Appendix C. EVI-FAST Results

## C.1 Depot Results

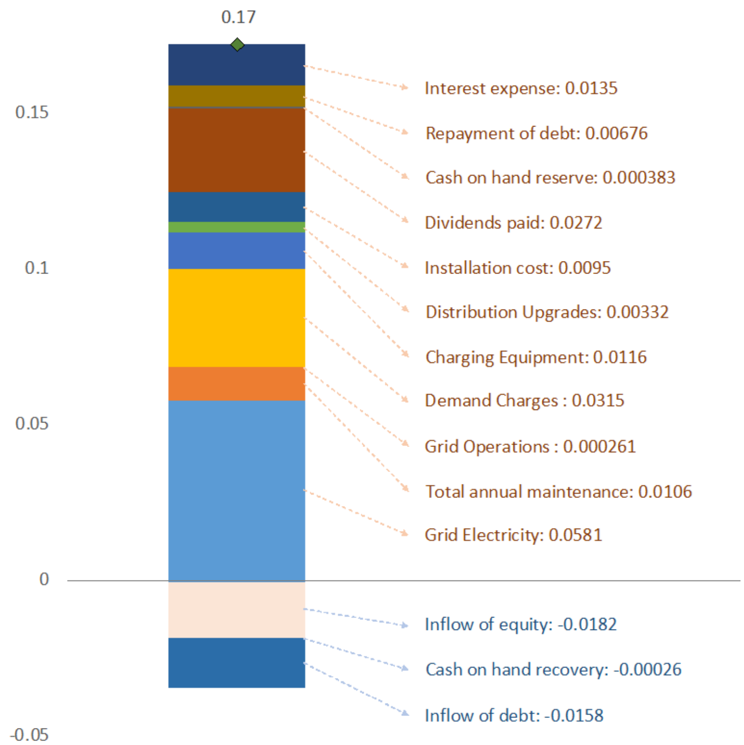


**Figure C-1. DHL Rate 1 charging cost breakdown ($/kWh)**

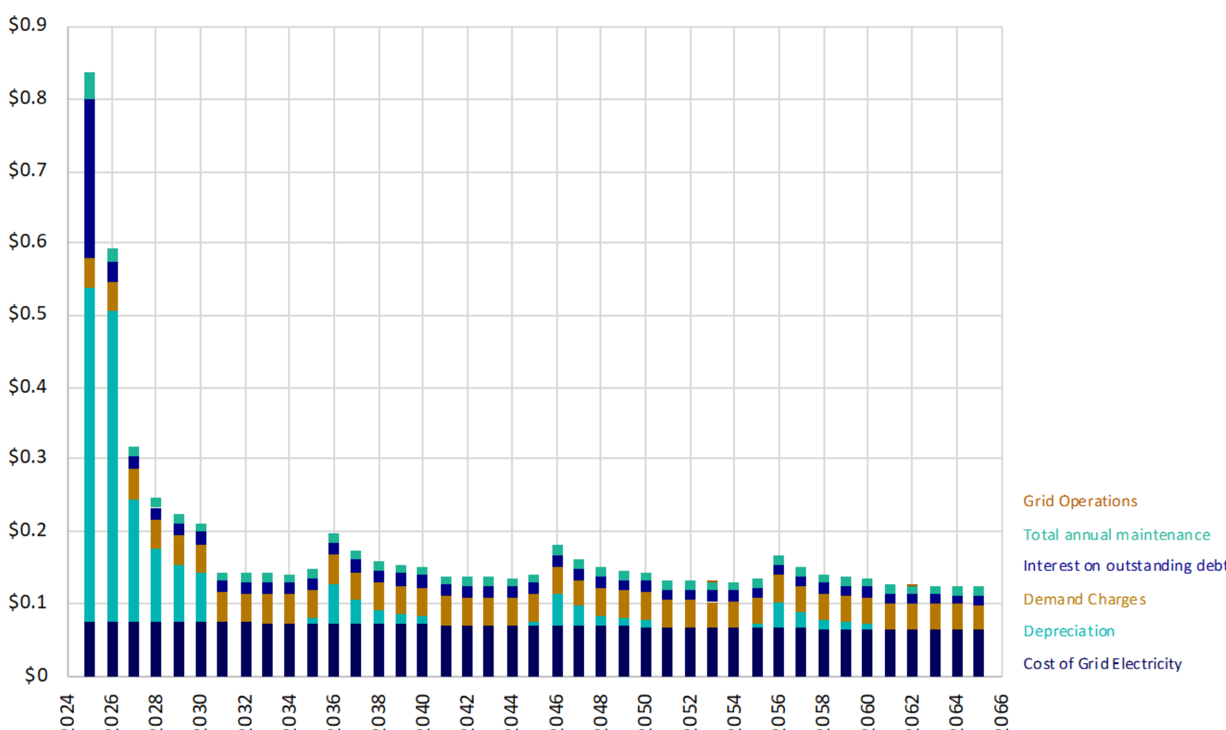


**Figure C-2. DHL Rate 1 annual cost of goods sold ($/kWh) in real 2025 dollars**

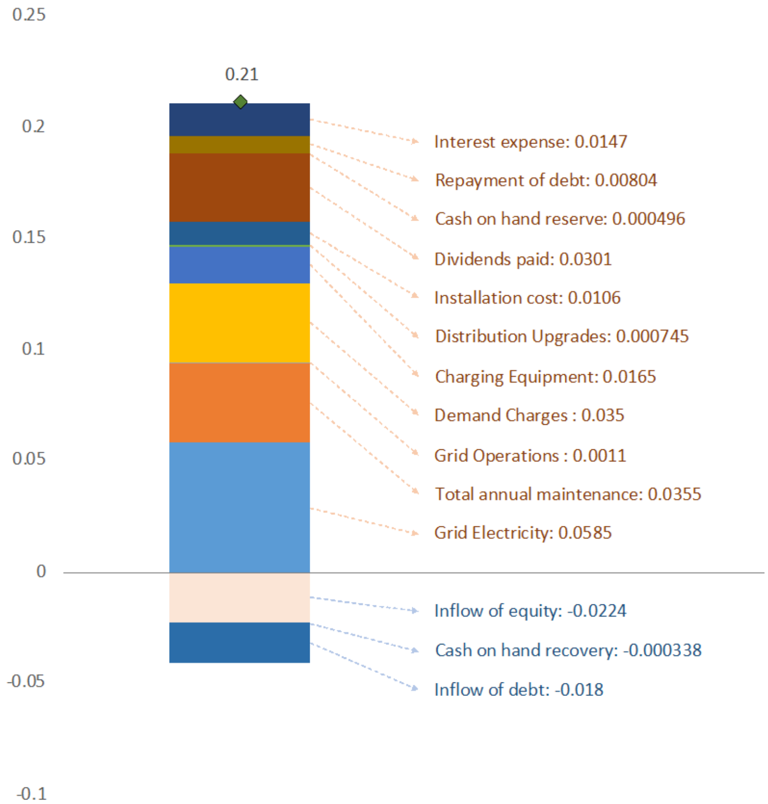


**Figure C-3. DLL Rate 1 charging cost breakdown ($/kWh)**

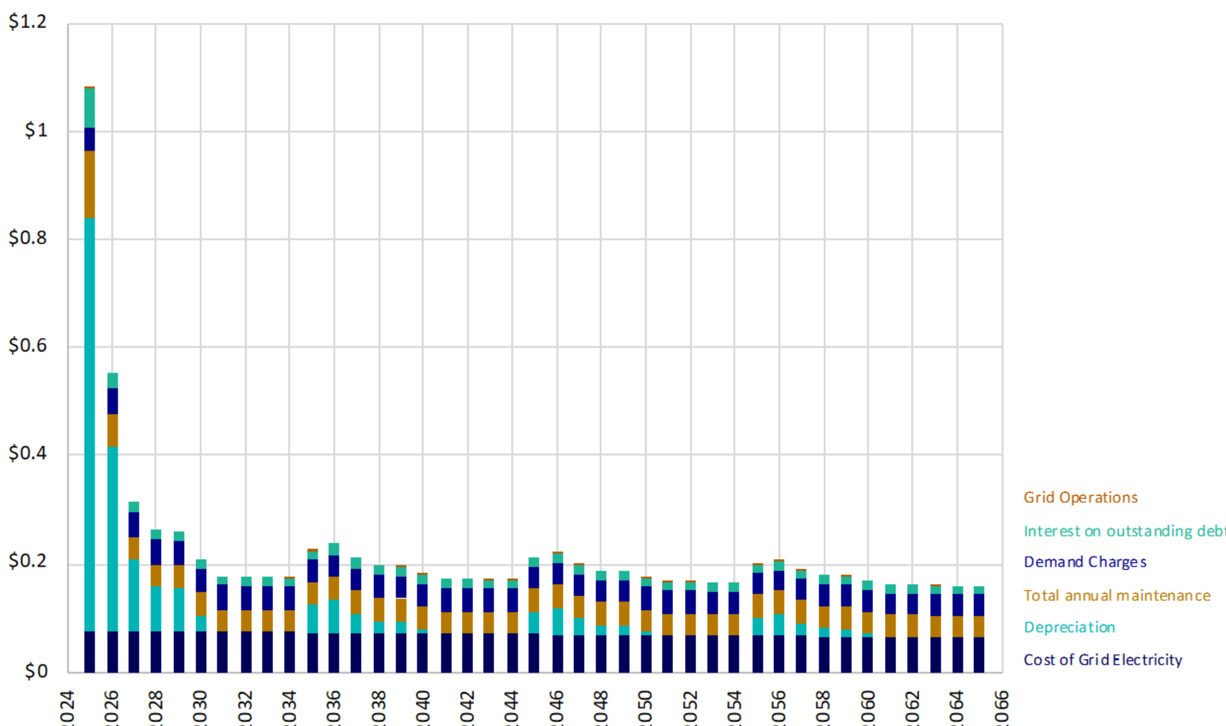


**Figure C-4. DLL Rate 1 annual cost of goods sold ($/kWh) in real 2025 dollars**

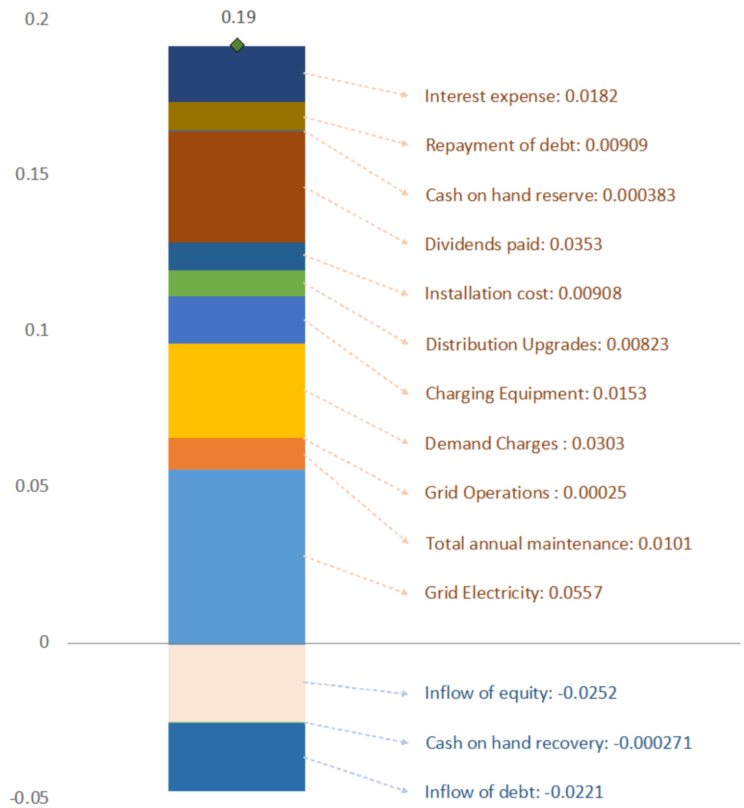


**Figure C-5. DHH Rate 1 charging cost breakdown ($/kWh)**

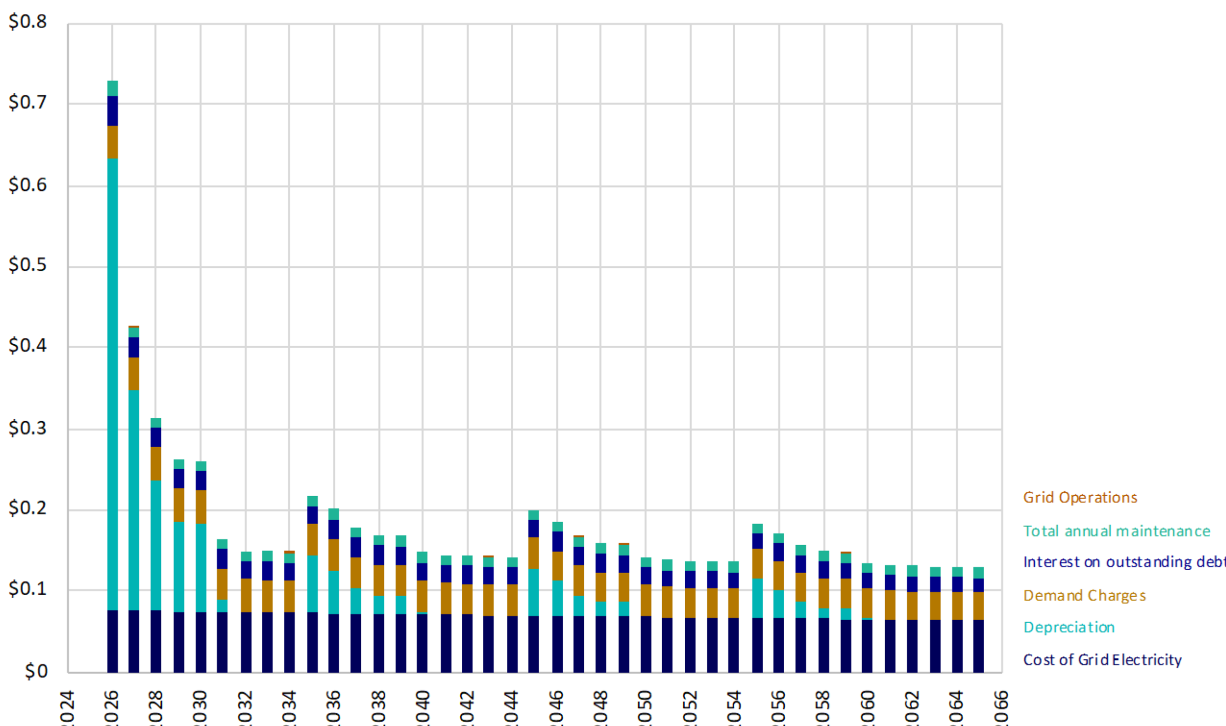


