COST SAVINGS FROM IMPROVING ENERGIZATION TIMELINES FOR EV CHARGING

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Executive Summary

The electrification of transportation is advancing rapidly, but a critical barrier to speed and scale remains: the lengthy and costly process of energizing electric vehicle (EV) charging stations at some sites. This report examines the financial impact of utility energization delays on Direct Current Fast Charging (DCFC) stations for a) public light-duty vehicle (LDV) charging and b) heavy-duty vehicle (HDV) charging.

Atlas Public Policy estimates the savings associated with energization timeline reductions, in net present value (NPV) terms. For public DCFC charging for LDVs, we estimate a six-month reduction produces NPV gains of $104,200 for a 600 kilowatt (kW) station[1] and $165,500 for a 1 megawatt (MW) station. For HDV charging, where capital intensity and utilization are higher, an eighteen-month reduction yields $1.8 million for a 4 MW station and $3.4 million for an 8 MW station. These benefits are driven primarily by making it faster to begin earning money at charging stations. Heavy-duty vehicle stations also capture significant public health gains by displacing diesel emissions.

Sensitivity analysis indicates NPV benefits could range ±16-21 percent for LDV stations and ±15-42 percent for HDV stations depending on revenue per kWh, utilization rates, and analysis period assumptions, with the economic case for timeline reductions being stronger at higher-utilization stations.

The capacity of these modeled stations are meant to approximate those that are commonly installed today. As multi-megawatt light-duty fast charging plazas become more common, some LDV charging stations will have power capacities resembling the HDV stations modeled here and therefore may share cost and timeline similarities.

Importantly, this analysis does not capture any costs to implement improvements to timelines. Consequently, the NPV figures presented throughout this report represent gross benefits of timeline reductions rather than net benefits after accounting for implementation costs.

Beyond the numbers, stakeholder interviews with EV service providers, site hosts, and researchers highlight systemic challenges and actionable solutions. Permitting delays and fragmented utility processes were cited as the most significant barriers, while battery storage and microgrids emerged as potential grid constraint solutions for site hosts. States, counties, utility commissions, and utilities across the U.S. are beginning to implement reforms such as energization deadlines, streamlined permitting, load hosting capacity

[1] We use "station" to refer to any configuration of charging ports that add up to the overall nameplate capacity stated (600kW, 1MW, 4MW, 8MW).

maps, and bridge-to-wires solutions. Stakeholders emphasized the urgency of aligning utilities, regulators, and charging developers under reduced, standardized timelines and coordinated processes to reduce project dropout rates and mitigate opportunity costs that ripple across fleets, automakers, and grant programs.

In an environment where electricity demand and load requests are rising beyond recent historical norms, accelerating energization timelines is essential to achieving transportation electrification goals and helping stimulate private sector investment by improving economics for charging owners and operators. By implementing the strategies outlined in this report, stakeholders can overcome systemic bottlenecks, reduce costs, and enable a more accessible EV charging network nationwide.

Introduction

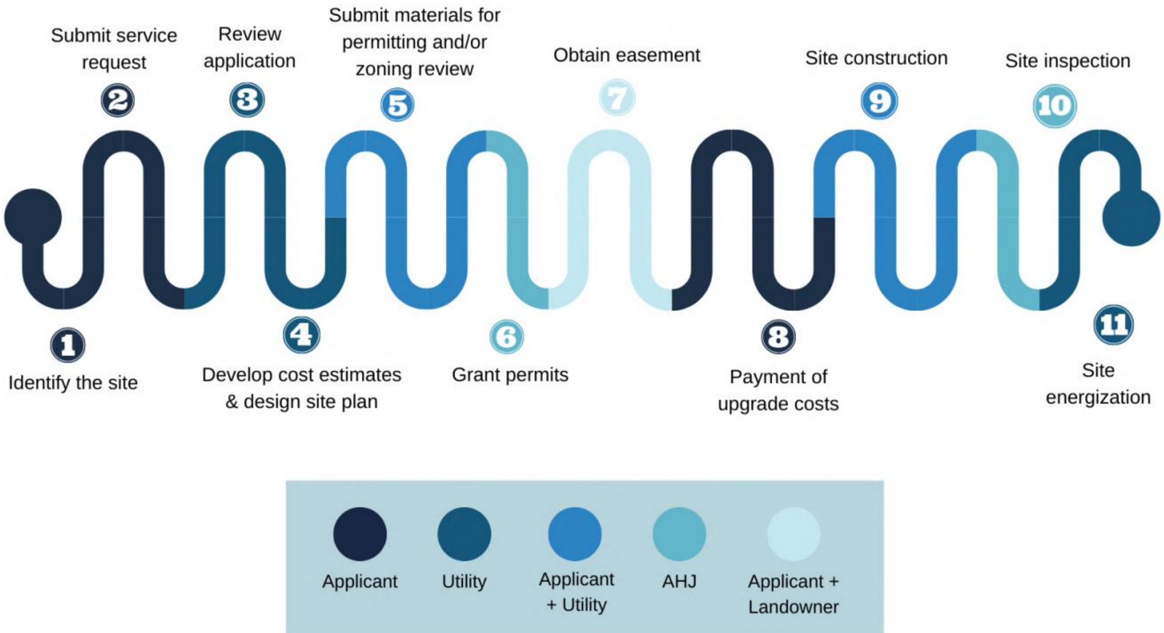
The electrification of transportation is rapidly reshaping the American mobility landscape, driven by the economic, environmental, and performance advantages of electric vehicles (EVs). Many EVs already outperform internal combustion vehicles on lifetime cost [1]. Beyond affordability, electrification promises over $1.7 trillion in climate benefits over the next 30 years [2], enhanced national energy security through reduced petroleum imports, and downward pressure on electricity rates by optimizing use of existing utility assets [3]. Federal investments, including $7.5 billion through the National Electric Vehicle Infrastructure (NEVI) and Charging and Fueling Infrastructure (CFI) programs [4], have catalyzed a wave of public and private funding, spurring domestic manufacturing and creating thousands of local jobs for electricians, line workers, and construction laborers [5].

Despite this momentum, a critical barrier to speed and scale remains: the lengthy and costly process of energizing EV charging stations at some sites. The timeline for energization for the purposes of our modeling starts at site identification and ends with a fully operational, energized site. This report quantifies the financial impact of utility energization delays on Direct Current Fast Charging (DCFC) stations for a) public light-duty vehicle charging and b) heavy-duty vehicle charging. This report offers a unique and timely contribution to the ongoing national conversation around electric vehicle (EV) infrastructure deployment by focusing on the financial implications of utility energization delays. Drawing on interviews with EV service providers, site hosts, and researchers, the analysis estimates the net present value of time lost per station, identifies opportunities to streamline permitting, engineering, construction, and utility coordination, and highlights emerging solutions that can reduce delays and support the rapid expansion of EV charging networks. This analysis does not capture any costs to implement improvements to the timeline due to limited available data for these costs.

Background

The deployment of EV charging infrastructure in the United States has been hindered by sometimes long and complex energization timelines. These timelines include actions by charging developers and their contractors, local permitting agencies, and electric utilities. Numerous reports have documented these timelines, which can extend up to two to three years, and have identified a range of factors that can contribute to delays, such as fragmented utility processes, permitting hurdles, and supply chain constraints [6, 7, 8, 9, 10].

