Climate Resilient Battery Electric Fleet Feasibility Assessment for Humboldt County Public Transit

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EXECUTIVE SUMMARY

Many transit agencies have planned and implemented climate change mitigation and adaptation measures, some of which have catalyzed the adoption of battery electric buses (BEBs). The California Innovative Clean Transit Program has accelerated the adoption of BEBs in California. However, commercially available BEBs and charging infrastructure are associated with a nascent industry with less than a decade of in-service deployment. As such, publicly available planning resources and tools are limited.

This feasibility assessment presents the results of an analysis conducted with a novel cost optimization tool developed for this project called the Battery Electric Bus Optimization (BEBOP) Model. The results of this Model are presented through a climate resilience lens with the goal of providing holistic and robust guidance for the twenty first century.

The first sections of this report introduce the topic of electrification and present a literature review of best practices developed by transit agencies and supporting organizations. This is followed by a detailed overview of anticipated climate change impacts in Humboldt County as they relate to road, electricity, and communication infrastructure, along with climate adaptation recommendations. Fleet electrification feasibility results from the BEBOP Model are then presented along with additional climate adaptation recommendations specific to vehicle charging infrastructure. The report concludes with recommended next steps for transit fleet electrification planning in Humboldt County.

Transit Electrification Planning Best Practices

Resources that are available tend to provide general high-level guidance. Insights from early-adopter transit agencies generally have the following recommendations in common: engage stakeholders (e.g., municipalities, utility companies, the communities) at the start of the planning process, leverage lessons learned from other agencies implementing BEBs, and designate internal champions to oversee both the financial and technical aspects of BEB deployment.

Climate Change Vulnerability and Adaptation

There is increased awareness of the importance for integrating climate change risks and adaptation into planning processes. This plan addresses climate change impacts that are of concern to transit services and infrastructure. For Humboldt County, three climate change effects of primary concern are 1) sea level rise, 2) an increase in wildfire frequency and/or intensity, 3) and an increase in frequency and intensity of extreme precipitation events. These will impact roads, electricity transmission and distribution, and communication infrastructure. The following table summarizes the risks, impacts, and recommended adaptation strategies for these climate change effects.

Table 1: Summary of climate change risks and impacts, and adaptation strategies to minimize impacts

Risk	Impact	Adaptation
Sea level rise will impact the Humboldt Bay region, and coastal road infrastructure in northern Humboldt.	By 2100, assuming no adaptation measures are undertaken by the County, the HTA campus and numerous routes will be periodically or continually inundated.	Relocate existing infrastructure and evaluate alternative routes (**retreat**). Where no options exist, evaluate defensive options to protect against inundation (**protect**). Avoid planning new infrastructure in impacted areas (**accommodate**)
Increased frequency and intensity of wildfires.	Wildfires will directly impact infrastructure primarily in Southern and Eastern Humboldt County. Public Safety Power Shutoff events caused by high wildfire risk weather will impact reliability of electrical and communication infrastructure throughout the County. Wildfires will impact evacuation planning.	Plan for additional capital costs to provide resiliency to key infrastructure that relies on electricity (**accommodate**). Work with County OES to identify evacuation routes that transit vehicles may serve, and plan for additional charging infrastructure to support those evacuation routes (**accommodate**).
Increased intensity and frequency of extreme weather events.	Will directly impact all transit related infrastructure: roads and routes, electrical, communication.	Develop re-route contingency plans for areas at high risk of flooding and landslides (**accommodate**). Work with CalTrans and OES to harden and protect road and communication infrastructure along service and evacuation routes (**protect**).

Based on the local context eighteen additional adaptation strategies are recommended in Chapter 3 within an action timeframe (i.e. now, near term, and long term). These strategies can be summarized as follows:

- Now
  - Begin aligning transit planning with adaptation measures for climate change impacts and community resiliency.
- Near term
  - Plan the re-location and/or protection of vulnerable existing infrastructure.
  - Integrate resiliency planning into the design of new infrastructure.
  - Develop clear emergency response procedures and evacuation routes.
- Long term
  - Develop re-route contingency plans for areas at risk of periodic water inundation.
  - Monitor impacts on key infrastructures and modify plans and operations as climate change impacts become more pronounced.

Another important step in integrating climate change into the planning process is consideration of emergency response requirements. Currently, Humboldt County does not have clear emergency response requirements for transit agencies in the Emergency Operation Plan. There is currently a verbal agreement that transit agencies may be called upon to provide evacuation services, especially for the access and functional need population. Fuel security has always been of concern during emergency situations and fuel switching to electricity brings unique challenges that must be planned for. Greater coordination between the Office of Emergency Services and transit agencies is needed to identify and address these challenges.

Battery Electric Fleet Feasibility Results

Per results of the Battery Electric Bus Optimization (BEBOP) Model developed for this analysis, it is feasible for all existing public transit fixed routes in Humboldt County to switch to battery electric buses with currently available technology. We used the following key assumptions in the BEBOP Model to develop the results in this report:

- Constant efficiency for all buses of 0.529 miles/kWh (see Appendix C for details),
- Effective bus battery capacity of 80% of advertised capacity reflecting a battery near the end of useful life, and
- 15% battery reserve safety factor for all buses, meaning no bus is allowed to use more than 85% of the effective battery capacity, or 68% of the advertised capacity.

The BEBOP Model results also include charging loads associated with Redwood Coast Transit and Trinity Transit routes that travel within Humboldt County in anticipation of the potential electrification of these routes. Inclusion of these transit systems influences the location and availability of charging infrastructure which impacts on-route charging schedules of in-County transit systems.

In general, using the cost assumptions detailed in Appendix C, the BEBOP Model recommends the following infrastructure choices in order from lower to higher total system amortized cost: larger battery capacity buses first, then higher power on-route chargers second, and finally lower power on-route chargers third. Adding additional bus battery capacity always presents the lowest incremental cost to enabling electrification of routes. Although high power on-route chargers present a larger capital and O&M cost, because of the fast charging time fewer stations are need compared with lower power on-route stations which typically results in a lower total system amortized cost. The BEBOP Model limits the allowed location of lower power on-route charging stations to stops where breaks of 10 minutes or longer are built into the route schedule.

Anticipated total cost of bus replacement plus depot fueling infrastructure for each transit system is shown in Table 2. One 50kW depot charger per electric bus is assumed. Estimated location and costs of on-route charging infrastructure that is shared across transit systems is shown in Table 3. The BEBOP Model results recommended eight 500kW on-route pantograph chargers which multiple transit systems utilize.

Table 2: Estimated bus and depot charging infrastructure costs for each transit system.

Transit System	Buses	Depot Chargers
BLRTS	$0.77M	$50k
KTNET	$0.77M	$50k
AMRTS	$1.54M	$950k, all located at HTA maintenance yard.
ETS	$3.12M	
RTS	$7.17M	
SHI	$2.41M	
WC	$0.80M	

Table 3: Estimated on-route charging infrastructure locations and costs.

Stop Location	On-Route Chargers
Arcata Transit Center	$693,280
Bayshore Mall	$721,000
Benbow KOA	$578,000
College of the Redwoods	$713,000
Dean Creek Resort	$642,000
Myers Flat	$770,800
Trinidad Park & Ride	$618,800
Willow Creek	$624,800

Estimated total cost per mile of electricity for each transit system is shown in the Figure 1. This cost per mile includes an optimized charging schedule for each bus that accounts for the time-of-use rate structure offered by PG&E's EV Fleet Program.

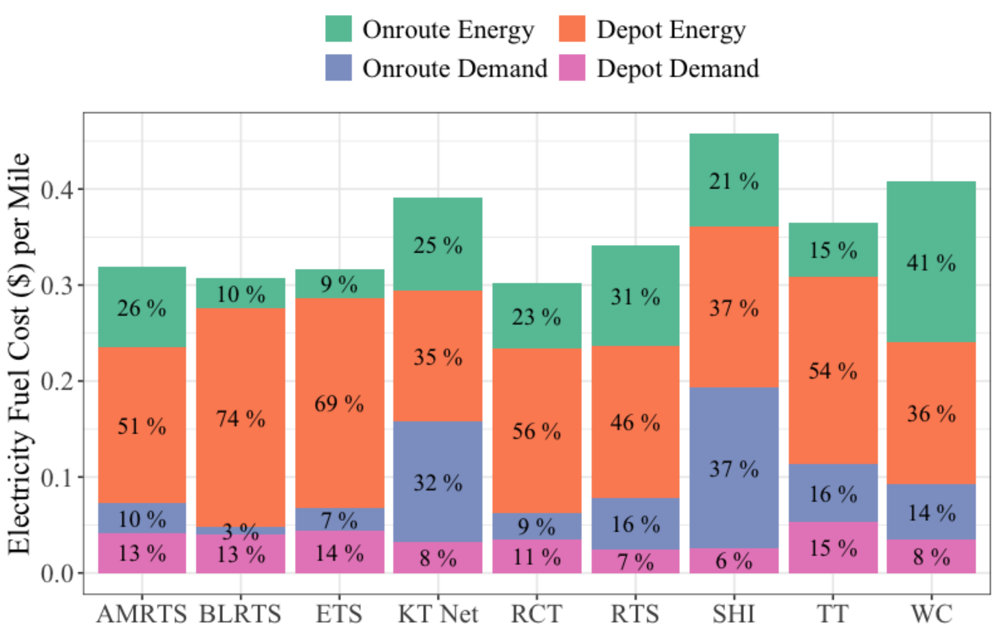

Figure 1: Estimated electricity cost per mile for all Humboldt County transit systems, including Redwood Coast Transit and Trinity Transit routes that travel within Humboldt County.

A regional coordinated fuel-switching effort across all transit systems in the region will be important for minimizing on-route charging infrastructure costs. To this end:

- It will be important for neighboring transit systems to share on-route infrastructure.
- To enable sharing of infrastructure, it is recommended that transit systems coordinate regarding bus OEMs and charging infrastructure OEMs to ensure compatibility between buses and charging infrastructure.

An initial look at anticipated battery useful life for all buses running existing routes indicate the following:

- All AMRTS, BLRTS, and ETS buses are anticipated to have battery lifetimes ≥12 years
- All other transit systems have some buses that are anticipated to have battery lifetimes <12 years indicating an additional battery replacement cost during the lifetime of the bus.

Early analysis of the performance of HTA's Proterra XR+ 330kWh 40 foot low floor bus shows that bus efficiency is initially performing as advertised for routes within the Humboldt Bay area, and initial battery capacity is as advertised. However, efficiency appears to be declining at a rate of somewhere between 5% and 14% per year (depending on the data set), and battery capacity appears to be declining at a rate of 17% per year, which suggests that the initial battery useful life estimates may not reflect actual observed performance. Furthermore, HVAC and battery management loads can range from less than 5% up to greater than 30% of total energy consumption per run, and begins to be a significant load for ambient temperatures below ~60°F and above ~85°F. Sensitivity analysis of BEBOP Model results regarding on-route charging infrastructure requirements and total fuel cost per mile indicate that a 20% reduction in average bus efficiency results in 50% more on-route charging infrastructure needed, and ~30% increase in fuel cost per mile.

Because HTA currently sees +30% to -40% range in advertised efficiency, and average efficiency appears to be declining, it is recommended that transit systems:

- Conduct more detailed feasibility analyses for long routes and/or routes with significant elevation changes, and
- Consider doubling the bus battery capacity that is calculated as required based on specification sheet efficiency.

As transit operators gain experience operating electric buses, and as technology improves with time, agencies should re-visit and adjust these recommendations.

CONTENTS

CHAPTER 1: INTRODUCTION

Planning the future of public transit in Humboldt County requires integrating targets for zero-emission vehicles into transit fleets. The following California goals and mandates have aggressively accelerated the implementation timelines of the California Air Resources Board's Innovative Clean Transit Program:

- EO-B-30-15: Statewide Greenhouse Gas reduction target of 40% below 1990 levels by 2030
- EO-B-48-18: Goal of 5 million zero-emission vehicles (ZEVs) on the road by 2030
- California ZEV Action Plan: Maximize the use of ZEVs by transit agencies

The State has also required the integration of climate adaptation into transportation planning processes, as reflected in the following policies:

- EO-S-13-08: Mandated the creation of a statewide climate adaptation strategy and identifies the need to incorporate sea level rise into transportation infrastructure planning
- California Transportation Plan 2040 identifies; Goal 2, Policy 3 recommends identifying transit vulnerabilities and adaptation recommendations

The structure of this Plan follows the steps outlined in the "Planning and Investing for a Resilient California" (PIRC) report (Governor's Office of Planning and Research, 2017), and provides a blueprint for future planning efforts by other transit agencies. The PIRC report recommends the following steps:

1. Identify how climate change could affect a project or plan
2. Conduct an analysis of climate risks
3. Make a climate-informed decision
4. Track and monitor progress

In line with the PIRC report, this Plan is structured as follows:

- Chapter 1 summarizes current literature and guidelines on transit planning regarding both the deployment of BEBs and integrating climate change adaptation into the process.
- Chapter 2 identifies climate change impacts and risks (step one and two of the PIRC guidelines) that are related to transit infrastructure and operations. This chapter also provides adaptation recommendations.
- Chapter 3 presents the results from an optimization model that projects infrastructure needs to support the transition to BEBs within current routes and service times. This provides objective and optimized recommendations into the capital investment required to support fuel switching to electricity. Recommendations are generated using open-source methods and code.
- Chapter 4 combines the information from Chapters 2 and 3 to arrive at recommendations and strategies (step three of the PIRC guidelines).

- Chapter 5 provides guidance on next steps for transit electrification planning in the County (step four of the PIRC guidelines).

Note that a cost comparison to current diesel bus operations is not provided, nor are full O&M costs accounted for to enable a complete cost comparison with currently available diesel and hybrid diesel technologies. The intent of this report is to simply present the capital cost of currently available battery electric transit buses, the capital cost of currently available electric vehicle charging stations, and the electricity (i.e. fuel) cost of operating battery electric buses and charging stations as these are the significant unknowns to transit operators. Under the Innovative Clean Transit program transit agencies are required to transition to battery electric or hydrogen fuel cell electric technologies. Therefore, a comparison of total cost of ownership with diesel and diesel hybrid technologies is not applicable for long term planning of transit operations.

CHAPTER 2: TRANSIT PLANNING FOR BATTERY ELECTRIC BUSES AND CLIMATE CHANGE

Battery electric bus (BEB) deployment is still in the early stages and few published reports applicable to BEB planning are available. In addition, there is little guidance for transit agencies (especially in non-metropolitan areas) on best practices for integrating zero-emissions vehicle targets with climate adaptation planning. Federal agencies and the State of California have developed many climate adaptation guidelines for public agencies. *Planning and Investing for a Resilient California*, for example, provides a framework to increase climate resiliency (Governor's Office of Planning and Research, 2017). Transit specific climate adaptation efforts (i.e., the 2011 Federal Transit Administration's [FTA] Climate Change Adaptation Initiative) tend to focus on metropolitan areas (e.g., San Francisco, Chicago, etc.) However, electric bus adoption has been moving rapidly across all community types, albeit with the limited current resources on climate resiliency planning regarding electric bus infrastructure.

This chapter draws mainly from *Battery Electric Buses - State of the Practice* report by the National Academies of Sciences, Engineering, and Medicine (NASEM) (National Academies of Sciences Engineering and Medicine, 2018). In addition, American Public Transportation Association has a forthcoming *Bus Procurement Guidelines* document which may be useful for BEB planning. This chapter reviews the current literature and planning efforts and sets the stage for the rest of this Plan.

1: Planning Considerations and Deployment Challenges

BEB planning is unique to each transit agency, but broadly the NASEM report categorized BEB planning into six planning considerations. The considerations are:

1. Lifecycle cost analysis (economic feasibility)
2. Bus technical specification, operational requirements, and route selection (technical feasibility)
3. Charging infrastructure and layover location characteristics (technical feasibility)
4. Electricity rate structure (economic feasibility)
5. Planning and supporting tools
6. Scalability

Considerations 1-4 cover the technical and economic aspects of BEB planning. Planning and supporting tools help to implement the first four considerations and scalability is achieved through time and experience. The BEB industry is still in the early stages of establishing the technical and economic feasibility of BEBs. Planning and supporting tools are still in development and evidence of scalability has not yet been shown.

Similar to the planning process, there are both common and unique challenges encountered with BEB deployment across transit agencies. Examples include uncertainty in BEB energy efficiency, selection of the most cost-effective utility rate structure, and passenger frustration with new BEB schedule and layover increases. These challenges are currently being addressed with better coordination between stakeholders, better training, and more robust planning.

1.1: Guidance from Early Adopters

In the NASEM report, five transit agencies operating BEBs were surveyed and each agency provided advice for other transit agencies planning to implement BEBs. The key takeaways are engagement with stakeholders, peer learning, and the need for internal champions.

Engagement with stakeholders, especially original equipment manufacturers, jurisdictions, and utility companies, is a commonly recommended planning factor across different transit agencies deploying BEBs. For example, BEB operation will likely incur peak demand charge costs that transit agencies previously did not have to consider. The BEB operation cost (e.g., electricity cost) could become higher than the per-mile cost of other fuels if unaddressed. Thus, the electricity rate structure should be evaluated and negotiated early on in the project. Other stakeholder engagement includes coordination with jurisdictions and permitting agencies on charger installation and engagement with the broader community for BEB technology education and awareness.

Peer learning and internal champions help transit agencies stay informed of best practices and lessons learned by others, and help overcome the obstacles of BEB implementation. For example, King County Metro founded helpful to designate a team or staff person to stay up-to-date on BEB development and engage with other BEB operating agencies. However, it can be difficult for smaller transit agencies to allocate staff resources to champion fuel switching efforts.

Managing the cost of operation is crucial in ensuring the economic feasibility of BEB implementations; especially for transit agencies in California since it has some of the highest demand charges in the nation (National Renewable Energy Laboratory, 2017). To mitigate the potential higher operation cost transit agencies can: 1) procure electric buses with higher efficiency, 2) better manage electric bus charging, including employing energy transfer technology, 3) manage time-of-use pricing, 4) explore modification of peak demand charges with the utility, and 5) optimize the deployment of on-route charging infrastructure (Bloch-Rubin, Ted; Gallo, Jean-Baptiste, Tomic, 2014). Furthermore, scaling up the BEB fleet could have mixed effects on the peak demand charges. If deployed optimally, the demand charge could be spread among various routes. Conversely, if not optimized, the demand charges could become additive.

The unique considerations for BEB charging infrastructure include charger locations and schedule modification. Aside from optimizing the locations of chargers to minimize costs while meeting the BEB travel demands, transit agencies prefer locating on-route charging stations at existing transit centers that are already owned by transit agencies. Schedules and layover times were commonly modified to accommodate BEB operation.

Some transit agencies operating BEBs reported that route and charging infrastructure modeling exercises are helpful, however only one third of the 18 transit agencies surveyed in the NASEM report used planning tools when planning for BEB deployment. Part of the reason for this is that BEB route and charging modeling software and tools are not yet widely available. However, methods and tools produced by the academic community do exist (e.g., Liu and Wei's spatiotemporal cost optimization model [Liu & Wei, 2018] used for this Plan), and commercial products are beginning to appear (e.g. BeWhere-Bus's cost and energy optimization model [Xylia, Leduc, Patrizio, Kraxner, & Silveira, 2017] , and ViriCiti). Notably, these tools are missing important operation variables such as elevation changes and regenerative braking.

2: Climate Change Considerations for Transit Planning

The general planning guidelines used in *Climate Change & Extreme Weather Vulnerability Assessment Framework* by the Federal Highway Administration or *Planning and Investing for a Resilient California* are recommended. A summary of these guidelines are (Federal Highway Administration, 2017):

1. Articulate objectives and define study scope
2. Obtain asset data
3. Obtain climate data
4. Assess vulnerability
5. Identify, analyze and prioritize adaptation options
6. Incorporate assessment results in decision-making
7. Monitor and revisit

Step 7 should include climate considerations and could be combined with the Transit Asset Management practice—specifically, the climate impacts on the state of good repair. The framework (Appendix B) developed by Ortega provides an example of this approach (Ortega, 2018).

The Transit Evacuation Vulnerability Index developed with sociodemographic and transit related variables can be used to inform transit planning to increase livability and resiliency. Transit access or evacuation support could then be increased in vulnerable areas based on the index. *Public Transit and Mandatory Evacuations Prior to Extreme Weather Events in New York City* by the University Transportation Research Center provides more information (University Transportation Research Center, 2017).

In addition to transit assets and infrastructure, transit agencies need to consider extreme weather impacts on passengers. As with climate change in general, vulnerable populations (i.e., population with disabilities) are likely to experience greater impacts during extreme weather events (National Academies of Sciences Engineering and Medicine, 2017). For example, accessing bus stops and navigating around localized flooding can be challenging for certain populations.

3: Integrating Battery Electric Buses into Transit Planning

Conventional transit planning standards are beginning to be re-defined with the increasing need to incorporate climate change adaptation and electrification into planning efforts. Conventional transit planning standards generally include three main topics: service design standards, performance measurement, and service evaluation (Figure 2).

Figure 2 Main transit planning topics. Adapted from "Best Practices in Transit Service Planning", by Florida Department of Transportation Research Center, 2009.

Table 4 Relevance of climate change and battery electric bus 9BEB) deployment to service design standards

	Climate Change	BEB Deployment
Classification Systems	No	No
Service Availability	Mid	High
Travel Time and Capacity	Low	High
Service Delivery	Low	Low
Vehicle Standards	No	High
Service Equity	Mid	Low

This section reviews the best practices and standards for transit planning (Florida Deparment of Transportation Research Center, 2009) and highlights areas potentially impacted by climate change adaptation and BEB planning (Table 4). Below are six areas of service design standards and relevant examples of climate change and BEB deployment considerations. The examples are non-exhaustive and meant to serve as starting points for transit planning with consideration for BEB deployment and climate change adaptation.

3.1: Classification Systems or Service Types

In order to plan for the transit system, services are categorized (e.g., commuter/ work-based service, community service) first and then other design standards are defined accordingly. Climate change adaptation and BEB planning are not directly related to this aspect of service design.

3.2: Service Availability

The availability of services is defined and adjusted if needed after the transit services are categorized. Service availability includes service area characteristics (e.g., population and employment density), service coverage (e.g., % population located within certain distance of a bus stop), route layout and design, and stop location and spacing. BEB deployment could impact the route layout and design and the stop location and spacing standards. For example, route spacing may be reduced near a shared on-route charger stop and these stops may be more feasible with mid-block stop design to avoid obstructing traffic. Climate change could impact the roadway conditions and safety concerns and consequently affect the service coverage.