**Figure C-6. DHH Rate 1 annual cost of goods sold ($/kWh) in real 2025 dollars**

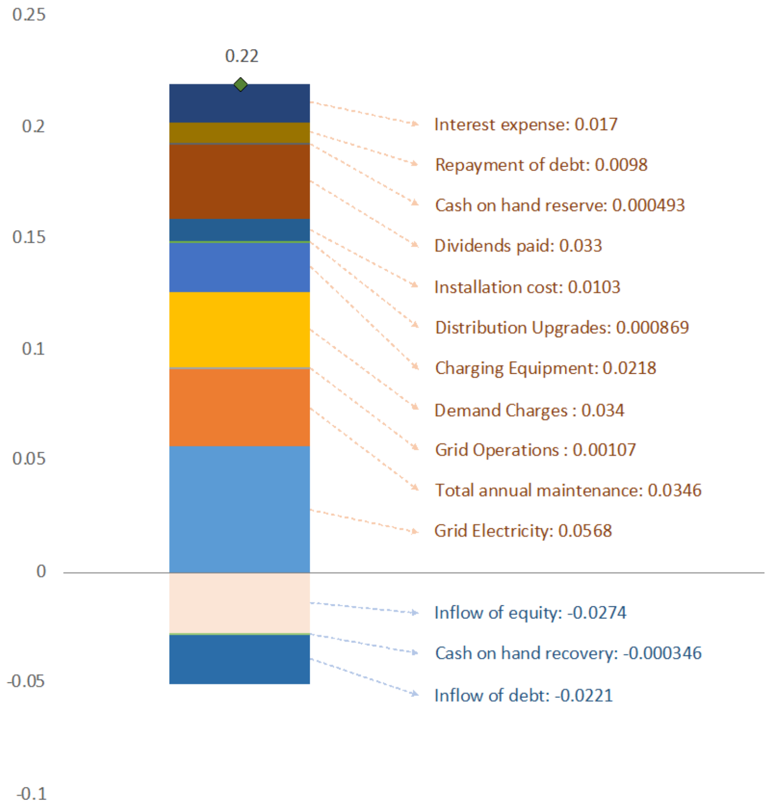


**Figure C-7. DLH Rate 1 charging cost breakdown ($/kWh)**

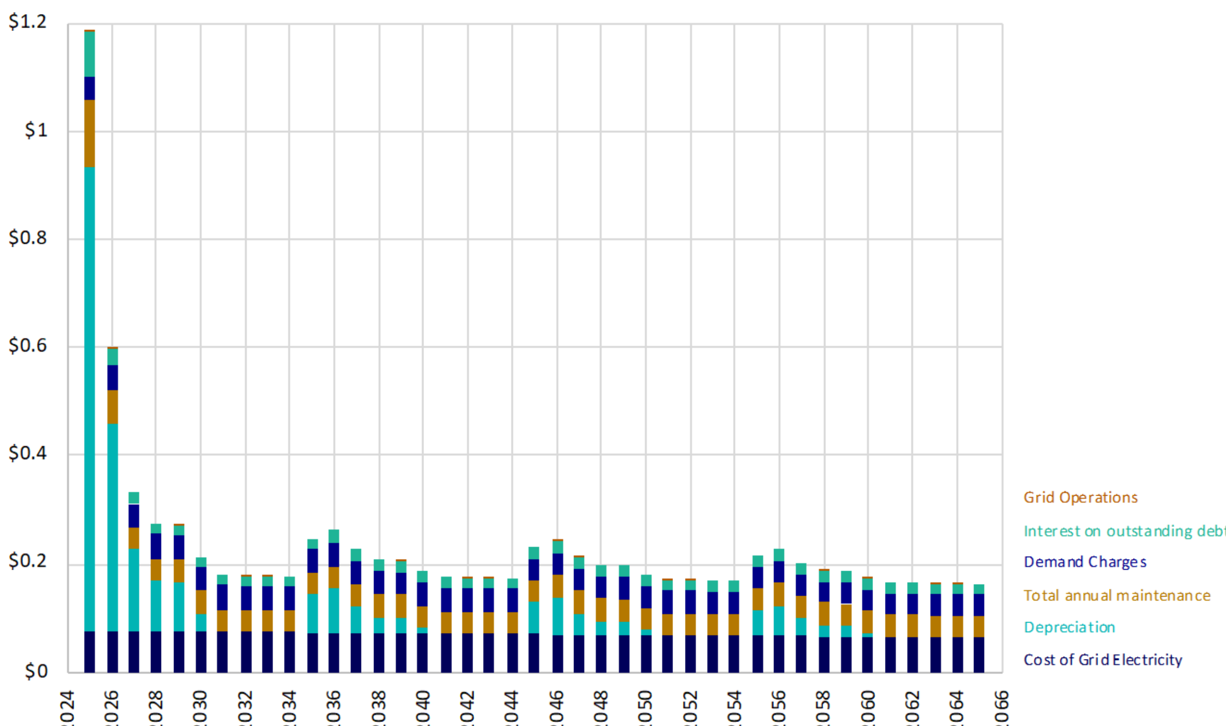


**Figure C-8. DLH Rate 1 annual cost of goods sold ($/kWh) in real 2025 dollars**

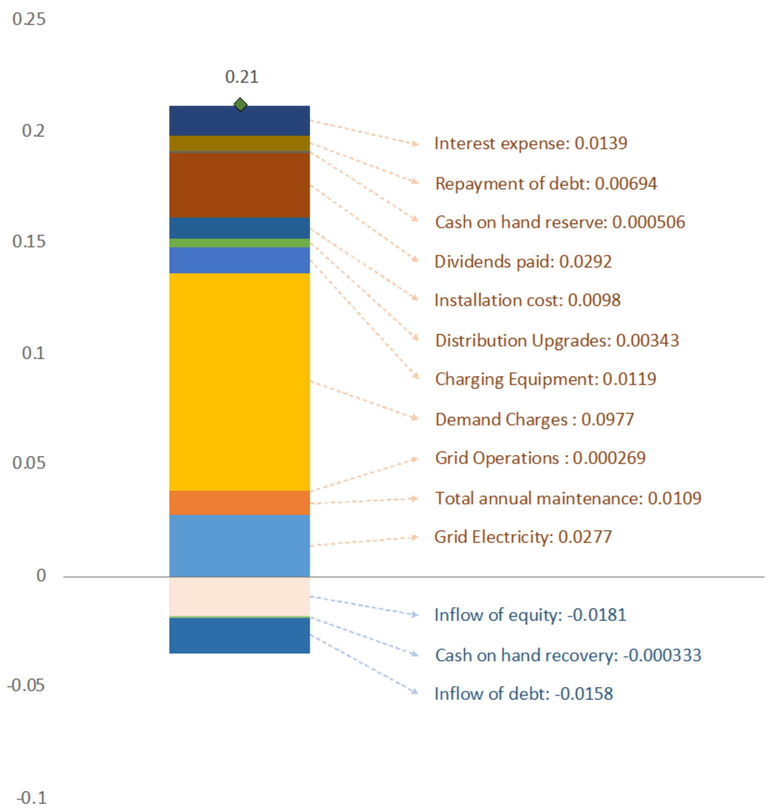


**Figure C-9. DHL Rate 2 charging cost breakdown ($/kWh)**

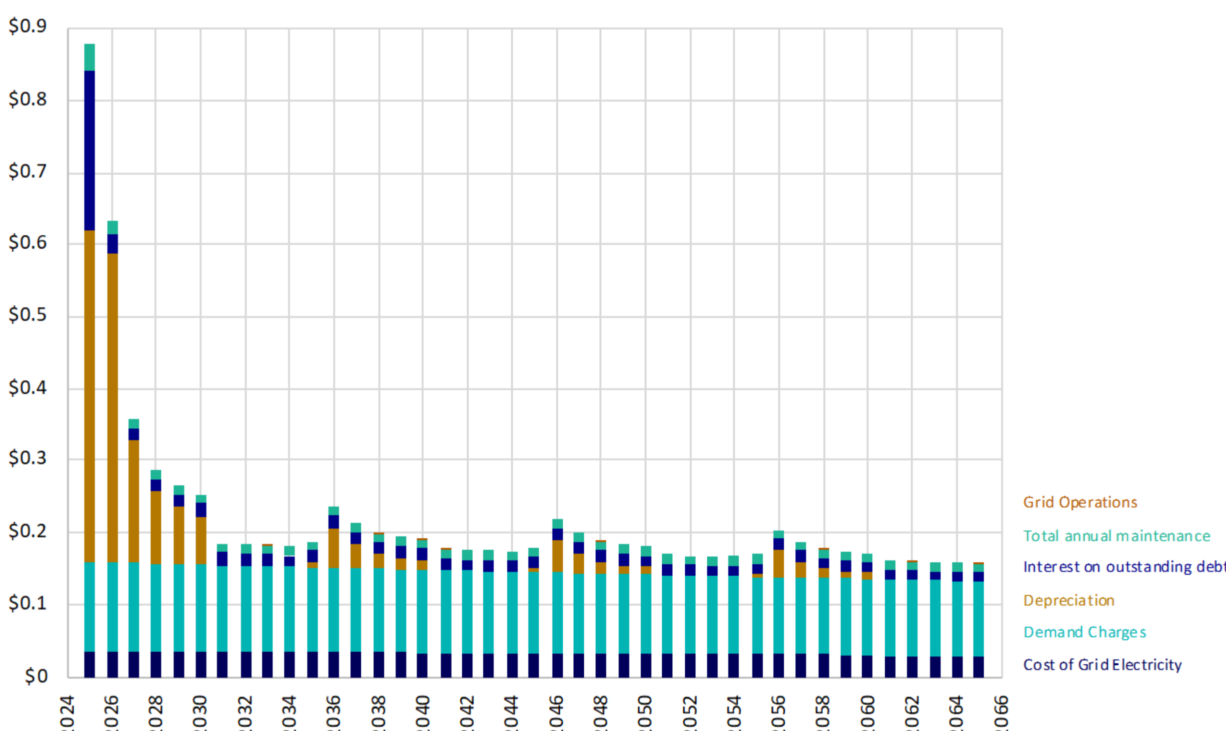


**Figure C-10. DHL Rate 2 annual cost of goods sold ($/kWh) in real 2025 dollars**

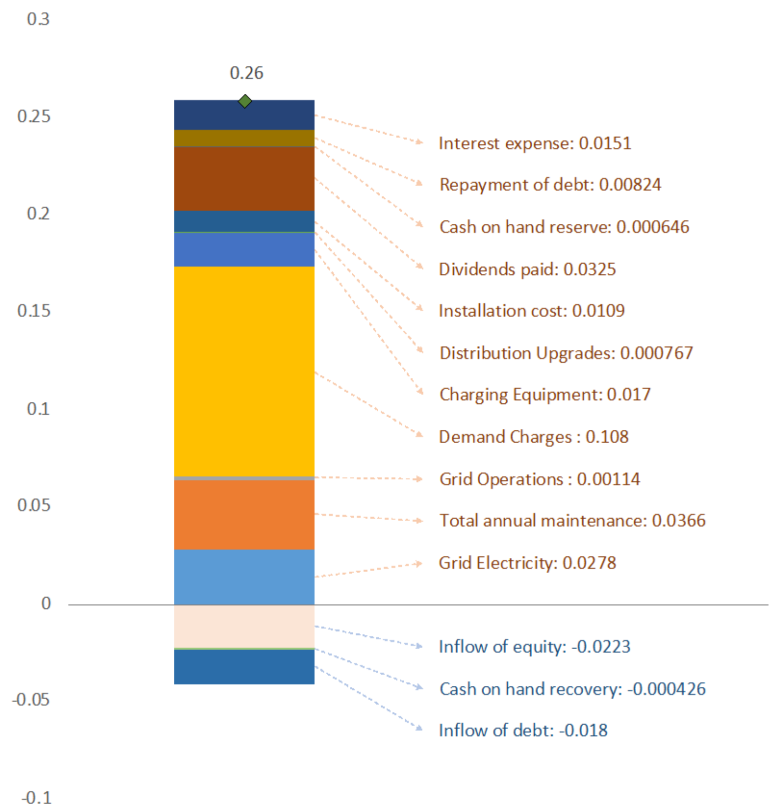


**Figure C-11. DLL Rate 2 charging cost breakdown ($/kWh)**

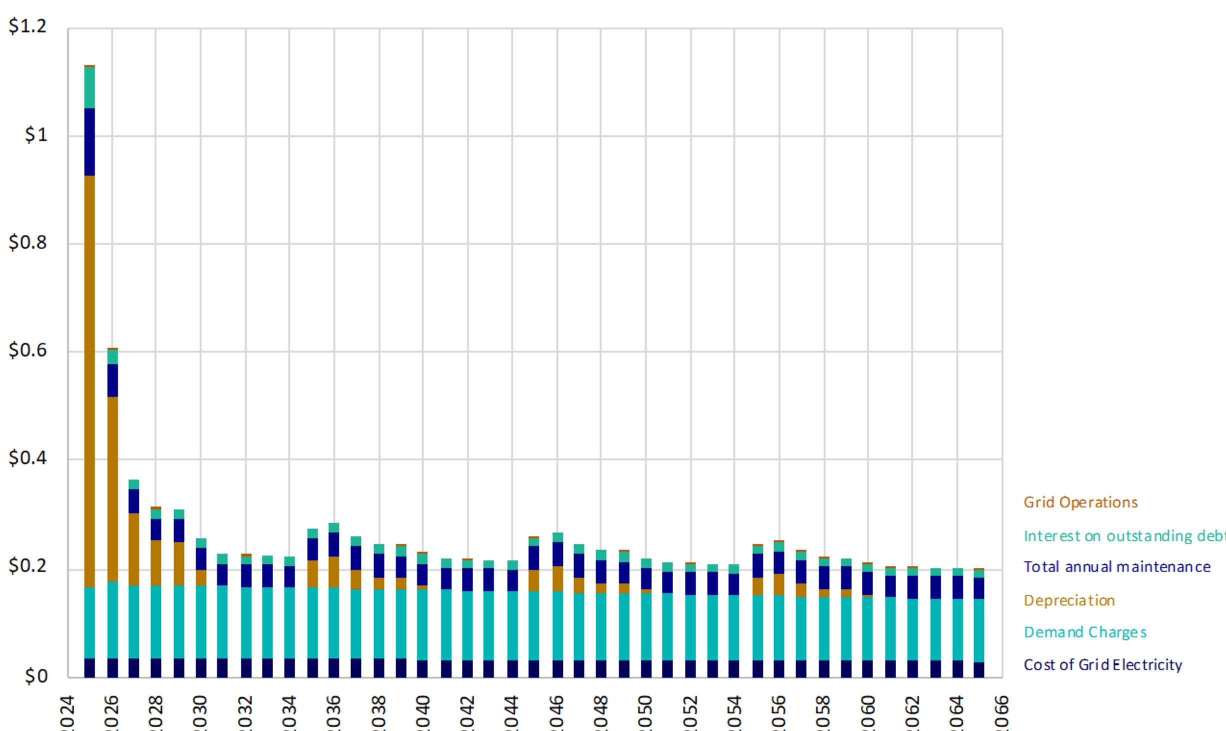


**Figure C-12. DLL Rate 2 annual cost of goods sold ($/kWh) in real 2025 dollars**

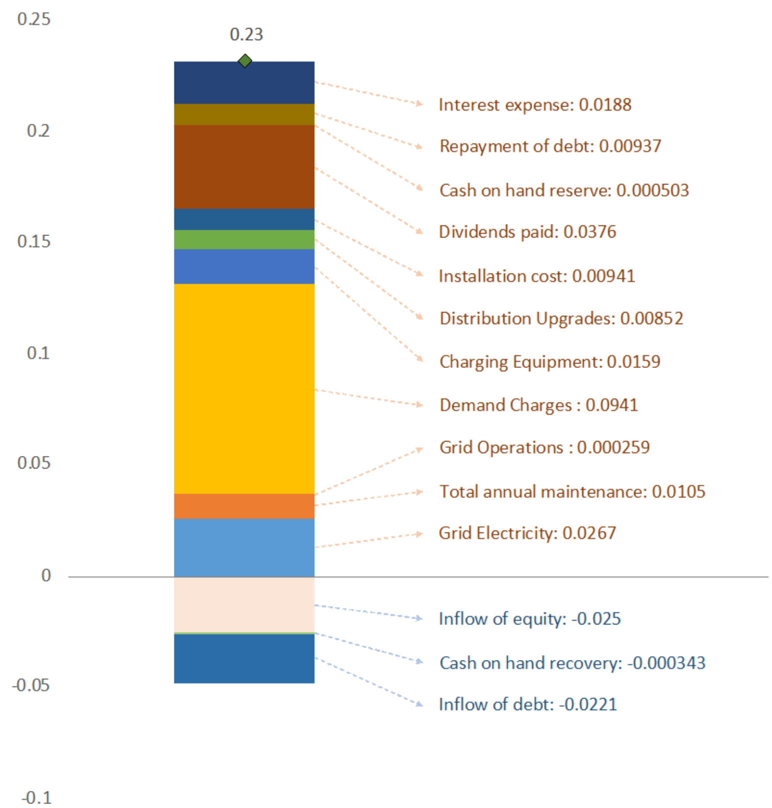