Figure 1. Energization timeline for an EV charging station



Source: Interstate Renewable Energy Council (IREC) [9]

An evaluation of California's investor-owned utilities' EV charging programs revealed that activation timelines are not only lengthy but are increasing [8]. In 2024, the median time from application to utility activation in California exceeded 950 days across all three major investor-owned utilities (IOUs)—San Diego Gas and Electric (1,106 days), Southern California Edison (959 days), and Pacific Gas and Electric (989 days) [8]. The design and permitting phase[2] alone often surpasses one year, especially for complex sites like medium- and heavy-duty vehicle fleet charging installations.

Defining the Challenges and Solutions

The deployment of EV charging infrastructure faces a range of persistent challenges that slow down energization timelines and increase project costs. According to IREC's survey of EV charging station developers, delays stem from interconnection process inefficiencies, difficulties securing utility easements, slow permitting procedures, and a lack of dedicated utility staff and EV-specific policies [6]. Developers also cited long lead times for equipment upgrades, limited grid transparency, and the absence of performance incentives for utilities.

[2] Design and permitting phases shown in Figure 1 include "design site plan," "submit materials for permitting." "grant permits," and "obtain easements."

These issues are compounded by unclear timelines and fragmented coordination among stakeholders.

To address these barriers, reports from Interstate Renewable Energy Council (IREC) and Idaho National Lab (INL) and the Alliance for Transportation Electrification (ATE) have outlined a suite of emerging best practices and solutions. IREC recommends utilities assign dedicated EV teams, implement make-ready programs, publish clear interconnection timelines, and maintain inventories of common upgrade equipment. State regulators are encouraged to adopt load hosting capacity maps and performance incentives, while permitting authorities can streamline approvals through online portals and model ordinances [9]. INL builds on these recommendations by proposing automated load service request tools, flexible interconnection agreements, and proactive grid investments based on EV adoption forecasts. INL also emphasizes the importance of standardized workforce training and cybersecurity protocols to ensure reliable and secure grid integration [7]. ATE highlights the need to mitigate supply chain delays through measures such as pre-ordering transformers and switchgear, standardizing equipment specifications, and establishing "zones of no regret" for proactive upgrades in high-demand areas. ATE also recommends utilities provide limited power or temporary on-site storage while awaiting full equipment delivery, and work closely with regulators to approve advance cost recovery for critical infrastructure investments [11].

Based on real-world deployment of charging stations for HDVs in California, Cadmus adds further recommendations to improve program transparency and efficiency. These include tracking energization timelines by application year, reporting committed spending for projects not yet financially closed, and extending programs if funding remains unspent [8].

Together, these insights point to solutions for accelerating EV charger deployment timelines, which can reduce costs and support broader transportation electrification goals.

Actions to Improve the Energization Process

States across the U.S. are beginning to take action to address the sometimes long and costly timelines associated with energizing EV charging infrastructure.

Targeting Energization Timelines

In an effort to reduce long timelines, *The Powering Up Californians Act* (Senate Bill 410) was recently enacted which led to California Public Utility Commission (CPUC) Decision 24-09-020 [12]. This decision established energization timeline targets for the state's three major IOUs and introduced new procedures for customers to report service activation delays. These requirements should reduce grid connection timelines for new or upgraded electrical services. The decision also mandates biannual reporting of timelines from IOUs and sets maximum timelines for various infrastructure upgrades, such as 684 days for new circuits.

Colorado followed suit with the passage of Senate Bill 218, titled “Modernize Energy Distribution Systems,” in early 2024 [13]. This legislation requires utilities to provide transparent energization deadlines, develop flexible interconnection programs, and invest in rightsizing and future-proofing grid infrastructure to support growing electrification needs. The *Power Up Illinois Act* (SB 25) [14] was recently signed into law as part of the *Clean and Reliable Grid Affordability Act* meant to address shorter energization timelines. And the New York Public Utilities Commission recently approved a set of standardized utility practices to streamline service activation timelines [15]. And *The Power Up New Jersey Act* (A6153) was recently introduced to also expediate the energization of EV charging and distributed generation [16].

Streamlining Permitting

States have also moved to improve some of the permitting issues that underlie long timelines. California requires all cities and counties to develop an expedited, streamlined permitting process for EV charging stations through AB 1236, which mandates an ordinance and official checklist. AB 970 complements this by setting binding timelines for permit reviews based on project size and clarifying parking requirements [17].

Colorado’s HB 1173 similarly established an expedited permitting process, requiring municipal agencies to approve, conditionally approve, or deny EV charger permits within 30 days for applications with fewer than 13 stations on parcels where charging is an accessory use, or 60 days for larger projects or those aligned with primary land use. If agencies fail to act within these timelines, applications are automatically approved. The bill also directs the Colorado Energy Office to develop a model code and provide technical assistance [17].

Delaware, through its Administrative Code (Title 22, Ch. 1, Sec. 119) and SB 187 (2022), requires municipalities with populations over 30,000 to apply or deny permits within 90 days of receiving an application [17]. New Jersey’s S3223 enacted a model statewide EV ordinance that designates EV charger and make-ready parking spaces as permitted accessory uses, streamlining permitting and zoning processes for EV infrastructure [17]. Massachusetts, through its Climate Act, embedded permit deadlines to accelerate deployment [18].

Grid Data Transparency

Some states have compelled their utilities to offer and/or improve load hosting capacity maps, which can save time and money by helping charging providers identify sites that might face distribution grid constraints early in the development process. For example, the New Jersey Board of Public Utilities' interconnection rules require utilities to provide hosting capacity maps and the Board has ordered changes to the rules based on best practices [19]. After Nevada passed S.B. 146 in 2017, the state's Public Utilities Commission directed NV Energy to develop a comprehensive distribution resource planning framework that included hosting capacity maps [20]. The Minnesota Public Utilities Commission directed Xcel Energy to enhance its maps [21]. And in California, the CPUC's High DER proceeding and the California Energy Commission's Integrated Energy Policy Report are central to the state's efforts to enhance hosting capacity maps [22, 23].

"Bridge-to-Wires" Solutions

States are also increasingly adopting "bridge-to-wires" solutions to address grid capacity constraints and accelerate energization timelines for EV charging and other electrification projects. California's SB 410 and subsequent CPUC proceeding (R.24-01-018) introduced static flexible service connections as interim measures when full distribution capacity is unavailable, while also setting energization targets for utilities. Colorado's SB 24-218 directs Xcel Energy to offer optional flexible interconnection or phased agreements as alternatives to costly system upgrades, and Illinois' multi-year grid modernization plans require utilities to develop flexible interconnection strategies for both load and generation.

Similarly, Massachusetts approved funding for a flexible connection pilot for commercial and fleet charging customers, and Minnesota identified flexible interconnection as a priority for future grid upgrade frameworks. In New York, PSC orders under Dockets 22-E-0236 and 18-E-0138 promote phased and flexible service connections alongside load management incentives, signaling a broader trend toward regulatory support for dynamic and temporary solutions that bridge capacity gaps while long-term upgrades are implemented [6].

Utility Interconnection Process Improvements

It is also worth noting that utilities can also choose to focus on and improve many elements of energization timelines and processes without legislative or commission intervention. Some examples of the kinds of process improvements that can be implemented are found in utilities' applications to the U.S. Department of Energy's i2X Innovative Queue Management Solutions for Clean Energy Interconnection and Energization program [24]. Additional examples include Orange and Rockland's streamlining electrification processes and timeline efforts that reduced the energization timeline by 40 percent [25], Con Edison's EV charging station installation guide [26], and Hawaiian Electric's templates and strategic roadmap with goals focused on energization timelines [27]. Several utilities have also established dedicated EV interconnection teams, including advisory services to help charging sites (especially fleets) right-size their service applications to their operations.