3.3: Travel Time and Capacity

Travel time and capacity standards address the frequency of the transit service. Specific components include service frequencies, service directness, span of service, and loading standards. Usually service frequency and directness are inversely related; more direct service bypasses stop out of the way thus reducing the service frequency at those particular stops. BEB deployment would likely negatively impact both service frequency and directness. BEB deployment could impact the service frequency by increasing the headway from on-route charging. For example, without adding additional buses to a service route, any on-route charging session adds equivalent time to the headway at subsequent stops after the charging stop. BEB deployment could also impact the service directness due to the potential need to reroute for on-route charging at stops equipped with chargers. Climate change could potentially decrease the service directness if the most direct road or major corridors are impacted.

3.4: Service Delivery

Service delivery standards address the direct impact on customers. Specific components include on-time performance, passenger shelters, customer service, safety issues, and other amenities. BEB performance (i.e., energy efficiency) is sensitive to driving patterns, leading to a potential uncertainty in on-route charging time, which could then impact transit on-time performance. Climate change could decrease the electricity system reliability causing transit schedule disruption. Climate change could also impact rider safety at stop locations (or surrounding areas) that are prone to flooding.

3.5: Vehicle Standards

Vehicle standards address the operating of BEBs. Specific components include assignment of vehicles, utilization and efficiency, and reliability and condition. BEB deployment is highly relevant to the vehicle standard. Under the utilization and efficiency component, BEB deployment could increase the deadhead (non-revenue) miles if a majority of the charging is done in the garage throughout the day. BEB deployment could also increase the layover time between schedule runs for the need to recharge.

Regarding the reliability and condition component, the service life of the vehicles must be redefined to account for battery life. Under high BEB deployment, the 20% maximum spare ratio guidance for the Bus and Bus Facilities Program could impact the resiliency of the operation (Federal Transit Agency, 2015). For example, power outages or charger issues (as experienced with Charge Point) could leave the transit agencies with only a small fraction of the buses to operate without a sufficient contingency fleet to maintain their service level.

The reliability and condition component is limited by the state of BEB technology. Proterra, a major manufacturer of electric buses, has a 12 year unlimited mile battery warranty (Proterra, n.d.) which is comparable to the FTA’s minimal asset useful life standards for grants of 12 years (Federal Transit Administration, 2017).

3.6: Service Equity

Service equity standards address the FTA Title VI requirements which refers to the equitable distribution of the services to all population groups. Title VI requires all fixed route transit agencies to set system-wide standards on five minimum indicators to ensure transit operation does not result in discrimination. The five minimum indicators required are vehicle load, vehicle assignment, vehicle headway, distribution of transit amenities, and transit access (Federal Transit Administration, 2012).

Service equity will likely become more important as climate change may disproportionately impact vulnerable populations. For example, populations that rely on public transit and are unable to relocate from climate impacted areas would have lower transit access compared to other populations. BEB deployment could disproportionally impact certain passengers. For example, passengers with trips elapsing charging stops could experience increased travel times due to bus charging needs.

4: Risks of Fleet Electrification

Fleet electrification involves a number of important risks in the context of climate change. Some key risks are the following:

- Successful fleet electrification involves coordinated regional deployment of fueling infrastructure over a large geographic area in order to achieve the reliability currently realized by fossil fuel vehicles. Full fleet electrification will realize limited success if Humboldt is alone in the effort. Active and regular coordination with local, regional, and statewide partners will be important.
- Currently there are limited data on the long term performance of electric buses and charging infrastructure. Durability of batteries and bus battery management systems is still an unknown. The long term performance of charging infrastructure is also not known. Transit agencies will need to keep track of the performance of vehicles and infrastructure, and use this information to develop long term asset management strategies.
- Technology is likely to see significant changes over the coming decades. This will cause fleet management to become more complex over the next couple decades. In addition, vehicle-grid integration technology standards are still in development which adds risk of obsolescence to equipment and buses deployed in the near term. It will be important for transit agencies to plan for and prepare to the extent possible for this added complexity.

5: Conclusion

It will be important to adopt an adaptive management approach by tracking the changing climate condition and monitoring asset performance. HTA should develop metrics to continuously track the climate impacts at specific project sites (i.e., the on-route charger locations, HTA campus). Clear check points to evaluate the project with the metrics should be set both over the planning process and the project's lifetime.

A stakeholder analysis, or an assessment of all the key participants involved in the implementation of the climate adaptation and resiliency plan, can be performed to analyze how the transit project will affect their respective problems and needs. By identifying each of the stakeholder's characteristics and interests, different roles and level of participation can be defined. This will also help to determine if there are conflicts of interest among groups of stakeholders. The adaptation requirements need to be well understood and communicated between all stakeholders, the participants can keep track of the progress and discuss alternatives to the adaptation plan by organizing meetings or stablishing a centralized line of online communication.

Every stakeholder may have a different idea of what project success looks like. An upfront layout of the overall objectives of the climate change and adaptation strategy should be compiled to help ensure that all stakeholders will be supportive of the final outcomes. For HTA, climate adaptation and resiliency tracking and monitoring could be integrated with the asset management system as suggested in Chapter 3 and the guidelines in Appendix A.

By collaborating and inviting public participation, the transit agency and the policymakers can seek out common goals that can enable zero emission vehicle (ZEV) technology deployment while helping to ensure that the community priorities are considered. Advocates should consider supporting strategies that are simultaneously supportive of expanded transit service that also help accelerate ZEV deployment.

CHAPTER 3: CLIMATE VULNERABILITY AND EXTREME WEATHER EVENT PLANNING

This chapter presents climate change impacts and adaptation recommendations in the context of long-term infrastructure planning in support of electrified transit. Available literature and guidelines along with local climate change impact assessments are used to devise a set of climate adaptation strategies for electric bus operation and infrastructure.

1: Climate Change Impact and Risks on Long-Term Energy Planning

Climate change impacts need to be considered for the long-term planning of transit operations and infrastructure for a future wherein transit fleets are 100% electrified. These impacts are assessed on transit-related road infrastructure, routes, electricity distribution, future bus charging infrastructure, and communication infrastructure. Key recommendations are made to assist with planning for predicted impacts on this infrastructure.

1.1: Climate Change Effects That Are Considered

There are three main climate change effects addressed in this report: sea level rise, changes in wildfire probability and severity, and frequency of occurrence of extreme weather events. These impacts are briefly summarized in this section.

1.1.1: Sea Level Rise

One of the direct results of climate change is the rising global average temperature caused by an increasing atmospheric concentration of greenhouse gas (Intergovernmental Panel on Climate Change, 2014). Increased global average temperature subsequently will lead to the thermal expansion of seawater and melting of glaciers and ice caps resulting in rising sea level (Laird, 2018).

There are many projected levels of sea level rise, each based on different emissions scenarios, climate models used, and other regional factors. Local studies suggest the following changes in sea level for the Humboldt Bay region:

- Median projection: 0.8, 1.5, and 2.9 feet by 2030, 2050, and 2100 respectively (Laird, 2018).
- High emission projection: as much as 0.9, 1.9, 3.2, and 5.4 feet for 2030, 2050, 2070, and 2100 (Northern Hydrology & Engineering, 2014a)

One of the main concerns regarding sea level rise is the vulnerability of near-shore infrastructure. A significant fraction of transit revenue miles occurs in the Humboldt Bay region on roads that are expected to be impacted by sea level rise, and the main campus for the Humboldt Transit

Authority is at risk of flooding. Additionally, seventy-five percent of the shoreline surrounding Humboldt Bay is artificial and requires periodic maintenance (Laird, 2018). If and when the shoreline infrastructure is compromised, the tidally inundated areas surrounding Humboldt Bay will experience additional flooding.

Sea level rise mainly impacts the northern coastal portion of the county (Figure 3). Humboldt Bay has had many in-depth local studies considering shoreline structure, resulting in localized sea-level-rise projections (Figure 4).

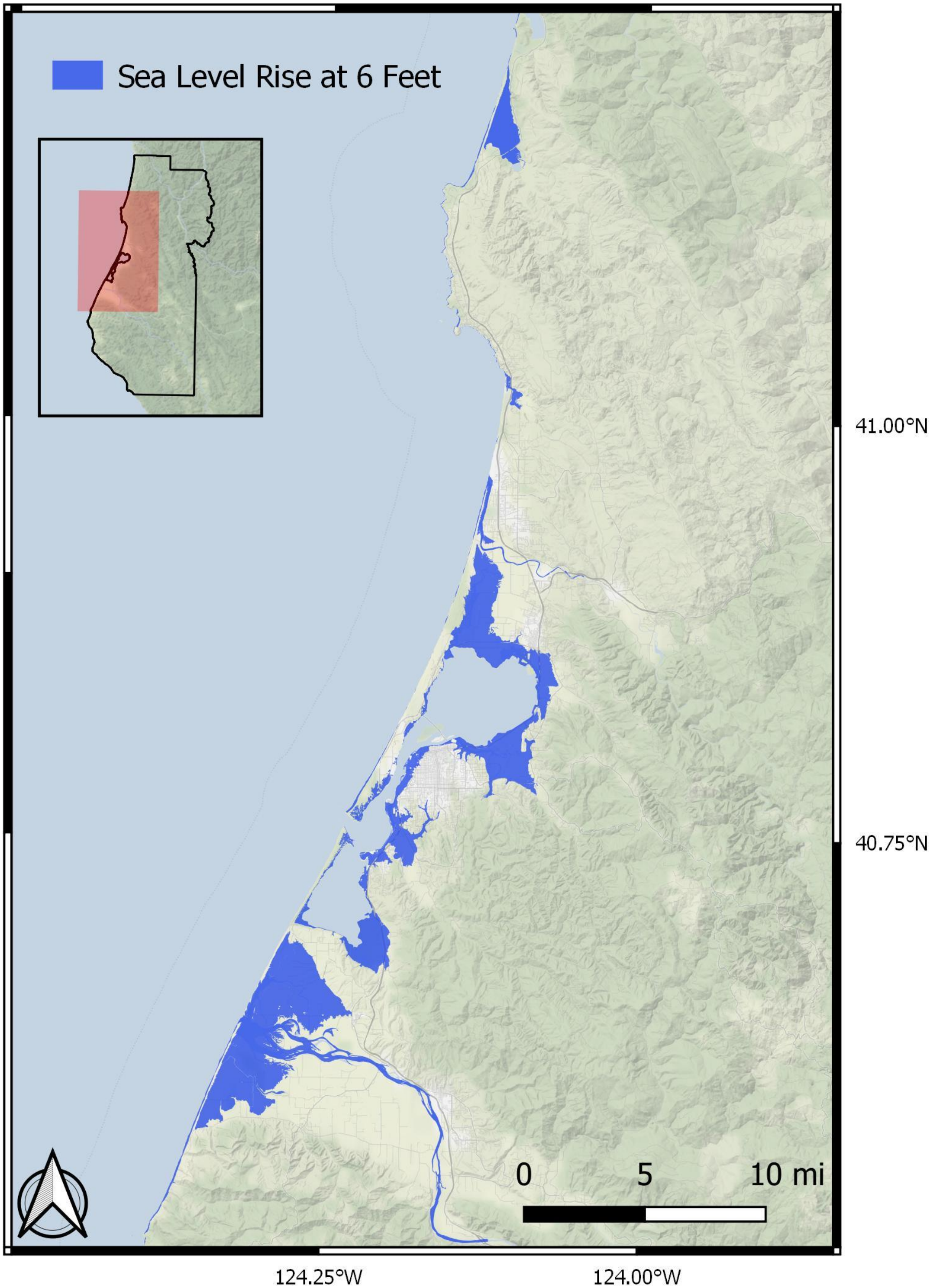

Figure 3 Impacts of 6 feet of sea level rise (SLR) for Humboldt County coast. 6 feet SLR, which is more severe than the high SLR projection (i.e., 5.4 feet) by the end of this century, is chosen to illustrate the "worst-case scenario". Created by the Schatz Energy Research Center. Source: National Oceanic and Atmospheric Administration (2019)

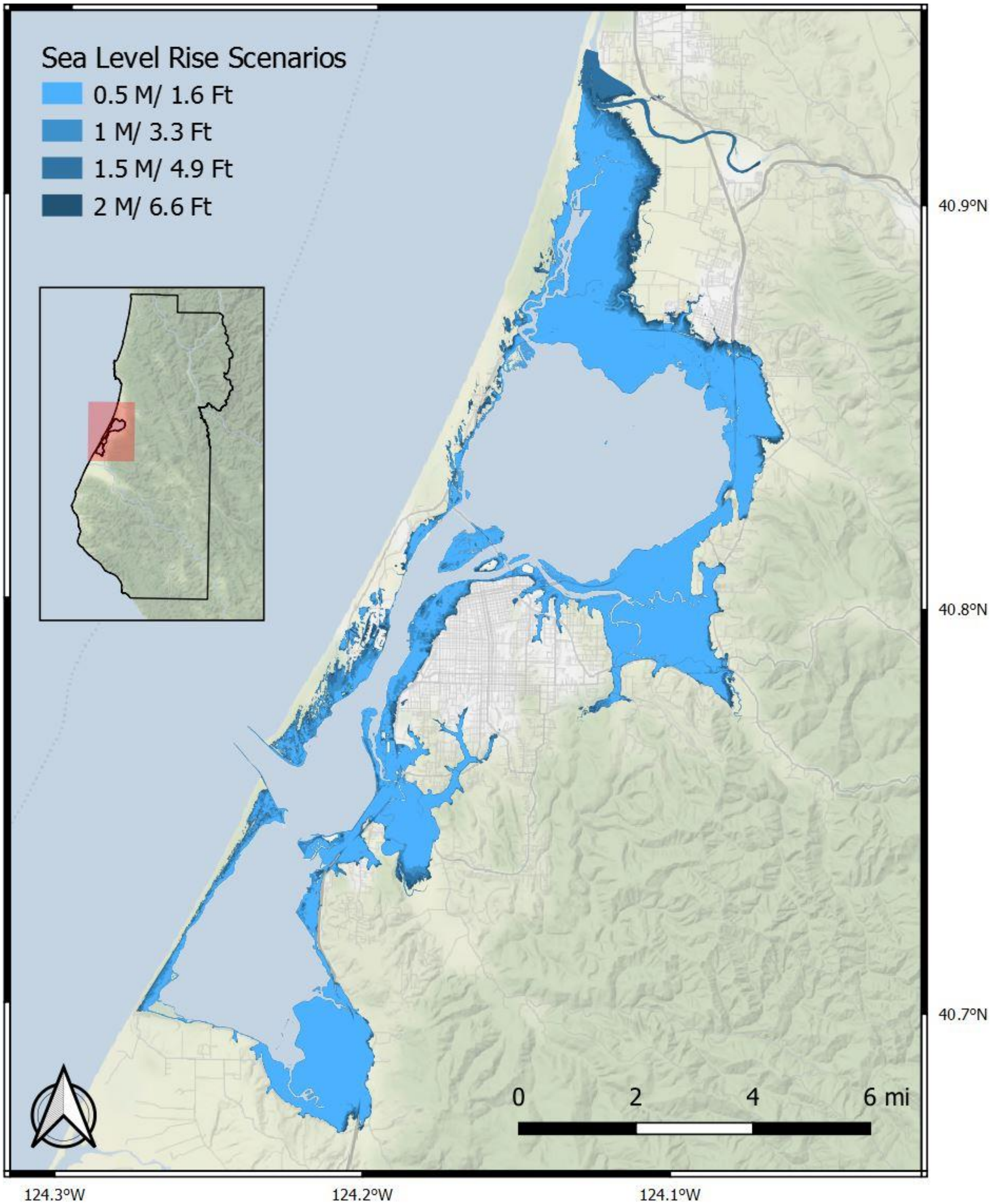

Figure 4 Humboldt Bay sea level rise projections at mean annual maximum water. Created by the Schatz Energy Research Center. Souces: Northern Hydrology & Engineering (2014b).

1.1.2: Wildfire

Wildfire severity and frequency will be affected by both climate and continued development and population growth. The variability of temperature and precipitation determines the severity and frequency of wildfires. Temperature and precipitation also determines the availability of fuels for wildfires, and short-term variability in weather impacts the combustion of existing fuels (Westerling et al., 2011). Due to climate change, these factors are shifting in the direction of making wildfires more severe and frequent.

According to the Forest Service wildfire database, approximately 85% of the wildfires in California from 1992 – 2015 were human-caused (Short, 2017). Although only a small percent (0.6%) of the wildfires were caused by power lines, recent wildfires such as the tragic Camp Fire show the crucial role of power utility companies in preventing and mitigating wildfires.

PG&E, pursuant to California Senate Bill 901, released a wildfire mitigation plan on February 6, 2019. In the plan, PG&E recognizes the increasing frequency and severity of wildfires and outlines programs to mitigate wildfires. PG&E states that its service territory contains more high fire-threat districts and high-density forest areas than the other utility company in the state (Pacific Gas and Electric Company, 2019). One specific program, Public Safety Power Shutoff, is discussed further in the Electricity Infrastructure section of this document.

Wildfire Severity

Median wildfire burn areas in California are projected to increase approximately 19%, 23%, and 43% by 2020, 2050, and 2085, respectively, under the Special Report on Emissions Scenarios (SRES) A2 high emissions scenario (Westerling et al., 2011). By 2085, Northern California burn areas are projected to increase over 100% under the same emissions scenario (Westerling et al., 2011). Humboldt County is projected to have one of the highest increases in burn areas in CA, with projections as high as 300% by 2085 under SRES A2 scenario (Figure 5).

In the absence of local studies or a higher spatial resolution of the projected wildfire impacts for Humboldt County, the CalFire fire hazard maps can be used to better understand the risks and vulnerabilities with increasing probability and severity of wildfires. The majority of the Humboldt Bay area is in a low fire-hazard severity zone, but the majority of the rest of Humboldt County is either in a high or very high fire-hazard severity zone (CalFire, 2007).

Wildfire Frequency

Across the State the percent changes[1] in the annual risk of large wildfires (larger than 200 hectares) compared to the 1961-1990 reference period are projected to increase 15% in the 2005-2034 period, and 53% in the 2070-2099 period. In the North Coast and Upstate California, the

[1] 100% percent change in probability means the probability doubles; e.g., 1% risk becomes 2% risk

disproportionate wildfire risk is highlighted by 90% percent increase in large wildfire annual risk in the 2070-2099 period (Westerling & Bryant, 2006). For Humboldt County, the annual risk (not percent change) of at least one large wildfire remains lower (i.e., lower than 0.06%) than the interior counties through 2099.

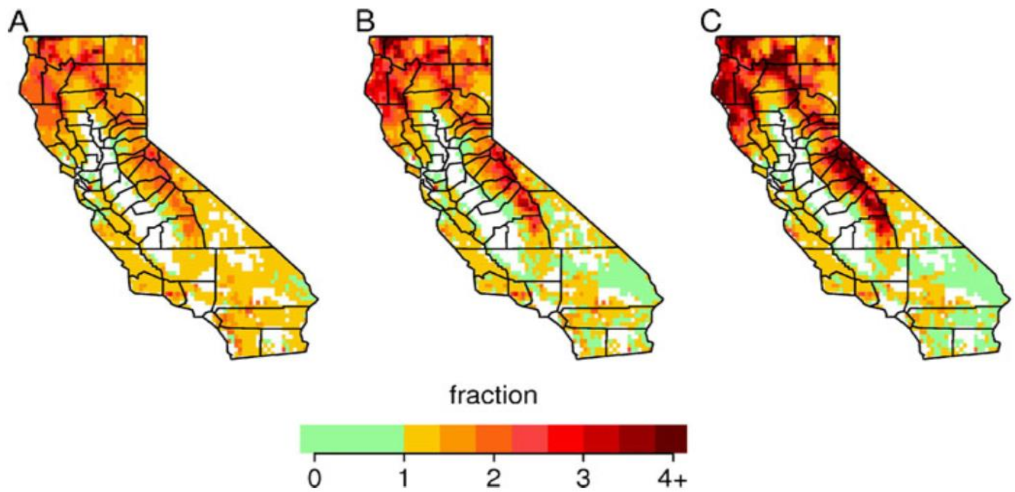

Figure 5 2085 Predicted wildfire burn area change in fraction compared to the reference period from 1960 to 1990 for three different climate models (i.e., NCAR PCM1, CNRM CM3, and GFDL CM2.1) under Special Report on Emissions Scenarios A2 high emissions scenario. Fraction of 1 indicates no change. Figure adapted from Westerling et al. (2011).

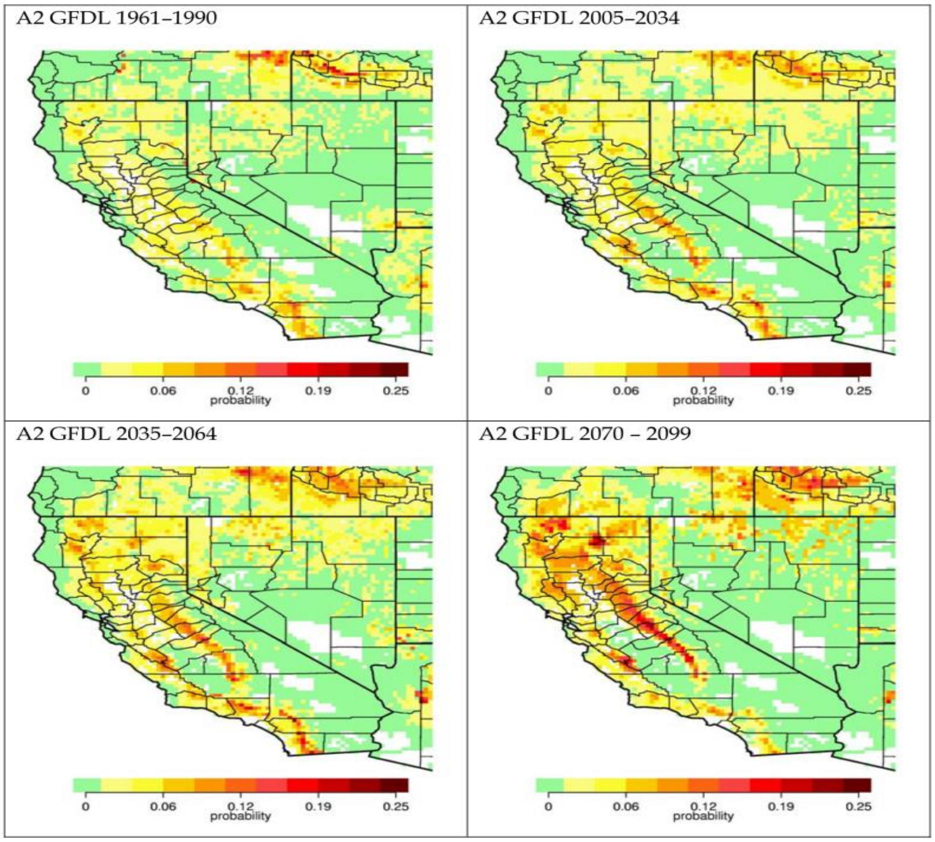

Figure 6 Annual Probabilities of at least one wildfire greater than 200 hectares occurring. Figure adapted from Westerling et al. (2006).

