Clean Transportation Technologies and Solutions

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Jeff Killip
Executive Director & Secretary
Washington Utilities & Transportation Commission
621 Woodland Square Loop SE
Lacey, WA 98503

RE: Comments on Behalf of CALSTART in Docket UE-160799, Notice of Opportunity to File Written Comments ("Notice")

Dear Mr. Killip,

CALSTART appreciates the opportunity to respond to Staff's questions regarding rate recovery and rate design for EV infrastructure. CALSTART, headquartered in California, is a globally renowned 501(c)3 nonprofit organization dedicated to the advancement of zero emission vehicle and infrastructure technology. With a global member consortium of nearly 300 technology, government, industry, and community partners, CALSTART has worked for 30+ years to accelerate the commercialization and deployment of advanced technologies and solutions. Through policy development, incentive program administration, and first-of-its-kind deployment partnerships, CALSTART drives the market toward clean transportation technologies to transform the transportation sector and reduce greenhouse gas and criteria pollutant emissions.

CALSTART's response and participation in this proceeding is intended to represent our mission to accelerate clean transportation and to advance Washington's ambitious zero-emission vehicle adoption targets. We also aim to represent the perspective of the industry most impacted, including shared charging infrastructure developers working diligently to expedite charging station development for fleets. CALSTART's intention in responding to this docket is to introduce information into the Utilities and Transportation Commission's ("Commission's") record specific to the needs of shared charging station developers for medium- and heavy-duty vehicle ("MHDV") fleets. While CALSTART is a membership organization, it is not a trade association and CALSTART members hold a range of views on these issues.

In 2021, Washington adopted the Advanced Clean Trucks ("ACT") rule,[1] requiring manufacturers to increase sales of zero-emission MHDVs, with targets ramping up annually. The ACT is a critical step in meeting Washington's climate goals by reducing emissions from one of the state's largest sources of greenhouse gases—transportation. Successful implementation of the ACT depends on the development of a reliable and cost-effective charging infrastructure network. This includes proactive utility planning for grid capacity, streamlined interconnection processes, and appropriate rate structures to incentivize fleet electrification while minimizing costs for all ratepayers. Atlas Public Policy conducted a study of the chargers need to support the ACT in Washington and estimated 20,000 chargers would be needed, but their analysis seemed more focused on

[1] Chapter 173-423 WAC and WAC 173-400-025 – Low Emission Vehicles.

Level 2 than Direct Current Fast Chargers ("DCFC").[2] As part of California's ACT implementation, the California Energy Commission conducted a comprehensive Charging Assessment estimating that by 2030 California will need an additional 157,000 chargers to support MHDVs—we would estimate Washington will need nearly 33,000 chargers for MHDVs[3] for the same purpose, and would assume that the majority of these are DCFC, not Level 2.

The role of the utility in the transition of fleets to electricity as a fuel source cannot be understated. Therefore, the role of this Commission in setting appropriate policy to ensure that utilities can effectively fulfill this role is paramount. As part of their duty to provide universal service, the highest goal of the utility should be to provide fleet energization on the fastest timeframe possible while controlling costs as much as possible. The utility is the only party who can provide interconnection on the distribution grid by ensuring that there is sufficient distribution system capacity to serve the needs of fleets. In our experience, this often involves distribution system upgrades, and with proactive planning, utilities can help guide fleets and charging providers to locations where energization can be done most expeditiously, e.g., locations with available capacity.

While only the utility can provide energization and interconnection, it is also extremely valuable to have utilities as trusted advisors and support for "make-ready" infrastructure as well as the charging infrastructure itself. Therefore, our response to this Notice discusses all of these key components of fleet electrification.

CALSTART's comments focus on addressing the questions in this docket with an emphasis on the unique needs of shared charging sites that provide infrastructure for MHDV fleets, as opposed to light-duty vehicle ("LDV") charging infrastructure. Specifically, we prioritize answering questions related to the appropriate ratemaking tools for supporting fleet electrification, including system benefit charges, rate-based capital recovery, and proactive planning for grid upgrades. Our responses highlight the importance of ensuring that charging infrastructure programs align with the needs of commercial vehicle fleets, addressing barriers such as the cost of behind-the-meter ("BTM") infrastructure and challenges with demand charges. We encourage the Commission to leverage insights from other jurisdictions to support Washington's ambitious transportation electrification goals and we therefore provide references to programs and findings from other states that are leading on ACT implementation.