Methodology

This report employs a dual-method approach to assess the cost savings available from utility energization timeline reductions for EV DCFC charging infrastructure deployment. First, we developed a modeling tool to estimate the net present value (NPV) of time delays across the energization timeline, enabling scenario-based analysis of cost implications. Second, we conducted a series of structured interviews with industry stakeholders across the industry to validate the model's assumptions and refine its inputs.

This analysis quantifies the economic benefits of reducing energization timelines but does not assess the costs that utilities or other stakeholders would incur to achieve these timeline improvements. Implementation costs will vary depending on the approach taken. Some process improvements (e.g., such as standardizing and publishing energization guides, undertaking customer journeying to understand points of friction, implementing dedicated EV intake teams comprised of existing staff, or standardizing permitting language) primarily require organizational focus and coordination with relatively modest incremental costs. Other interventions (e.g. developing and maintaining hosting capacity maps, deploying bridge-to-wires solutions) will likely require more significant additional staffing and expenses. Unfortunately, sufficient data on these costs is not currently available. Consequently, the NPV figures presented throughout this report represent gross benefits of timeline reduction rather than net benefits after accounting for implementation costs.

Modeling Cost Savings: Assumptions and Scenarios

This analysis quantifies the NPV of reducing EV charging station energization timelines by comparing two hypothetical scenarios:

a) a Baseline Scenario, in which projects face current energization timelines
b) an Improved Scenario, in which projects face reduced timelines.

The Baseline Scenario for LDV DCFC stations reflects current typical deployment timelines. According to EVgo's detailed project documentation, typical depot deployments for DCFC stations follow an 18-month timeline from initial planning through commissioning [28]. This timeline includes site identification and acquisition, utility interconnection planning, permitting processes, procurement, construction, and final commissioning. The Improved

Scenario represents a streamlined, 12-month energization timeline. This 12-month Improved Scenario, which is a timeline improvement of six months, is based on EVgo's accelerated deployment framework and aligns with the CPUC's timeline requirements for minor upgrades [8]. For larger stations that serve HDVs, timelines are on average longer and therefore the potential for time savings is greater. Based on findings in the report from the Cadmus Group and CLEAResult Energetics exploring HDV charging station deployments in California [8], we set the Baseline Scenario timelines for the 4-MW and 8-MW HDV charging stations at 30 and 36 months, respectively. We assumed an 18-month improvement for both HDV stations. See Table 1 for the summary of scenario assumptions.

Table 1. Charging Station Energization Timeline Assumptions for Modeled Scenarios

Charging Station Type	Baseline Scenario Timeline	Improved Scenario Timeline	Timeline Savings Between Scenarios
LDV 600 kW	18 months	12 months	6 months
LDV 1,000 kW	18 months	12 months	6 months
HDV 4,000 kW (4 MW)	30 months	12 months	18 months
HDV 8,000 kW (8 MW)	36 months	18 months	18 months

The model assumes constant real prices for net revenue per kWh and monthly costs (permits, storage, project management) throughout the analysis period, with both labor and material inflation rates set to zero. This represents a conservative assumption that understates the NPV benefits of timeline reduction. In reality, deployment cost escalation would make avoided costs during extended timelines more valuable. By holding all prices constant in real terms, the model represents a lower bound on the economic benefits, as it does not capture the additional value from avoiding cost escalation during delays.

Financial benefits of improved station deployment timelines are modeled to occur through three mechanisms. First, costs accumulate during the Baseline Scenario that are avoided under the shorter Improved Scenario timeline. These include ongoing project management expenses (with a modeled 50 percent floor ensuring costs cannot be reduced below half of the baseline total, reflecting fixed oversight costs), financing costs on committed capital, permitting fees, and equipment storage costs. Second, accelerated revenue streams provide substantial value in the Improved Scenario. Third, for the HDV stations we estimate the accelerated health benefits associated with realizing emissions reductions more quickly under the Improved Scenario timeline.

The analysis models four representative station rated capacities, as shown in Figure 2.

For LDV charging, we model two station capacities:

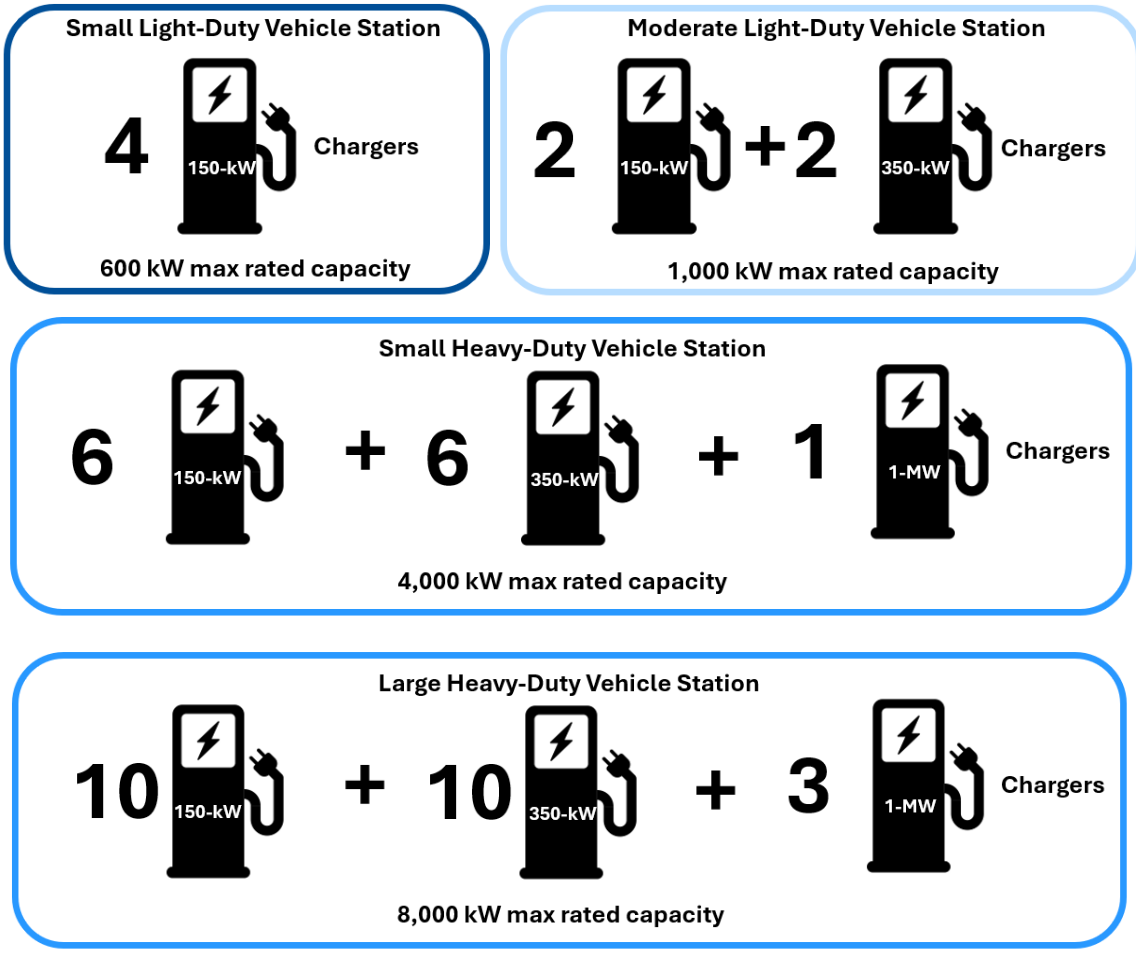
- 600 kW station, representing for example four 150 kW chargers similar to a minimum NEVI station and
- 1,000 kW station, representing for example two 350 kW chargers and two 150 kW chargers

For HDV charging we model two capacities:

- 4-MW station, representing for example six 150 kW chargers, six 350 kW chargers and one 1-MW charger and
- 8-MW station, representing for example ten 150 kW chargers, ten 350 kW chargers, and three 1-MW chargers

The makeup and capacity of the stations are meant to approximate those that are commonly used today. As larger and higher powered light-duty fast charging plazas become more common, some light-duty stations will have power capacities resembling the heavy-duty stations modeled here and therefore may share some cost and timeline similarities as well.