1.1.3: Extreme Precipitation Events

Climate change is expected to result in many types of extreme weather events. The primary concern for the Humboldt region is the frequency and intensity of extremely wet seasons and the associated impacts such as flooding and landslides. Climate change is expected to increase the frequency of extreme atmospheric river events which lead to high precipitation amounts over short periods of time (Dettinger, 2011). High precipitation events increase the likelihood of flooding and landslides.

Swain et al. modeled the potential change in frequency of 200-year sub-seasonal events (comparable to that which caused the Great Flood of 1862) (Swain, Langenbrunner, Neelin, & Hall, 2018). They show the change in frequency of the 200-year sub-seasonal events in Northern California to increase by approximately 50%, 100%, and 150% in 2035, 2055, and 2080 respectively (Figure 7). Interpolating the spatial plot of the model results, Humboldt County could see an increase of frequency between 150% and 250% by 2080. From their analysis, the researchers predict that three to four storms comparable to the 1862 flood could occur between now and 2100.

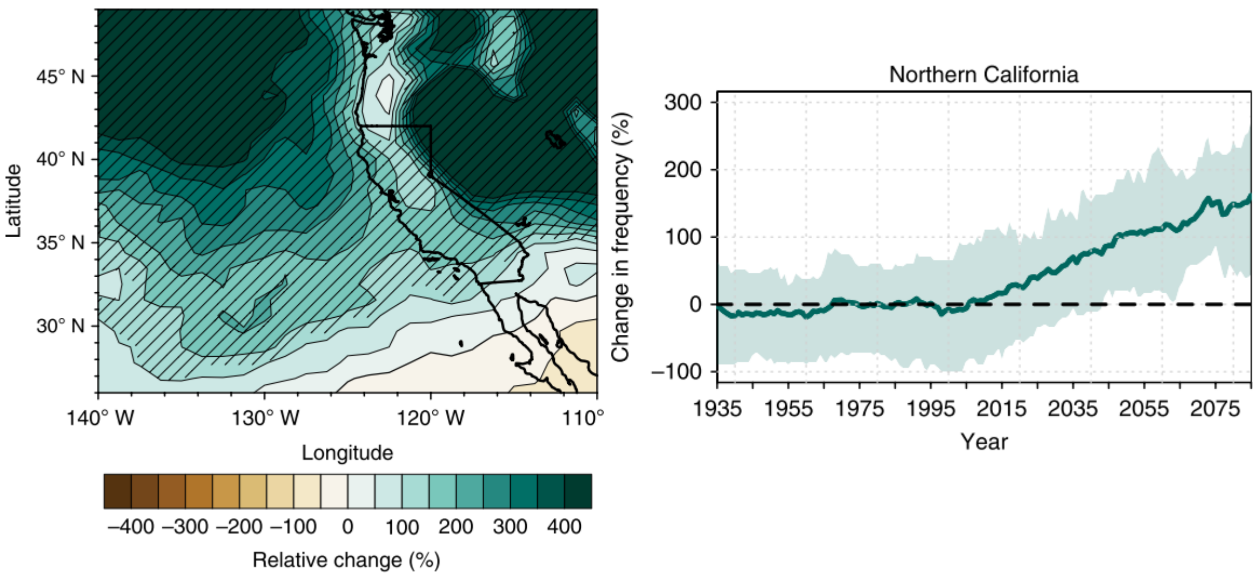

Figure 7 Relative change in frequency of extremely wet seasons. Left figure shows the value by the end of the century (2070 – 2100). Right figure shows year by year projection to 2085. Figures adapted from Swain et al. (2018).

The intensity of extreme weather events will also increase with climate change. Aghakouchak et al. projected the intensity and duration of precipitation events (i.e., 25-, 50-, 100-year precipitation events) for cities across California and found both to increase as the result of climate change (Aghakouchak, Ragno, & Love, 2018). Their results for Eureka are shown in Figure 8.

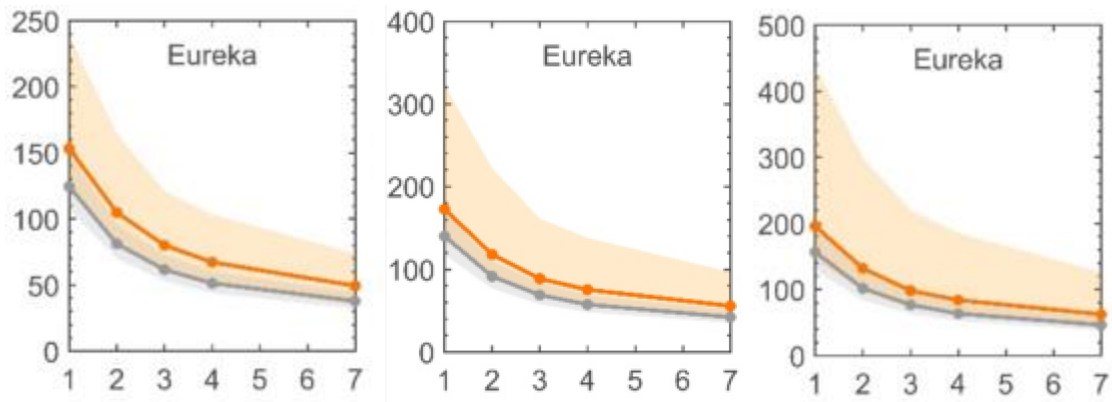

Figure 8 Intensity-duration-frequency curve of 25-, 50-, 100-year (left to right) precipitation events. The gray line is the current climate and the orange line is the RCP 4.5 projection. The horizontal axis represents storm duration in days. The vertical axis represents storm intensity in mm/day. Adapted from Aghakouchak et al (2018).

1.2: Predicted Impacts to Road Infrastructure and Transit Routes

Details on the potential impacts to road infrastructure and associated transit routes from various climate change effects are discussed. Impacts are discussed for key transit route corridors, and are presented regionally for Humboldt Bay and Humboldt County.

Adaptation Strategies

Integrate the information provided in this section into planning for:

- Depot and on-route charger locations
- Alternative transit routes
- HTA campus relocation, and near-term reinforcement.

See Section 3 for details regarding these strategies.

1.2.1: Key Corridors

Caltrans performed a pilot study on the vulnerability of the major corridors in District 1 including Humboldt County. The study estimated and scored the impact of climate change and the vulnerability on key corridors (Caltrans, 2014). The impacted highway segments for 2050 medium-high emissions scenario are listed in Table 5.

Table 5: High impact and vulnerability corridor segments. Data adapted from Caltrans (2014).

Highway Segment	Vulnerability (1-100)	Impact (1-10)	Factors
101 between south Eureka and Rio Dell	94	10	Potential tidal inundation
101 between Arcata and Eureka	77	10	Potential projected daily high tide
255 between Arcata and Eureka	50	10	Potential projected daily high tide
101 between Richardson Grove and Weott	62	8	Frequent historical slope movements
101 segment between McKinleyville and Berry Glenn	60	10	Complete failure caused potential erosion hazards
96 between Willow Creek and Orleans	50	8	Temporary failure caused historical slope movement and drainage issues
101 between Rio Dell and Pepperwood, Myers Flat and Garberville	30	8	Potential historic slope movement

1.2.2: Humboldt Bay Region

Sea Level Rise

In the Humboldt Bay area, the following affected road segments and stops are adapted from the sea-level rise projections and vulnerable asset assessment by Laird (2018). Only roads relevant to HTA's current routes are listed.[2]

- 2030 – High projection of 0.9 feet sea level rise:
    - **Humboldt Bay Coastal Planning Area (HBCPA):** Highway 101 segments around Humboldt Bay could become tidally inundated in the lower Arcata Bay segment and south segment (segment next to the Humboldt Bay Wildlife Refuge), affecting the travel routes through these segments. The same segments are currently also susceptible to 100-year flood events.
- 2050 – High projection of 1.9 feet sea level rise:
    - **HBCPA**:
        - Route segments on Highway 255 south of Liscom and Mad River Slough
        - King Salmon Ave and Spruce Point bus stops
        - Route segments on Highway 101 between College of the Redwoods and Fields Landing

[2] For other roads impacted by sea level rise, refer to the original study report section 3.3.2 and the National Oceanic and Atmospheric Administration Sea Level Rise Viewer (link in appendix)

        - Highway 255 at the segment east of the Mad River Slough affecting the Redwood Transit System route that traverses Highway 255
- 2070 – High projection of 3.2 feet sea level rise:
    - **HBCPA:** The routes mentioned above could become more severely and frequently inundated.
    - **City of Eureka:** The HTA campus in Eureka may start experiencing flooding when high tide corresponds with high storm precipitation (Figure 9 which shows the 100-year flood with 3.3 feet of sea level rise).
- 2100 – High projection of 5.4 feet sea level rise:
    - **City of Eureka & HBCPA:** The HTA campus and the routes mentioned above could become more severely and frequently inundated. In addition, the Eureka Transit Service route around the Herrick and Vance bus stop will become tidally inundated.

Between 2070-2100, a projected sea-level rise of 4.9 feet (1.5 meters) would inundate much of the Humboldt Bay waterfront and cause disruption to the current bus routes (Figure 10). This would also impact the main travel routes between Eureka and Arcata (Figure 11).

Figure 9: Flooding at HTA campus under 1-meter (2070 high projection) and 1.5 meters (between 2070 and 2100 high projections) sea level rise scenarios. Note mean annual maximum water (MAMW) layer indicates areas that have a high likelihood of annual inundations. Created by the Schatz Energy Research Center. Source: Google Satellite Map, Northern Hydrology and Engineering (2014b).

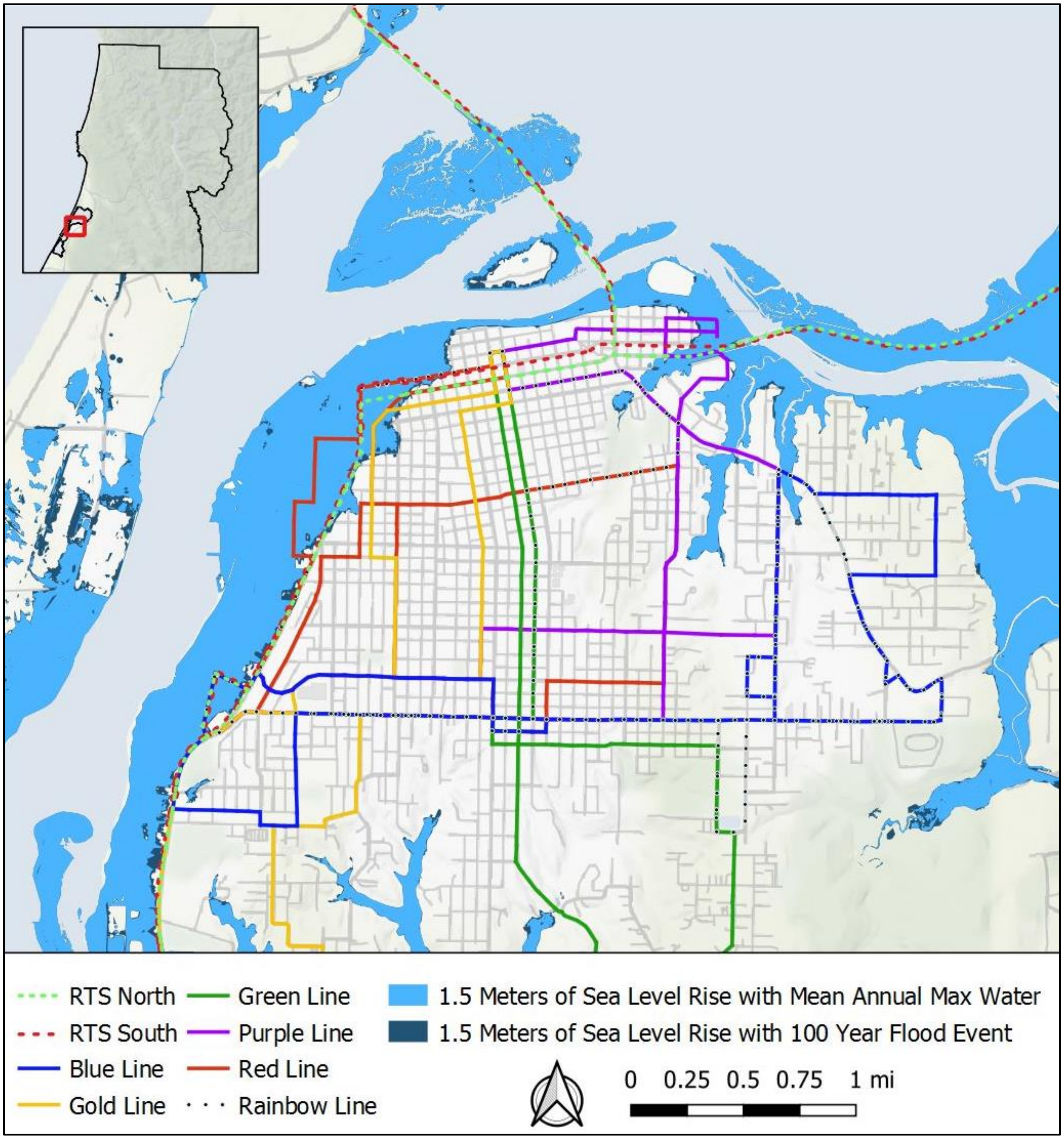

Figure 10. HTA routes in Eureka overlaid with 4.9 feet (1.5 meters) sea level rise with mean annual maximum water and 100-year flood. Created by the Schatz Energy Research Center. Source: HTA, Northern Hydrology and Engineering (2014b)

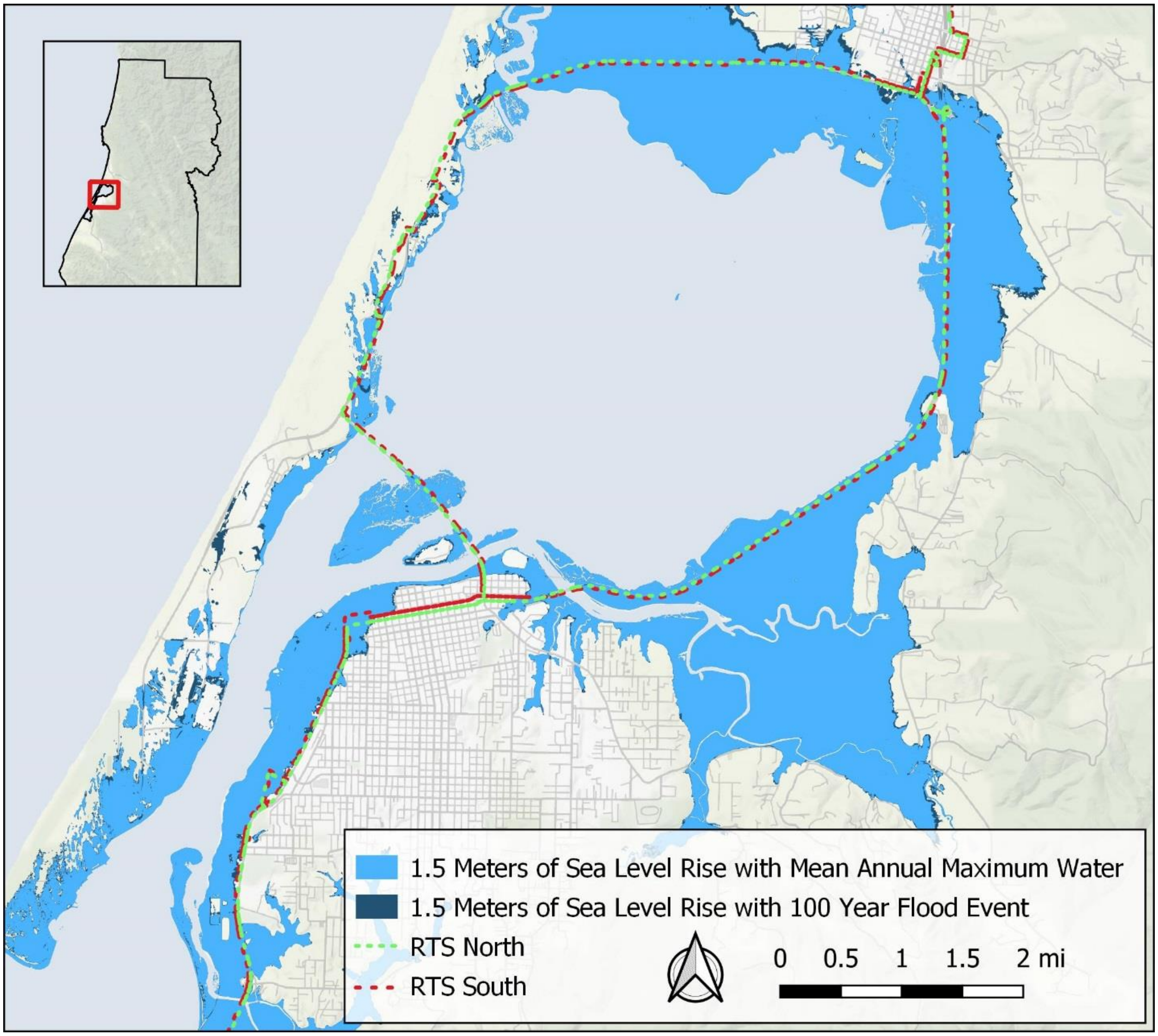

Figure 11 HTA RTS routes along the 101 corridor overlaid with 4.9 feet (1.5 meters) sea level rise with mean annual maximum water and 100-year flood. Created by the Schatz Energy Research Center. Source: HTA, Northern Hydrology and Engineering (2014b)

Flooding

More intense weather and frequent storm events compounded with sea level rise are expected to further increase the risk of flooding. Although no studies were found with specific locations prone to climate-change-induced flooding, the Federal Emergency Management Agency (FEMA) 100-year flood zone map can be used to identify potential flooding areas under extreme storm events with current sea level. The following routes travel through the FEMA 100-year flood zone and may be affected by the flooding events resulting from the wet sub-seasonal storm sequence as described by Swain et al. (2018): [3]

- **City of Arcata:** Arcata and Mad River Transit System GOLD ROUTE around Guintoli Lane
- **McKinleyville Community Planning Area & McKinleyville Coastal Planning Area:** Redwood Transit System route traveling on Highway101 north of Arcata, near McKinleyville High School, and south of Moonstone Beach
- **North Coast Coastal Planning Area:** Connection route with Redwood Coast Transit Authority near Big Lagoon and Orick
- **HBCPA:** Eureka Transit System (ETS) GOLD ROUTE near the Elk River Road and Herrick bus stop
- **HBCPA:** Redwood Transit System routes traveling through Humboldt Hill, King Salmon, Loleta, Ferndale
- **City of Eureka & HBCPA:** ETS GREEN ROUTE traveling on Bayshore Street near Bayshore Mall and Myrtle Avenue next to Harrison Avenue
- **City of Eureka:** ETS RED ROUTE traveling on Washington Street, Koster Street, and W 14th street
- **City of Eureka:** ETS RAINBOW ROUTE near the intersection between Broadway Street and 4th street

As discussed earlier, HTA campus could be inundated by 100-year flood events compounded with the sea level rises even though the campus is currently outside of the FEMA 100-year flood zone.

1.2.3: Areas Outside of the Humboldt Bay Region

Sea Level Rise

In our literature review, we did not find detailed sea level rise information or local road impacts outside of the Humboldt Bay area. National Oceanic and Atmospheric Administration's Sea Level Rise Viewer interactive map shows few impacts on the road infrastructure with the 2100 high sea level rise projection. However, there are segments of Highway 101 that are located near rivers or lagoons that could potentially be affected by the sea level rise and extreme storm events (e.g., segments passing through Mad River, Little River, Big Lagoon, and Redwood Creek).

Wildfire

Wildfire could also affect road infrastructure. The western portion of Highway 299 starting from Korbel Drive lies within a high fire-hazard severity zone and the rest of Highway 299 in the county lies in a very high fire-hazard severity zone. Highway 101 south of Rio Dell lies mostly

[3] For other roads in the FEMA 100-year flood zone refer to Humboldt County Web GIS

in the high fire hazard severity zone. With increasing wildfire probability and severity, roads and highways along Highway 299 and the south portion of Highway101 within Humboldt County could be exposed to higher wildfire risks.

Willow Creek Station is an important connection point between Trinity Transit and the Willow Creek line. Garberville is also an important destination. These locations are likely candidates for installing critical infrastructure to support electric buses. Garberville lies within a high fire-hazard zone, and Willow Creek lies within a very high fire-hazard zone.

Flooding

The following routes travel through the FEMA 100-year flood zone and may be affected by the flooding events resulting from the wet sub-seasonal storm sequence as described by Swain et al. (2018):

- Sections along the Redwood Transit System route traveling to and from Rio Dell and Scotia
- Bridgeville route on highway 36 between Hydesville and Carlotta and Bridgeville
- Sections along Southern Humboldt Intercity route

Furthermore, Ferndale, Myers Flat, and Phillipsville all have parts of the town centers under a 100-year flood zone. Willow Creek Station also lies within a dam inundation zone.

Landslides

Landslides are more likely to happen with increased precipitation. The California Geological Survey developed highway corridor hazard maps and study reports for Highway 101, between Wilson Creek and Crescent City, and Highway 299, between Blue Lake and Willow Creek. The Highway 101 study area is in Del Norte County and the report shows multiple landslides that could affect the areas of Cushing Creek, Del North Coast Redwoods State Park, Damnation Creek, and Last Chance Grade (Wills, 2000). The Highway 299 study area includes more than 200 landslide areas; The report summarizes the most active slides and recent pavement damage. Many of these landslides could result in lane and highway closure (Falls, Wills, & Hardin, 2006).