Our response to Question 1 discusses why it is appropriate for capital expenses on the utility side of the meter (e.g., distribution system upgrades and line extensions) to be rate based, whereas BTM incentives can be appropriately recovered though a system benefits charge. We discuss the benefits and importance of proactive planning in our Question 2 response. Our response to question 4 focuses on the challenges posed by demand charges and developing thoughtful policy to support shared charging. In general, we recommend

[2] *See Charging Infrastructure Needed to Support Advanced Clean Trucks in Washington,* Atlas Public Policy, June 2024; "The capacity of the distribution system will likely need to increase by 4-7 gigawatts (GW) by 2035" Washington Utility-Side Charging Infrastructure Assessment (WUSCIA), Final Report, Nov. 2024.
[3] Simply scaling down the CA estimate based on Washington's population.

that the Commission should aim to recover necessary system infrastructure costs for distribution system capacity upgrades and line extensions through EV-specific rates.

Background: Shared DC fast charging is an important model to support early fleet adoption of electric MHDVs

Shared charging depots provided by third-parties are playing an increasingly important role for fleets, especially small fleets. Shared charging sites, also called "shared multi-fleet depots" are open to more than one fleet, typically made available by a third party. Shared sites allow fleets to use assets without owning them in a controlled, predictable, and secure setting.[4] This type of deployment, which involves a specific configuration mixed with a business model tailored to actual fleet needs, lets fleets use chargers without having to build out their own infrastructure or acquire chargers before they acquire vehicles. By using shared charging sites, fleets know what to expect from a charger, rather than risk using "public" stops that may not cater to their needs or may require long wait times that would be fatal to the freight business, which has strict delivery schedules and typically runs on very thin margins. Therefore, this model reduces the financial risk that fleet operators are taking on, guarantees charging availability, and makes far more efficient use of resources. This will also help ensure that utility investments in infrastructure use both capacity and funds most effectively.

Another advantage from the grid's perspective is that shared charging station operators can work to manage charging—lowering peak capacity demand. Managed charging can have a measurable impact on ensuring that simultaneous charging with the daily peaks on the electric grid are avoided as much as possible.[5] As further explained in our answer to question 4, below, shared charging is similar to public DCFC in that depots may have lower utilization rates in early days as they get off the ground. Once the depots are at "full" utilization, demand charges will be less of a concern. It will be important for the Commission to develop clear policies around phasing in demand charges to ensure that the shared-charging model is viable for fleets in Washington.

1. **What types of ratemaking tools should the Commission consider for EV charging infrastructure? For each option, please explain why such tools are appropriate:**

    a. **A system benefits charge for all customers that creates a budget for utilities?**
    b. **Capital expenses for EV infrastructure recovered in base rates?**
    c. **Increased incentives for Multi-Unit Dwelling building owners or developers?**
    d. **A line extension allowance similar to that proposed in Oregon?**
    e. **An option not listed here (please describe both the preferred option and why it is preferred.)**

[4] *See* "Shared Charging Sites: Accelerating the ZEV Market and Delivering Public Benefits," available at https://calstart.org/shared-charging/.
[5] *See* Reply Comments of CALSTART, Inc. on Administrative Law Judge's Ruling Initiating Track 1 and Inviting Party Comment", filed July 18, 2024 in CPUC Docket R.23-12-008, available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M536/K273/536273000.PDF at 8-9.

General funding principles for MHDV charging infrastructure

Using ratepayer funds for EV charging make-ready infrastructure and hardware is appropriate because utilities can promote effective load management through specialized managed charging rates, programs, and incentives. By implementing managed charging strategies, utilities can reduce the strain of charging demand on the grid, which can lead to lower costs and potentially defer the need for extensive grid upgrades.[6] In the context of fleet charging for MHDVs, both a system benefits charge and/or rate based recovery have been utilized by Commissions in other states and are appropriate for different elements of EV charging infrastructure and hardware.