**Figure C-13. DHH Rate 2 charging cost breakdown ($/kWh)**

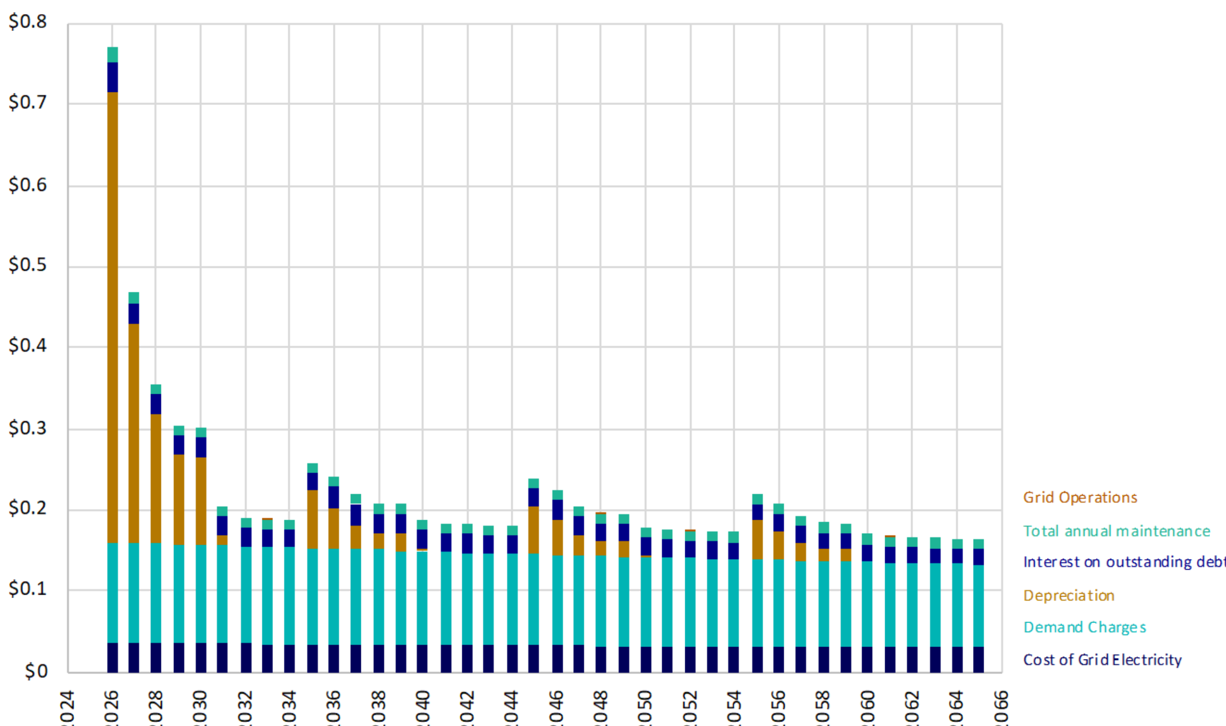


**Figure C-14. DHH Rate 2 annual cost of goods sold ($/kWh) in real 2025 dollars**

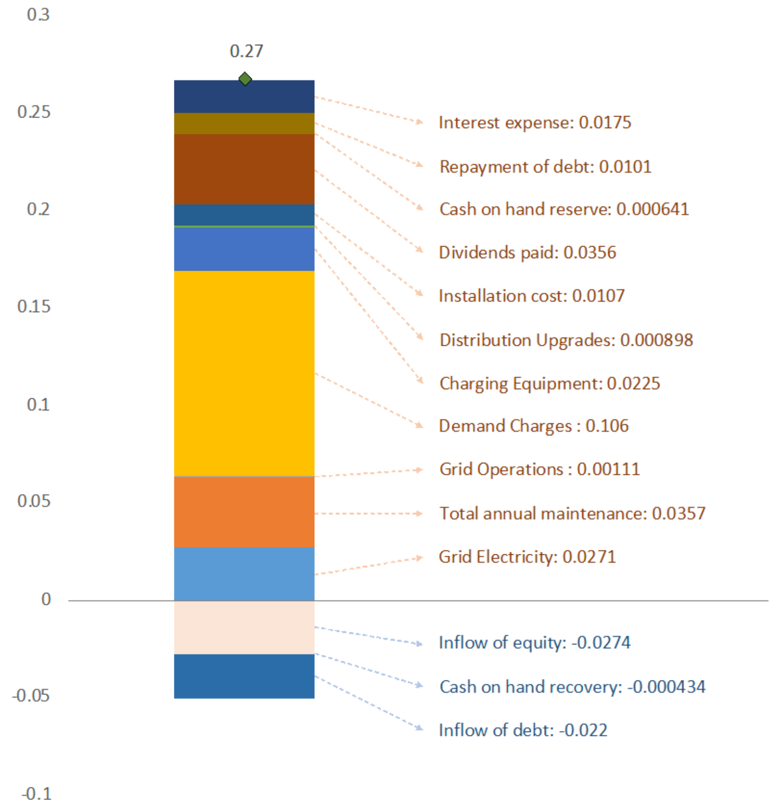


**Figure C-15. DLH Rate 2 charging cost breakdown ($/kWh)**

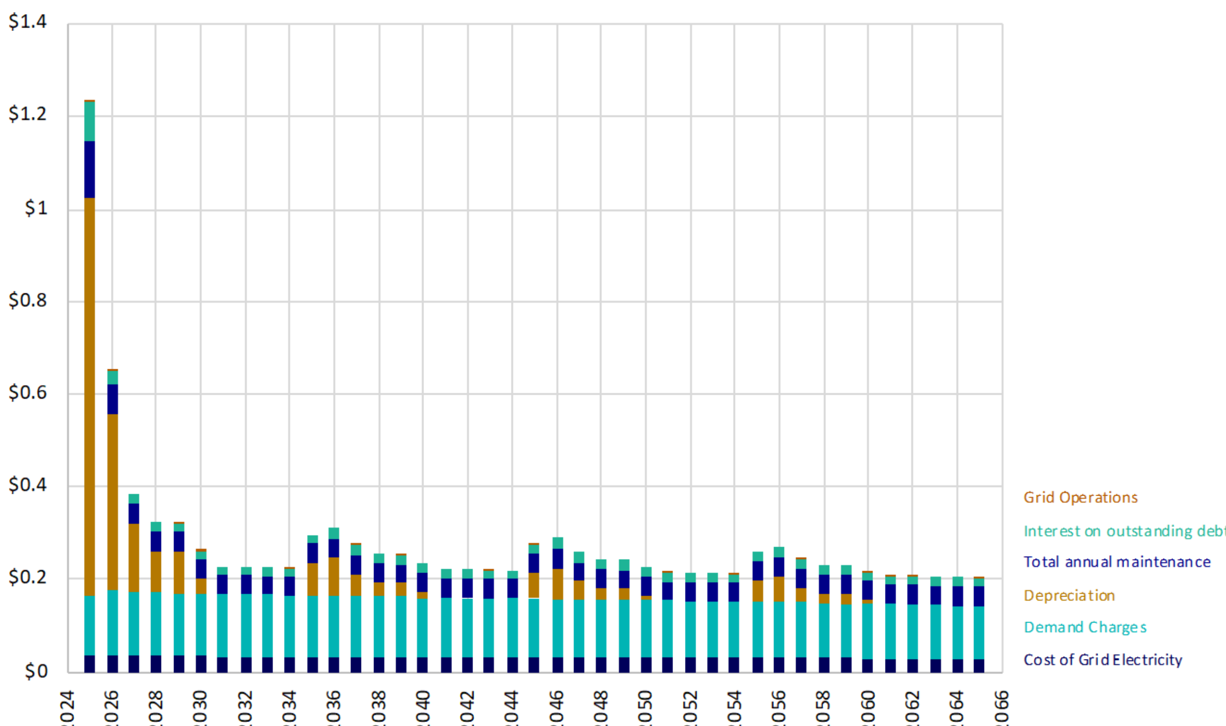


**Figure C-16. DLH Rate 2 annual cost of goods sold ($/kWh) in real 2025 dollars**

## C.2 Travel Center Results

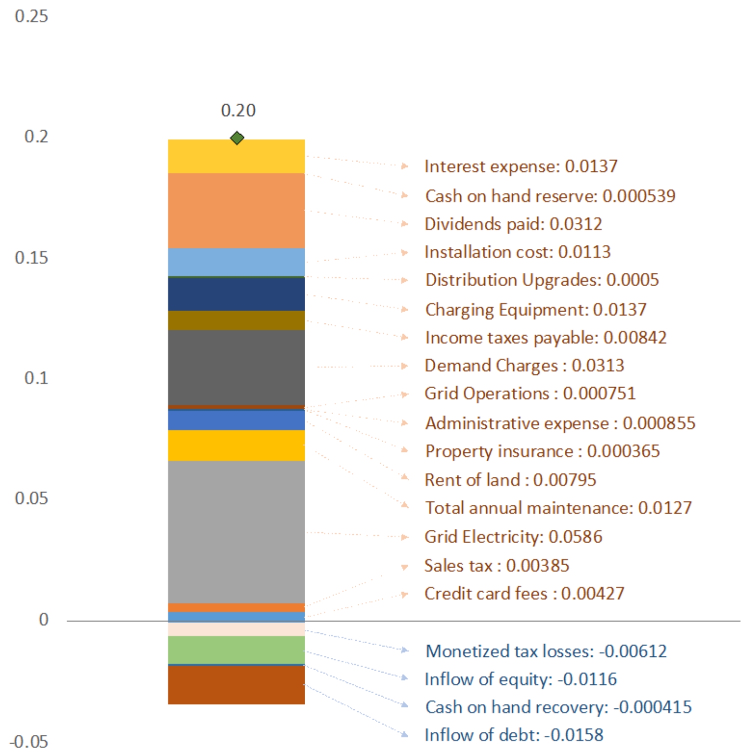


**Figure C-17. THL Rate 1 charging cost breakdown ($/kWh)**

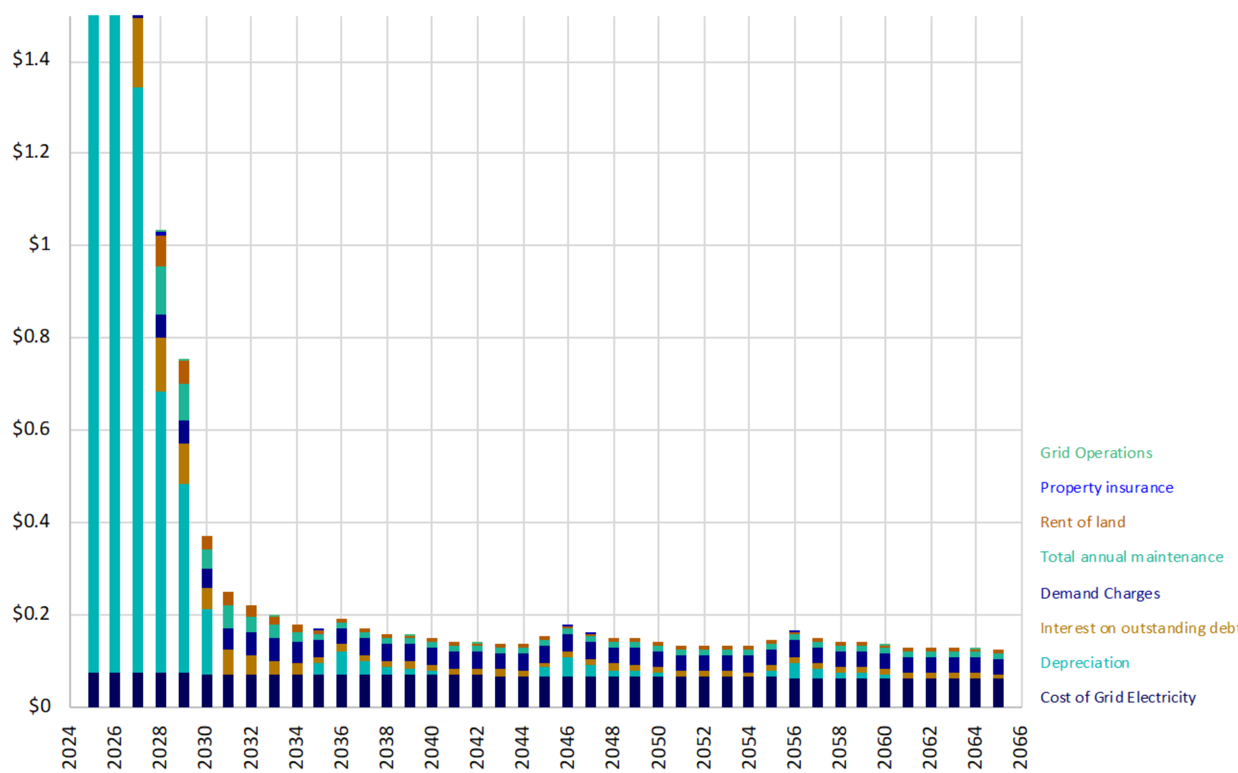