1.3: Predicted Impacts to Electricity Infrastructure

Humboldt County generates 60% of annual electricity and imports the remaining 40% (California Energy Commission, n.d.-a). Currently, the bulk of locally-generated electricity comes from the PG&E-owned Humboldt Bay Generating Station (85%), which is powered by natural gas. The remaining 15% of the local generation comes from biomass power plants and hydroelectric power plants. Imported electricity is carried over four transmission circuits. The majority of imports are carried through two 115kV circuits, which run from Cottonwood and roughly follow Highway 36 and Highway 299. The remaining imports are carried through two lower capacity 60kV circuits that roughly follow Highway 101 from Garberville and along Highway 299 from Trinity County (Zoellick, 2013).

Adaptation Strategies

Integrate the information provided in this section into planning for:

- Depot and on-route charging infrastructure resiliency for providing service continuity.
- Monitoring and tracking utility plans and annual reliability reports for updating outage duration projections as needed.

See Section 3 for details regarding these strategies.

Local generation is critical to meeting local electricity needs. The combined capacity of the four circuits described above is approximately 70MW (Zoellick, 2013), roughly 41% of the county's current peak demand of 170MW (Humboldt County, 2017). The combined capacity of currently operating biomass power plants is 47.5 MW (California Energy Commission, n.d.-b). The county is dependent on the Humboldt Bay Generating Station to meet peak power demands.

The county is supplied by one major natural gas supply line that comes from a compressor station in Gerber in the Central Valley, and roughly follows Highway 36. PG&E reports this single line is capable of meeting current local needs (Zoellick, 2013).

1.3.1: Impacts

Humboldt County is at the end of PG&E's electrical and natural gas supply grids. These supply grids have minimal to no redundant infrastructure, which makes Humboldt an energy island. Any significant damage to this infrastructure will significantly impact the majority of the county.

In 2017, the five-year average System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) for Humboldt, including planned outages and major event days, was 955.3 minutes and 2.526 occurrences respectively (PG&E, 2018). This means the average customer experiences roughly two outages a year totaling roughly 6.3 hours for each outage (divide SAIDI by SAIFI). Excluding major event days (e.g., major storms, wildfires), Humboldt Service Division is ranked highest in all service divisions for both SAIDI and SAIFI, meaning the division's electricity infrastructure is currently the most unreliable among all PG&E service divisions. Specifically, Garberville and Hoopa circuits were ranked as top 1% worst-performing circuits in PG&E service territory both in terms of frequency and duration interruptions (PG&E, 2018).

Major reports suggest that extreme weather events, including wildfire, are the primary cause of power outages (American Society of Civil Engineers, 2017; Department of Energy, 2017; Zamuda et al., 2018). These reports also suggest that power outages will increase in frequency and duration due to climate change related weather events, wildfires, and sea level rise. Historically, the Department of Energy's quadrennial energy review shows that outages in the Humboldt area are mainly caused by winter and thunderstorm events (United States Department of Energy, 2017). In 2017, 45 of the 56 outages in Humboldt County were due to falling trees. A major winter storm on January 3, 2017, contributed to significant outages n Hoopa and Willow Creek service areas, and a high wind event on May 6 caused numerous outages across the county (PG&E, 2018)

Weather Impacts

With climate change and increases in storm intensity and frequency, SAIDI and SAIFI could both increase further. Customer Average Interruption Duration Index (CAIDI)—SAIDI divided by SAIFI—is the average outage duration per event per year. CAIDI is used to investigate the potential change in outage frequency and duration from climate change impacts. Using the intensity, duration, and frequency increase in precipitation events projected by Aghakouchak et al. and Swain et al. discussed above, CAIDI could increase to approximately 7.9, 8.5, and 9.0 hours in 2035, 2055, 2080 compared to 6.5 hours in 2017.[4] Not only could the power outages last longer, they could also become more frequent as discussed above (Swain et al., 2018). Furthermore, a factor not considered in the above CAIDI value is that the Humboldt Bay Generation Station could become tidally inundated with 4.9 feet of sea level rise (the 2100 high projection) creating further challenges for reliable local power (Laird, 2018).

Wildfires would likely further increase the outage frequency and/or duration. The October 2017 Northern California wildfire storms resulted in an average system-wide incident-specific CAIDI of approximately 31 hours. The wildfires were not burning in Humboldt County, but still resulted

[4] 10-year average SAIDI with and without major event days (MED) and SAIFI with and without MED were calculated. The total MED outage time per customer is the difference between the average SAIDI with and without MED. The total MED outage frequency per customer is the difference between the average SAIFI with and without MED. The total MED outage time was divided by total MED outage frequency to get single MED outage time. Assuming all MED are storm events, the single MED outage time and frequency is scaled up with the projected increase in storm frequency and intensity. The storm frequency factors (1.5, 2, 2.5) and intensity factors (1.25) were multiplied by the single MED outage time to get the projected MED only SAIDI for 2035, 2055, and 2080. The projected MED only SAIDI is added to the 10-year average SAIDI without MED and divided by projected MED only SAIFI plus 10-year average SAIFI to derive the projected CAIDI.

in an average incident-specific CAIDI of approximately 13 hours in the county (PG&E, 2018). With the projected wildfire intensity and frequency discussed in the wildfire section above, the system average incident CAIDI associated with specific wildfire events could increase from 37 hours in 2020 to as much as 44 hours in 2085.[5]

Further Impacts by PG&E Wildfire Mitigation Program

The duration and frequency of power outages could further change as the result of the PG&E's Public Safety Power Shutoff (PSPS) program. The purpose of PG&E's PSPS program is to reduce the likelihood of wildfire by preemptively shutting down either or both transmission and distribution lines in zones deemed at risk. PG&E updated and expanded the PSPS program in the 2019 Wildfire Mitigation Plan to include all transmission and distribution lines up to 500 kV in high fire-threat areas (i.e., California Public Utility Commission's Tire 2 & 3 High Fire Threat Districts [HFTD]) (PG&E, 2019). The majority of the county's transmission circuits are located in Tier 2 and Tier 3 HFTDs. A significant amount of distribution infrastructure in southern and eastern areas of the county are also located in either Tier 2 or 3 HFTDs (Figure 12).

With the current power line locations and the expanded PSPS program, CAIDI could further change beyond the level discussed above. The expected CAIDI increase is uncertain, but according to PG&E, PSPS programs can last several days (PG&E, n.d.).

[5] California statewide wildfire intensity factor of 1.19 and 1.43 (Westerling et al., 2011) were used for 2020 and 2085. System average wildfire incident CAIDI was multiplied by the intensity factor to derive the projected system average wildfire incident CAIDI.

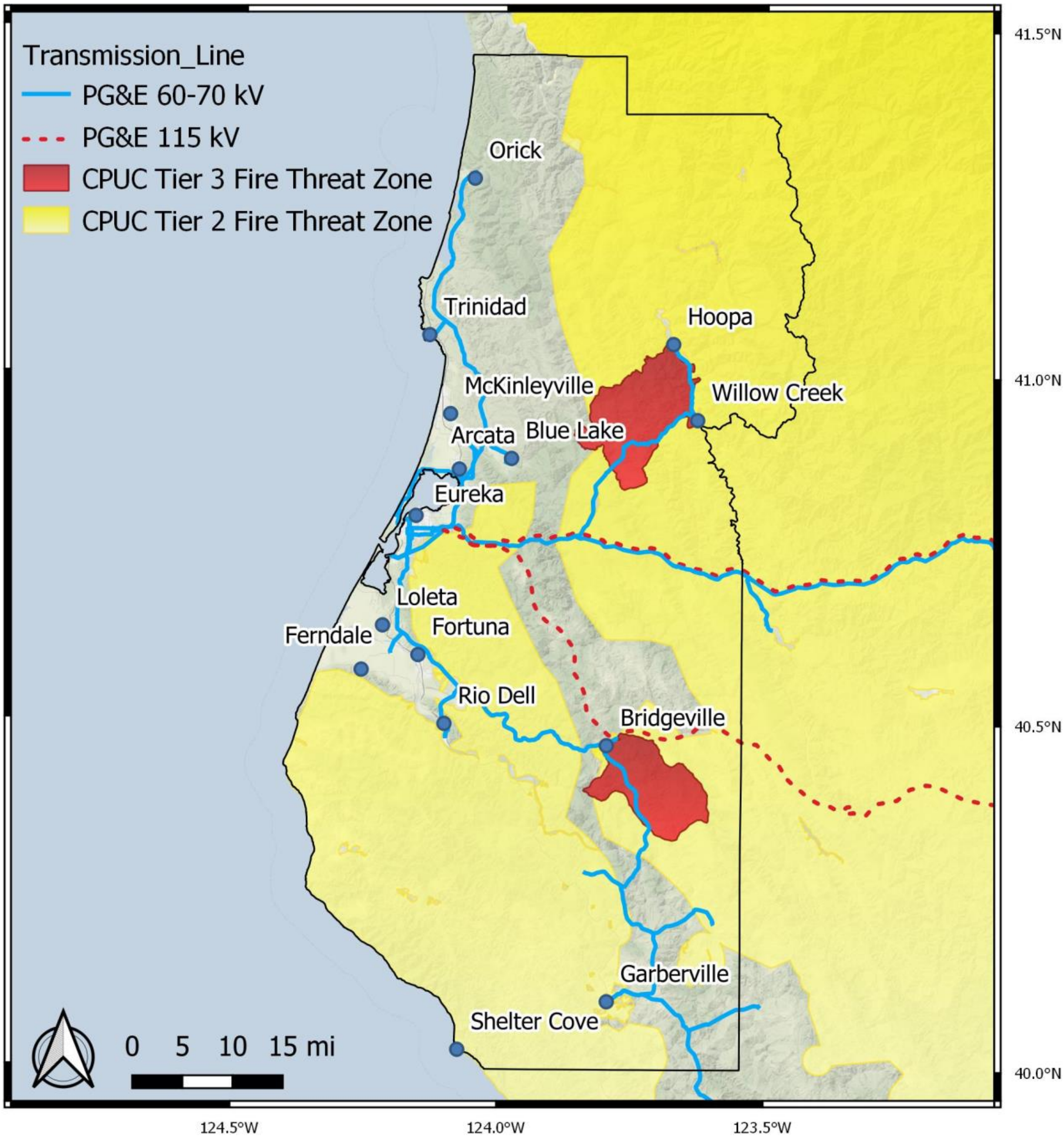

Figure 12 Transmission and main distribution circuits for Humboldt County overlaid with CPUC Fire Threat Map. Created by the Schatz Energy Research Center. Source: Transmission line data obtained from the California Energy Commission.

1.4: Predicted Impacts to Communication Infrastructure

Communication infrastructure is considered because it is integral to operating buses and bus-charging technology. Software systems and algorithms that manage fleet charging are often cloud-based, and also typically require bus telematics that are typically transmitted over cellular networks. In addition, HTA's current radio communication system uses radio over internet protocol technology, which utilizes three repeaters connected to a private IP network in order to extend communication range.

Adaptation Strategies

Integrate the information provided in this section into planning for:

- Communication service provider infrastructure redundancy, both for existing communication services, and for charging infrastructure communication requirements
- Internal communication pathway redundancy
- Public communication redundancy

See Section 3 for details regarding these strategies.

1.4.1: Impacts

Internet communication infrastructure, like our energy supply infrastructure, also lacks redundancy. There are only two main fiber-optic cables—one along Highway 101 and one along Highway 36—that supply broadband services. Damage to either cable could affect the majority of the county (California Center for Rural Policy, 2014). A third fiber optic cable is currently being constructed along Highway 299. The Digital 299 Project will connect the Humboldt County fiber network to the Redding and Cottonwood areas (Inyo Networks, n.d.).

In addition, much of our cellular communication infrastructure is located in high or very high fire-hazard zones (Figure 13).

Sea Level Rise Impacts

Although no specific studies were found on potential local impacts, a national study by Durairajan et al. suggested 4,000 miles of fiber conduit and 1,000 nodes around the nation could be surrounded by water in 15 years (Durairajan, Barford, & Barford, 2018). The same study shows that current main fiber-optic cables for the county are located away from the coast except for the sections in Eureka. The cable along Highway 101 is connected to San Francisco, which the study ranked in the top five for climate change risk for broadband node assets. This suggests a relatively smaller likelihood of local infrastructure being compromised. However, due to the interconnected nature of the internet, compromised infrastructure elsewhere (e.g. San Francisco) could impact the county locally.

Wildfires Impacts

As wildfire frequency and intensity increases, internet service could potentially be negatively impacted on a large geographic scale. According to the study by North Bay/ North Coast Broadband Consortium (2018), the Mendocino, Napa, Sonoma County firestorms in 2017 left an average of 73.5% of survey respondents without cellular and internet service. Future wildfires in and around Humboldt County could result in similar cellular and internet service outages.

Since HTA's radio communication system does not rely on the public network, it should be unaffected by the interruption to the main fiber optic cables[6]. However, the repeater infrastructure could potentially be affected by the increasing frequency and severity of wildfires. Of the three current repeater locations relied upon by HTA, the Horse Mountain and Mount Pierce repeaters are in or near high fire hazard zones (Figure 13).

[6] Private communication with HTA's communication service provider.

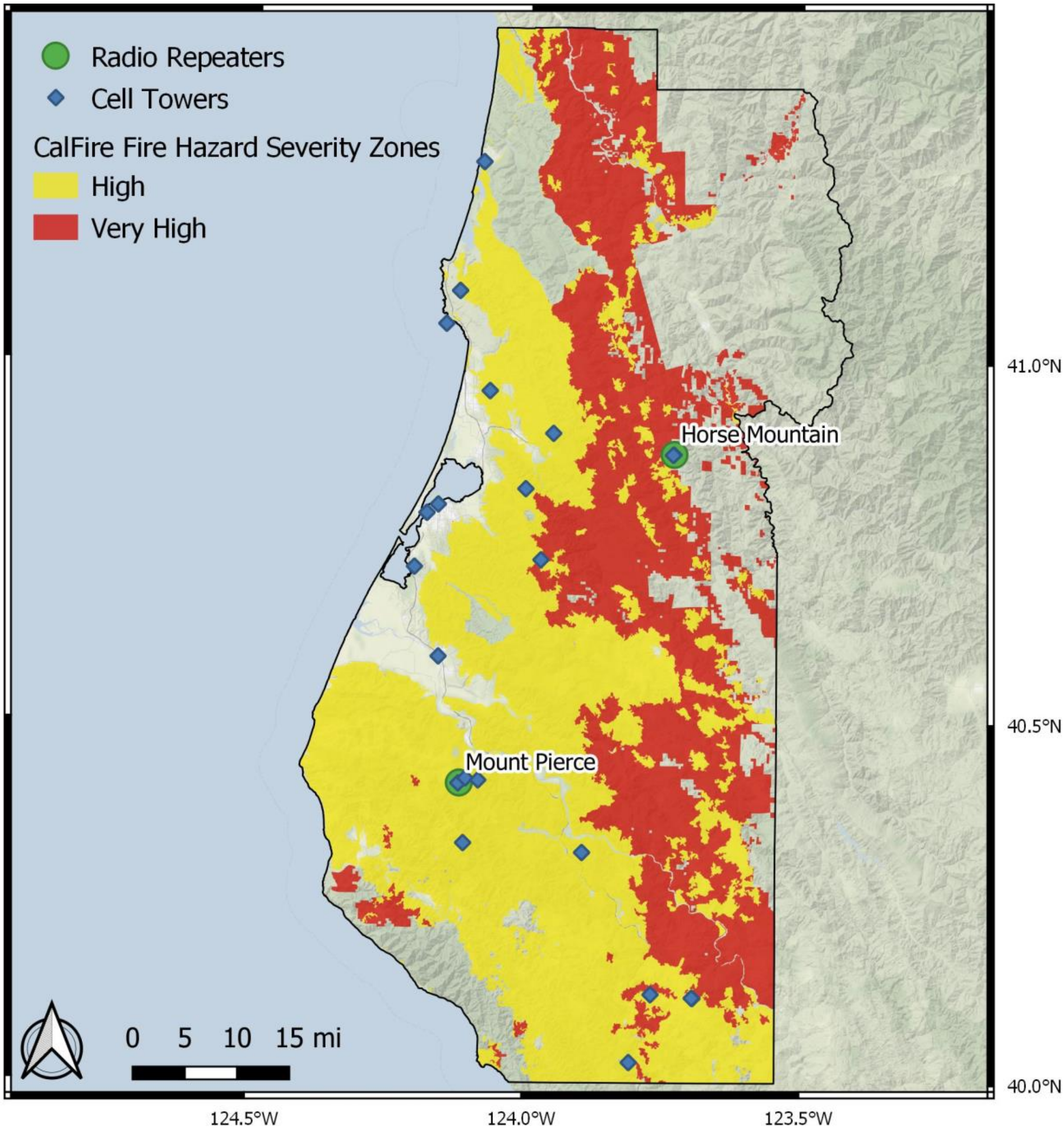

Figure 13 Humboldt County cell tower and radio repeater locations overlaid with CalFire Fire Hazard Severity Zone Map. Created by the Schatz Energy Research Center. Source: Cell tower data obtained from Humboldt County GIS website.

2: Resiliency and Emergency Services

Transit agencies can play a crucial role in the emergency evacuation process, especially for the transit-dependent population with limited transportation means. A literature review on Emergency Operations Plans (EOP) of large urbanized areas by the Transportation Research

Board (2008) highlighted the lack of focus on transit agencies' role in evacuation operations despite the critical role they play. The Transportation Research Board recommended a greater emphasis on evacuation in emergency planning as well as incorporating transit agencies into all four phases of the emergency plan—mitigation, preparedness, response, and recovery. Transit agencies could bring a cross-jurisdictional and regional perspective to the emergency planning table and greatly enhance the efficiency and efficacy of evacuation planning (Transportation Research Board, 2008). In addition, as transit agencies begin to electrify fleets they are not limited to evacuation operations during emergencies; their role can expand to support efforts to restore electricity service during outages through resilient infrastructure design and vehicle-to-grid opportunities.

As part of the California Air Resources Board's Innovative Clean Transit regulation, transit agencies need to generate compliance plans. Transit agencies can leverage these compliance plans to coordinate with emergency management agencies and transportation plan update efforts.

2.1: Current Transit Agency Emergency Responsibilities

Under California's Standardized Emergency Management System, transit agencies could potentially fall under both operation and logistic divisions. The operation division is involved in field operations in accordance with the Incident Action Plan, while the logistic division provides facilities, services, personnel, equipment, and materials to support the incident (State of California, 2017).

2.1.1: CA Emergency Operation Plans & Emergency Functions

Municipal emergency operation centers (EOC) often use the State's Emergency Function (EF) framework, which follows the Federal Emergency Support Functions, to create a structure for interagency coordination and support. The most relevant EF to transit agencies is EF #1Transportation, which directs entities to "work together within their statutory and regulatory authorities to effectively and efficiently mitigate, prepare for, respond to, and recover from emergencies" (CalOES, 2013). Under EF #1, regional transit agencies are listed as stakeholders and more specific responsibilities are usually defined in municipal and/or county EOPs.

As transit bus fleets become electrified, transit agencies could also become more involved in EF #12 Utilities, which is intended to "collaboratively provide emergency management expertise, support and services related to utility infrastructure system damage and outage response, as well as to restoration of service" (CalOES, 2013b). Specific responsibilities could also be defined in municipal and/or county EOPs.

2.1.2: Humboldt County Emergency Operations Plan

Consistent with the Transportation Research Board's findings, Humboldt County's current EOP has a limited discussion of transit agencies' responsibilities during emergency events. Transit agencies are also not listed as a responsible local agency for any of the 18 EFs (e.g., transportation, utilities). The only mention of transit agencies is under the Logistic Function Transportation Unit Leader checklist; during the operational phase of the emergency, the transportation unit is to establish contacts with local transportation agencies for evacuation and other operations, as needed.

The Humboldt County Emergency Services Manager confirmed that transit agencies receiving public funds are required to provide disaster transportation resources as needed. Humboldt County does not currently mandate transit agencies to reserve fuel for emergency operations. It is worth noting that the county is currently updating the EOP and will include more information on evacuation transportation. Furthermore, the Humboldt County Association of Governments (HCAOG) intends to continue including County OES in future updates to the Regional Transportation Plan.

2.1.3: Requirements of Recipients of Formula Grants for Rural Areas

As a Formula Grants for Rural Areas (section 5311) recipient agency, HTA is required to comply with the Transit Asset Management (TAM) rule and is deferred from the final rule of Public Transportation Agency Safety Plan (PTASP). For 5311 recipient agencies, the PTASP would still need to be implemented, but is drafted by the state. Neither the TAM nor the PTASP require or recommend an emergency response responsibility for bus transit agencies. Both FTA and Caltrans recommend a System Security and Emergency Preparedness Plan (SSEPP), but neither mandate transit responsibilities.[7]

2.1.4: Paratransit & Dial-A-Ride

City Ambulance of Eureka (CAE) is the contracted service provider for the access and functional needs (AFN) paratransit service for HTA. The service is available for the cities of Eureka, Arcata, and McKinleyville. The AFN population includes those with physical or developmental disabilities, elders, limited English proficiency, low-income, homeless, other transit-dependent population, and pregnant women. Each of these groups has its unique needs in the emergency operation and evacuation processes.

CAE has their own emergency operation and evacuation plan and is mandated to evacuate paratransit users. During an emergency where an EOC is activated, CAE will communicate with the EOC through its communication center, although CAE is not listed in the EOP.

Other paratransit providers in the county include Fortuna Transit and Blue Lake Rancheria. There are other dial-a-ride service providers throughout the county. Each service provider may have its own emergency operation and evacuation plan.

[7] Information from the Public Transportation Agency Safety Plan Final Rule Fact Sheet, February, 2019.

2.2: Guidelines for Transit Agency Emergency Response & Preparedness

The Federal Transit Administration Emergency Relief Manual provides considerations for transit agencies to implement in their emergency planning.[8] In summary, transit agencies should:

- develop their own EOP with recordkeeping policy;
- train staff on the emergency plan; engage with local EOCs and participate in drills;
- engage with local governments and community health and human service agencies to identify special needs and transit-dependent populations and devise corresponding evacuation plan;
- establish alternative evacuation routes for advance-notice emergencies such as floods and tsunamis;
- align asset and capital project management with resiliency to future climate and weather-related hazard (Federal Transit Administration, 2015).

Many recommendations in the FTA manual were echoed in other reports such as the Caltrans' Transit Emergency Planning Guide and the Transportation Research Board report (California Department of Transportation, 2007; Transportation Research Board, 2008). One common recommendation across all documents was for transit agencies to become a full partner with emergency management agencies and increase their role in the emergency command structure.

In regard to AFN services, with the anticipated extreme weather events associated with climate change, it is important to identify alternative routes and evacuation plans, and communicate these to transit-dependent passengers—especially those in more vulnerable areas.