Both a system benefits charge (a) and capital expense recovery (b) would be an appropriate solution for Washington to pursue, and examples exist from other states who have pursued both a system benefits charge and rate recovery for EV "make-ready"[7] expenses and EV charging infrastructure incentives. In general, this is still a nascent industry and the payback period for make-ready infrastructure is generally too long for fleets to absorb or justify based on near-term savings. Therefore, utility support for both make-ready infrastructure and publicly funded charging incentives are appropriate. As a matter of policy, rate recovery is most appropriately used for the distribution system upgrades and electrification up to the point of the customer's meter while it may be appropriate for a system benefits charge to fund time-limited customer-side charging incentives. We will elaborate below on answers to questions (a) - (d).

As other jurisdictions have considered the question of rate recovery, they have found that the "net impact on electricity ratepayers from such a program will depend on whether the increased distribution revenue from MHDV electricity sales can offset the costs of distribution system upgrades (including make-ready programs)."[8]

While CALSTART is not aware of a rate impact analysis conducted for the state of Washington, decisionmakers should look to studies completed elsewhere in the country specific to MHDVs. On behalf of Environmental Defense Fund ("EDF"), Synapse recently studied the impact on rates of a MHDV make-ready program in two very different areas of New York: an urban service area in New York City and the more rural western part of upstate New York.[9] The study calculated the cost of the distribution system upgrades necessary to support 100 percent electric MHDV sales by 2045, consistent with the state's targets, as well as make-ready program costs. The study then compared these costs to the expected revenues generated from MHDV electrification under existing utility tariffs. The study concluded: "[w]e find that a make-ready program

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[6] "Proactive Grid Investment Assessment Medium-and Heavy-Duty Vehicle Transportation Electrification," prepared for EDF by Black and Veatch, November 6, 2024 ("EDF Report") at 14.

[7] "Make-ready" is a term generally used in the EV and utility industry to describe the infrastructure (including upgrades) on both the utility and customer's side of the meter needed to interconnect an EV charger, which may include trenching, conduit, wires, panels, transformers, power lines, etc.

[8] "Distribution System Investments to Enable Medium- and Heavy-Duty Vehicle Electrification," prepared for the Environmental Defense Fund by Synapse Energy Economics Inc on April 14, 2023, *available at:* https://acrobat.adobe.com/link/track?uri=urn%3Aaaid%3Ascds%3AUS%3Ab0fd0780-9882-3a25-9ef2-f8c73bd80c92). ("Synapse Report").

[9] *Ibid*.

would have a neutral-to-beneficial impact on rates in both utility service areas for the period 2023–2045."[10]

When California considered the issue of rates-funded charging incentives, it considered a few factors: primarily the state's vehicle regulations including ACT (which Washington has now adopted) as well as the nascency of the charging technology and vehicles. In a 2022 decision, the CA PUC established that targeted, ratepayer-funded incentives for BTM make-ready infrastructure and charging equipment were warranted based on the immaturity of the EV market, especially for MHDVs.[11] California has focused their utility funded program ("TE Rebate Program") on the most undeveloped segments and/or those which require incentive funding to achieve state policy goals: the MHDV segment as well as light-duty ("LD") chargers located at multi-family housing or public charging serving residents in multi-family housing.[12]

Amongst the reasons cited for the MHDV focus was air quality and environmental justice, also a focus for Washington. California uses the term "disadvantaged communities" or "DACs" whereas Washington refers to these communities as "highly impacted communities."[13] The decision approving the program found that "DACs suffer from poor air quality and the [MHDV] sectors have a disproportionate effect on air quality" and that "[e]lectrifying the [MHDV] sectors will reduce air pollution disproportionately impacting DACs;"[14] it also instituted a 65 percent spending requirement for DACs and higher rebates for MHDVs primarily operating and domiciled in DACs.[15] Given Washington's goal of reducing pollution burdens in highly impacted communities, greater investments in MHDV-supportive infrastructure will be similarly needed and justified.