Figure 2. Station Sizes Modeled for Analysis



Note that station configurations are meant to be illustrative and the rated capacity per charging port can vary while the maximum rated capacity for the station remains the same. For our purposes, we do not assume power sharing across charging ports.

Monthly energy delivery is calculated as: utilization rate × 730 hours/month × total charger capacity × 0.7 derating factor, where the derating factor accounts for charging sessions not maintaining peak power throughout. Station utilization follows a ramp-up profile, starting at five percent in month one and growing linearly to steady-state utilization (15 percent to 25 percent for LDV stations and 25 percent to 35 percent for HDV stations) over 24 months for LDV stations and 36 months for HDV stations.

Net revenue per kWh earned by the station represents the difference between the price that charging stations charge customers and utility electricity costs (including demand charges). Net revenues typically range from $0.20 to $0.33/kWh for LDV stations [29, 30, 31]. For HDV stations, we estimate lower net revenues of $0.14 to $0.22/kWh due to fleet price sensitivity and volume-based contract negotiations, though published data on HDV charging economics remains limited. All future revenue streams are discounted to present value using an 8 percent annual discount rate, reflecting typical infrastructure hurdle rates [29].

We calculate net health benefits by subtracting upstream electricity generation health impacts from avoided internal combustion engine (ICE) vehicle emissions. For ICE vehicle benefits, the analysis employs EPA BenMAP valuation factors [32] to monetize avoided particulate matter (PM2.5) and nitrogen oxide (NOx) emissions. Light-duty gasoline vehicles have emission factors of 0.2 grams PM2.5 and 4.0 grams NOx per gallon of fuel displaced [33, 34], valued at $882,000 per ton PM2.5 and $9,300 per ton NOx [32]. Heavy-duty diesel vehicles have substantially higher emission factors: 0.7 grams PM2.5 and 22.1 grams NOx per gallon [33, 34], valued at $560,000 per ton PM2.5 and $8,300 per ton NOx [32].

For electricity generation upstream impacts, the methodology applies EPA sector-based benefit-per-ton estimates for the electricity generating units sector [35] and U.S. average grid emission rates [36]. These upstream health impacts $57,000/ton SO2, $7,710/ton NOx) are subtracted from ICE emission benefits to calculate net health impacts. Importantly, we apply a conservative assumption for light-duty vehicle stations by setting health benefits to zero, reflecting uncertainty about whether marginal charging infrastructure additions lead to one-to-one replacement of ICE vehicles in the more mature light-duty EV market. For HDV stations, we include the full net health benefit calculation, as the nascent depot charging market more clearly justifies the assumption that new public infrastructure enables one-to-one replacement of diesel HDV vehicles.

We assume that all energy provided by each charging station is incremental—meaning it enables vehicle trips that would not otherwise occur. This assumption is likely accurate for HDV use cases because these fleets have specialized requirements (e.g., higher-power charging, pull-through locations) that limit charging alternatives. Without the station, the vehicle might not be able to complete its trip.

For LDVs, however, the situation differs. Because more public charging stations are available for LDVs, drivers could obtain the same energy from another public station or through extended home charging sessions, making our incrementality assumption less certain. Health benefits for LDV stations are small compared to other economic gains from faster energization. We therefore conservatively exclude these benefits from LDV station results.

The NPV calculation integrates health and emissions components and discounts for multi-period cash flows. The model calculates NPV for both Baseline and Improved timeline scenarios over the economic forecast period[3] of the charger (typically three to 10 years

[3] The economic forecast period is the time horizon over which a project's cash flows (costs and revenues) are explicitly modeled and discounted to calculate net present value for investment evaluation.

depending on station type and financing structure), with the NPV benefit representing the difference between these scenarios. This framework enables sensitivity analysis across key parameters including timeline reduction length, project scale, utilization assumptions, and discount rates. The methodology is generalizable across charging infrastructure projects while allowing customization for specific contexts and stakeholder perspectives.

For additional details on the modeling inputs, see Appendix A.

Industry Perspectives

To support the cost modeling and scenario analysis described above, we conducted a series of structured interviews with key industry stakeholders to validate assumptions, refine inputs, and gather qualitative insights on energization timelines. The interviews were designed to ensure that our model reflects real-world experiences and incorporates the most current and relevant data available.

The discussions were guided by a set of targeted questions aimed at uncovering best practices, quantifying the financial and operational impacts of energization delays, and identifying gaps in data collection. Stakeholders were asked to share examples of delays, data they track, costs associated with unsuccessful projects, and their ability to estimate revenue impacts (e.g., $ per station). We also explored modeled or targeted internal rates of return and payback periods for DC fast charging sites, and invited participants to share anonymized data or case studies to support our analysis. These conversations not only strengthened the credibility of our modeling approach but also surfaced actionable recommendations for utilities, regulators, and developers to reduce energization delays and improve project outcomes.

Results

Results from each of the two approaches are presented below.

Net Present Value Analysis

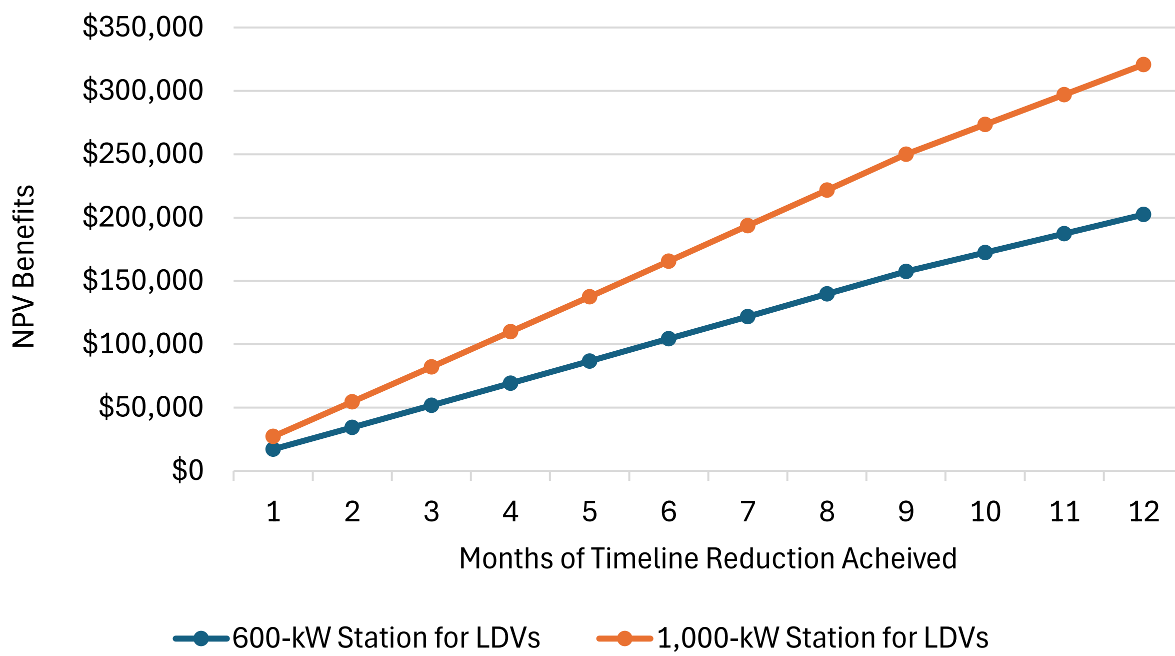
Table 2 presents the component breakdown of NPV benefits for each station type at the maximum modeled energization timeline reductions: six months for LDV stations and 18 months for HDV stations. Appendix A shows additional high and low ranges of the NPV scenario analysis for each of the station configurations. Table 2 presents the mid-case.