The *Humboldt County Regional Transportation Plan* (Humboldt County Association of Governments, 2017) outlined the best practice for emergency response. The report recommended

- drafting a memorandum of understanding with emergency responding agencies;
- leveraging the information transit and paratransit agencies have for the individuals who most need transportation assistance; and
- updating route conditions.

[8] This paragraph highlights a few recommendations. Refer to the original report for a complete list of recommendations.

2.3: Emergency Response Challenges and Opportunities for Electrified Fleets

2.3.1: Challenges

Alternative fuel vehicles (AFV), including electric vehicles, are not yet widely adopted by public agencies and first responders; therefore, there is a lack of AFV-specific emergency plans. The Initiative for Resiliency in Energy through Vehicles (iREV), a working group under the National Association of State Energy Officials, conducted a baseline study investigating the role of AFVs in current EOP at state and municipal levels. It found that AFUs are largely unmentioned for both state and municipal EOPs (Initiative for Resiliency in Energy through Vehicles, 2014).

2.3.2: Opportunities

Transit fleets can leverage the work that is already being done to fuel-switch away from diesel. With the resources cited in this report, transit agencies can include emergency planning tasks in grant applications that support efforts to integrate transit agencies into emergency planning operations.

As transit agency bus fleets electrify, transit agencies can also play a more prominent role in emergency responses by expanding beyond mobility and evacuation operations. For example, reduced diesel consumption can help mitigate petroleum disruptions and shortages. In addition, electrical infrastructure installed to support fleets can be designed to provide energy islands to support emergency operation centers, or relieve demand on the grid while PG&E addresses damage to utility infrastructure. Vehicle-Grid-Integration design concepts can also be used to leverage electric buses as sources of electricity. For example, PG&E used a plug-in hybrid vehicle to power an emergency shelter during the Calaveras County wildfire in 2015 (Initiative for Resiliency in Energy through Vehicles, 2016).

iREV Pilot Studies

The iREV pilot program examined the opportunity for states and municipalities to increase resiliency to natural disasters and fuel and energy emergencies by incorporating AFVs, including electric vehicles. The reports created by this program emphasized the importance of a diversified fleet of mandatory emergency response vehicles as well as voluntary fleets from various entities (e.g., transit agencies, utility companies, school districts, etc.). The reports suggest the emergency planning entity (i.e., OES) to include

- specific language on AFVs in all phases of emergency planning;
- facilitate communication between AFV fleet managers to create an inventory of AFV fleets willing to assist in emergencies; and
- catalog available fueling infrastructure (e.g., fast EV charging ports, compressed natural gas stations, etc.) (Horton, 2010b, 2010a).

Although all-electric fleets are well suited to support a petroleum shortage emergency, this benefit is replaced by the threat of electricity outages. This challenge highlights the need to incorporate back-up generation systems into the electrical infrastructure that supports transit fleets. These systems can be traditional fossil-fuel generators, although this is not recommended as that fuel is better used in a diesel bus or other diesel vehicles. Battery storage systems with integrated solar generation provide a cleaner and more resilient back-up system.

3: Adaptation Strategies

Recommended adaptation strategies are discussed in this section and are organized into the recommended action timeframe (i.e., Now, Near Term, Long Term). They are largely informed by the main adaptation strategies identified for metropolitan transit agencies that came out of various FTA pilot projects (FTA, 2014). These are summarized in Appendix A.

Recommended strategies are broken into the following categories:

- Systemwide: generally, apply to transit planning and operations.
- HTA Campus: apply to the main HTA campus, both current and future locations. This includes charging infrastructure located on the campus.
- On-Route Charging Infrastructure: apply to charging infrastructure not located on the HTA campus. This includes critical transit hubs such as Willow Creek and the Arcata Transit Center.
- Roads and Service Routes: apply to road infrastructure and route planning.

In addition, suggested for each category are lead agencies who should be tasked with spearheading the recommended adaptation strategies.

Table 6: Summary of adaptation strategies.

Strategy ID	Lead Agency	Applicable Category			
		System-Wide	HTA Campus	On-Route Charging Infrastructure	Roads and Service Routes
A	HTA	X			
B	HTA	X			
C	HTA & OES	X			
D	HTA	X			
E	HTA		X	X	
F	HTA & OES			X	
G	HTA	X			
H	HTA		X		
I	HTA		X	X	
J	HTA & Public Works & Caltrans		X		
K	HTA			X	
L	HTA & Caltrans				X
M	HTA & PG&E	X			
N	HTA & OES	X			
O	HTA			X	
P	HTA				X
Q	HTA & county office	X			
R	HTA	X			

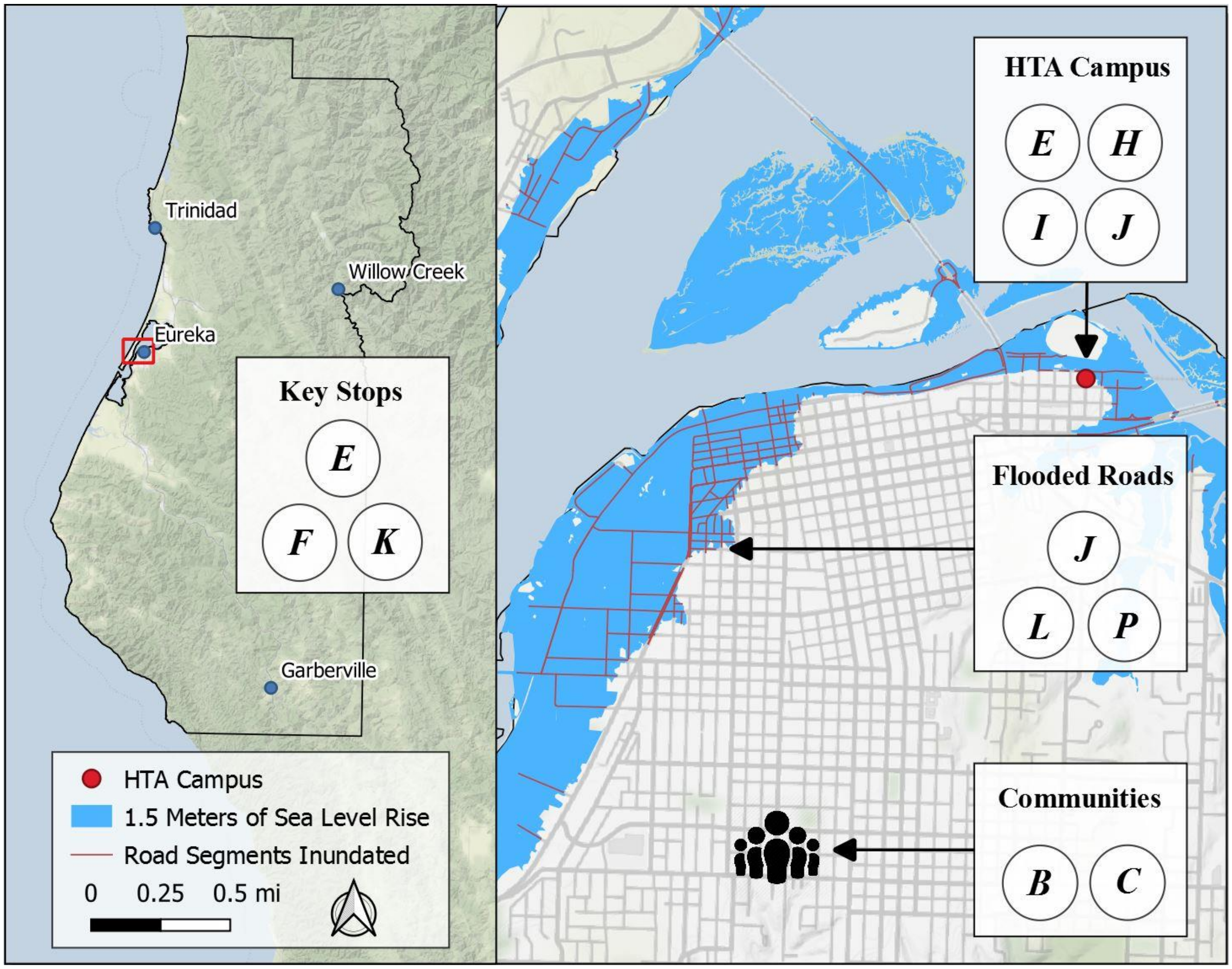

Figure 14 Climate change adaptation strategies for Humboldt Transit Authority. Sea level rise of 1.5 meters (high projection between 2070 and 2100) shown at mean annual maximum water level. Not all strategies are shown on map. Created by the Schatz Energy Research Center. Source: Northern Hydrology and Engineering (2014b)

3.1: Now

A. Incorporate climate vulnerability and resiliency into current transit operation and asset management practices. This means addressing climate change should be considered side-by-side with other system performance objectives such as safety, mobility, and the state-of-good-repair.
B. Consider community resiliency and equity in the adaptation plans and projects as emphasized in the Planning and Investing for a Resilient California (PIRC) report. Some adaptation strategies suggested below (e.g., altering routes both temporarily and permanently) would have a higher impact on the Access and Functional Needs (AFN) population. Participatory process should be utilized to involve the wider community. For more resources, see the equity checklist appendix in the PIRC report.

C. Identify, engage, and plan for the AFN population for emergency situations. Specific actions include communicating emergency alternative routes, developing memorandums of understanding with other transportation service providers (e.g., paratransit, school districts, hospitals, first responders) to assist in the evacuation of AFN population, considering the use of AFN registries etc.
D. Integrate Life-cycle cost accounting (LCCA) into the planning process for new transit infrastructure. For example, LCCA over the charging infrastructure's lifetime (charger life time approximately 12 to 15 years)[9] should be based on the future climate projections and include the maintenance and operating costs associated with climate impacts. When applicable, the LCCA should also consider the new electricity infrastructure that has to be built to support the chargers by factoring in the extended project lifetime and additional initial costs.
E. Leverage resiliency infrastructure options (e.g., back up generation, microgrids, etc.) to support planned infrastructure identified as critical assets (e.g., key charging locations). The resiliency infrastructure needs to account for projected CAIDI estimations (discussed in Section 2) of at least 7.9, 8.5, and 9.0 hours in 2035, 2055, and 2080 respectively. Willow Creek Station is a critical location to consider for resiliency infrastructure because it has the potential of co-benefiting other transit agencies serving as the intercounty connection station. Additional attention is needed for the infrastructure relying on the specific distribution circuits in Garberville, Trinidad, and Hoopa[10] which are among the least reliable circuits in PG&E's service territory.
F. Coordinate with government and municipal critical facilities to consider adding backup charging infrastructure. For example, IndyGo, a transit agency in Indianapolis, is actively planning for energy resiliency by identifying emergency operation facilities for back-up charging locations (Alex Roman, 2018).
G. Update the internal HTA emergency response standard operating procedure to better react to extreme climate and weather events.

3.2: Near Term

H. Start the planning process to move the campus outside projected flood-prone areas by 2050. The HTA campus is exposed to the risk of flooding caused by both sea level rise and extreme precipitation events. The HTA campus is currently not located in the FEMA 100-year floodplain. But with sea level rise compounded by more concentrated precipitation, the campus will be at risk of flooding within 50 years.

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[9] According to Proterra, electric bus charging station lifetime is approximately 12 to 15 years.

[10] See Table 160 and Table 161 in the Pacific Gas & Electric Company's 2017 Annual Electric Reliability Report for more details on circuit name, circuit miles, and reliability index.

I. Assess and protect HTA campus and infrastructure with strategies such as elevating assets, building flood protection infrastructure, improving storm water management through permeable pavement, storm water ponds, and other similar measures.
J. Collaborate with the city, County Public Works Departments, and Caltrans to ascertain that proper measures are taken to prepare for increased precipitation intensity and ensure 1) storm sewers surrounding the present or future campus and key infrastructure are kept clear and 2) streets properly storm-proofed.
K. Ensure the chargers are sited at locations with lower flooding and wildfire risks. This strategy should improve transit reliability and reduce the LCCA of the chargers by avoiding excess maintenance and operating costs.
L. Work with Caltrans to identify, strengthen, and protect key road and route segments. Example strategies include 1) hardening key road segments to route operation that are more prone to landslides, and 2) improve storm water drainage to key road segments prone to flooding.
M. Work closely with PG&E on issues related to the PSPS program. HTA should ensure advance notices for the PSPS events are given to allow for adequate operation planning and public communication regarding possibly altered service routes. Transit service is currently not considered as a critical service identified by PG&E. Working with PG&E to identify HTA as a critical service would be beneficial, as PG&E will provide additional services and support programs during PSPS events.
N. Work with the County OES to align the emergency operation efforts by leveraging the electric bus fleet advantages. Additionally, recognize and prepare for the potential of using the electrified bus fleet for emergency power supply in emergency operations. HTA should also address the electric bus limitations and challenges with OES.
O. Take steps to ensure the communication system required by bus chargers is reliable by choosing a provider with infrastructure redundancy. For example, if the on-route chargers communicate with the campus via broadband internet service, HTA should consider the service provider with multiple fiber optic cables entering the county. Additionally, the charger should able to transfer data through a backup communication channel such as the cellular network.

3.3: Long Term

P. Identify alternative routes for flood prone transit route segments. If alternative routes substantially differ from regular routes, planned on-route chargers may not meet the BEB charging demand. In this case, additional charging infrastructure must be planned. In the near term while transit agencies still have diesel buses in operation, the alternate routes could be served by diesel buses during the time requiring rerouting.
Q. Integrate communication of temporary route changes into existing rider outreach channels. HTA needs to effectively communicate the alternative routes to riders using various communication options. The communication channels should include public

announcement tools such as radio and TV channels, social media, etc. to ensure equitable access to information. For example, Island Transit in Galveston includes alternative routes on bus route brochure maps for routes that are frequently flooded (Figure 15) (Texas A&M Transportation Institute, 2013).

R. Monitor planned road projects that will address sea level rise, and adjust transit routes accordingly if needed. If permanent rerouting is required, special attention should be paid to the AFN populations as they could be more adversely impacted by route changes.

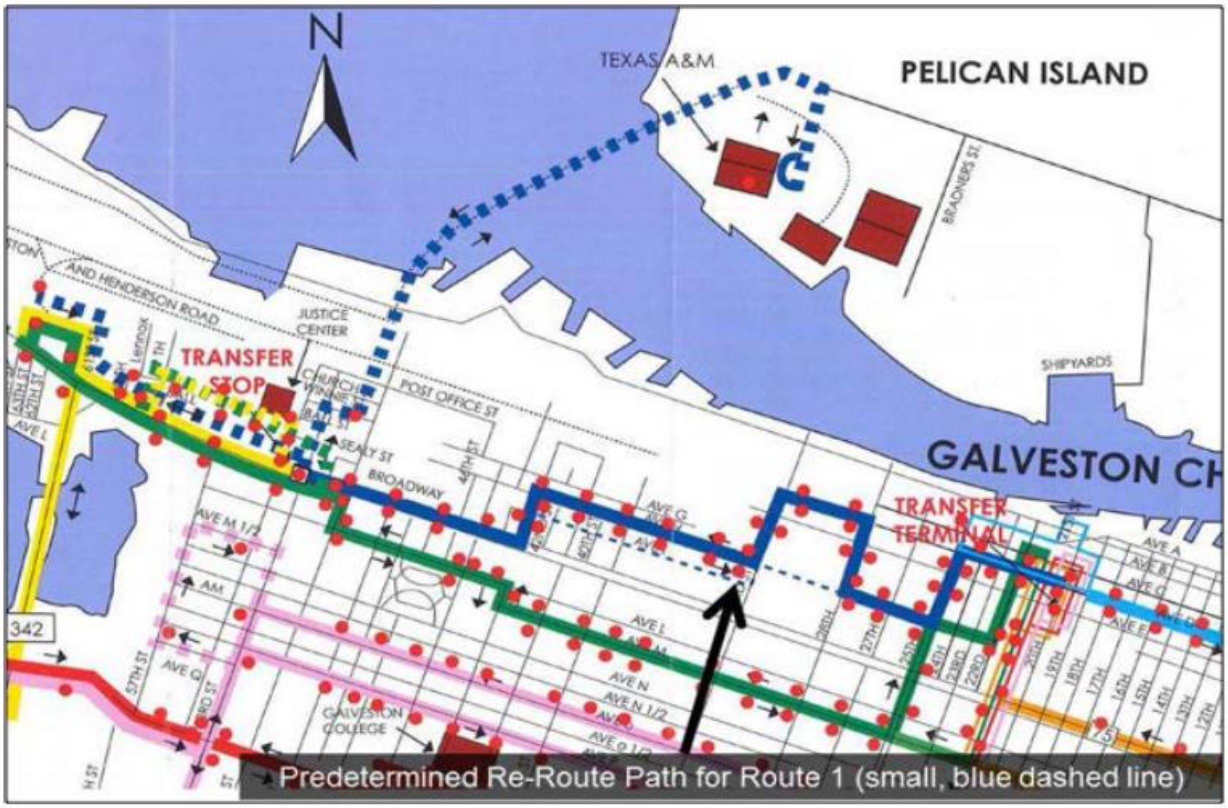

Figure 15 Example of predetermined re-route path for bus operation. Figure adapted from Texas A&M Transportation Institute (2013).

4: Additional Resources

- Cal-Adapt (https://cal-adapt.org/): California Energy Commission funded portal of interactive tools, data, resources, and maps showing the impacts of climate change in California.
- Cal-Fire Fire Hazard Severity Zone Maps (http://www.fire.ca.gov/fire_prevention/fhsz_maps_humboldt): Maps showing fire hazard within the state and local responsibility areas.

- California 4th Climate Change Assessment Report Website (http://resources.ca.gov/climate/safeguarding/research/): The latest climate change research and data for the state of California with regional reports including the north coast region.
- Humble County Geospatial Information System web portal (http://webgis.co.humboldt.ca.us/HCEGIS2.0/): Interactive web GIS with information including FEMA flood zones, fire hazard severity zones, and sea level rise impact visualization.
- California Geological Survey Highway Corridor Landslide Hazard Mapping (https://www.conservation.ca.gov/cgs/Pages/Landslides/landslides-caltrans.aspx): Collection of highway corridor landslide hazard maps including Highway 101 corridor in Del Norte County and Mendocino County and Highway 299 corridor in Humboldt County.
- National Oceanic and Atmospheric Administration Sea Level Rise Viewer (https://coast.noaa.gov/slr/): Interactive map that provides visualization for different levels of sea level rise.

CHAPTER 4: BUS AND CHARGING INFRASTRUCTURE RECOMMENDATIONS

This chapter details the recommended charging infrastructure needed to meet full electrification of transit systems in Humboldt County. Recommendations include location and specifications of chargers, bus model recommendations for each bus in each transit system, and capital costs and electricity (fuel) costs for each transit system. In addition, detailed electricity load profiles are provided for each charger to support preliminary engineering designs as a next step in the planning process.

1: Modeling Methods

The Battery Electric Bus Optimization (BEBOP) Model[11] was developed to identify a cost-optimized mix of various types of electric buses and electric vehicle chargers (EVCs) that can meet the demands of the current route schedules of all public transit systems in Humboldt County. The BEBOP Model uses a mixed integer linear programming (MILP) method for solving problems in which a quantity must be minimized (or maximized) and is limited by other factors. The objective of the Model is to minimize the amortized capital cost of battery electric buses (BEBs) and EVCs along with the electricity (fuel) costs of operation. The Model does not include any other operation and maintenance (O&M) costs for either BEBs or EVCs. The MILP Model is based on the work by Liu and Wei (2018).

The results of the battery electric bus optimization (BEBOP) Model specify three characteristics of a fleet of BEBs and the supporting infrastructure:

- Quantity, charging rate, and location of on-route and in-depot EVCs,
- Mix of BEBs and EVCs of varying specifications and costs, and
- Time-explicit electricity (fuel) consumption profiles and costs for all EVCs.

The Model does not optimize routes or schedules; rather, it uses a fixed and currently used set of operation routes and schedules to enable a smooth transition from traditional fossil fuel buses to BEBs. The route and schedule input data format follow the General Transit Feed Specification (GTFS) with modifications to make the input data bus-centric rather than rider-centric.

Humboldt Transit Authority (HTA) is a joint powers authority that administers transit between Humboldt County and the cities of Arcata, Eureka, Fortuna, Rio Dell, and Trinidad. HTA

[11] This is an open source model developed by the Schatz Energy Research Center. It is available on GitHub at www.github.com/schatzcenter/BEBOP

operates and/or manages five transit systems (Figure 16) which are included in the optimization Model:[12]

- Arcata & Mad River Transit System (AMRTS),
- Eureka Transit System (ETS),
- Redwood Transit System (RTS),
- Southern Humboldt Intercity (SHI), and
- Willow Creek (WC).

In addition, there are four additional transit systems operated by separate entities that also serve Humboldt County residents, and which are also included in the optimization Model:

- Blue Lake Rancheria Transit System (BLRTS),
- Klamath Trinity Non-Emergency Transportation (KTNet),
- Redwood Coast Transit (RCT) - route 20, and
- Trinity Transit (TT) - route 181.

Modeling details on bus and charger specifications, cost assumptions, and MILP methodology can be found in Appendix C.

The BEBOP Model does not consider passenger loading profiles, route speed profiles, or altitude changes in the bus routes. These variables could be analyzed and incorporated into the Model for further refining of spatial and temporal variable bus efficiency. The current efficiency value used in the Model is a static value that does not take in consideration the variables mentioned above. A more realistic bus efficiency scenario would help to better understand the infrastructure requirements for on-route and depot charging. Results consider 40-foot bus models as the only length option, although some transit agencies require or prefer different bus length options for certain routes. Thirty-foot and cutaway buses are becoming available, but specifications were not available when the BEBOP Model was run for this project.

[12] Note that Dial-A-Ride and school bus systems are not included in the optimization model because of challenges with integrating route data. In addition, it is expected that both of these services can be served solely with depot charging.