<u>Answer to question A: System benefits charges are an appropriate way to fund customer-side infrastructure and hardware incentives.</u>

Utilities will need a budget for utility side infrastructure and customer side "make-ready" infrastructure. A system-benefit charge for customer-side (aka "behind the meter" or "BTM") charging infrastructure is a demonstrated way to incentivize adoption of EVs. Incentives will be needed for some time to ensure the market can develop momentum. To lower costs for all and protect ratepayers, BTM programs should be provided via rebates that are not capitalized or included in rate base—they should be simply a pass-through cost.

As one example: the CA PUC's TE Rebate Program is funded by a system benefits charge that recovers costs allocated on an equal cents per kWh basis. The CPUC found this use of

[10] *Ibid.*
[11] "Decision on Transportation Electrification Policy and Investment," D.22-11-040, issued November 17, 2022 ("D.22-11-040"), available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M499/K005/499005805.PDF.
[12] *Id.* at 218-219.
[13] The Department of Health designates as a highly impacted community any census tract with a 9 or 10 overall rank on the Environmental Health Disparities (EHD) map, or any census tract with tribal lands. For the purposes of designating highly impacted communities, the EHD map is the CIA referenced under <u>RCW 19.405.140</u>.
[14] D.22-11-040 at 206-208.
[15] *Id.* at 137-139.

funds to be justified given broad-based pollution reduction benefits. As one ratepayer advocate organization in California explained:

> The goal . . .is to provide societal benefits by helping to enable large-scale EV adoption that lowers pollution and greenhouse gases (GHGs). These benefits accrue to society and all ratepayers, not specific portions of utility infrastructure…Since all customers are expected to benefit from widespread EV adoption and resultant lower GHGs, air pollution, and potentially electric rates, all customers should pay equally for these programs.[16]

While we note that the California program is currently on "pause;" Washington may wish to consider adopting a time-limited program or creating some other tangible milestones to be reached before pausing or phasing out the system benefits charge.

Washington could create funding mechanisms from its Low Carbon Fuel Standard program or its cap & trade program. Higher incentives for fleets domiciled and/or primarily operating in highly impacted communities may be warranted, given pollution reduction benefits and that MDHVs play an outsized role in the NOx and diesel particulate pollution that disproportionately affects highly impacted communities. Other leading states have complemented utility-provided BTM incentives with taxpayer funded incentives or through the use of special funds. Utility-funded incentives can leverage federal incentive dollars,[17] as well as other state funds. For example, California has funded EV hardware incentive programs using both dollars received through the state's cap-and-trade program and through a special fund collected with vehicle registration fees, as well as general fund (taxpayer) dollars during times of budget surplus.[18] California is also poised to use their Low Carbon Fuel Standard program to focus on MHDV incentives going forward.[19]

<u>Answer to question B and D: Necessary utility-side capital and infrastructure costs to serve fleets can be appropriately recovered through commercial rate classes via base rates, including line extension costs.</u>

CALSTART has encouraged Commissions across the country to adopt EV-specific commercial rates once the class of customers becomes more mature and there is some

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[16] "Comments of the Utility Reform Network on Sections 9, 10, and 12 of the Draft Transportation Electrification Framework" (Filed September 11, 2020 in R. 18-12-006,) at 3-4. *See also* "Opening Comments of CALSTART, Inc. on Administrative Law Judge's Ruling Initiating Track 1 and Inviting Party Comments," (filed July 2, 2024 in R. 23-12-008 ("CALSTART Comments"), available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M535/K108/535108005.PDF) at 13-15.
[17] For example, the Dept. of Transportation's Charging and Fueling Infrastructure Grant Program, https://www.transportation.gov/rural/grant-toolkit/charging-and-fueling-infrastructure-grant-program
[18] *See, e.g.*, California Electric Vehicle Infrastructure Project (CALeVIP):https://www.energy.ca.gov/programs-and-topics/programs/california-electric-vehicle-infrastructure-project-calevip-20.
[19] CARB Resolution 24-14, issued November 8, 2024, available at https://ww2.arb.ca.gov/sites/default/files/barcu/board/res/2024/res24-14.pdf.

diversity of fleet types being served by the utilities.[20] In the absence of an EV specific commercial tariff, if fleets are grouped in another commercial rate class as a phase-in measure, it is still appropriate to recover capital costs through rate design.