Table 2. Per-Station NPV of Benefits, by Station Type

	Per-Station NPV Benefit Over Station Economic Forecast Period				
Station Type and Timeline Scenario	**Avoided Deployment Costs**	**Accelerated Revenue**	**Health Benefits**	**Total Benefits**	**Total Per-Station NPV Benefits Average per Day**
LDV 600 kW 6-month acceleration	$36,600	$67,600	-	$104,200	$570
LDV 1 MW 6-month acceleration	$52,800	$112,700	-	$165,500	$910
HDV 4 MW 18-month acceleration	$492,500	$1,216,900	$201,200	$1,791,000	$3,490
HDV 8 MW 18-month acceleration	$760,800	$2,265,600	$374,600	$3,401,000	$6,220

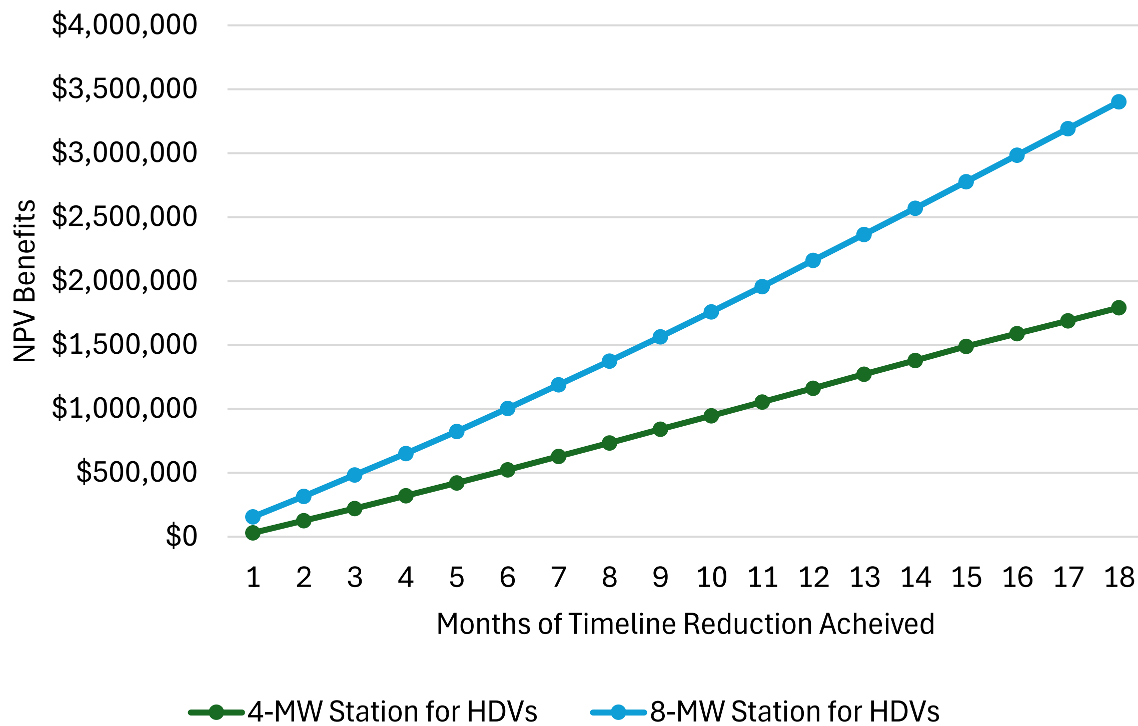
The NPV benefits are modeled to scale approximately linearly with timeline reduction magnitude across all station configurations (Figure 3 and Figure 4). For LDV stations, a 12-month timeline reduction generates NPV benefits of $202,300 for the 600-kW configuration and $320,600 for the 1,000-kW configuration. These benefits derive primarily from accelerated revenue (68 percent and 72 percent of total benefits, respectively), with avoided costs comprising the remainder. Consistent with our conservative health benefit methodology, health benefits for LDV stations are set to zero due to uncertainty regarding whether marginal charging infrastructure additions lead to one-to-one replacement of internal combustion engine vehicles in the light-duty EV market, which is more commercially mature than the electric HDV market.

Figure 3: Cumulative NPV of Benefits of Improved Scenario Timelines for LDV Charging Station Over Economic Forecast Period of 5 Years



HDV stations exhibit substantially larger NPV benefits, reflecting higher utilization rates (30 percent steady-state versus 20 percent for LDV), greater charging throughput, and significant net health benefits from replacing diesel HDV vehicles. An 18-month timeline reduction for the 4 MW configuration generates $1,791,000 in NPV benefits over the five-year economic forecast period, while the 8-MW configuration produces $3,401,000 in benefits. The component breakdown reveals that accelerated revenue comprises the largest share of total NPV benefits for HDV stations at 64 percent to 68 percent. Avoided deployment costs account for 21 percent to 25 percent of total benefits, while health benefits from earlier diesel vehicle displacement contribute 11 percent of total value.

Figure 4: Cumulative NPV Benefits of Improved Scenario Timelines for HDV Charging Stations Over Economic Forecast Period of 5 Years