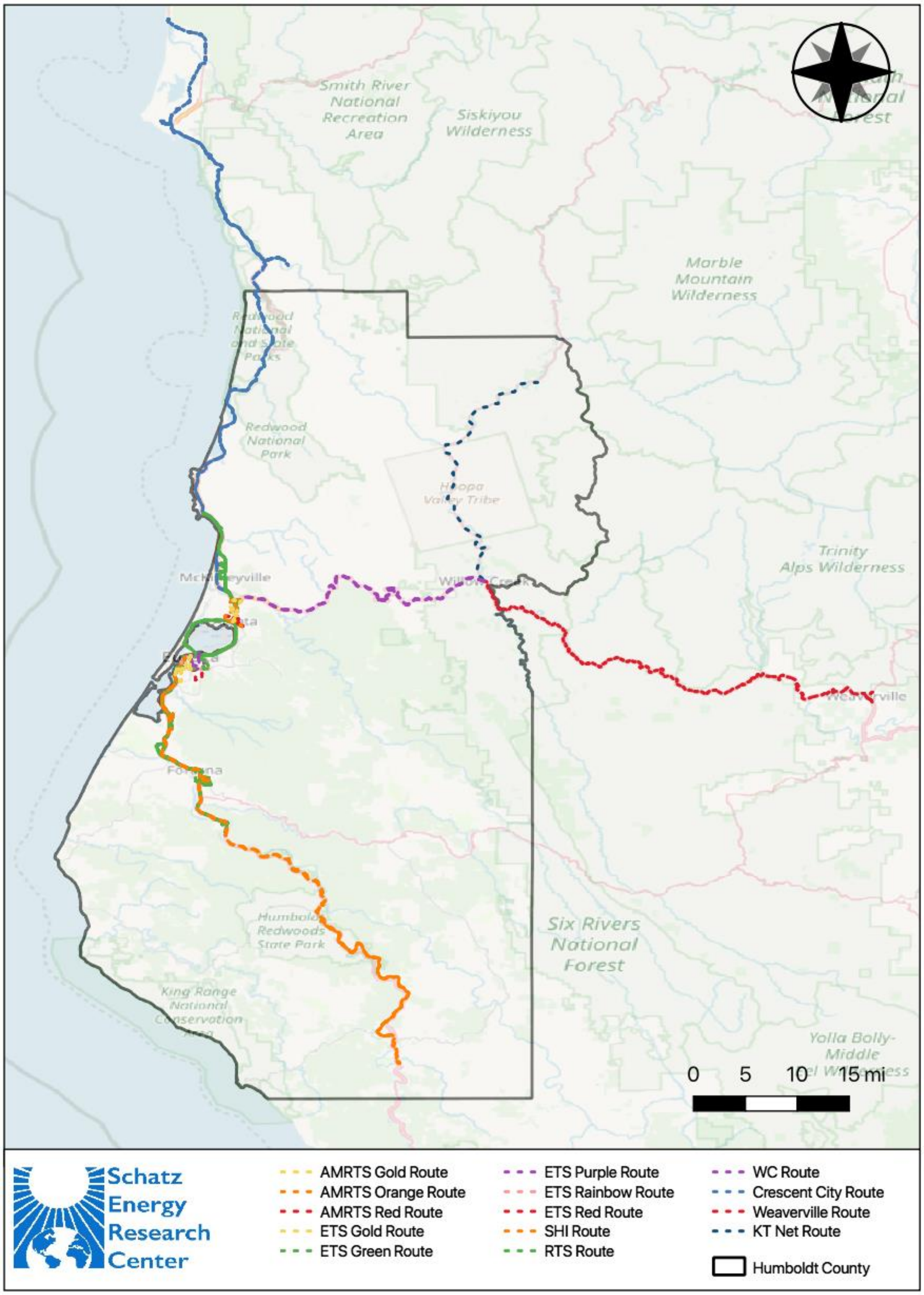

Figure 16. The routes considered in the infrastructure optimization modeling include those served by the Redwood Transit System (RTS), the Eureka Transit System (ETS), the Arcata & Mad River Transit System (AMRTS), the Blue Lake Rancheria (BLR), the Klamath Trinity Non-Emergency Transportation (KTNet), route 20 of Redwood Coast Transit (RCT), and the Willow Creek route of Trinity Transit (TT).

2: Bus and Charging Infrastructure Recommendations

The following sections provide bus and charging infrastructure recommendations. Key assumptions used for these recommendations are the following:

- Constant efficiency for all buses of 0.529 miles/kWh (see Appedix C for details),
- Effective bus battery capacity of 80% of advertised capacity reflecting a battery near the end of useful life, and
- 15% battery reserve safety factor for all buses, meaning no bus is allowed to use more than 85% of the effective battery capacity, or 65% of the advertised capacity.

Recommended charging infrastructure phases are shown in Table 7.

Table 7: Summary recommendations for charging station locations.

Recommended Installation Phase	Stop Location	# of Chargers	Charger Power (kW)	Notes
0	Depot	As Needed	≥50	Install chargers at depots as electric buses are procured. Potential sea level rise impacts at HTA yard. Consider resiliency concerns related to any cause of power outage.
1	Arcata Transit Center	1	≥500	Specific location is critical. Potential sea level rise impacts in extreme climate change scenario.
	Bayshore Mall	1	≥500	Specific location is critical. Significant sea level rise concerns. Re-location would involve significant re-routing of multiple systems.
	College of the Redwoods	1	≥500	This charger is critical for enabling systems that utilize Arcata Transit Center and Bayshore Mall. However, the location could move to Fortuna at Kenmar Rd. Potential sea level rise impacts in extreme climate change scenario.
2	Willow Creek	1	≥500	Specific location is critical. Station enables WC, KTNET, and TT systems. Consider resiliency concerns related to potential wildfire impacts.
	Trinidad Park & Ride	1	≥500	This location is critical for RTS route. Location could move to the airport.
3	Benbow KOA	1	≥500	This location is critical for SoHum route. Consider resiliency concerns related to potential wildfire impacts.
	Dean Creek Resort	1	≥500	Specific location is less important than the need for two charging stations. Route reschedule may reduce to one required charger. Consider resiliency concerns related to potential wildfire impacts.
	Myers Flat	1	≥500	

2.1: Bus Models by Transit System and Existing Bus Number

Out of three different bus models considered (see Appendix C for details) the BEBOP Model recommended two different bus models across all transit system fleets. A list of other available BEBs currently on the market is presented in Appendix Recommended bus models are shown in

Table 8. Shorter routes (e.g., AMRTS Red, AMRTS Gold, ETS 66) can utilize a smaller battery capacity BEB, the E2 with 440 kWh. All other routes are recommended to have the larger E2 Max 660 kWh bus.

The BEBOP Model always chose larger battery capacity buses over more chargers. The main driver for this is not always out of necessity, but more often because the incremental cost for additional battery capacity is extremely low (see Appendix C for details on bus and charger capital costs). It is important to note, however, that no known bus manufacturers are commercially producing BEBs with a 660-kWh battery pack yet. The E2 max series bus is advertised in Proterra's website, but production has not started yet.

Table 8. Corresponding BEB bus model and daily additional headway from charging.

Bus Number	Transit Service	Bus Model	Maximum Additional Headway from Charging (Minutes/day)
Gold	AMRTS	E2 (440 kWh)	2
Red	AMRTS	E2 (440 kWh)	10
BLRTS	BLRTS	E2 (440 kWh)	0
66	ETS	E2 (440 kWh)	2
67	ETS	E2 Max (660 kWh)	0
68	ETS	E2 (440 kWh)	18
69	ETS	E2 (440 kWh)	10
KT Net	KT Net	E2 (440 kWh)	2
11374 *	RCT	E2 Max (660 kWh)	1
20238 *	RCT	E2 (440 kWh)	0
44 *	RCT	E2 Max (660 kWh)	0
886	RTS	E2 (440 kWh)	14
888	RTS	E2 Max (660 kWh)	18
889	RTS	E2 Max (660 kWh)	36
890	RTS	E2 Max (660 kWh)	7
891	RTS	E2 Max (660 kWh)	16
892	RTS	E2 Max (660 kWh)	28
893	RTS	E2 Max (660 kWh)	0
894	RTS	E2 (440 kWh)	8
896	RTS	E2 Max (660 kWh)	10
410	SHI	E2 Max (660 kWh)	13
512	SHI	E2 Max (660 kWh)	22
514	SHI	E2 Max (660 kWh)	15
181 +	TT	E2 Max (660 kWh)	0
714	WC	E2 Max (660 kWh)	6

* Bus numbers were not obtained for RCT buses that run Route 20. GTFS block id is used instead.
+ Bus numbers were not obtained for the TT bus that runs route 181. GTFS block id is used instead.

2.2: On-Route Charging Infrastructure

The BEBOP Model results show eight chargers at eight different locations that are the optimal outcome leading to minimizing the cost for the baseline technological and operational assumptions (Figure 17). Table 7 presents the recommended on-route charging locations in order of priority and groups the chargers into phases for reasons noted in the table. Two different models of on-route chargers were considered in the BEBOP Model: a 150kW and a 500kW nameplate charger (comparable to the ChargePoint Express Plus system[13] or the ABB Pantograph solutions[14]). There are a small handful of commercial options with these power ratings, but it is expected that these nameplate ratings will become increasingly common. The BEBOP Model identified the 500kW nameplate charger as the only cost-effective option given bus and charger performance and cost assumptions (see Appendix C).

Except for Willow Creek, the chargers are all sited along the U.S. Highway 101. Arcata Transit Center has the most utilized charger in terms of energy usage, consuming 1,319 kWh daily (Table 9). It is also the only charger location shared by five different transit services. Conversely, Dean Creek Resort and Myers Flat are the least utilized chargers in terms of energy usage, consuming 90 and 91 kWh daily, respectively. Both are only utilized by the Southern Humboldt Intercity route.

System wide, there are 153 charging sessions a day in the baseline result, with each session lasting 9 minutes on average. Since charging sessions happening at scheduled break stops do not add additional headway to route schedules, only charging events at passenger stops are considered when calculating additional headway (

Table 8). A total of 123 daily charging sessions at passenger stops lead to an additional 4 hours of headway system-wide, or on average 9 minutes per bus. The RTS 889, RTS 892, and SHI 512 are the most impacted routes, each with 20 minutes or more additional headway.

[13] https://www.chargepoint.com/products/commercial/express-plus/

[14] https://library.e.abb.com/public/09cd5a7dc3434ee399c0cbb531716773/4EVC901704-BREN_HeavyVehicleCharging%20solutions%20portfolio_11_19.pdf

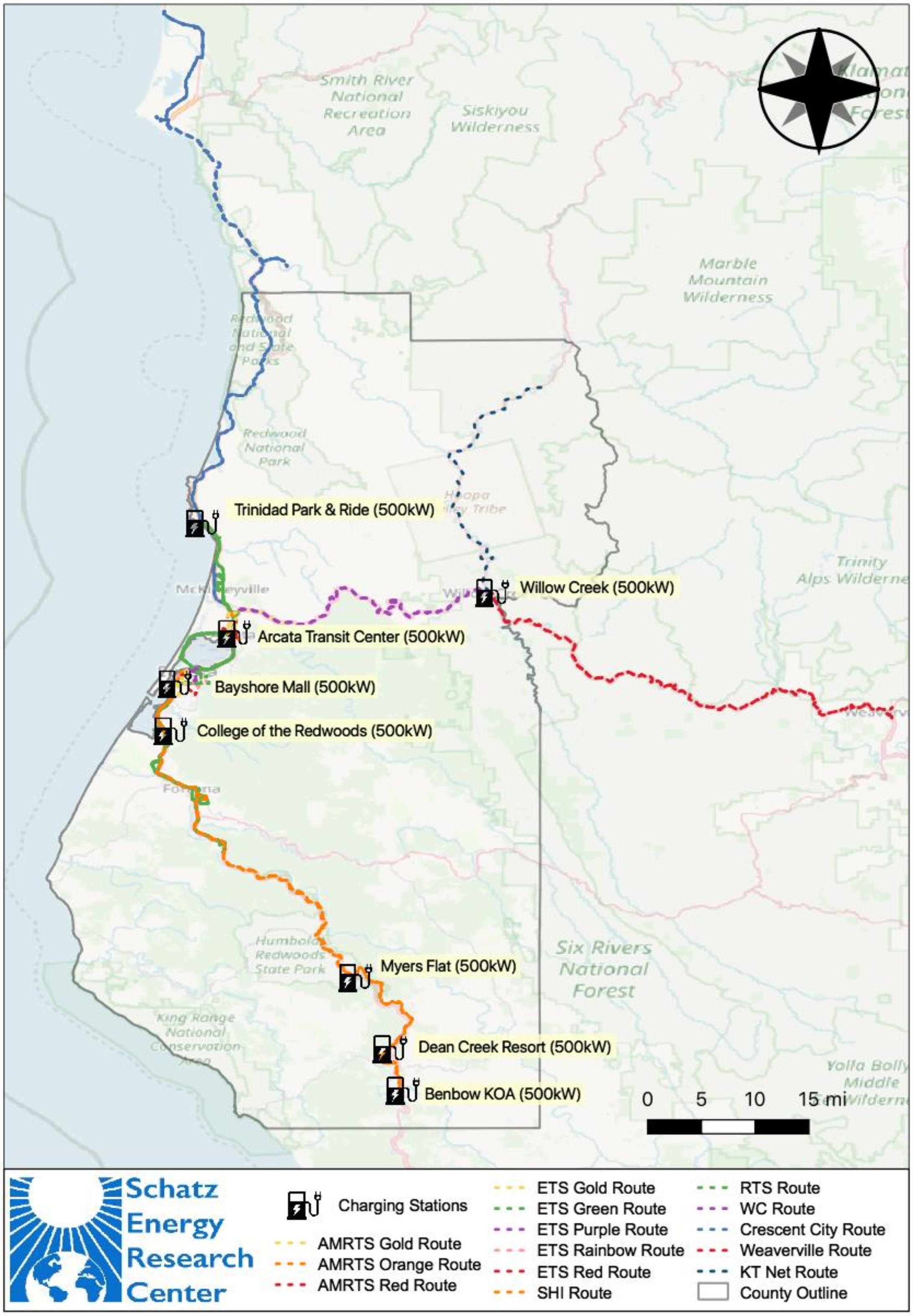

Figure 17: Modeled BEB on-route charging stations location and power rate for HTA.

Table 9: Charger location, daily electricity demand and consumption, and daily number of charging events.

Stop Location	Modeled Maximum Demand (kW)	Total Daily Energy (kWh)	Number of Charging Events	Time of usage per day (min)	Regular Stop Count	Break Stop Count
Arcata Transit Center	397	1319	40	245	31	9
Bayshore Mall	397	613	51	102	51	0
Benbow KOA	397	425	6	83	1	5
College of the Redwoods	397	777	33	128	24	9
Dean Creek Resort	397	91	7	14	7	0
Myers Flat	397	90	7	14	7	0
Trinidad Park & Ride	397	819	4	191	0	4
Willow Creek	397	423	5	132	2	3

The installation phase recommendations were driven primarily by a station's criticality. This is defined qualitatively based on the following Model results:

- Number of transit systems that utilize the charger (see Table 10).
- Importance for enabling multiple routes
- Total daily utilization time (see Table 9)

Modest route schedule modifications could avoid the need to install chargers at locations that have low criticality, i.e., stations with low utilization by a single route or transit system. For example, given the current route schedule, the charger at Myers Flat is an important charger because it ensures the BEBs serving the SHI routes have enough capacity to finish the run and return to the depot with enough battery capacity. However, the charger at Myers Flat is only used for 4 minutes each day by bus 410, 6 minutes by bus 512, and 5 minutes by 514, which totals to 15 minutes a day by the three buses. If the route schedule for the three buses are modified so that the stop duration at Benbow KOA, a stop that all three buses already stop at and already has a 500kW charger, is increased by 15 minutes per day, the Myers Flat charger could be avoided. The Dean Creek Resort charging station has a similar situation, where it is only used for 14 min per day by the Southern Humboldt Intercity buses.

Table 10: Daily charger utilization at each charging location among transit services. Each row (i.e., charger location) sums to 100%.

Charger Location	AMRTS	BLRTS	ETS	KT Net	RCT	RTS	SHI	TT	WC
Arcata Transit Center	18%	3%			40%	20%			19%
Bayshore Mall			27%			62%	11%		
Benbow KOA							100%		
College of the Redwoods						92%	8%		
Dean Creek Resort							100%		
Myers Flat							100%		
Trinidad Park & Ride						100%			
Willow Creek				49%				28%	23%

2.2.1: Coordination Regarding Proprietary Charging Standards

Planning for charging infrastructure that serves multiple transit systems with different owners and operators can present challenges with regards to the use of proprietary charging standards by bus manufacturers. As of January of 2020 the following manufacturer-agnostic charging equipment standards are available for different charger power levels[15]

- SAE J1772-CCS basic: plug, 20kW – 150kW, 50V – 500V, 350A limit
- SAE J1772-CCS XFC: plug, 150kW – 350kW, 200V – 1,000V, 350A limit
- SAE J2954/2: inductive (wireless), 60kW – 590kW
- SAE J3105: pantograph, 150kW – 1,200kW, 250V – 1,000V, 600A – 1,200A limit

Furthermore, there continues to be further development in high power charging standards. It is recommended that transit systems coordinate regarding bus OEMs and charging infrastructure OEMs to ensure on-route charging infrastructure is usable by all interested transit systems.

2.3: Depot Charging Infrastructure

Excluding Redwood Coast Transit (RCT) and Trinity Transit (TT), there are three separate bus depots for the public bus fleets in Humboldt County.

1. Humboldt Transit Authority bus yard at 113 V Street, Eureka

[15] Bohn, Theodore. *Multi-port, 1+ MW Charging Systems for Medium- and Heavy-Duty EVs: What We Know and What Is On the Horizon?* Argonne National Laboratory webinar. January 7th, 2020. https://cleancities.energy.gov/files/u/news_events/document/document_url/525/ANL_CleanCities_MW_plus_WhatsAhead_Jan7_2020.pdf

2. Blue Lake Rancheria office building at 426 Chartin Road, Blue Lake
3. Hoopa Tribal Police station at 12637 CA-96, Hoopa

To avoid adding additional personnel to manage overnight charging, each bus is recommended to have an electric bus charger. A 62.5 kW in-depot charger is assumed (equivalent to the ChargePoint CPE250[16] or the ChargePoint Express Plus system[17]). Details of recommended charging infrastructure requirements are shown in Table 11.

Table 11. Recommended in-depot charging infrastructure requirements.

Bus Depots	# of Operating Buses	Max Potential Instantaneous Demand (kW)	# of Chargers Needed	Average Expected Overnight Load (kW)
HTA Bus Yard	19	1,187.5	19	857
Blue Lake Rancheria Office	1	62.5	1	62.5
Hoopa Tribal Police Station	1	62.5	1	62.5

For the HTA Bus Yard, automated cascaded charging options[18] are available and highly recommended in order to minimize electricity demand (kW) costs. The average expected overnight load shown in Table 11 indicates potential reduction in total demand from smart charging of a few hundred kW (difference between the Max Potential Instantaneous Demand and the Average Expected Overnight Load).

2.4: Potential Utility Distribution Capacity Concerns

Utility distribution capacity refers to the amount of additional electrical load that can be carried by the poles and wires that make up the distribution system. PG&E's Integrated Capacity Analysis[19] and PVRAM[20] maps allow insight into whether there may be interconnection challenges with the expected load at each recommended charger location. Interconnection challenges are of concern because they can substantially increase installation costs. Table 12 details any potential interconnection challenges. Transit systems would need to work with PG&E to confirm if any interconnection challenges are present.

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[16] https://www.chargepoint.com/products/guides/#cpe250_a

[17] https://www.chargepoint.com/products/commercial/express-plus/

[18] "Automated cascaded charging", often referred to under the broader term "smart charging", means a charging system that manages how many buses charge at any given time based on battery state-of-charge and the route schedule assigned to each bus.

[19] https://www.pge.com/b2b/distribution-resource-planning/integration-capacity-map.shtml

[20] https://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/PVRAMMap/index.shtml

Note that Table 12 shows a number of potential constraints on the particular distribution feeders serving the exact location associated with a bus stop. These constraints could result in additional costs with either or both of the following (determined during the engineering design phase):

- Utility upgrades to the feeder to accommodate the expected load,
- On-site battery storage that can provide required loads within constraints of the existing distribution feeder capacity.

On-site battery storage offers the ability to “trickle charge” the on-site battery to keep loads within the constraints of the distribution feeder. The battery is then discharged in order to provide the power that is needed by the buses without exceeding the limits of the distribution feeder.

Table 12: Summary of Potential Utility Interconnection Challenges

Charger Location	Design Load (MW)	Available Distribution Capacity (MW) [a]			Potential Concerns
		Feeder	Circuit	Substation	
Arcata Transit Center	0.5	2.6	4.4	20	None
Bayshore Mall	0.5	1.4	3.1	2.8	None
Benbow KOA	0.5	0.2	5.4	3.3	Likely feeder constraint [b]
Blue Lake Rancheria	0.07	1.4	7.4	7.8	None
College of the Redwoods	0.5	0.3	4.6	4.7	Likely feeder constraint [c]
Alt: Fortuna Overlook	0.5	1.3	5.1	4.4	None
Dean Creek Resort	0.5	0	1.9	3.3	Likely feeder constraint
Hoopa Tribal Police Station	0.07	0.3	2.4	1.3	None
HTA Bus Yard	1.2	1st St.: 0.1 2nd St.: 1.5	1st St: 8.5 2nd St: 4.4	1st St.: 2.8 2nd St.: 9.4	Possible feeder constraint
Myers Flat	0.5	0.6	5.1	2.3	Possible feeder constraint
Trinidad Park & Ride	0.5	Main St.: 1.9	2.6	5.6	May require new feeder [d]
Alternate: Airport	0.5	0.2	4.1	5.0	Likely feeder constraint
Willow Creek	0.5	2.8	2.4	2.2	None

a. Note that all distribution capacity estimates were obtained on April 3rd, 2020. Available capacity changes regularly. Possible challenges must be re-visited with the utility when initiating a project.
b. There is 0.7MW of feeder capacity at the abandoned building on the corner of Lake Benbow Dr. and Benbow Dr., at the freeway off-ramp. This could be a potential charging location. However, this would force the driver to walk for amenities during their break.
c. Also note that the college maintains on-campus distribution infrastructure. Transit systems would need to work with the college to determine any additional on-campus distribution constraints.
d. The Main St. feeder currently has sufficient capacity. However, there is currently no feeder serving the park-and-ride lot itself. Either a near-by charging location would need to be identified, or additional utility costs may be incurred for running a new 3-phase feeder.

2.5: Power Outage Design Considerations

As discussed in CHAPTER 3: of this report, power outages caused by weather and wildfire can impact the availability of electricity (fuel). Back-up power should be considered for both on-route and depot charging infrastructure. Table 13 provides guidance regarding the recommended back-up power duration using reliability data provided for PG&E's service territory (see CHAPTER 3:1.3:) for details.