Utilities should provide utility-side infrastructure, including line extensions. They are in fact the only entity who can provide this and this infrastructure remains in utility ownership and control. This is what legislatures across the west have recently directed via the Powering Up Colorado Act[21] and AB 841[22] in California.

PacificCorp noted in their response to this Notice that they already have a line extension policy and discussed that there is some risk of under-utilization.[23] We wish to point out that for commercial MHDV customers, like fleets, the risk of under-utilization in the long run is very low. As we have observed in other jurisdictions, if you build it, they will come. As this relates to proactive planning for fleets, we will discuss these concepts further below.

2. **In a time of upward pressure on utility rates, how can the Commission balance the need for more proactive planning with transportation electrification ("TE") infrastructure while sufficiently protecting ratepayers and mitigating risks? (i.e. overbuilding or unanticipated costs)**

    a. **Please provide any known resources or examples demonstrating your proposal.**

<u>The Commission should focus on proactive planning for Fleet Charging needs to decrease costs and energization timelines.</u>

The Commission will do a great service to both ratepayers and public and private fleets if it undertakes proactive planning to address the distribution-grid issues and costs that can be anticipated and planned for. Washington will be much more likely to achieve its targets under the Advanced Clean Cars ("ACC") and ACT regulations with proactive planning for charging infrastructure. Washington has the benefit of learning from the successes and challenges experienced by other states. While not all fleets have great flexibility about where to locate their chargers, many have some flexibility and would gladly take the certainty of an interconnection timeline over a drawn out and uncertain process of waiting for upgrades to serve their load. California has passed laws mandating that its investor-owned utilities conduct proactive planning,[24] but this Commission does not need to wait to be told by legislators to take practical measures to avoid the mistakes of other jurisdictions.

[20] *See, e.g.*, CALSTART Comments; CALSTART has weighed in on EV rate design and rate recovery in NY, MD, NC, MA, MI Commission proceedings, amongst others.
[21] Colorado Senate Bill 24-218 (2024).
[22] Assembly Bill ("AB") 841 (Ting, Chapter 372, California Statutes of 2020).
[23] PacifiCorp's Comments in Docket UE-160799, filed September 26, 2024.
[24] *See* California AB 2700 (McCarty, Chapter 354, California Statutes of 2022). *See also* California Senate Bill ("SB") 410 (Becker, Chapter 394, California Statutes of 2023).

Luckily, the Commission can draw upon very relevant research and white papers published by reputable organizations such as the Rocky Mountain Institute ("RMI").[25] RMI has done a thorough job exploring the pros and cons of proactive planning. In a recent study it concluded that proactive, market-informed planning frameworks and forecasting tools[26] can help the Commission more efficiently align grid investments with projected EV adoption, mitigating risks like overbuilding or unanticipated costs.

An important tool to mitigate costs and therefore control upward rate pressure is managed charging. Therefore, the Commission should ensure that it is requiring, or at a minimum, incentivizing managed charging as much as possible. A recent study focused on MHDVs in New York found that rate impacts range from net positive impact on rates to basically neutral impact under worse-case scenario without managed charging. In other words, managed charging is critical to ensuring grid benefits. Many shared charging depots provide this valuable service to fleets in helping to minimize charging costs and ensure positive grid benefits.[27]

National NGOs like EDF and the Natural Resources Defense Council ("NRDC") have also documented the benefits of proactive planning and found that it is far cheaper over the long-run for proactive planning on the distribution grid to be too fast than too slow. They have concluded that risk of load not "showing up" is still lower than the risk of escalating costs over time.[28] In other words, even if a utility proactively upgrades a substation before full utilization is known, and then load materializes behind schedule, it is still far more expensive if the utility has to upgrade the system sequentially every time there's new load. Whether upgrades are needed depends on a multitude of factors, including existing capacity of the specific location.