**Figure C-18. THL Rate 1 annual cost of goods sold ($/kWh) in real 2025 dollars**

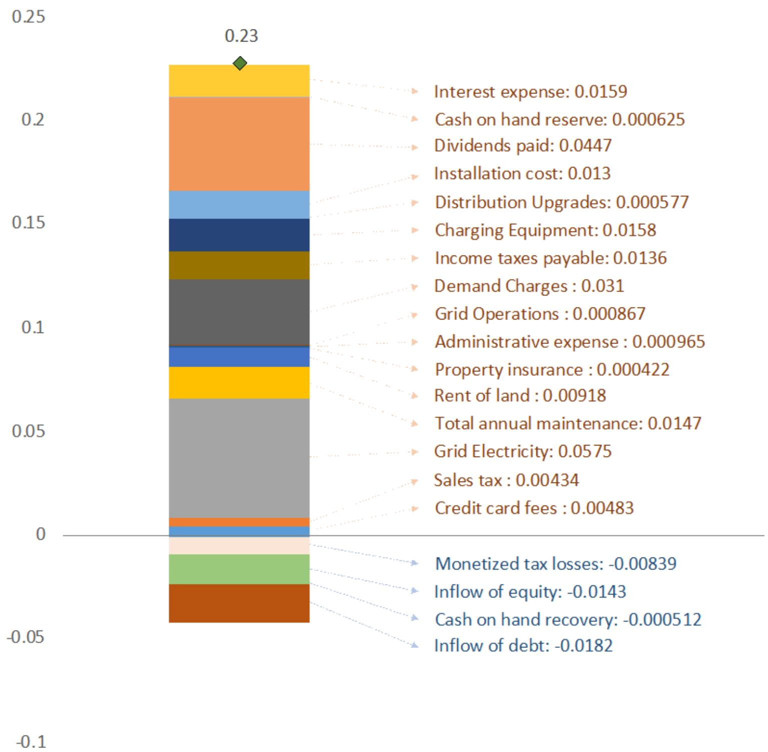


**Figure C-19. TLL Rate 1 charging cost breakdown ($/kWh)**

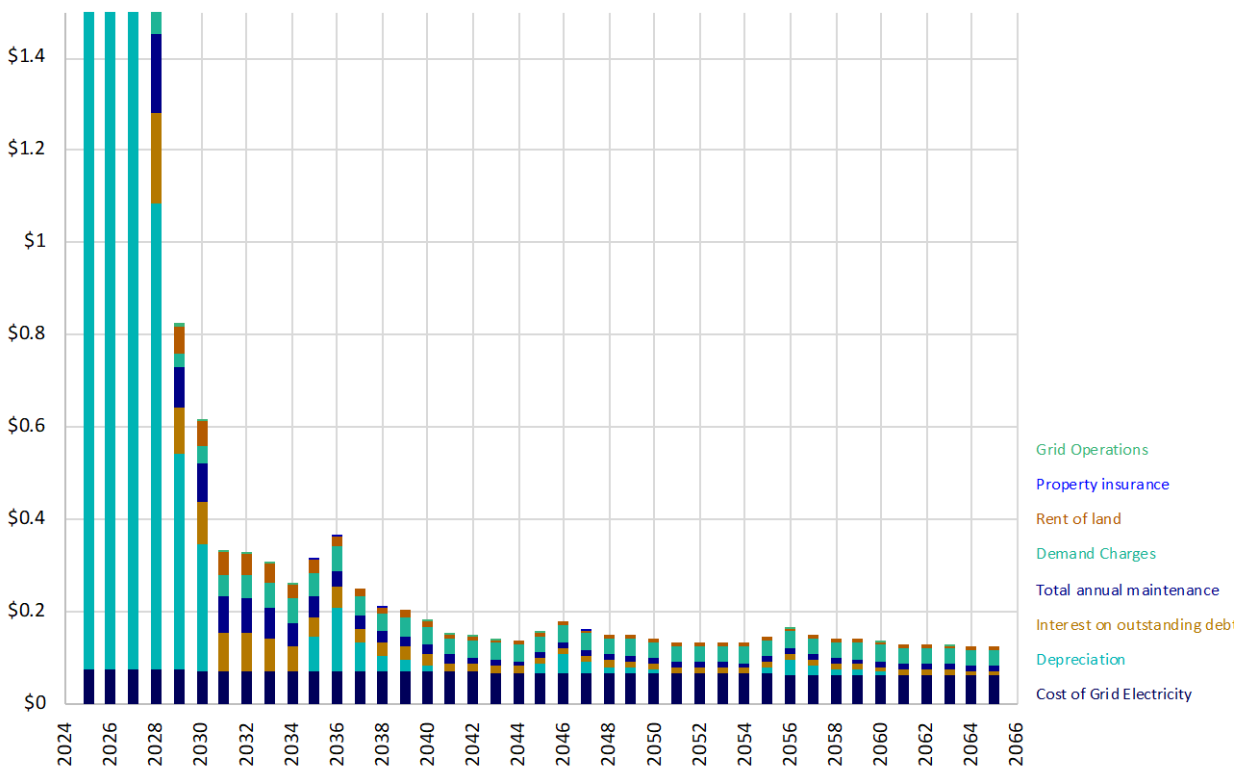


**Figure C-20. TLL Rate 1 annual cost of goods sold ($/kWh) in real 2025 dollars**

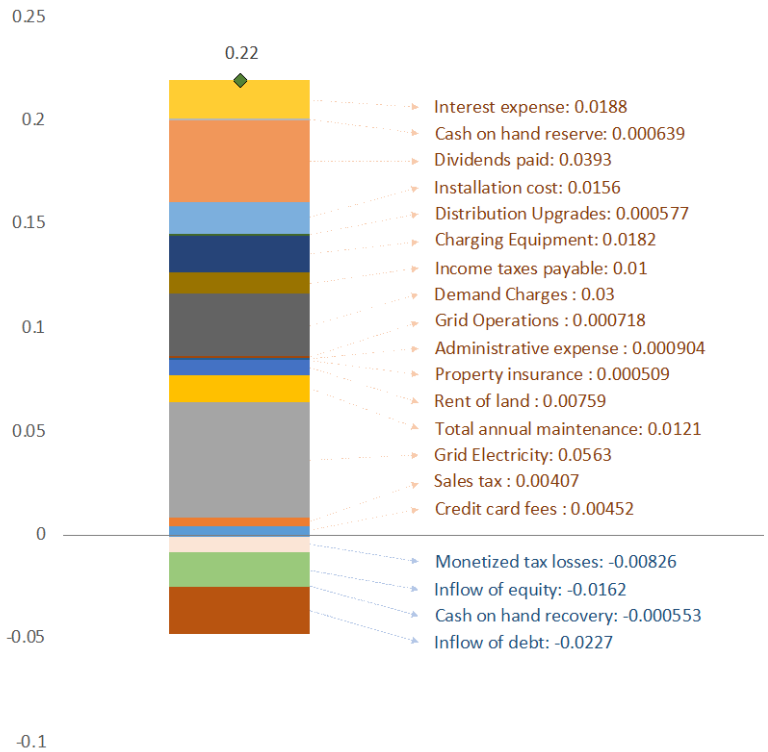


**Figure C-21. THH Rate 1 charging cost breakdown ($/kWh)**

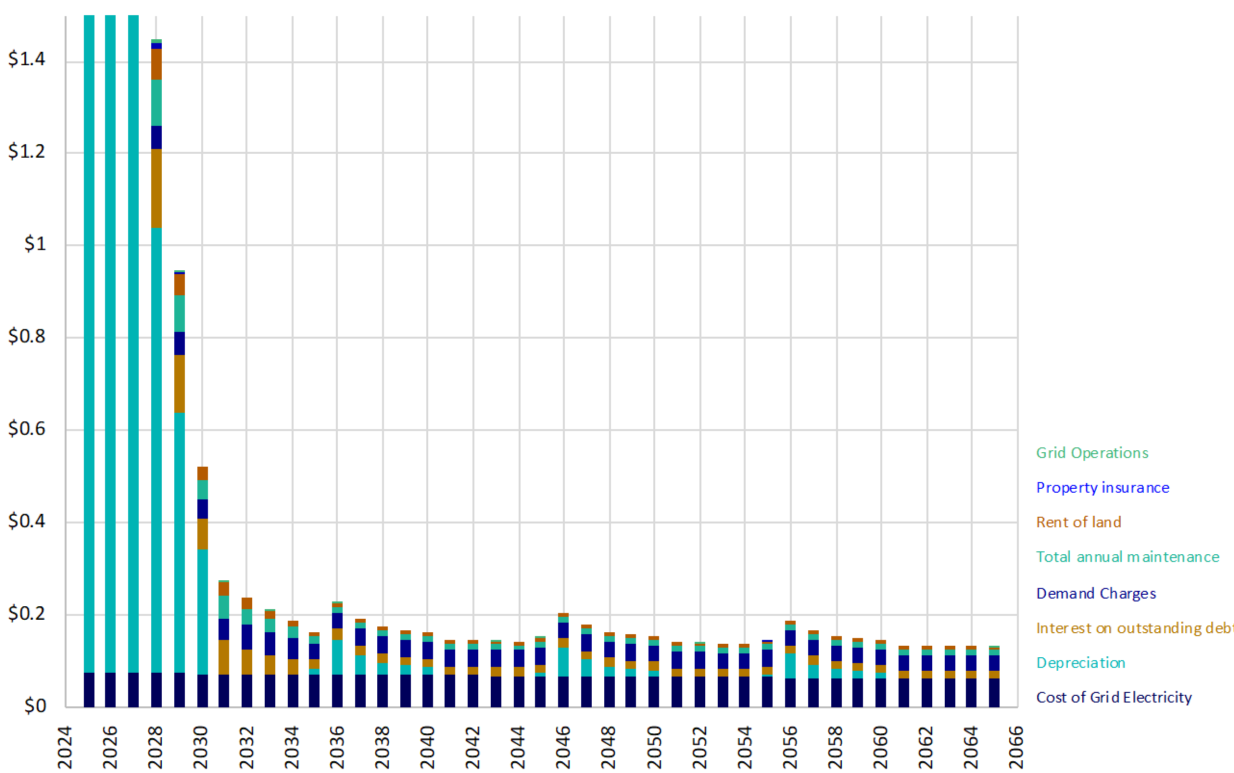


**Figure C-22. THH Rate 1 annual cost of goods sold ($/kWh) in real 2025 dollars**

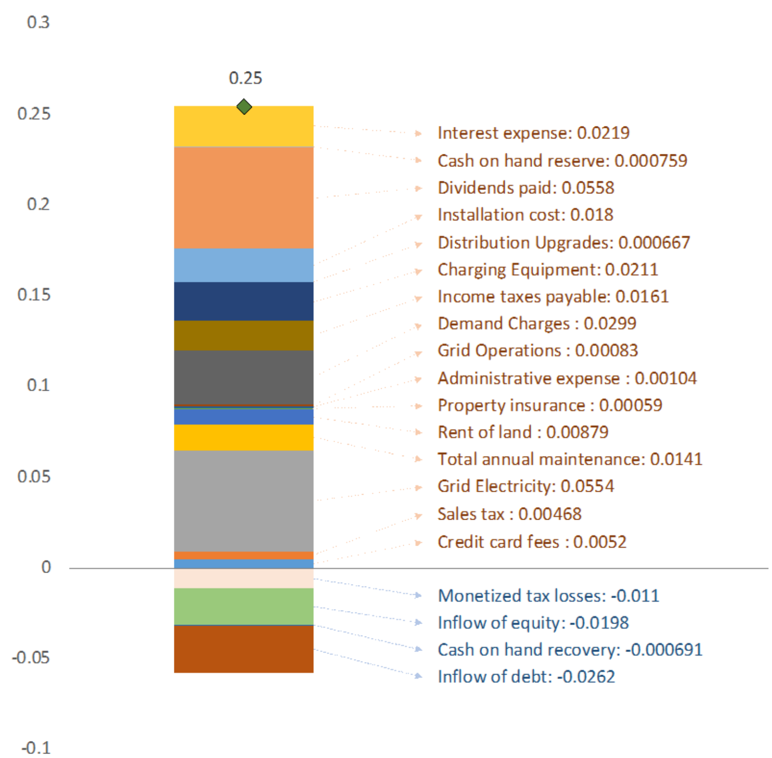


**Figure C-23. TLH Rate 1 charging cost breakdown ($/kWh)**

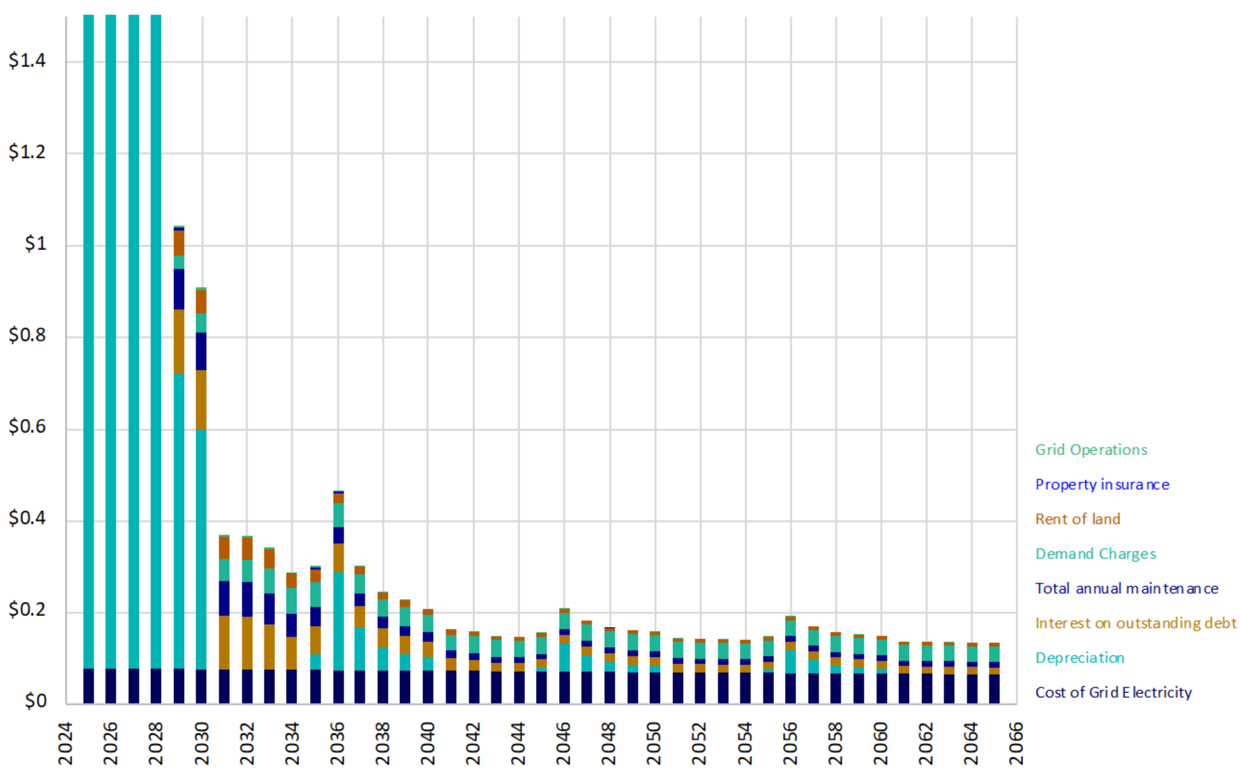