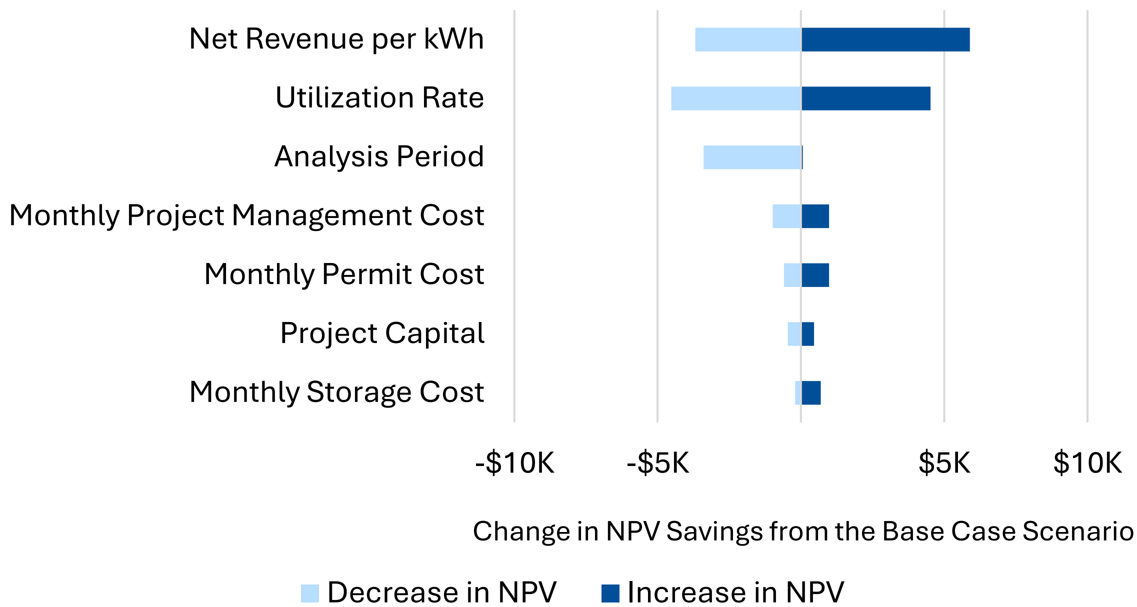
The difference between LDV and HDV benefits reflects multiple factors. First, HDV stations are assumed to operate at higher steady-state utilization rates (30 percent versus 20 percent), generating greater throughput over equivalent deployment delays. Second, based on our review of the literature, we estimate that HDV station capital investments are five to 27 times larger than LDV stations, leading to proportionally greater financing costs during extended timelines [37]. Third, and most significantly, HDV stations capture substantial health benefits (roughly $201,000 to $375,000) from displacing diesel vehicle emissions, which have emission factors 50 times higher for $PM_{2.5}$ and seven to eight times higher for NOx compared to gasoline vehicles. When combined with the upstream electricity generation health impacts subtracted in our net benefits calculation, HDV stations demonstrate clear positive health externalities that amplify the economic case for timeline reduction.

Sensitivity Analysis

We performed a sensitivity analysis to identify the parameters that most influence NPV benefits. The low and high values used for the sensitivity analysis are summarized in

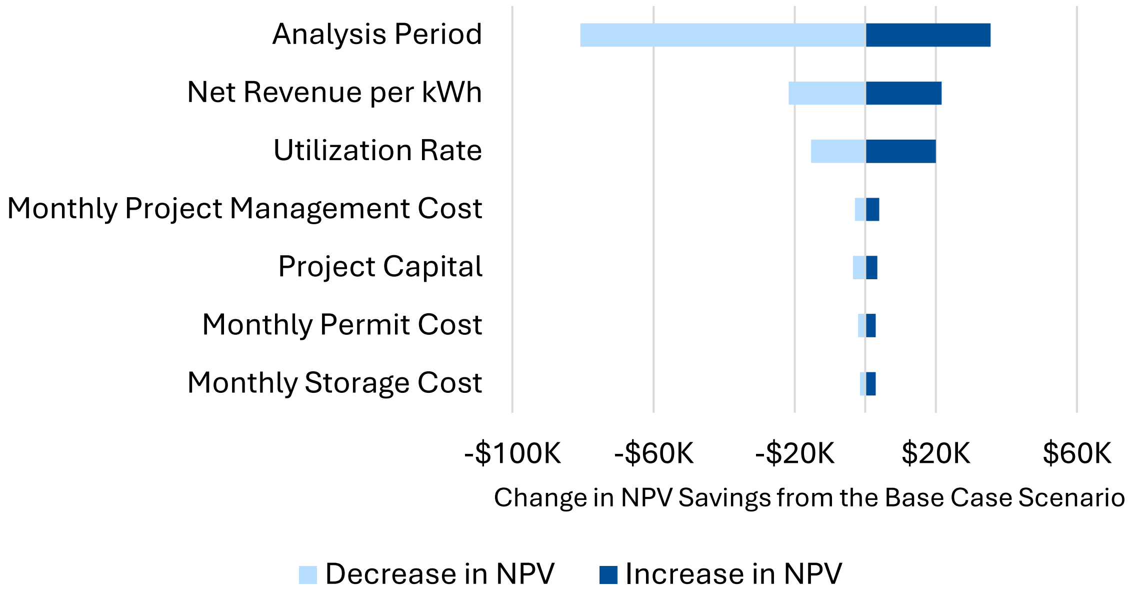
Appendix A. We estimate that the value of getting LDV charging stations energized more quickly is primarily driven by utilization rates and net revenue. For HDV charging stations, this value is primarily driven by the time periods that we chose to evaluate the charging station and energization timelines over. Sensitivity analysis results for the 1-MW LDV station and the 8-MW HDV station are shown in Figure 5 and Figure 6 below. Additional details on the sensitivity analysis and inputs can be found in Appendix A.

Figure 5: Sensitivity Analysis Results for a 1 MW Light-Duty Vehicle Charging Station



This chart shows impact on net present value savings from a 6-month energization timeline reduction over economic forecast period of five years.

Figure 6: Sensitivity Analysis Results for 8 MW Medium- and Heavy-Duty Vehicle Charging Station



This chart shows impact on net present value savings from an 18-month energization timeline reduction over economic forecast period of five years.

Results reveal distinct patterns between LDV and HDV stations regarding the primary value drivers. For LDV stations, net revenue per kWh emerges as the dominant sensitivity factor, with parameter variation creating NPV swings of 34 percent to 35 percent relative to base case net present values. Utilization rate exhibits nearly equivalent influence (32 percent to 33 percent swings), underscoring the significant impact of both pricing strategy and station usage on potential energization savings. These two factors collectively account for nearly 70 percent of NPV variability, while variance in deployment phase cost factors (project management costs, project capital) contributes minimally (three percent to five percent combined).

Heavy-duty stations show a markedly different sensitivity profile. Adjusting the economic forecast period (analysis period) dominates NPV variability for both configurations, creating swings in NPV of 75 percent to 99 percent. Following the analysis period, the monthly project management cost swing from the low to high case is the second largest impact to NPV for the 4 MW station. Net revenue per kWh ranks second for the 8-MW HDV station, highlighting the importance of pricing and revenue optimization.

Deployment phase cost factors show modest influence across all configurations. Monthly project management costs account for seven percent to 13 percent of NPV variability, with the 50 percent floor constraint appropriately capturing realistic cost reduction limits without artificially constraining the model. Project capital shows minimal sensitivity (three percent to 12 percent across all stations), indicating that financing cost variations during deployment have limited impact on total project economics relative to operational factors.

Insights from Stakeholders

Based on the interviews we conducted with stakeholders several key themes emerged that highlight both the challenges and promising solutions to accelerate EV charging infrastructure deployment. These insights are organized into six core areas, each reflecting the most pressing issues and actionable recommendations shared during the discussions.

Streamlining Permitting and Easements

Permitting delays were consistently cited as the most significant bottleneck in the service activation timeline. Stakeholders emphasized the need to separate timeline data on permitting from engineering and design phases to better isolate and address delays. Standardizing permitting language and processes across jurisdictions was also recommended to reduce confusion and negotiation time. Publishing energization guides, such as Con Edison's, was highlighted as a low-cost, high-impact solution to help customers navigate utility processes and avoid trial-and-error delays [26]. Easements, often entangled with site host needs and redevelopment plans, were flagged as a persistent challenge. Splitting easements and permitting data into distinct phases was suggested to better target solutions.