Also, "[n]ew load due to EV adoption is geographically lumpy and temporally specific. This is especially true of upgrade needs driven by medium-duty and heavy-duty EVs."[29] Delays in load growth materializing later than expected can often be explained by energization delays vs vehicle delays —if it takes time for load to arrive this is an argument that energization delays are costly for everyone, not that utilities should wait to upgrade the system only after new loads are 100 percent certain.[30]

Specifically, EDF found that "proactive planning for M/HDV electric load can result in capital expenditure (CAPEX) savings in the long run due to reduced need to upgrade the same station to accommodate load growth into the future, when compared to sequential

[25] "Transportation electrification building blocks," prepared by the Rocky Mountain Institute ("RMI") in October 2024, *available at* https://rmi.org/wp-content/uploads/dlm_uploads/2024/12/transportation_electrification_building_blocks.pdf.
[26] *Id.* at slide 14, 19, 25–27, 29–31.
[27] Synapse Report at 13.
[28] *See* EDF Report.
[29] NRDC Testimony at 7.
[30] "Opening Testimony of Mohit Chhabra on SCE General Rate Case Load Growth Projects Sponsored by the Natural Resources Defense Council," submitted February 29, 2024 in A.23-05-010 ("NRDC Testimony"), available at https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2305010/7080/526147523.pdf.

planning approaches." The report recommended that grid forecasting and planning be evaluated for periods of over 20 years to best quantify long-term costs and benefits.[31]

RMI's "building blocks" specifically consider how leveraging established forecasting resources,[32] publishing hosting capacity maps,[33] and facilitating stakeholder engagement[34]offers transparency and predictability, helping fleets to site and connect charging infrastructure without unnecessary delays. RMI also provides case studies for the "building blocks" from other states—such as flexible interconnection, tools for data-sharing, and performance-based mechanisms for utilities' capital investments[35] to demonstrate that systematic, proactive approaches can control rate impacts and avoid the pitfalls of incremental, reactive planning.

A few additional, specific ideas for proactive planning include:

1) Guiding fleets to locations where there is sufficient capacity to serve their needs, such as locations that have lost industrial or other commercial loads and where fleets can install significant capacity without triggering grid upgrades. CALSTART recently developed a roadmap for how building the infrastructure necessary to meet energy needs of MHDVs can be phased in in stages around favorable launch areas in a manner in which distribution grid upgrade costs are manageable.[36] A phased-in approach to MHDV infrastructure was also favored by the federal government's recently released Zero-Emission Freight Corridor Strategy, which clearly outlines key infrastructure buildout goals through 2040, broken into three stages.[37] Costs can be minimized when high freight traffic zones are located near areas of the grid that are known to require distribution upgrades or that are located near transmission infrastructure.[38]

   Hosting capacity maps are one tool that can provide project developers a window into available grid capacity. One utility that released these types of hosting capacity maps early on was the Sacramento Municipal Utility District ("SMUD"). The CPUC has ordered IOUs to develop these types of maps but it has proven more challenging for some large utilities. Washington has the benefit of some more condensed utilities where working directly with fleets to identify locations should be more feasible.

2) Explore clustered line upgrades: consider how best to equitably apportion costs between customers after upgrades are completed and costs are known vs burdening the "first mover" with a greater proportion of upgrade costs.

[31] EDF Report at 7.
[32] *See* RMI report for references to specific tools like NREL, IEA, BloombergNEF and DOE's EV Load Forecasting Guide.
[33] RMI at 39.
[34] *Id*. at 39-40.
[35] *Id.* at 35, 49.
[36] "Phasing in US Charging Infrastructure." CALSTART. https://calstart.org/ZEV-infrastructure-phase-in.
[37] "National Zero-Emission Freight Corridor Strategy," Joint Office of Energy and Transportation (March 2024) https://driveelectric.gov/files/zef-corridor-strategy.pdf.
[38] "Electric Highways: Accelerating and Optimizing Fast-Charging Deployment for Carbon-Free Transportation," National Grid, CALSTART, RMI, Stable Auto, Geotab (November 2022) *available at* https://www.nationalgrid.com/document/148616/download.