**Figure C-24. TLH Rate 1 annual cost of goods sold ($/kWh) in real 2025 dollars**

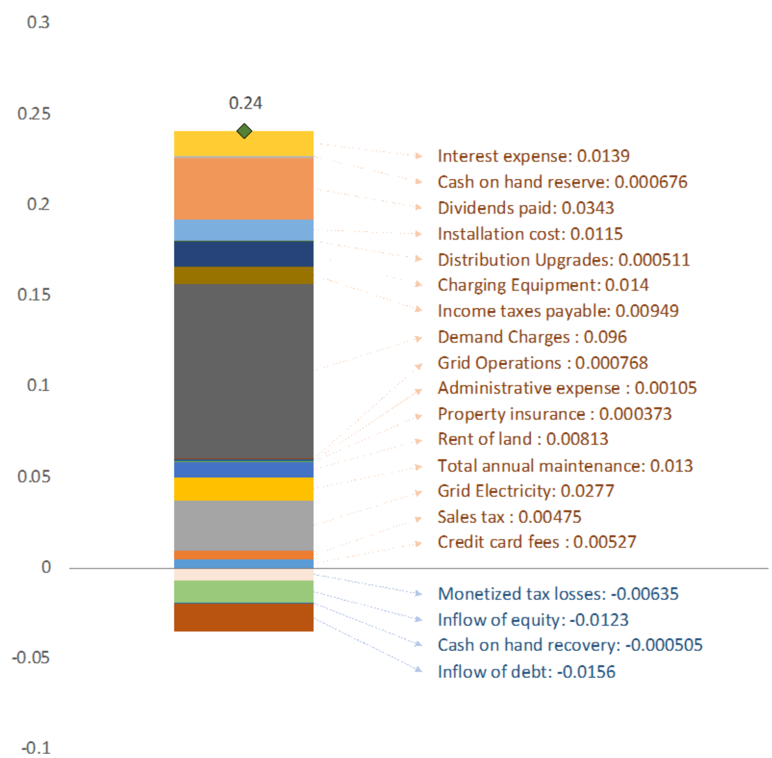


**Figure C-25. THL Rate 2 charging cost breakdown ($/kWh)**

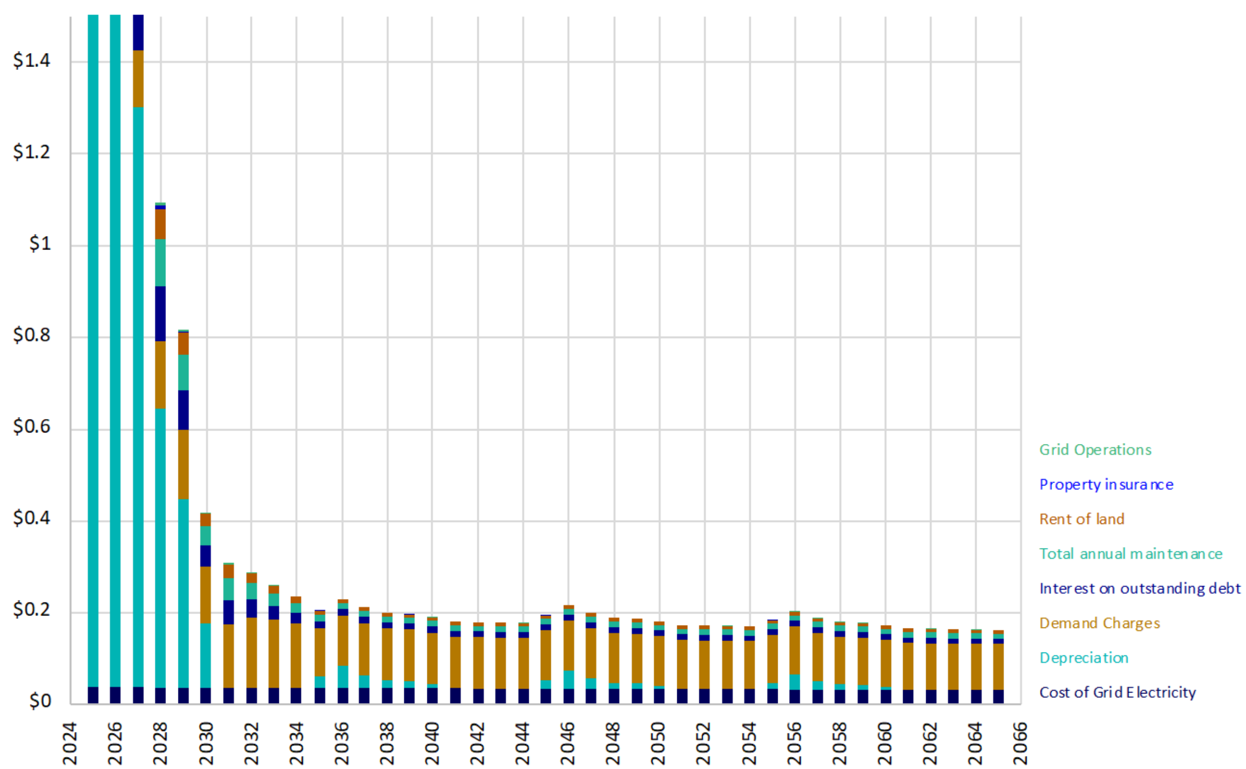


**Figure C-26. THL Rate 2 annual cost of goods sold ($/kWh) in real 2025 dollars**

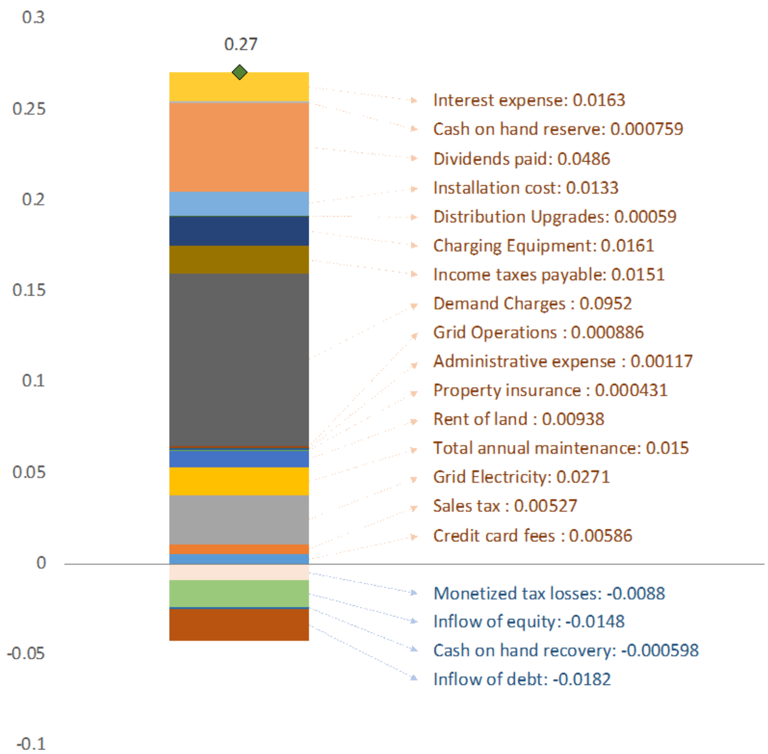


**Figure C-27. TLL Rate 2 charging cost breakdown ($/kWh)**

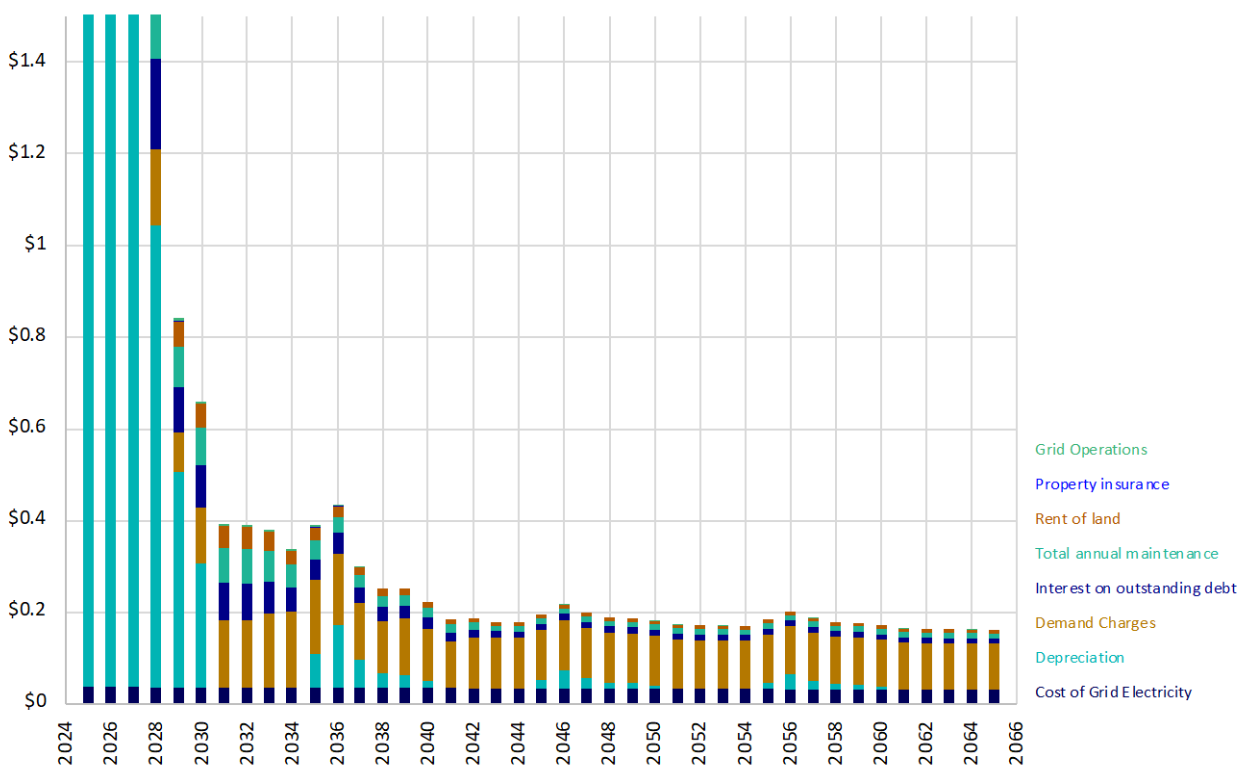


**Figure C-28. TLL Rate 2 annual cost of goods sold ($/kWh) in real 2025 dollars**


**Figure C-29. THH Rate 2 charging cost breakdown ($/kWh)**

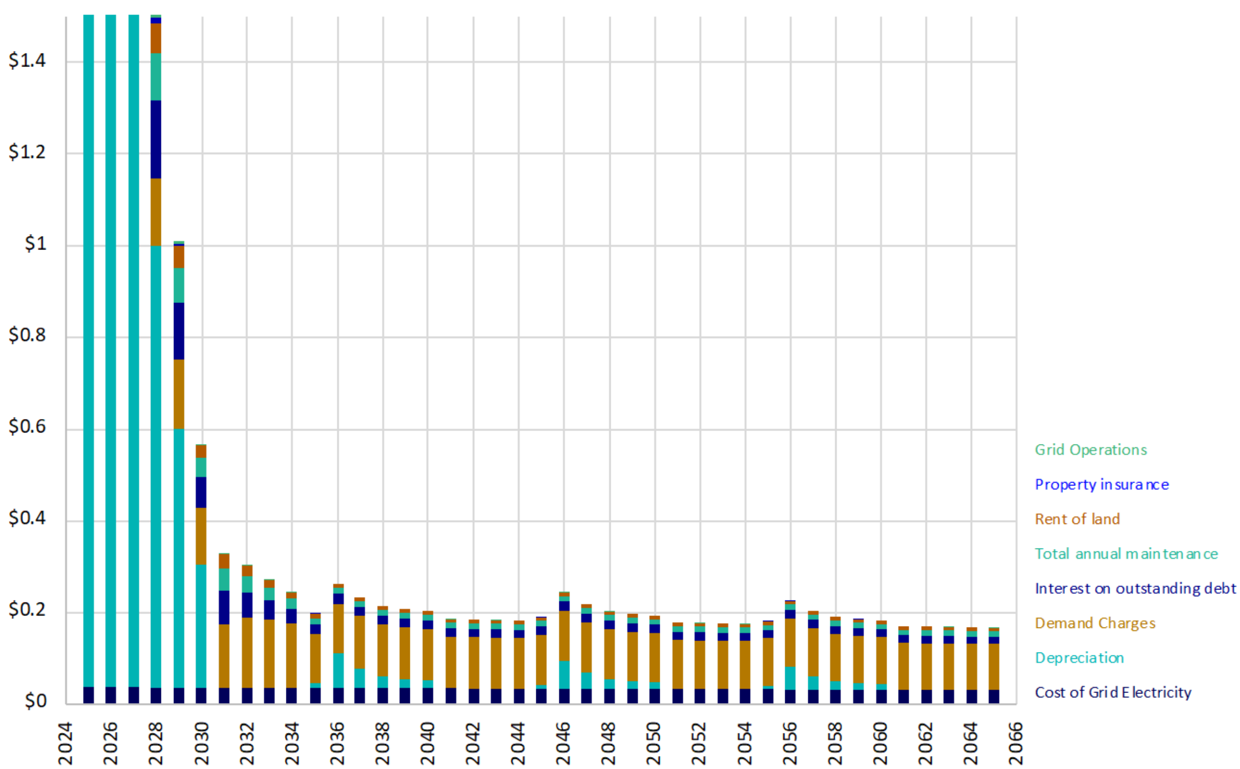


**Figure C-30. THH Rate 2 annual cost of goods sold ($/kWh) in real 2025 dollars**

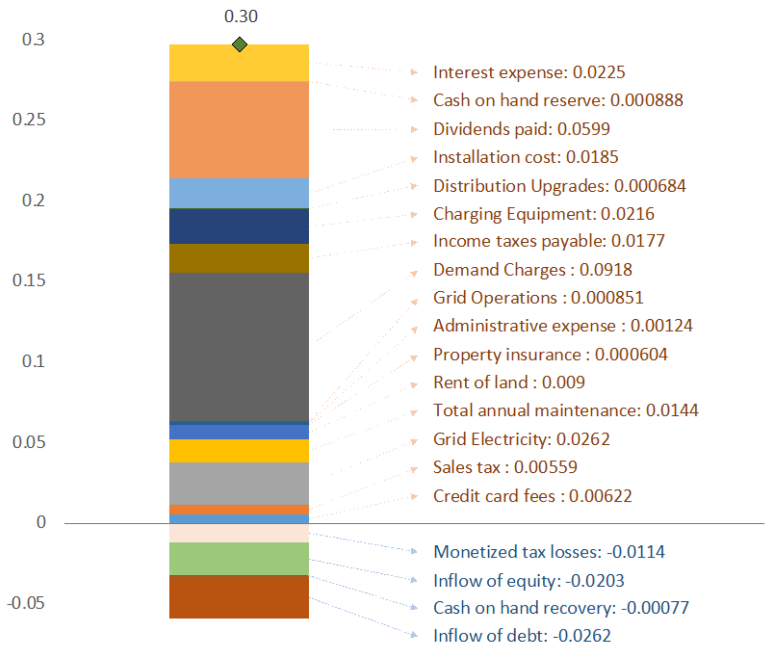