Enhancing Utility Processes and Transparency

A recurring recommendation was for utilities to establish dedicated intake, design, and construction teams for EV projects. This would help avoid delays caused by competing priorities and improve coordination between civil and utility construction teams. Desk reviews for capacity, rather than full engineering studies, were praised for reducing upfront costs and avoiding unnecessary delays. Misaligned timelines between trenching, curb work, and utility activation were cited as causes of multi-week or multi-month delays. Pre-application feasibility assessments, such as those offered by Oncor, were praised for helping developers avoid costly dead-end projects by providing grid capacity checks within three weeks. Stakeholders also stressed the importance of standardized energization timelines and definitions across programs to enable accurate benchmarking and policy enforcement. Utilities that have established dedicated EV intake, design, and construction teams have significantly improved timelines.

Leveraging Existing Capacity and DER Solutions

Stakeholders emphasized the importance of exploiting existing grid capacity, particularly at sites with off-peak usage potential, such as nighttime charging at underutilized buildings. Distributed Energy Resources (DERs), including batteries and microgrids, were identified as critical tools to bridge power gaps during early years of operation or in areas with grid constraints. These systems enable fast charging in grid-constrained areas, such as rural or corridor locations, by allowing stations to operate without triggering costly infrastructure upgrades like new transformers or three-phase power lines. However, DER integration remains challenging due to a lack of coordination between DER and EV teams within utilities, often resulting in longer timelines instead of shorter ones.

The U.S. Department of Energy's i2X DER Interconnection Roadmap outlines a strategic framework to transform DER interconnection processes by 2035 [24]. It emphasizes four primary goals: increasing data access and transparency, improving interconnection timelines, promoting economic efficiency, and maintaining a reliable and secure grid. Solutions include standardizing hosting capacity analysis tools, reforming cost allocation models beyond the traditional "cost-causer-pays" approach and integrating DER planning with long-term grid upgrades. The roadmap also calls for enhanced cybersecurity protocols and the adoption of standards like IEEE 1547 to support emerging technologies such as vehicle-to-grid systems.

Policy and Regulatory Recommendations

Make-ready tariffs and flexible interconnection programs, such as PG&E's FlexConnect, were recognized as effective for accelerating deployment of large projects, though not yet scalable for widespread DC fast charging installations [38]. CPUC's mandated six-month energization timeline was seen as ambitious but helpful in pushing utilities to improve. Stakeholders urged regulators to consider the economic opportunity cost of delays and incentivize faster timelines through streamlined requirements. Cross-agency coordination between emissions regulators (e.g., CARB), energy regulators (e.g., CPUC), and transportation agencies was deemed essential for holistic progress.

Data Transparency and Standardization

While hosting capacity maps were acknowledged as useful, they were often outdated or insufficient for investment-grade decisions. Frequently updated, accurate data is needed to support strategic planning. Stakeholders called for a unified data standard across utilities to reduce friction and improve planning accuracy. The lack of transparency in utility processes and inconsistent definitions of project phases were noted as barriers to effective coordination and benchmarking.

In addition, coordination across the industry is imperative for transparency and standardization and to perpetuate solutions across the various stakeholders and organizations. Efforts like the Interstate Renewable Energy Council (IREC) remain vital in advancing best practices and compelling successful implementation at the state and utility level. Continued tracking of policy efforts to reduce energization timelines, focused beyond passing bills to ensuring successful implementation is key to success.

Addressing Dropout Risk and Opportunity Costs

Project dropout rates were estimated to range from six percent to 14 percent with a high estimate of 90 percent across EV charging sites, with sunk costs incurred even for sites that only reached the design stage. Delays impact not only charging provider revenue but also automakers, grant eligibility, and broader fleet electrification goals. For example, stranded trucks due to delayed energization were cited as a major business risk. Stakeholders emphasized the need to account for these indirect costs in planning and policy discussions, especially as the industry shifts toward shared access charging hubs and higher power demands. While dropout rates are declining, they are still prevalent and a persistent challenge.

Conclusion

This analysis underscores the significant economic and operational benefits of reducing energization timelines for EV charging infrastructure. While the modeling presented here offers a robust framework for quantifying cost savings, it likely underestimates the true impact. The model does not fully capture upstream effects such as sunk costs from project dropouts or the broader opportunity costs borne by vehicle manufacturers and fleet operators when stations are delayed.

Our findings reveal that energization timeline improvements can be up to $104,200 to $165,500 for six months of time savings for LDV stations, whereas the opportunity costs of delayed revenue and stranded assets weigh most heavily on HDV stations of up $1.8 to $3.4 million for 18 months of time savings. These dynamics highlight the urgency of accelerating timelines for high-capacity sites that serve HDV fleets and freight corridors.

Stakeholder interviews and published resources provide various solutions including promising bridge-to-wires solutions. Several companies are already performing internal analyses to make these investments viable and are deploying these solutions to maintain operations while awaiting grid upgrades.

States are stepping up with actions to streamline permitting, enforce energization deadlines, and modernize interconnection processes. These efforts, combined with federal initiatives, represent a pivotal opportunity to align policy and practice toward faster deployment.

In an environment where electricity rates and load requests are in some locations rising beyond recent historical norms, flexible, collaborative solutions are essential. Stakeholders—including utilities, regulators, developers, and policymakers—must work together under standardized processes and shared definitions to ensure clarity and efficiency.

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Appendix AAppendix A: Modeling Inputs and Additional Sensitivity Analysis Results

Table 4. Universal modeling parameters

Parameter	Value	Notes
Discount rate	8%	Annual nominal discount rate for NPV calculations
Annual interest rate	6.5%	Annual interest rate for financing during delays

Table 5. Modeling inputs and sensitivity analysis ranges for the 600-kW LDV charging station

Parameter	Low	Medium / Base Case	High	Unit	Notes
Project management	$2,500	$3,000	$3,500	USD/month	Average monthly project management costs
Permitting	$400	$1,000	$2,000	USD/month	Permit holding fees and compliance during delays
Equipment storage	300	500	1200	USD/month	Equipment storage and depreciation during delays
Net electricity revenue	$0.20	$0.25	$0.33	USD/kWh	Net revenue (customer charge minus electricity/demand costs)

Capital cost	$240,000	$300,000	$360,000	USD	Total project capital cost for station deployment
Labor cost	$176,000	$220,000	$264,000	USD	Total project labor cost for station deployment
Steady State Utilization rate	15	20	25	%	Steady state utilization rate. LDV station is assumed to reach steady state at 2 years
Analysis period	3	5	10	years	Timeframe over which baseline and reduced timeline station are evaluated

Table 6. Modeling inputs and sensitivity analysis ranges for the 1 MW LDV charging station

Parameter	**Low**	**Medium / Base Case**	**High**	**Unit**	**Notes**
Project management	$4,000	$5,000	$6,000	USD/month	Average monthly project management costs
Permitting	$400	$1,000	$2,000	USD/month	Permit holding fees and compliance during delays
Equipment storage	$300	$500	$1,200	USD/month	Equipment storage and depreciation during delays

Net electricity revenue	$0.20	$0.25	$0.33	USD/kWh	Net revenue (customer charge minus electricity/demand costs)
Capital cost	$344,000	$430,000	$516,000	USD	Total project capital cost for station deployment
Labor cost	$330,720	$413,400	$496,080	USD	Total project labor cost for station deployment
Utilization rate	15	20	25	%	Steady state utilization rate. LDV station is assumed to reach steady state at 2 years.
Analysis period	3	5	10	years	Timeframe over which baseline and reduced timeline station are evaluated