Table 13: Back-up power generation design recommendations

Cause of outage	Average outage duration per outage event
Weather, adjusted for climate change projections through 2100.	~8 hours
Wildfire: direct impacts on local distribution infrastructure, adjusted for climate change projections through 2100.	~40 hours
Wildfire: Public Safety Power Shutoff program	Work with PG&E and RCEA to determine this as local generation and local distribution system management strategies are actively changing

Recommended back up power durations in Table 13 are based on average reported outage durations rather than maximum outage durations. It is recommended that transit systems work with local emergency planners to weigh infrastructure costs with the need for resilient charging infrastructure.

2.6: Sea Level Rise Considerations

As mentioned in Chapter 3 of this report, one of the direct results of climate change is sea level rise (IPCC, 2014). Part of the projected charging infrastructure as well as a significant fraction of transit revenue miles occurs in the Humboldt Bay region on roads that are expected to be impacted by sea level rise (Figure 18 & Figure 19) according to projections by NHE (2014a) and NOAA (2019).

BEBOP Model methods and assumptions were not modified to account for sea level rise because this requires an iterative consideration of re-routing existing transit system routes. It is left to future work for HTA and other transit system operators to project future possible transit routes. The BEBOP Model can be easily run on these future transit routes to identify how required charging infrastructure may need to change.

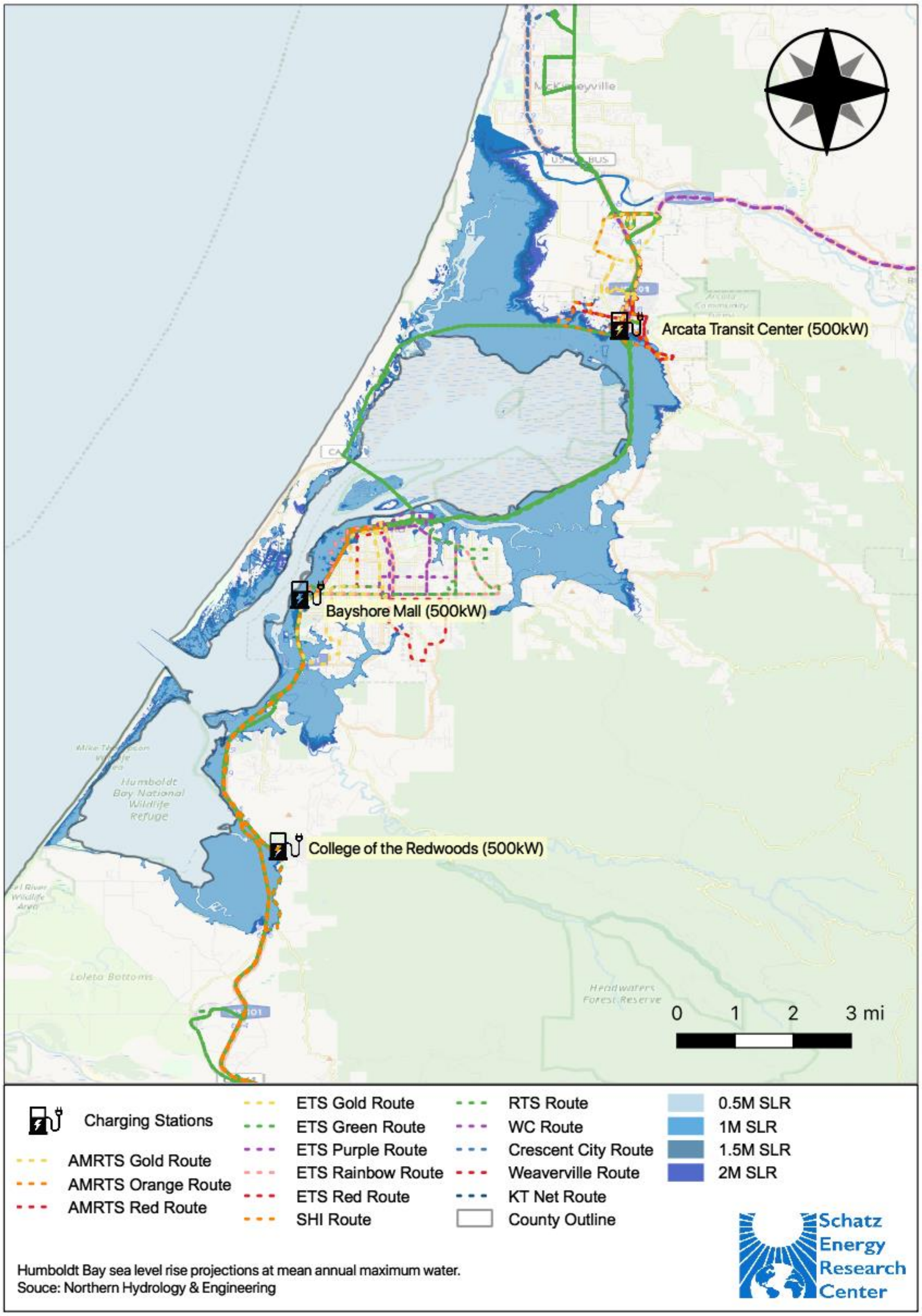

Figure 18. Humboldt Bay charging infrastructure and sea level rise projections at year 2100. NHE (2014b).

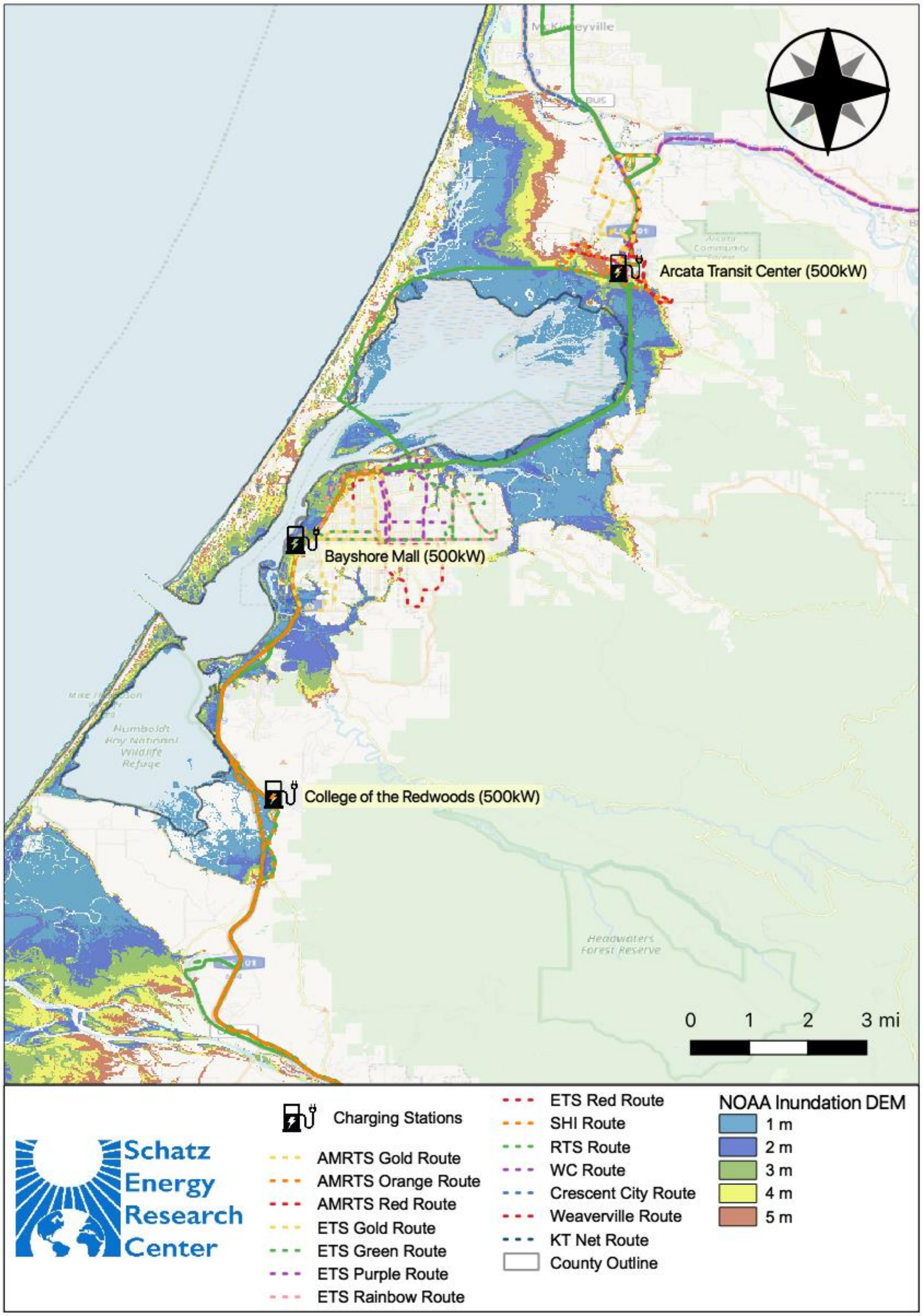

Figure 19. Humboldt Bay charging infrastructure and sea level rise projections at year 2100 (NOAA, 2019)

2.7: Wildfire Considerations

As mentioned in Chapter 3 of this report, one of the direct results of climate change besides sea level rise is an increase in wildfire frequency. Wildfire severity and frequency will be affected by both climate and continued development and population growth.

Part of the projected charging infrastructure as well as a significant fraction of transit revenue miles occurs in the southern and eastern areas (Figure 20) of the county which are located in either Tier 2 or Tier 3 CPUC High Fire Threat Districts (HFTDs).

BEBOP Model methods and assumptions were not modified to account for wildfire considerations because this requires an iterative consideration of re-routing existing transit system routes. It is left to future work for HTA and other transit system operators to project future possible transit routes. The BEBOP Model can be easily run on these future transit routes to identify how required charging infrastructure may need to change.

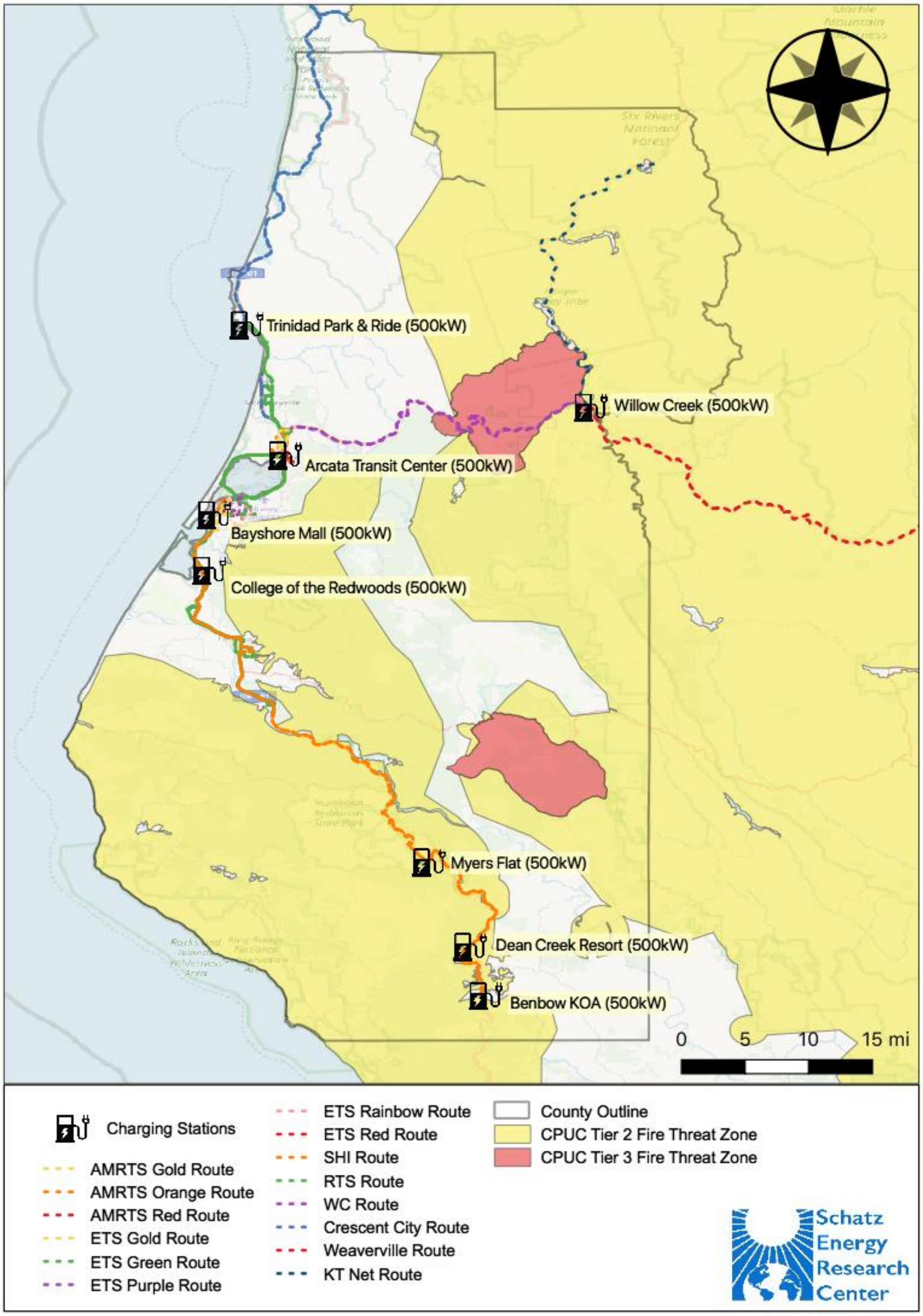

Figure 20. Charging infrastructure and California Public Utility Commission's Tire 2 & 3 High Fire Threat Districts

3: Cost Estimates

The following sections detail the projected costs associated with the bus and infrastructure recommendations presented above.

3.1: Infrastructure and Bus Capital Cost

Total up-front capital cost of buses and depot chargers for each transit system is shown in Table 14. Depot charger costs are taken from the California Air Resources Board Transit Fleet Cost Model, version 20170622, and include equipment and installation costs.

Table 14: Estimated bus and depot charger cost estimates for each transit system.

Transit System	Buses	Depot Chargers
BLRTS	$0.77M	$50k
KTNET	$0.77M	$50k
AMRTS	$1.54M	$950k, all located at HTA maintenance yard.
ETS	$3.12M	
RTS	$7.17M	
SHI	$2.41M	
WC	$0.80M	

On-route charger cost estimates are shown in Table 15. Values were estimated by McKeever Energy & Electric, Inc., and additional details on cost estimates can be found in Appendix H. Note that cost estimates do not consider additional potential utility costs associated with possible distribution system upgrades as indicated in Table 12.

Estimated useful life of charging infrastructure is 28 years. Capital costs and useful life estimates for on-route chargers are also taken from the CARB Fleet Cost Model. Estimated useful life of bus batteries[21] is shown in Table 16. Useful life is calculated by estimating the daily depth of discharge (DOD) as a percentage of useable battery capacity, assuming 250 operating days per year, and assuming 3,000 charge cycles over the life of a battery. For example, if a bus travels enough miles in one day to consume 100% of battery capacity (regardless of how many charging events that bus participates in during the day), then this bus has a DOD of 100%, 1 equivalent charge cycle per day, and 250 charge cycles per year. Therefore, the end of useful life (EUL) is 3,000 / 250 = 12 years.

[21] Defined as 3,000 round-trip charge/discharge cycles at 100% depth-of-discharge (DOD).

Table 15. On-route charging infrastructure capital cost. Includes equipment and installation.

Stop Location	On-Route Chargers
Arcata Transit Center	$693,280
Bayshore Mall	$721,000
Benbow KOA	$578,000
College of the Redwoods	$713,000
Dean Creek Resort	$642,000
Myers Flat	$770,800
Trinidad Park & Ride	$618,800
Willow Creek	$624,800

3.2: Electricity (Fuel) Cost

BEBOP minimizes the amortized combined costs of the initial infrastructure and the continuing operation costs associated with battery charging. The effect of the operation costs on the results is evident by the vast majority (89%) of the on-route charging sessions happening during the super off-peak (SOP) or off-peak time of the day when the electricity energy rate is lower (Figure 21).

Operation time is not considered as a cost in the Model, meaning that BEBOP only searches for solutions with the lowest operation “fuel” (i.e., electricity energy and demand) cost and infrastructure (i.e., BEBs, on-route and in-depot chargers) cost.

In other words, additional charging sessions may be scheduled for the SOP time of the day in the attempt to minimize the charging cost as opposed to charging during late afternoon and evening which has a higher peak time-of-use rate. These additional charging sessions during SOP time of the day, with the purpose of minimizing “fuel” cost, may not be needed to make the BEBs complete the routes, and could be avoided if headway reduction is needed for the particular bus and routes.

The BEBOP results show that almost all transit services included in the Model have an average fuel cost ($/mile) below $0.40 per mile (Figure 22). Southern Humboldt Intercity is the only route that exceeds $0.40 per mile. The largest portion of the electricity cost for all transit services is the depot charging energy cost which ranges from 36% to 74% of the total “fuel” cost. Across the transit services, energy costs account for 73% and demand costs account for 27% of the individual operation cost for each transit service on average. The daily cost of on-route charging is $542, while depot charging is $1008. Daily total demand charges are $394 and $185 for on-route and depot charging respectively. The daily cost of on route and depot charging per transit agency is shown in Table 17.

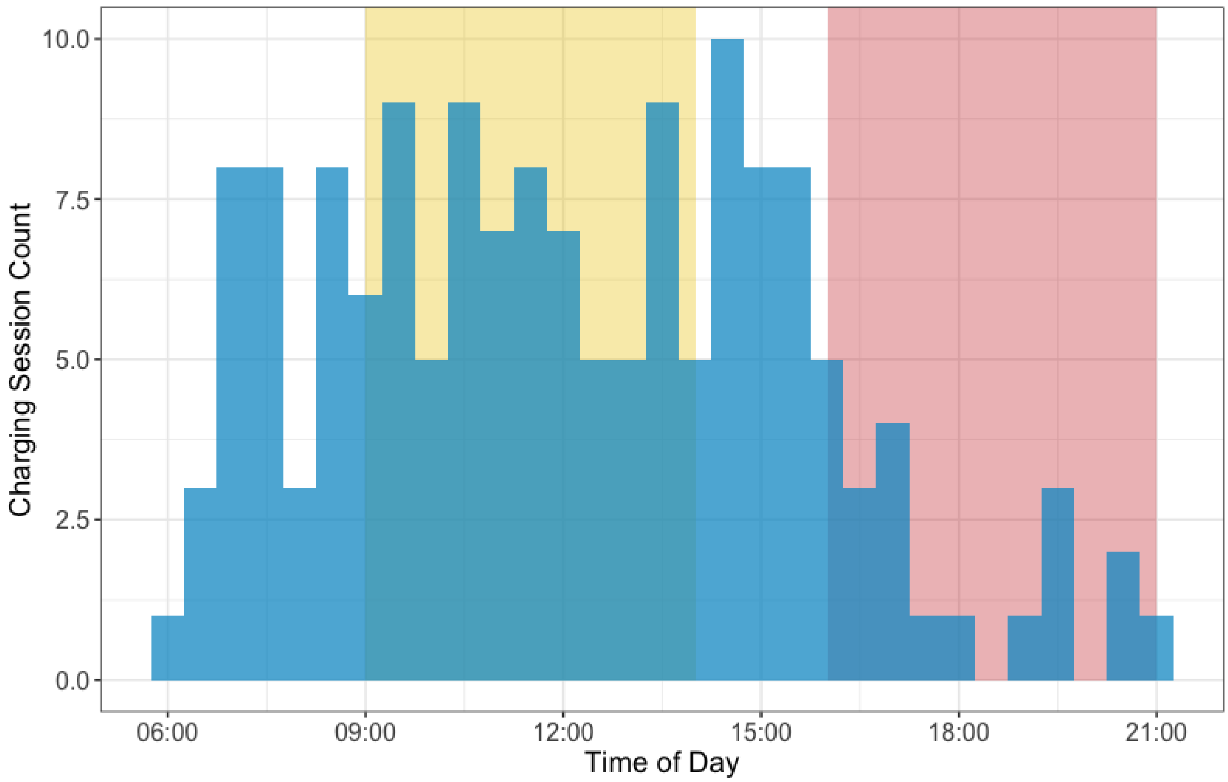

Figure 21 Charging session distribution over a day for all transit systems and EVC locations. Yellow highlighted segment represents the Super Off-Peak (i.e. the solar over production time of day) time-of-use rate. Red highlighted segment represents the peak time-of-use rate. Non-highlighted segments represent off-peak time-of-use rate.

Table 16: Estimates of bus battery end-of-useful life.