3) Surveying fleets to assess their plans over the next 5-10 years: as well as coordinating with other state and federal agencies to ascertain, as quickly as possible, when an entity has been awarded state or federal grants for electrification.[39]

4) Incorporating vehicle telematics data to forecast where and when MHDV loads will materialize, as well as third-party forecasts developed by research institutions and other organizations that incorporate vehicle telematics (such as EPRI's eRoadMap, RMI's GridUP, etc).[40]

5) Consider the realities of equipment availability: Proactive planning for fleet electrification will help utilities manage their equipment needs in the bigger picture. NRDC notes how the national shortages of critical equipment, like transformers, have only increased the justification for proactive planning.[41] Commissions need to develop a policy around where TE energization projects fit in the priorities for system upgrades that might be needed for safety, for example, or where projects may complement one another to make most efficient use of scarce equipment.

Over the long-term, TE has huge benefits for the climate, air quality, and ratepayers. TE will unlock new loads and create downward rate pressure for all customers. Once fully subscribed, shared charging depots can have high utilization and manage charging across fleet customers such that infrastructure is used very efficiently. While fleets have different duty cycles and charging requirements, many can charge overnight or can be somewhat price responsive to avoid peak usage. In Washington, MHDV loads charging overnight fit both a hydropower and wind generation profile very well. Fleets charging mid-day can match well with solar production. A well-designed EV charging rate can help incentivize off-peak charging to maximize grid benefits, as we will discuss further in our answer to question 4, below.

3. At what point should Transportation Electrification programs be rate-based rather than customer specific tariff schedules?

a. At what percentage of use (percent of time used for charging) do public chargers "break even" for EVSE owners?

Our answer to Question 1 provides a thorough overview of ratemaking principles that the Commission should consider relevant to electrifying fleets. CALSTART finds that other organizations are heavily focused on public DCFC charging and the economics of public charging. Our responses to this Notice focus on the needs of fleets for depot charging, rather than public charging or the light-duty vehicle market segment. While there is a need for public DCFC to serve the trucking industry, this does not seem to be the topic envisioned by this question. The necessary rate structures for shared depot charging for fleets are further discussed in our response to question 4, below.

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[39] CALSTART discusses strategies for predicting load growth in comments in comments on the CA PUC "Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future" *available at* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M532/K262/532262611.PDF
[40] RMI report at Slides 30-31.
[41] *See* NRDC Testimony.

4. **Some utilities across the country have implemented (or plan to implement) a flat-rate charging program for EVs. (i.e. For $35 per month, a customer can charge as much as they want during off-peak hours) Would a similar construct be viable in Washington?**

CALSTART declines to answer this general question regarding flat rate charging as we interpret it as not being applicable to commercial (fleet) customers.

c. **For charging stations with high intensity, but infrequent use, the utility may assess a demand charge which may be passed on to the charging provider and ultimately customers. Do third-party providers absorb significant costs for demand charges?**

Yes, for those entities developing shared charging depots, demand charges are a significant barrier in the early days of operation when utilization rates are lower. It is necessary to offer discounted demand charges and higher volumetric cost recovery to make a site economically viable until load factors increase.

CALSTART works closely with our members who offer shared charging for fleets, and therefore to answer this question we assume that these providers are considered "third parties" by the Commission. By necessity, shared fleet charging providers will build out charging capacity before the site is "fully subscribed." In these early days the volume of demand for charging is low (kWh) but "peak" utilization may be disproportionately high. Traditional demand charges, which were originally designed and intended for corporate and industrial load profiles that are quite different than those of an EV or shared charging depot during the early days of operations, can be one the of the most significant costs of electric fueling and can present a substantial barrier to electrifying fleets. High demand charges unfairly penalize the "first movers" by assigning upgrade costs to them—when over time, a much more diverse set of loads will benefit from the upgraded distribution system investments.