Table 7. Modeling inputs and sensitivity analysis ranges for the 4-MW HDV charging station

Parameter	**Low**	**Medium / Base Case**	**High**	**Unit**	**Notes**
Project management	$8,000	$10,000	$12,000	USD/month	Average monthly project management costs
Permitting	$1,000	$2,000	$3,500	USD/month	Permit holding fees and

					compliance during delays
Equipment storage	$750	$1,500	$3,000	USD/month	Equipment storage and depreciation during delays
Net electricity revenue	$0.14	$0.18	$0.22	USD/kWh	Net revenue (customer charge minus electricity/demand costs)
Capital cost	$1,312,000	$1,640,000	$1,968,000	USD	Total project capital cost for station deployment
Labor cost	$1,422,160	$1,777,700	$2,133,240	USD	Total project labor cost for station deployment
Utilization rate	25	30	35	%	Steady state utilization rate. HDV station is assumed to reach steady state at 3 years.
Analysis period	3	5	10	years	Timeframe over which baseline and reduced timeline station are evaluated

Table 8. Modeling inputs and sensitivity analysis ranges for the 8-MW heavy-duty vehicle charging station

Parameter	**Low**	**Medium / Base Case**	**High**	**Unit**	**Notes**
Project management	$15,000	$18,000	$22,000	USD/month	Average monthly project management costs
Permitting	$2,000	$4,000	$7,000	USD/month	Permit holding fees and compliance during delays
Equipment storage	$1,500	$3,000	$6,000	USD/month	Equipment storage and depreciation during delays
Net electricity revenue	$0.14	$0.18	$0.22	USD/kWh	Net revenue (customer charge minus electricity /demand costs)
Capital cost	$2,560,000	$3,200,000	$3,840,000	USD	Total project capital cost for station deployment
Labor cost	$3,295,600	$4,119,500	$4,943,400	USD	Total project labor cost for station deployment

Utilization rate	25	30	35	%	Steady state utilization rate. HDV station is assumed to reach steady state at 3 years.
Analysis period	3	5	10	years	Timeframe over which baseline and reduced timeline station are evaluated

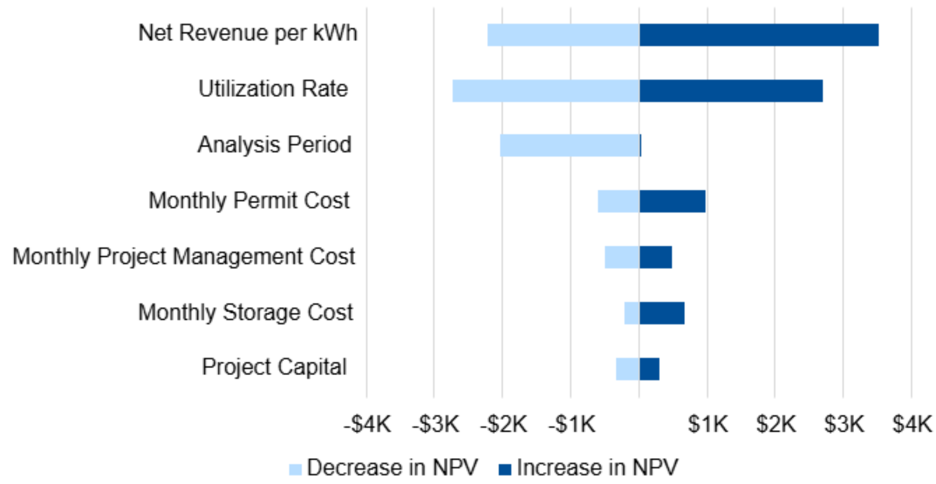
Table 9. Input parameters for the health benefits module

Parameter	**Value**	**Unit**	**Sources and Notes**
LDV PM2.5 emission factor	0.182	grams/gallon	Bureau of Transportation Statistics (2025); FHWA (2025)
LDV NOx emission factor	4.103	grams/gallon	Bureau of Transportation Statistics (2025); FHWA (2025)
HDV PM2.5 emission factor	0.66	grams/gallon	Bureau of Transportation Statistics (2025); FHWA (2025)
HDV NOx emission factor	22.07	grams/gallon	Bureau of Transportation Statistics (2025); FHWA (2025)
U.S. average electricity: upstream SO_2 emissions	0.359	lb/MWh	EPA eGRID (2025)
U.S. average electricity: upstream NOx emissions	0.452	lb/MWh	EPA eGRID (2025)

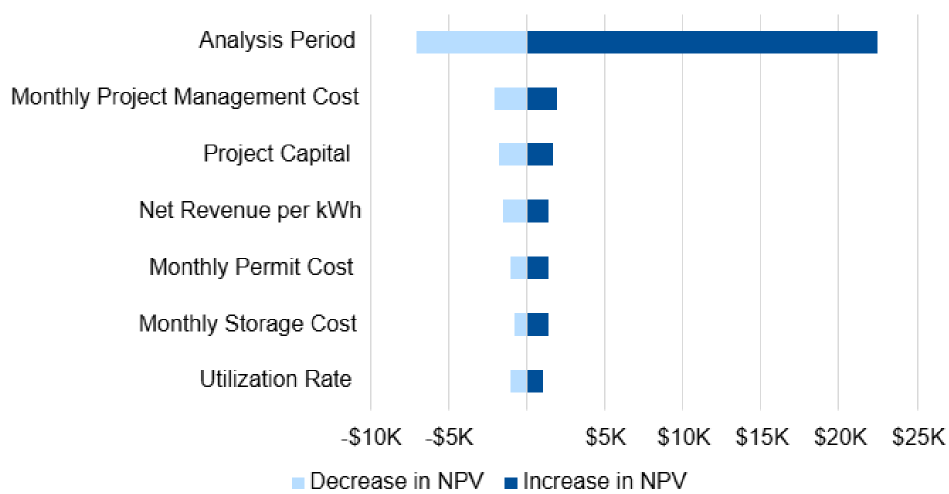
Health-related damages: LDV PM2.5	$882,000	$/ton	Wolfe et al (2018). Used values from Table 2 and converted from 2015 to 2025 dollars.
Health-related damages: LDV NOx	$9,300	$/ton	Wolfe et al (2018). Used values from Table 2 and converted from 2015 to 2025 dollars.
Health-related damages: HDV PM2.5	$560,000	$/ton	Wolfe et al (2018). Used values from Table 2 and converted from 2015 to 2025 dollars.
Health-related damages: HDV NOx	$8,300	$/ton	Wolfe et al (2018). Used values from Table 2 and converted from 2015 to 2025 dollars.
Health-related damages: upstream electricity SO_2	$57,000	$/ton	EPA (2025)
Health-related damages: upstream electricity NOx	$7,710	$/ton	EPA (2025)

Appendix Figure 1: Sensitivity Analysis Results for the 600 kW Light-Duty Vehicle and 4 MW Heavy-Duty Vehicle Stations

Change from the Base Case Scenario for the 600-kW Light-Duty Vehicle Station



Change from the Base Case Scenario for the 4-MW Heavy-Duty Vehicle Station



These charts show impact on net present value savings from a 6-month energization timeline reduction (for the 600kW station) and an 18-month energization timeline (for the 4MW station) over an economic forecast period of five years.

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