**Figure C-31. TLH Rate 2 charging cost breakdown ($/kWh)**

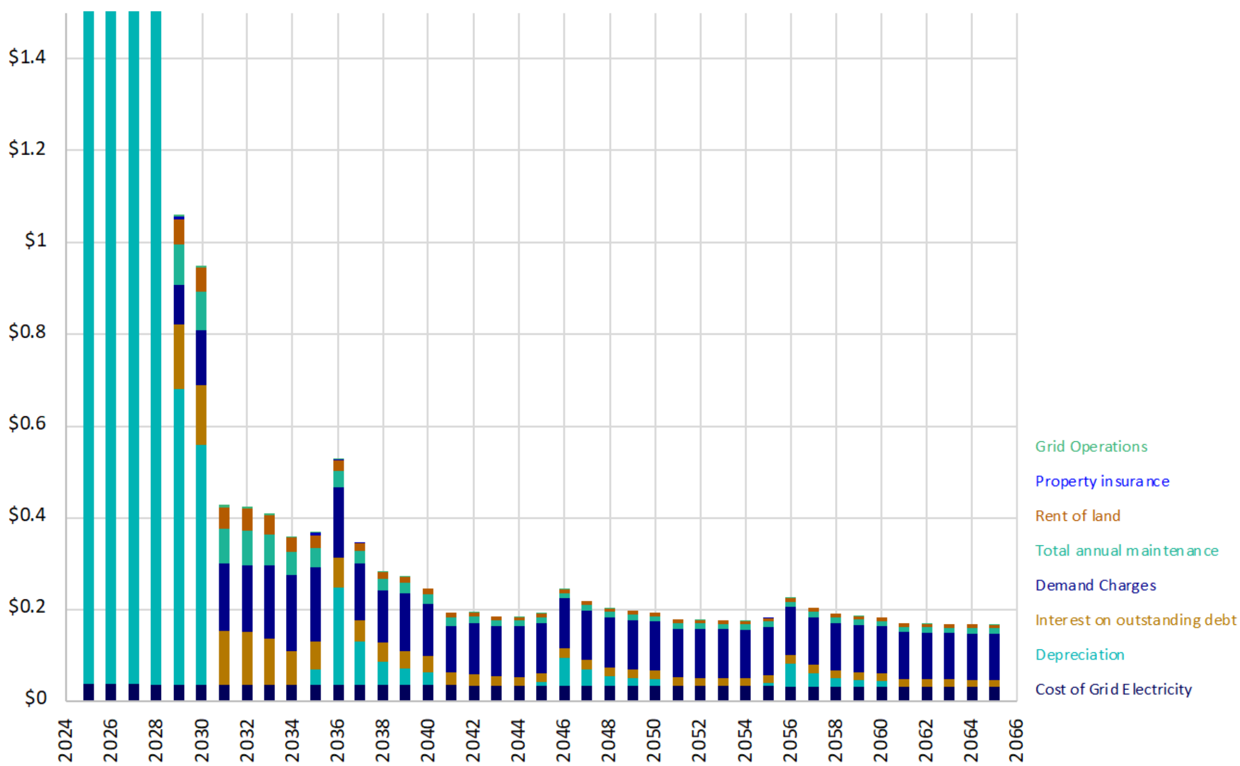


**Figure C-32. TLH Rate 2 annual cost of goods sold ($/kWh) in real 2025 dollars**

## C.3 En Route Results

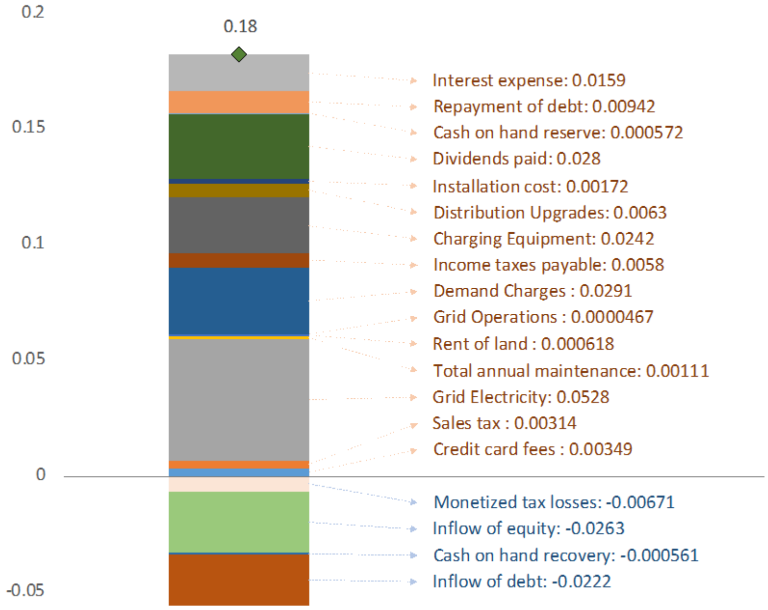


**Figure C-33. EHL MW Rate 1 charging cost breakdown ($/kWh)**

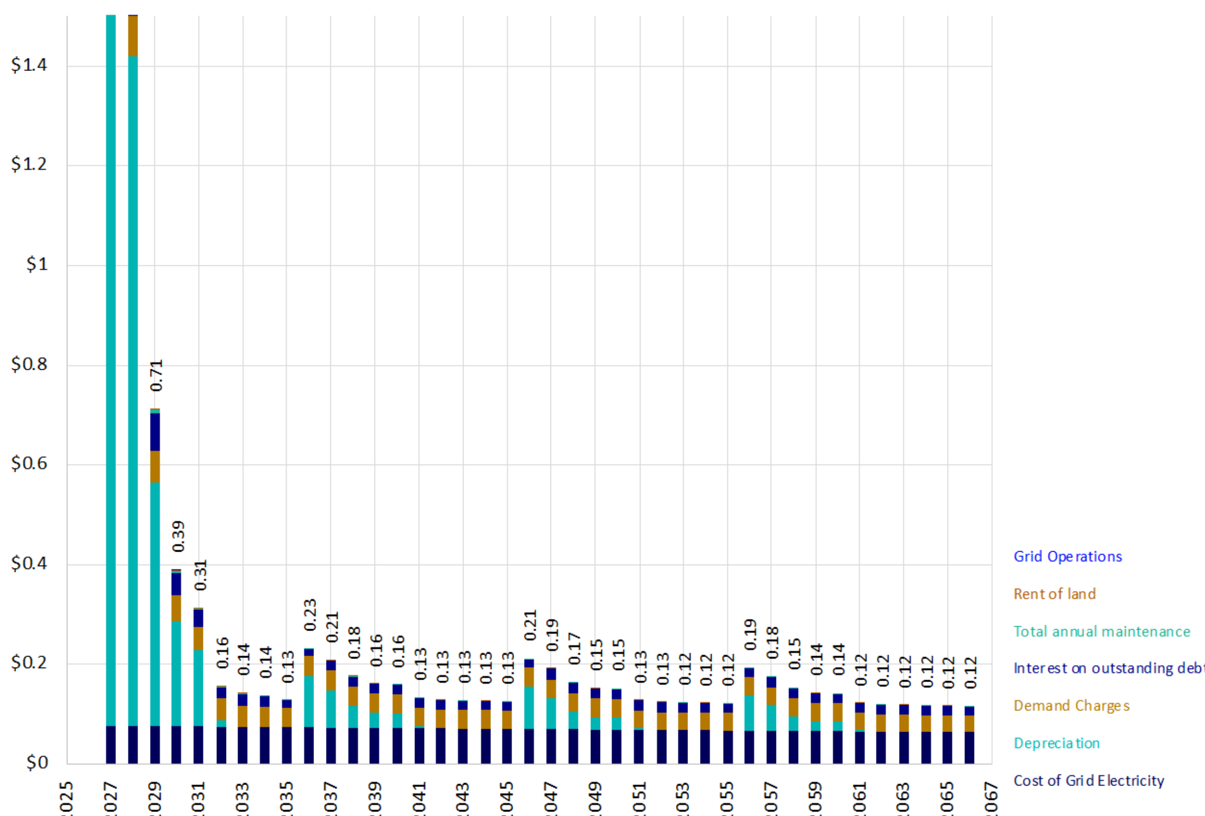


**Figure C-34. EHL MW Rate 1 annual cost of goods sold ($/kWh) in real 2025 dollars**

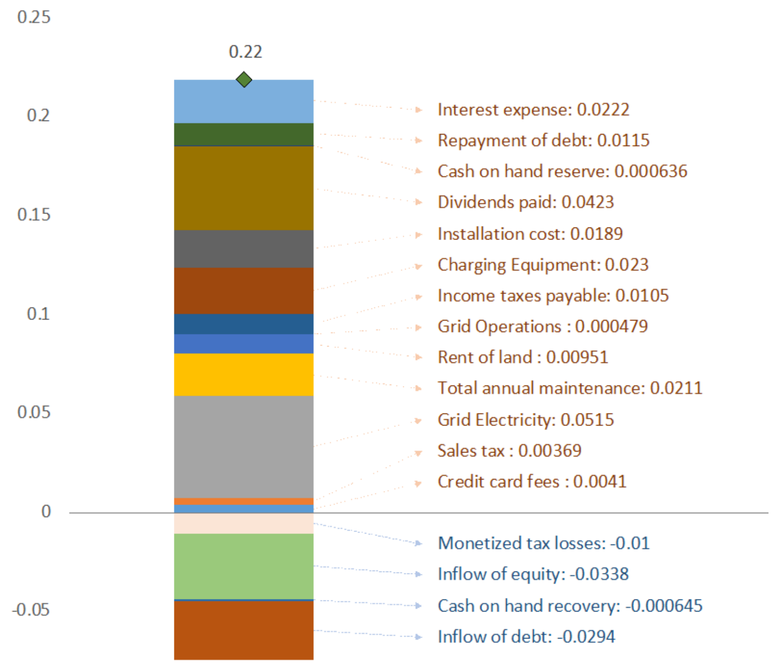


**Figure C-35. EHL kW Rate 1 charging cost breakdown ($/kWh)**

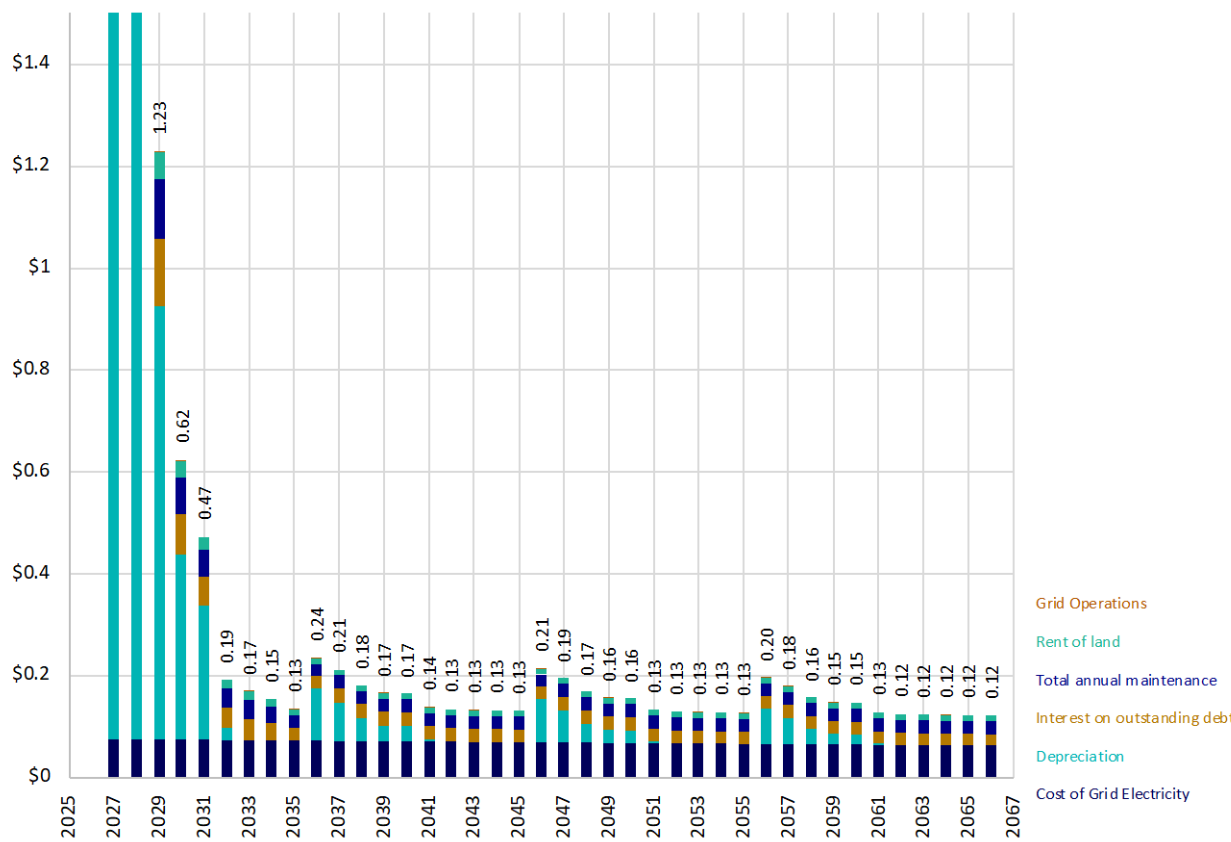


**Figure C-36. EHL kW Rate 1 annual cost of goods sold ($/kWh) in real 2025 dollars**

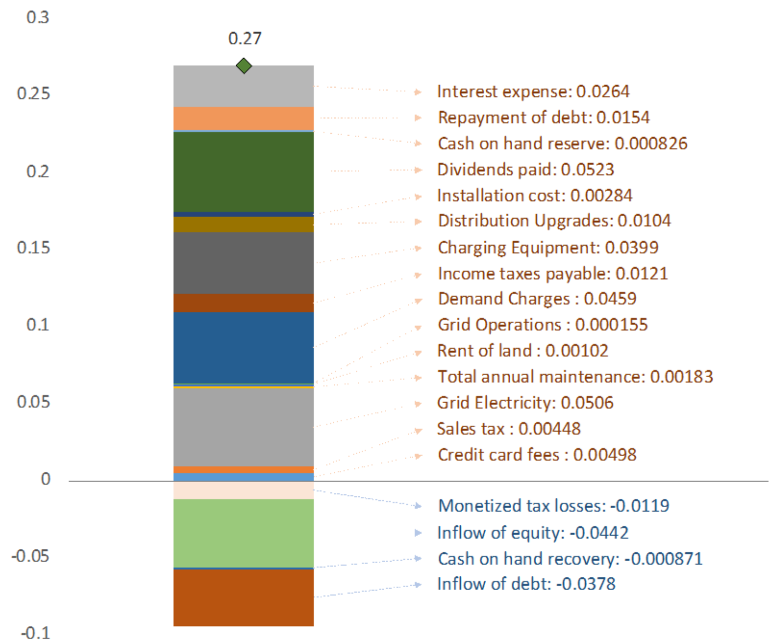