Experts have considered effective rate designs—the Regulatory Assistance Project (RAP) stands out as a neutral thought leader on demand charges and alternatives and considered them early on in EV utility policy development:

> More dynamic pricing methods can better match price to system impact than either NCP (non-coincident peak) or CP demand charges. . . The only costs that are "caused" by an individual customer's NCP demand are those near the point of delivery. . . Typically, the only system components sized based on the customer NCP are the final line transformer and the service wire to the meter.[42]

[42] Carl Linvill, PhD, Jim Lazar, Max Dupuy, Jessica Shipley, and Donna Brutkoski, "Smart Non-Residential Rate Design Optimizing Rates for Equity, Integration, and DER Deployment," Regulatory Assistance Project (December 2017). ("'Smart Non-Residential Rate Design,' RAP").Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/electric-rates/2017-electric-rate-forum/rap-cpuc-smart-non-residential-rate-design.pdf.

In other words, Commissions should be careful not to charge customers imaginary costs based on their peak load as this is not a valid proxy for actual utility costs.

Having a high ratio of demand charge vs volumetric charges doesn't become economic until higher depot utilization rates. As a near-term rate design, we recommend a sliding scale approach based on load factor (*i.e.,* lowest load factor customers receive the highest demand charge discounts). For example, customers with load factors of 0 to 5 percent may have an energy-only rate structure, customers with load factors of 5 to 10 percent may receive a 75 percent discount on demand charges, and so on, until customers with load factors above a given threshold pay the full demand charge. The specific brackets and discount levels should reflect customer bill impacts, based on the specific rate schedule. CALSTART has filed extensive testimony on this topic in rate cases in other states,[43] and our members would be happy to help inform Commission staff regarding which brackets are economically viable.

While CALSTART's recommendation is targeted towards the shared depot charging sites with the lowest utilization rates, such sites are not expected to have low utilization indefinitely. Shared charging depots have a business interest in increasing utilization and are doing their part to increase it in a way that maximizes use of grid infrastructure and minimizes costs for fleets. Demand charge discounts are not intended for indefinite use; they are intended to remove a major initial barrier so that shared charging sites can get off the ground and enable initially low utilization rates to ramp up over time, benefiting all customers by contributing to downward rate pressure and air quality benefits.

Finally, increasing cost recovery through time-varying, volumetric rates may be more cost reflective in systems with high penetrations of variable, renewable resources—which is becoming increasingly the case in Washington as the state implements the Clean Energy Transformation Act.[44] In systems with high renewables penetration, load shape becomes a more important contributor to system costs than load factor. For example, a large, high-load factor customer with steady consumption, such as a data center, is likely to contribute more to the system peak than a large but lower load factor customer who can shift to off-peak consumption. Rate designs that prioritize load factor, such as those with high demand charges, may shift costs from high to low load factor customers, even though low load factor customers with the ability to consume off-peak may place lower demands on the system and thus have lower cost to serve. [45] In contrast, increasing time-varying, volumetric recovery for customers such as shared charging station operators may be more cost reflective and can still avoid cost shifts between customer classes.[46]

[43] Testimony of CALSTART in CA PUC Docket A.24-03-019, filed January 8, 2025, available at https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2403019/7928/553185422.pdf.
[44] Clean Energy Transformation Act (CETA) (SB 5116, 2019), Chapter 288, Laws of 2019.
[45] "Smart Non-Residential Rate Design," RAP.
[46] *See* "Department of Public Service Whitepaper Regarding Alternatives to the Traditional Demand Charge for Commercial Customer Electric Vehicle Charging," prepared by the New York Department of Public Service (DPS) in Case 22-E-0236, September 2022 at 23. DPS contracted with Guidehouse to produce a study examining the effects of several rate design options on Commercial EV Charging Customers' bills for various charging use-cases.

Conclusion

CALSTART greatly appreciates the opportunity to respond to this Notice. We hope that our response is helpful in highlighting relevant studies and experiences in other jurisdictions working to advance fleet electrification. In particular, we hope that our responses help the Commission better understand the unique needs of shared charging station developers for fleets and MHDVs. We look forward to discussing our responses with your staff. Please contact us at your convenience.

Sincerely,

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