**Figure C-37. ELL MW Rate 1 charging cost breakdown ($/kWh)**

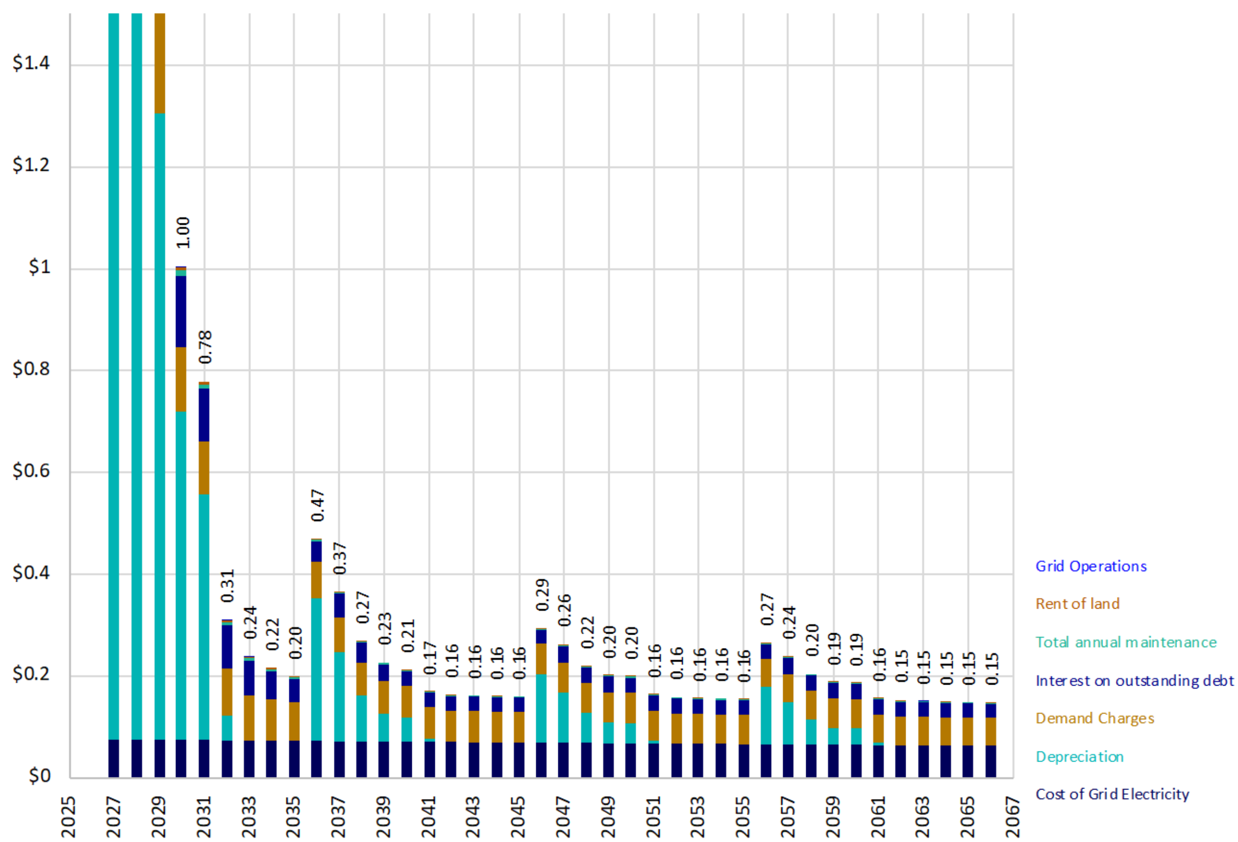


**Figure C-38. ELL MW Rate 1 annual cost of goods sold ($/kWh) in real 2025 dollars**

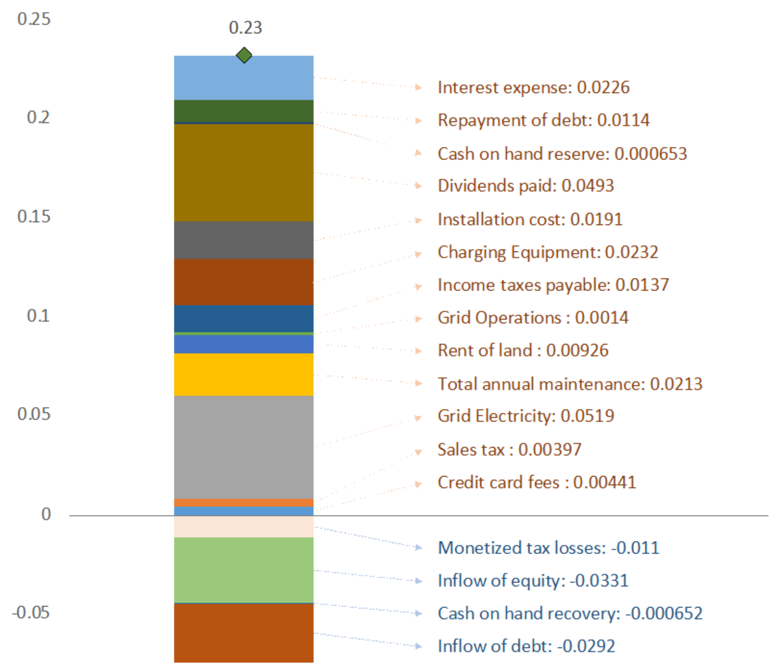


**Figure C-39. ELL kW Rate 1 charging cost breakdown ($/kWh)**

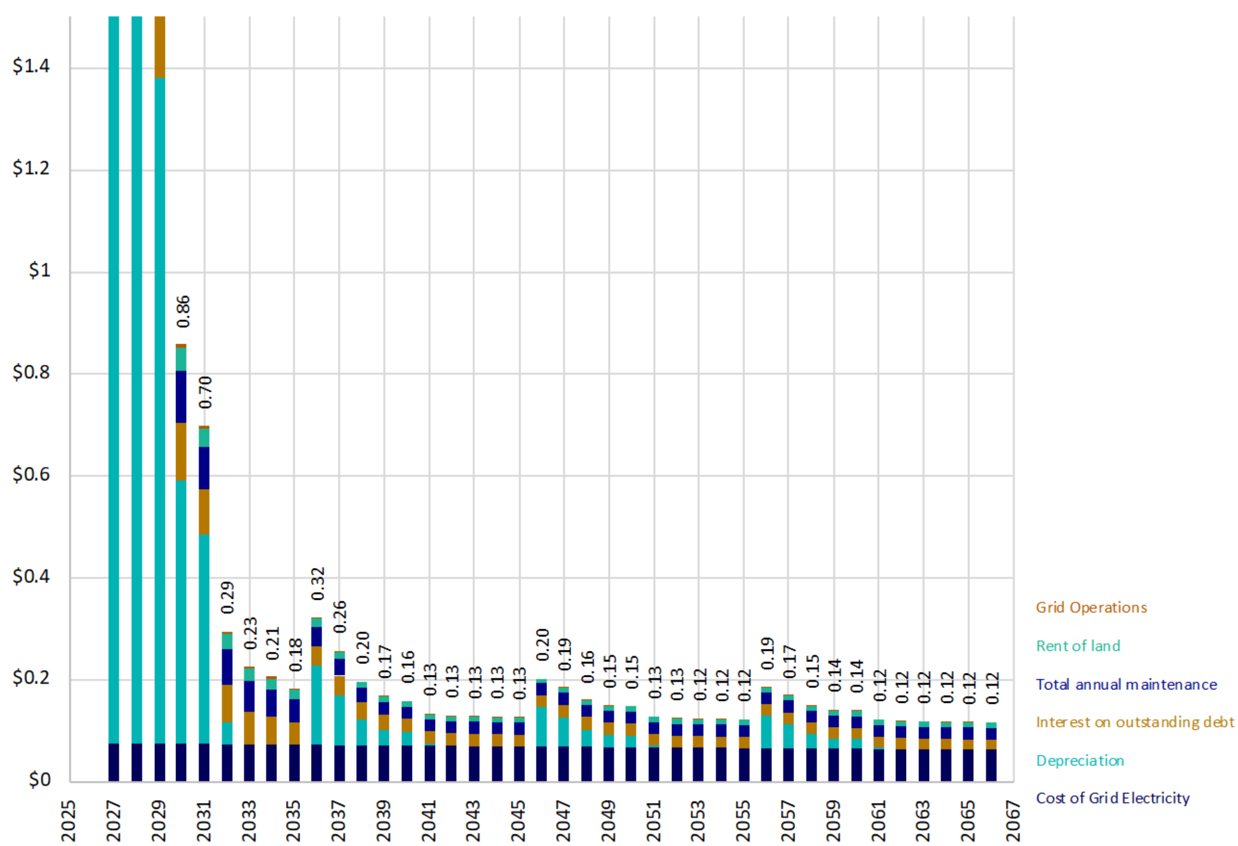


**Figure C-40. ELL kW Rate 1 annual cost of goods sold ($/kWh) in real 2025 dollars**

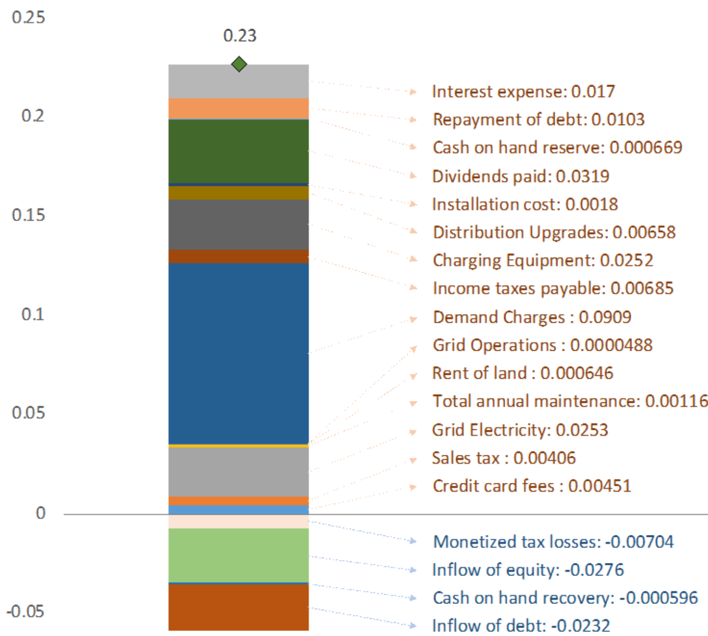


**Figure C-41. EHL MW Rate 2 charging cost breakdown ($/kWh)**

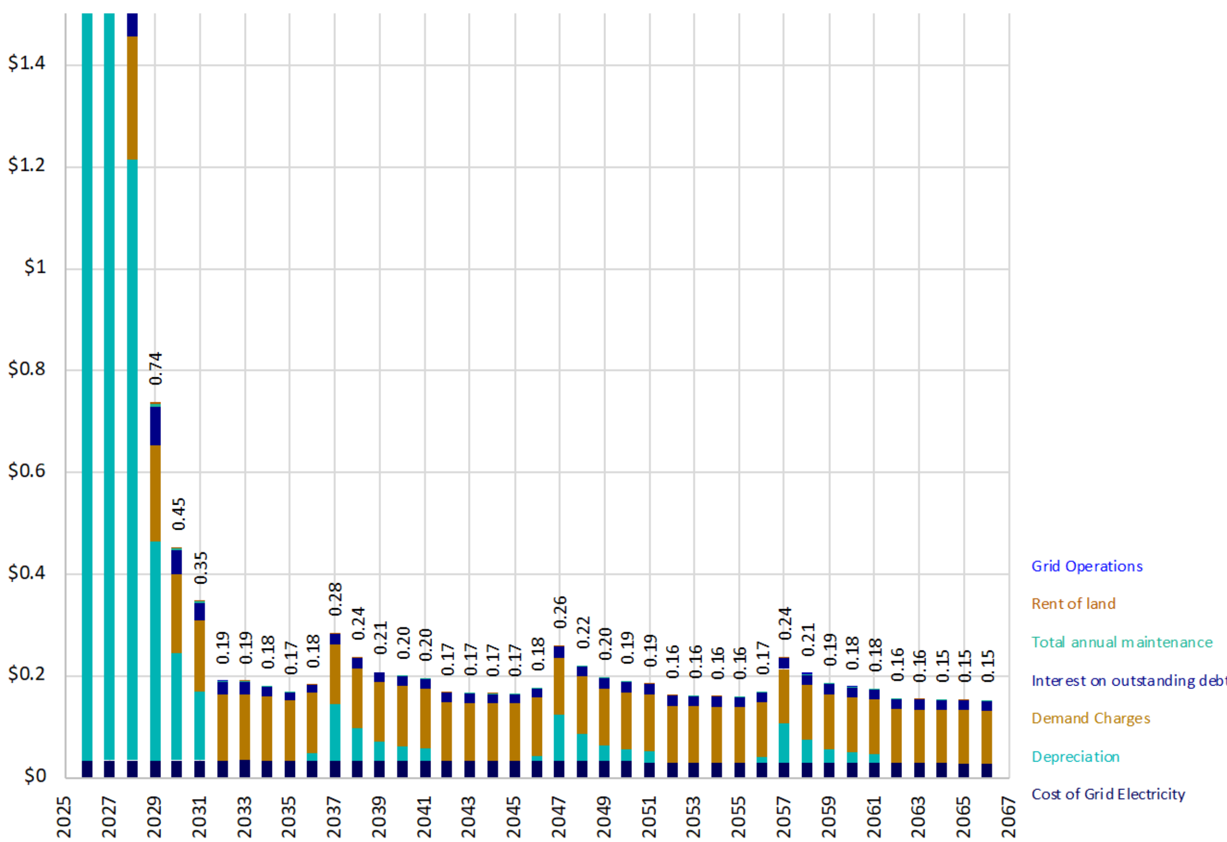


**Figure C-42. EHL MW Rate 2 annual cost of goods sold ($/kWh) in real 2025 dollars**

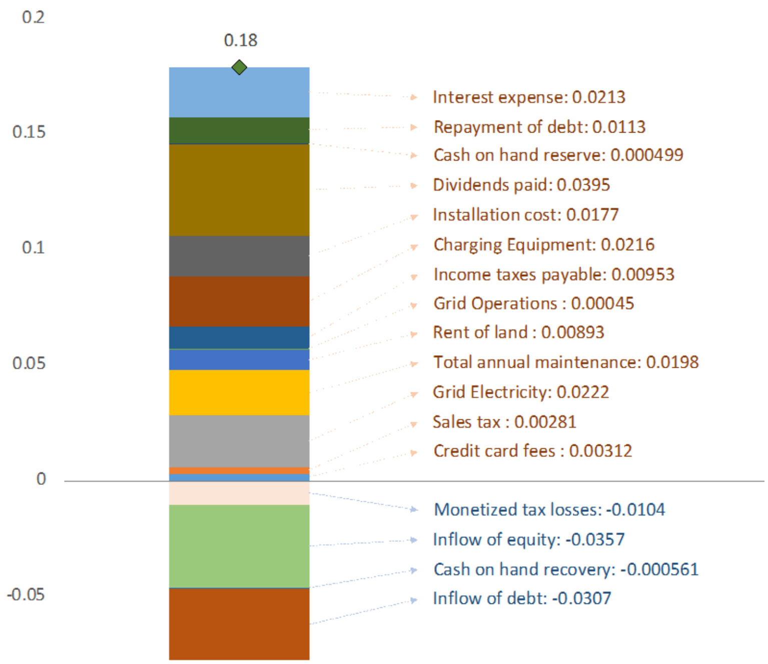


**Figure C-43. EHL kW Rate 2 charging cost breakdown ($/kWh)**

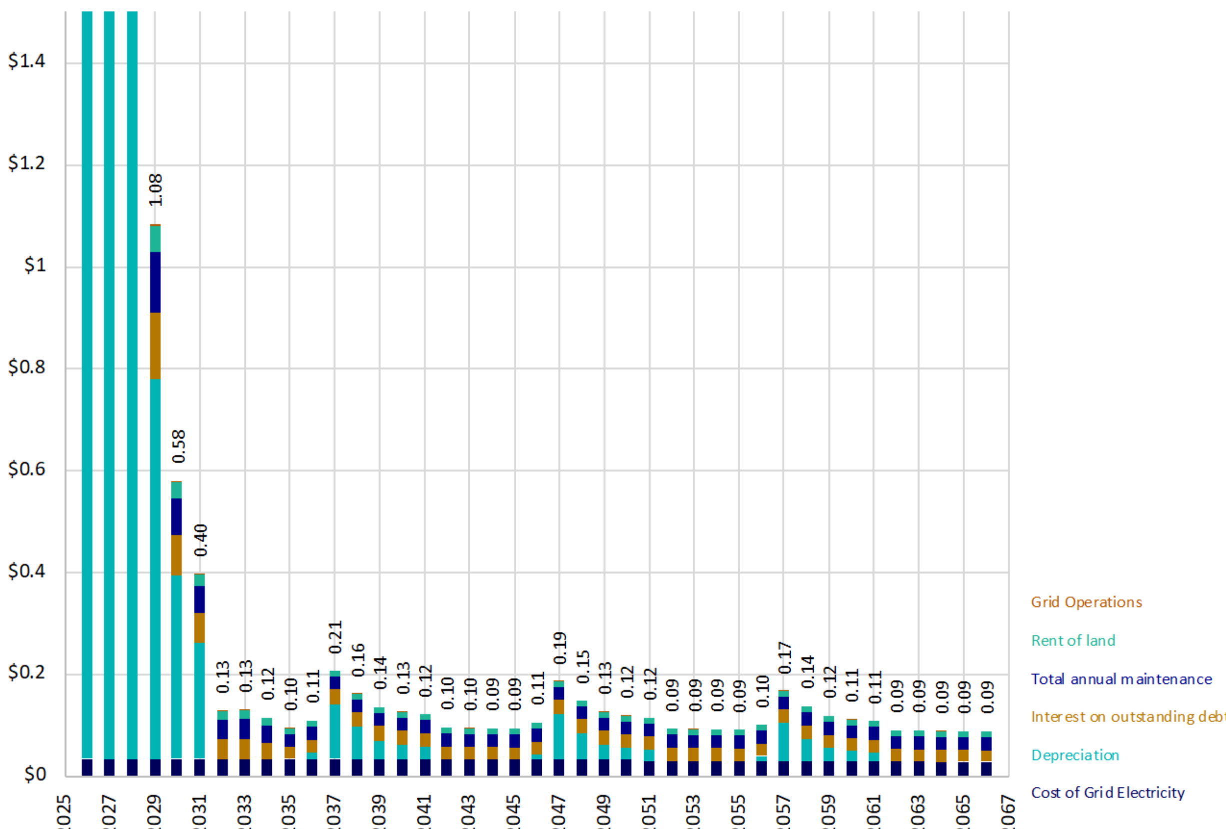


**Figure C-44. EHL kW Rate 2 annual cost of goods sold ($/kWh) in real 2025 dollars**

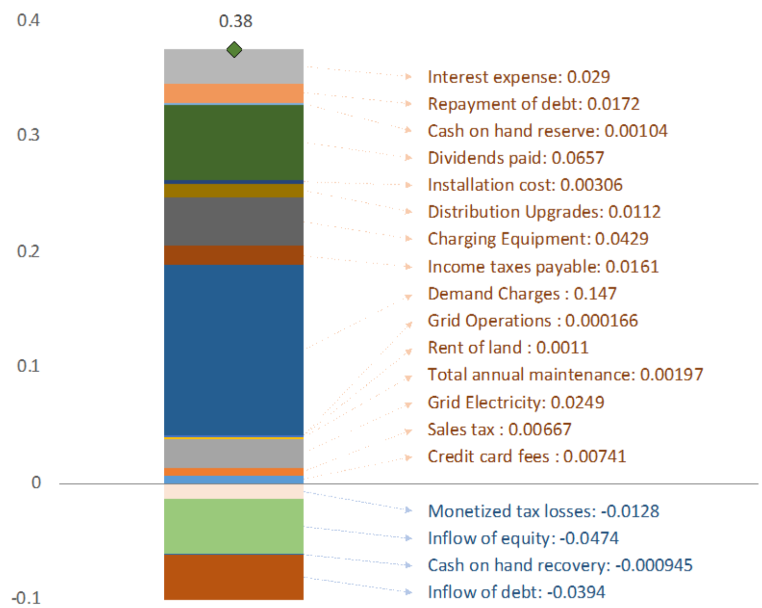


**Figure C-45. ELL MW Rate 2 charging cost breakdown ($/kWh)**

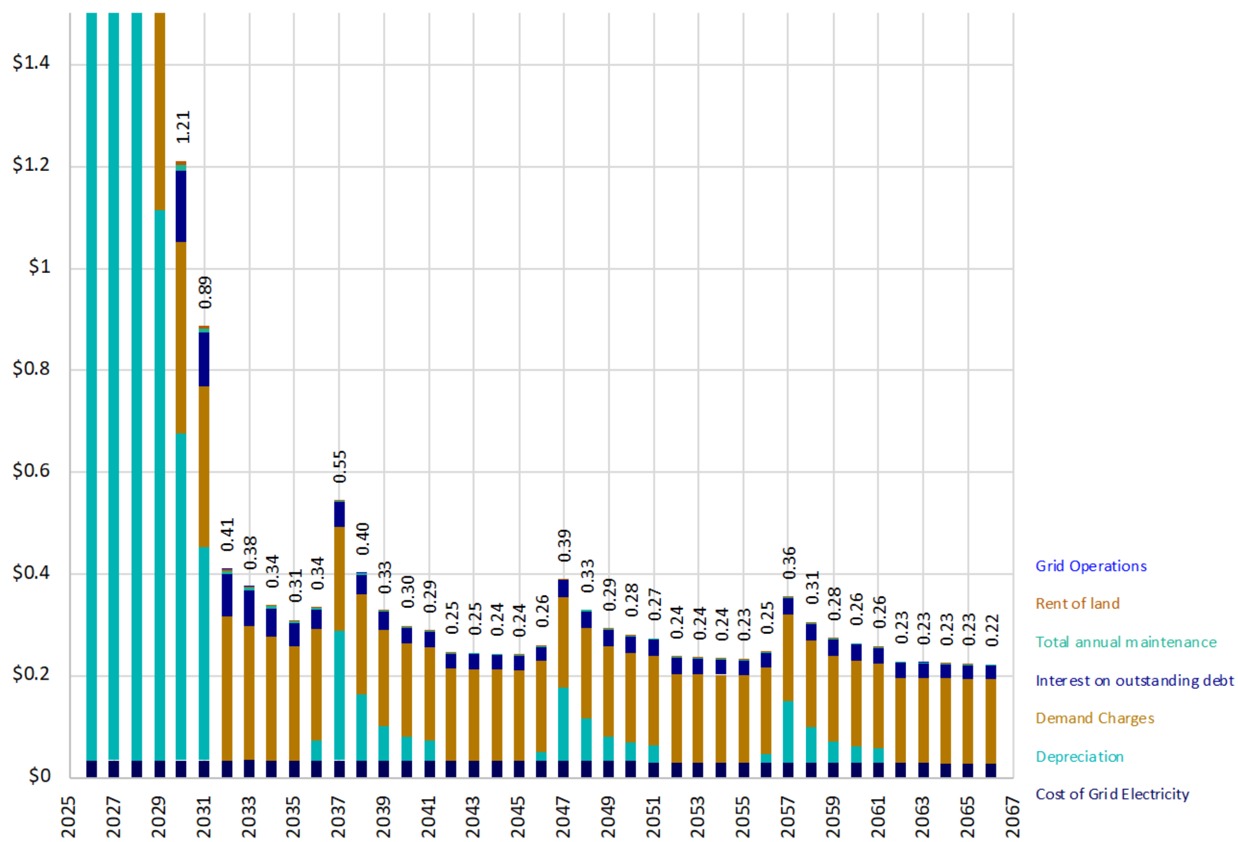


**Figure C-46. ELL MW Rate 2 annual cost of goods sold ($/kWh) in real 2025 dollars**

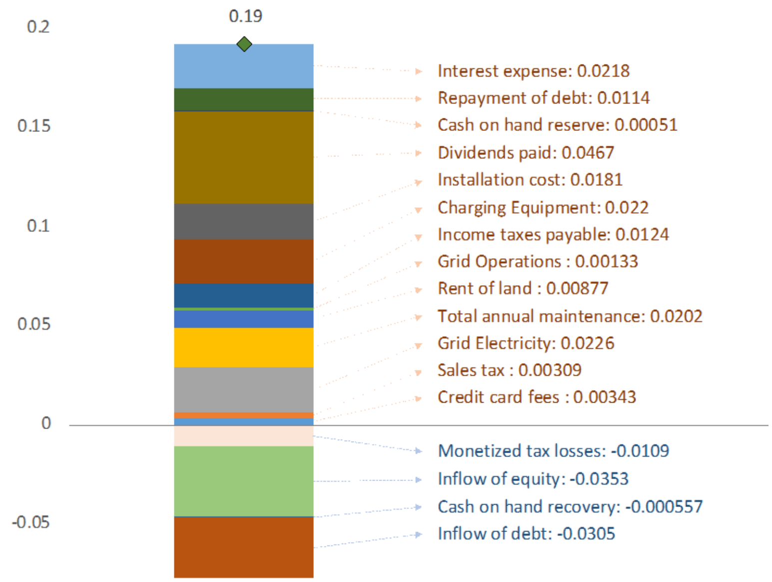


**Figure C-47. ELL kW Rate 2 charging cost breakdown ($/kWh)**

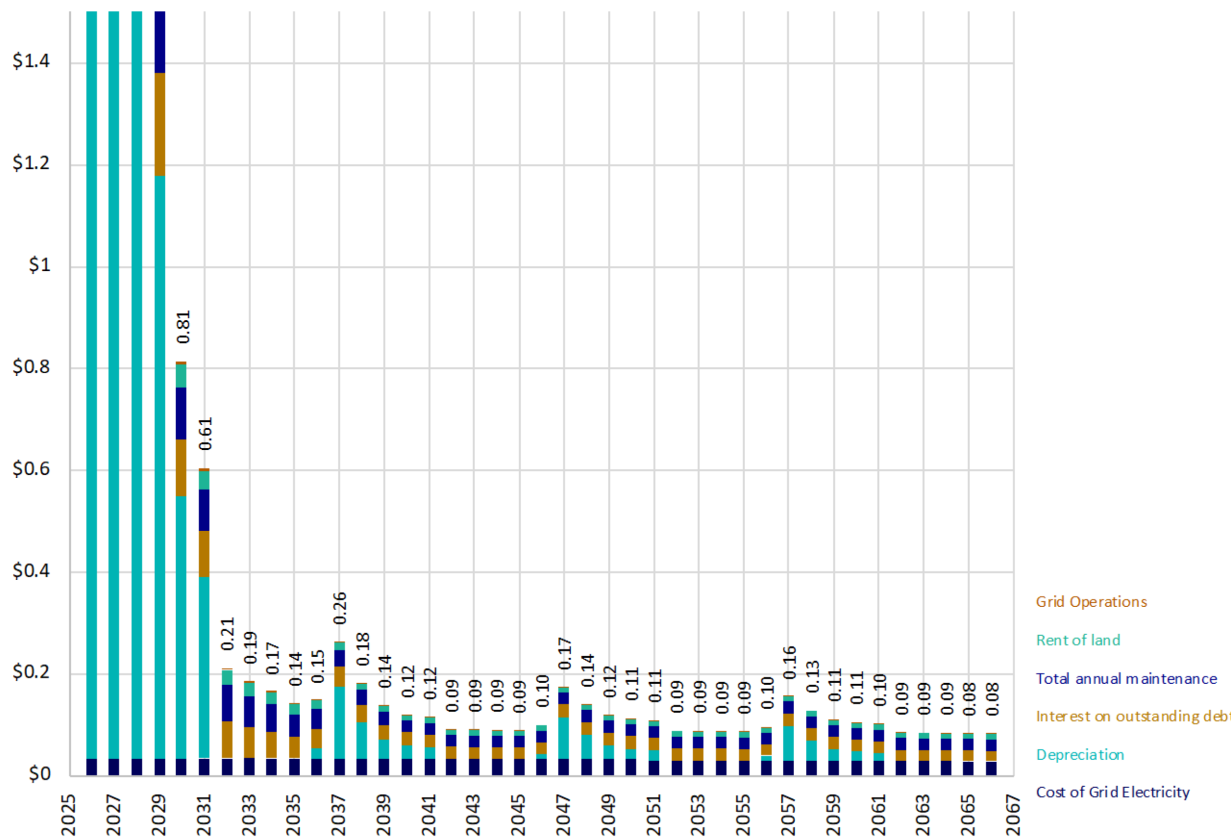


**Figure C-48. ELL MW Rate 2 annual cost of goods sold ($/kWh) in real 2025 dollars**