Agency	block_id	Battery Nameplate (kWh)	Usable battery energy, 80% of nameplate (kWh)	Total daily cumulative charging (kWh)	Equivalent daily DOD (%)	Operating Days (based on 3000 cycles @ 100% DOD)	EUL assuming 250 operating days per year (Years)
AMRTS	25500	440	352	308	0.88	3429	14
AMRTS	2552150	440	352	322	0.91	3280	13
BLRTS	428	440	352	329	0.93	3210	13
ETS	66	440	352	282	0.80	3745	15
ETS	67	660	528	314	0.59	5045	20
ETS	68	440	352	287	0.82	3679	15
ETS	69	440	352	321	0.91	3290	13
KT Net	1147	440	352	406	1.15	2601	10
RCT	44	660	528	587	1.11	2698	11
RCT	11374	440	352	681	1.93	1551	6
RCT	20238	660	528	251	0.48	6311	25
RTS	886	440	352	464	1.32	2276	9
RTS	888	660	528	613	1.16	2584	10
RTS	889	660	528	789	1.49	2008	8
RTS	890	660	528	731	1.38	2167	9
RTS	891	660	528	479	0.91	3307	13
RTS	892	660	528	777	1.47	2039	8
RTS	893	660	528	361	0.68	4388	18
RTS	894	440	352	739	2.10	1429	6
RTS	896	660	528	453	0.86	3497	14
SHI	410	660	528	681	1.29	2326	9
SHI	512	660	528	654	1.24	2422	10
SHI	514	660	528	677	1.28	2340	9
TT	181	660	528	497	0.94	3187	13
WC	714	660	528	762	1.44	2079	8

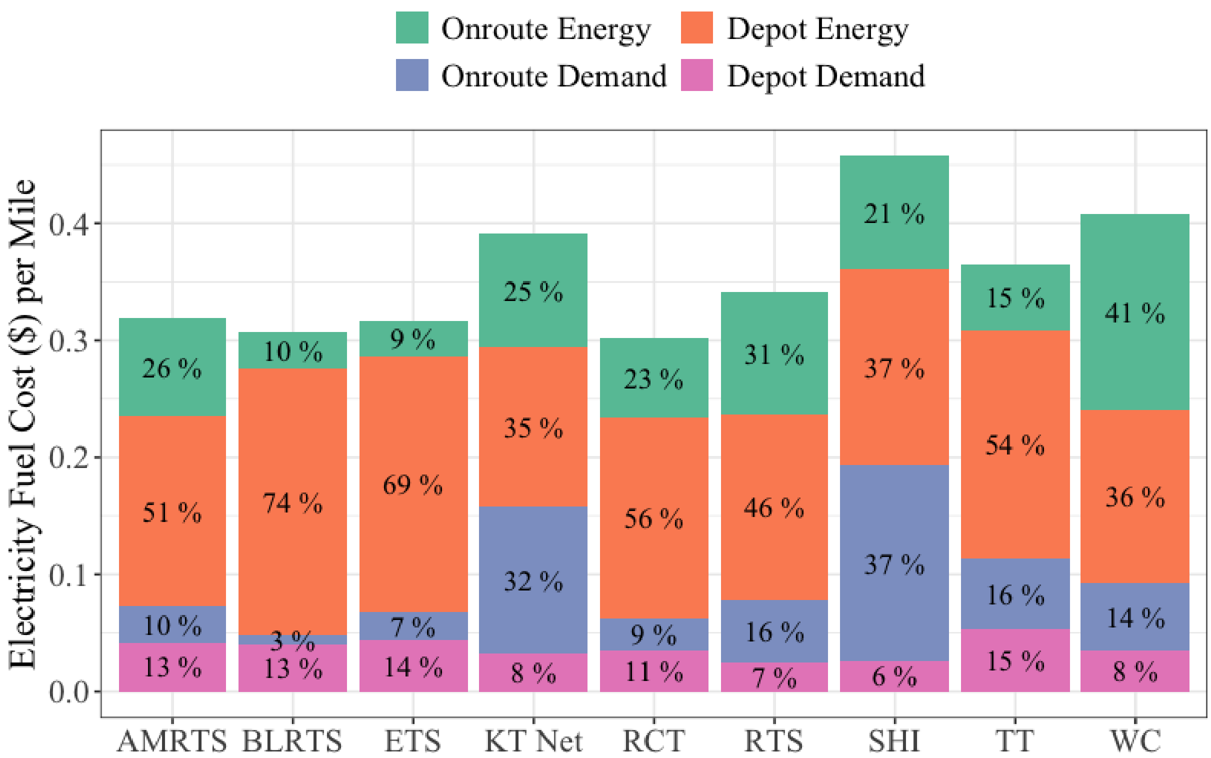

Figure 22. Average electricity cost per mile of full battery electric bus fleet. The labeled numbers represent the individual cost component as the percentage of the total operation cost.

Table 17. Daily cost of on-route and in-depot charging per transit agency.

Agency	On route Energy Cost ($/day)	On route Demand Charges ($/day)	Depot Energy Cost ($/day)	Depot Demand Charges ($/day)	Total Cost ($/day)
AMRTS	24	9	48	12	93
BLRTS	5	1	35	6	47
ETS	17	13	123	25	178
KT Net	18	24	26	6	74
RCT	49	20	121	25	215
RTS	265	135	401	62	863
SHI	91	157	157	25	430
TT	13	14	45	12	84
WC	60	21	52	12	145

3.2.1: Low Carbon Fuel Standard

The Low Carbon Fuel Standard (LCFS) credit regulation is designed to reduce carbon intensity (CI) associated with the lifecycle of transportation fuels used in California. A transit agency using a lower CI fuel may participate in the LCFS program and generate credits by operating battery electric buses, fuel cell electric buses, dispensing fossil compressed natural gas (CNG), or providing hydrogen as a transportation fuel.

Transit agencies can benefit from using the cleaner fuels in their fleet and the amount of LCFS credit generated may change from year to year. Opting into the LCFS program involves registering with California Air Resources Board (CARB) in the LCFS Reporting and Credit Bank & Transfer System (LRT-CBTS) and establishing an account.

The amount of LCFS credits that can be generated varies by fuel type, fuel pathway and annual carbon intensity benchmarks. A CARB credit value calculator is used to determine how many credits can be earned each year. The calculator uses input values (including calendar year, Energy Economy Ratio (EER) for vehicle type, CI of the fuel used, and credit price) to determine the potential revenue generated by a given fuel pathway in a compliance year (CARB, 2019). The input parameters for Humboldt Transit Authority are diesel reference fuel, and EER of 5.0, a CI of 85g CO_2e/MJ for a LCFS price of $150 or a fuel equivalency of $0.17 per kWh.

The equivalency credit of $0.17 per kWh is subtracted from the proposed electricity TOU rate. The off-peak and super off-peak rates become negative when the LCFS credit is applied and the peak rate decreases by approximately 50%. The total on-route charging cost with the LCFS credit is -$232 per day, and the in-depot charging cost is -$550 per day (Table 18 & Table 19). The daily cost comparison between the proposed TOU rate without and with LCFS per transit agency is shown in

Table 20.

Table 18. Proposed Time of Use rate and LCFS credit rate energy cost comparison for on-route charging

TOU Rate w/o LCFS ($/kWh)	LCFS credit rate ($/kWh)	Energy consumed (kWh/day)	TOU Cost w/o LCFS ($/day)	LCFS cost ($/day)
0.09 (SOP)	-0.08	2,116	190	-169
0.11 (off peak)	-0.06	2,025	223	-121
0.31 (peak)	0.14	416	129	58

Table 19. Proposed Time of Use rate and LCFS credit rate energy cost comparison for in-depot charging

TOU Rate ($/kWh)	LCFS credit rate ($/kWh)	Energy consumed (kWh/day)	TOU Cost ($/day)	LCFS cost ($/day)
0.11 (off peak)	-0.06	9,171	1,009	-550

Table 20. Proposed TOU rate and LCFS credit rate energy cost comparison for on-route charging by transit agency.

	TOU	Rate w/o LCFS ($/kWh)	LCFS credit rate ($/kWh)	Energy consumed (kWh/day)	Cost w/o LCFS ($/day)	LCFS cost ($/day)
AMRTS	SOP	0.09	-0.08	110	10	-9
	off peak	0.11	-0.06	132	15	-8
	peak	0.31	0.14	0	0	0
BLRTS	SOP	0.09	-0.08	0	0	0
	off peak	0.11	-0.06	27	3	-2
	peak	0.31	0.14	6	2	1
ETS	SOP	0.09	-0.08	77	7	-6
	off peak	0.11	-0.06	88	10	-5
	peak	0.31	0.14	0	0	0
KT Net	SOP	0.09	-0.08	205	18	-16
	off peak	0.11	-0.06	0	0	0
	peak	0.31	0.14	0	0	0
RCT	SOP	0.09	-0.08	526	47	-42
	off peak	0.11	-0.06	0	0	0
	peak	0.31	0.14	5	2	1
RTS	SOP	0.09	-0.08	936	84	-75
	off peak	0.11	-0.06	1,025	113	-62
	peak	0.31	0.14	219	68	31
SHI	SOP	0.09	-0.08	249	22	-20
	off peak	0.11	-0.06	413	45	-25
	peak	0.31	0.14	75	23	11
TT	SOP	0.09	-0.08	0	0	0
	off peak	0.11	-0.06	119	13	-7
	peak	0.31	0.14	0	0	0
WC	SOP	0.09	-0.08	13	1	-1
	off peak	0.11	-0.06	221	24	-13
	peak	0.31	0.14	111	34	16

The total daily cost including infrastructure (BEBS and on-route chargers) and electricity (energy and demand charges) without the LCFS credit is $2,975. When the LCFS credit cost is applied to on-route and depot energy charges the total daily cost is $643. A daily cost summary for the two cases (without and with LCFS credit) is shown in Figure 23 & Figure 24. The daily cost assumption considers a lifetime of 10 years for BEBs (battery replacement) and 15 years for charging infrastructure.

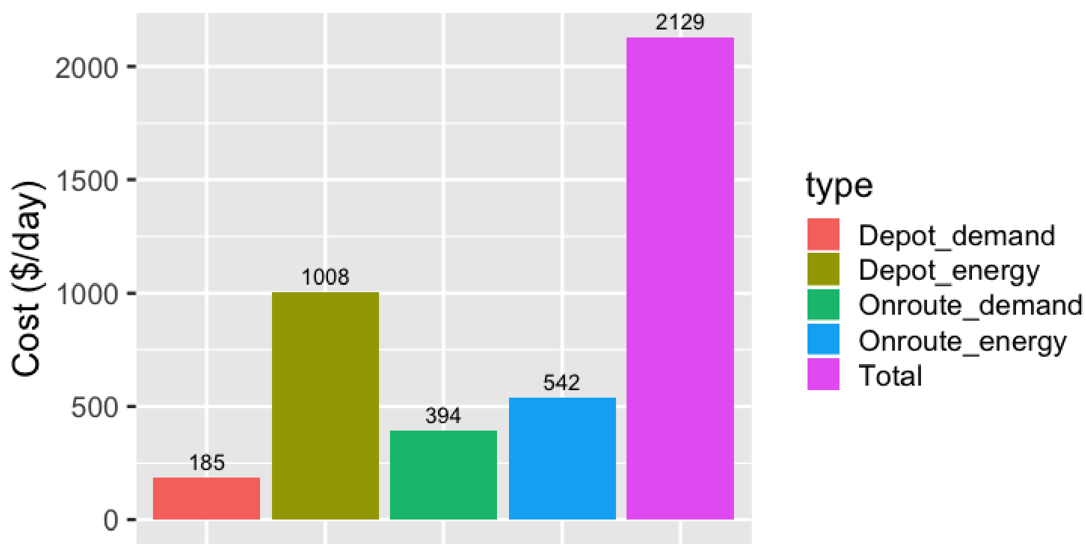

Figure 23. Daily cost of BEBs, on-route chargers, and electricity without LCFS credit.

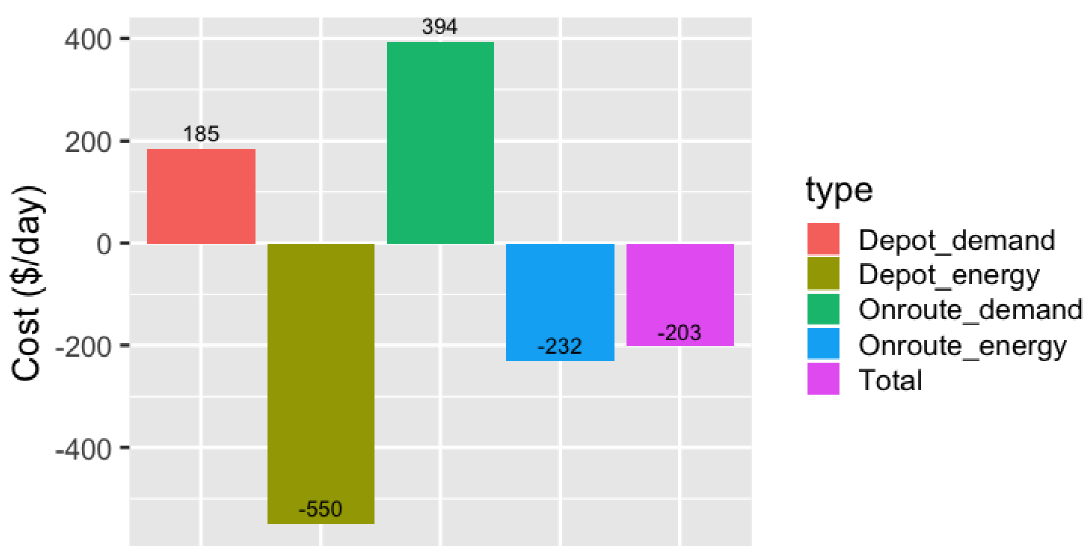

Figure 24. Daily cost of BEBs, on-route chargers, and electricity with LCFS credit applied.

4: Sensitivity Analysis

Two sensitivity analyses were conducted by changing the bus efficiency in the base case scenario. The bus efficiencies used in the sensitivity analyses are 0.465 and 0.615 miles/kWh, this represent the low and high efficiency estimates from Proterra bus specifications (Proterra, 2019). The BEBOP Model shows that using a constant efficiency of 0.465 miles/kWh instead of 0.529 miles/kWh results in an increase from 8 to a total of 14 charging stations (Figure 25). The total daily on-route charging energy consumption is 6,488 kWh with a number of 246 charging events compared to 4,557 kWh and 153 charging events in the base case scenario.

The lower efficiency model result shows an increase in the number of charging stations serving the Southern Humboldt Intercity and the Redwood Coast Transit routes. HSU Library Circle has the most utilized charger in terms of energy usage, consuming 1,304 kWh daily (Table 21). Conversely, Dean Creek Resort and Myers Flat are the least utilized chargers in terms of energy usage, consuming 104 kWh daily. Both are only utilized by the Southern Humboldt Intercity route.

Table 21. Charger location, daily electricity consumption, daily number of charging events, and daily time of usage for low efficiency value sensitivity analysis.

Stop Location	Total Daily Energy (kWh)	Number of Charging Events	Time of usage per day (min)	Regular Stop Count	Break Stop Count
Arcata Transit Center	1,255	37	262	24	13
Bayshore Mall	542	46	92	46	0
Benbow KOA	458	6	83	1	5
College of the Redwoods	627	30	109	23	7
Cultural Center	235	4	191	3	1
Dean Creek Resort	104	8	16	8	0
Fortuna 11th & N Streets	180	14	28	14	0
Founders Grove	104	8	16	8	0
HSU Library Circle	1,304	56	214	50	6
Lucky 7 Store	141	5	31	3	2
Myers Flat	104	8	16	8	0
Redwood Village	172	14	28	14	0
Trinidad Park & Ride	796	3	143	0	3
Willow Creek	466	7	101	4	3

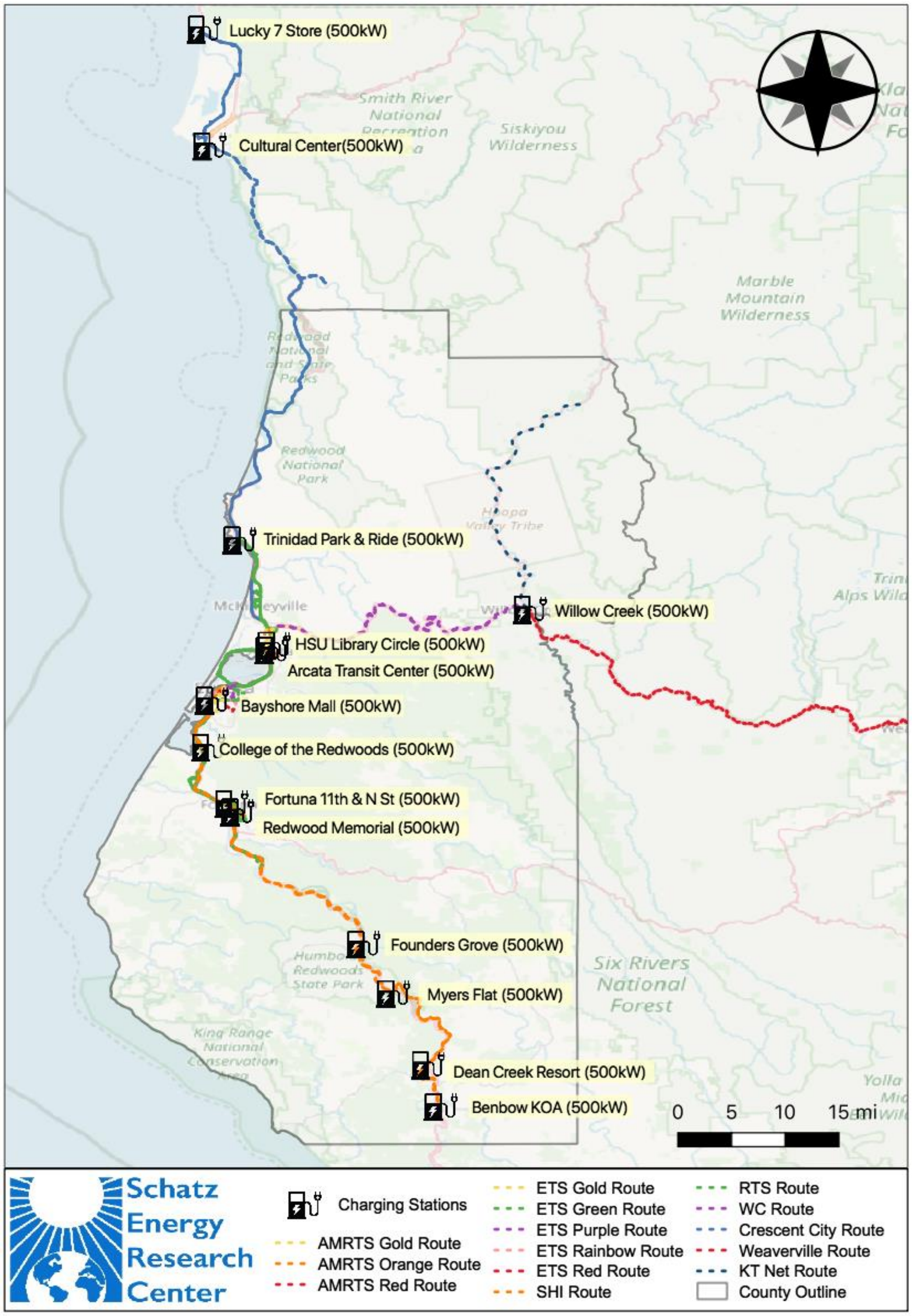

Figure 25. Modeled BEB on-route charging stations location and power rate for HTA, sensitivity analysis using efficiency value of 0.465 miles/kWh.

Using a low efficiency value results in an increase in electricity fuel cost ($/mile), with four transit systems having an average fuel cost below $0.40 per mile (Figure 26). The daily cost of on-route charging is $736, while depot charging is $594. Daily total demand charges are $691 and $105 for on-route and depot charging respectively. The daily cost of on route and depot charging per transit agency is shown in Table 22.

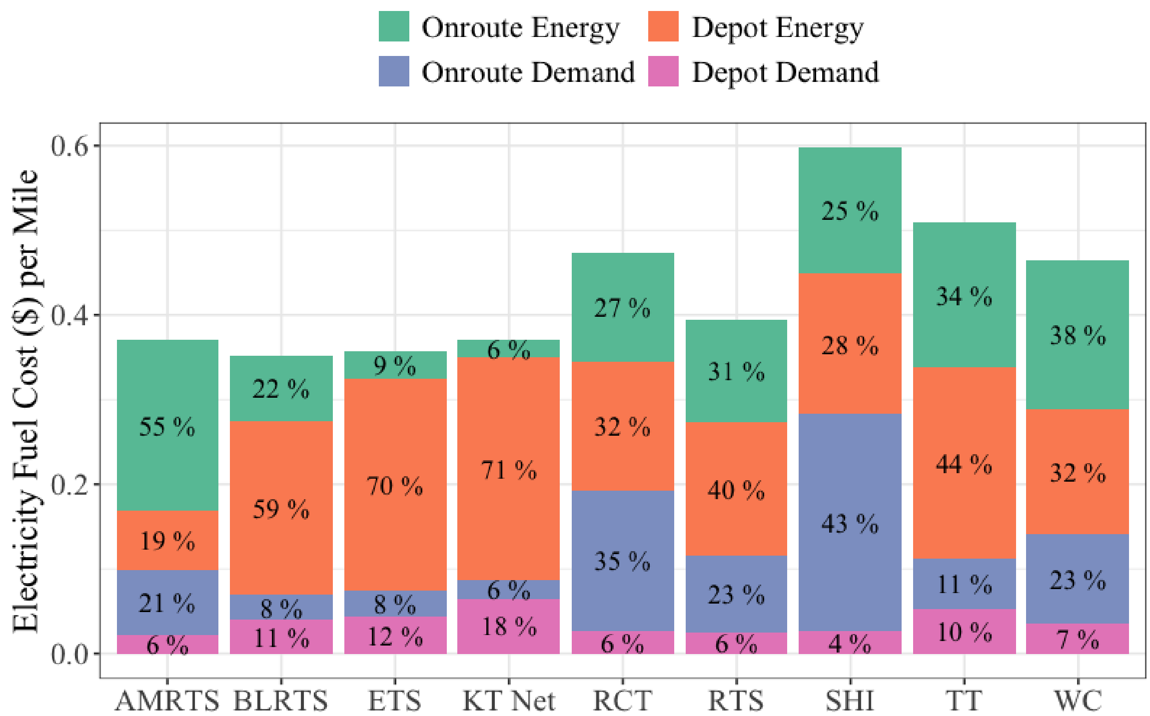

Figure 26. Average electricity cost per mile of full battery electric bus fleet for low efficiency value sensitivity analysis. The labeled numbers represent the individual cost component as the percentage of the total operation cost.

Table 22. Daily cost of on-route and in-depot charging per transit agency, low efficiency value sensitivity analysis.

Agency	On route Energy Cost ($/day)	On route Demand Charges ($/day)	Depot Energy Cost ($/day)	Depot Demand Charges ($/day)	Total Cost ($/day)
AMRTS	59	23	0	0	82
BLRTS	12	4	21	6	43
ETS	19	17	101	19	156
KT Net	4	4	37	6	51
RCT	91	119	59	12	281
RTS	309	231	222	31	792
SHI	139	241	91	19	490
TT	40	14	36	6	96
WC	63	38	28	6	135

The second sensitivity analysis was done using the higher efficiency value from the Proterra specification sheet for the Catalysts 40-foot bus. The BEBOP Model shows that using a constant efficiency of 0.615 miles/kWh results in a reduction from 8 to a total of 4 charging stations (Figure 27). The total daily on-route charging energy consumption is 2,980 kWh with 89 charging events compared to 4,557 kWh and 153 charging events in the base case scenario.

The higher efficiency model result shows a decrease in the number of charging stations serving the Southern Humboldt Intercity, the Redwood Coast Transit routes, and Eureka Transit Service. Arcata Transit Center has the most utilized charger in terms of energy usage, consuming 1,174 kWh daily (Table 23). Conversely, Benbow KOA is the least utilized charger in terms of energy usage, consuming 376 kWh daily.

Table 23. Charger location, daily electricity consumption, daily number of charging events, and daily time of usage for high efficiency value sensitivity analysis.

Stop Location	Total Daily Energy (kWh)	Number of Charging Events	Time of usage per day (min)	Regular Stop Count	Break Stop Count
Arcata Transit Center	1174	44	264	34	10
Benbow KOA	376	5	68	1	4
College of the Redwoods	750	35	132	26	9
Trinidad Park & Ride	680	5	187	1	4

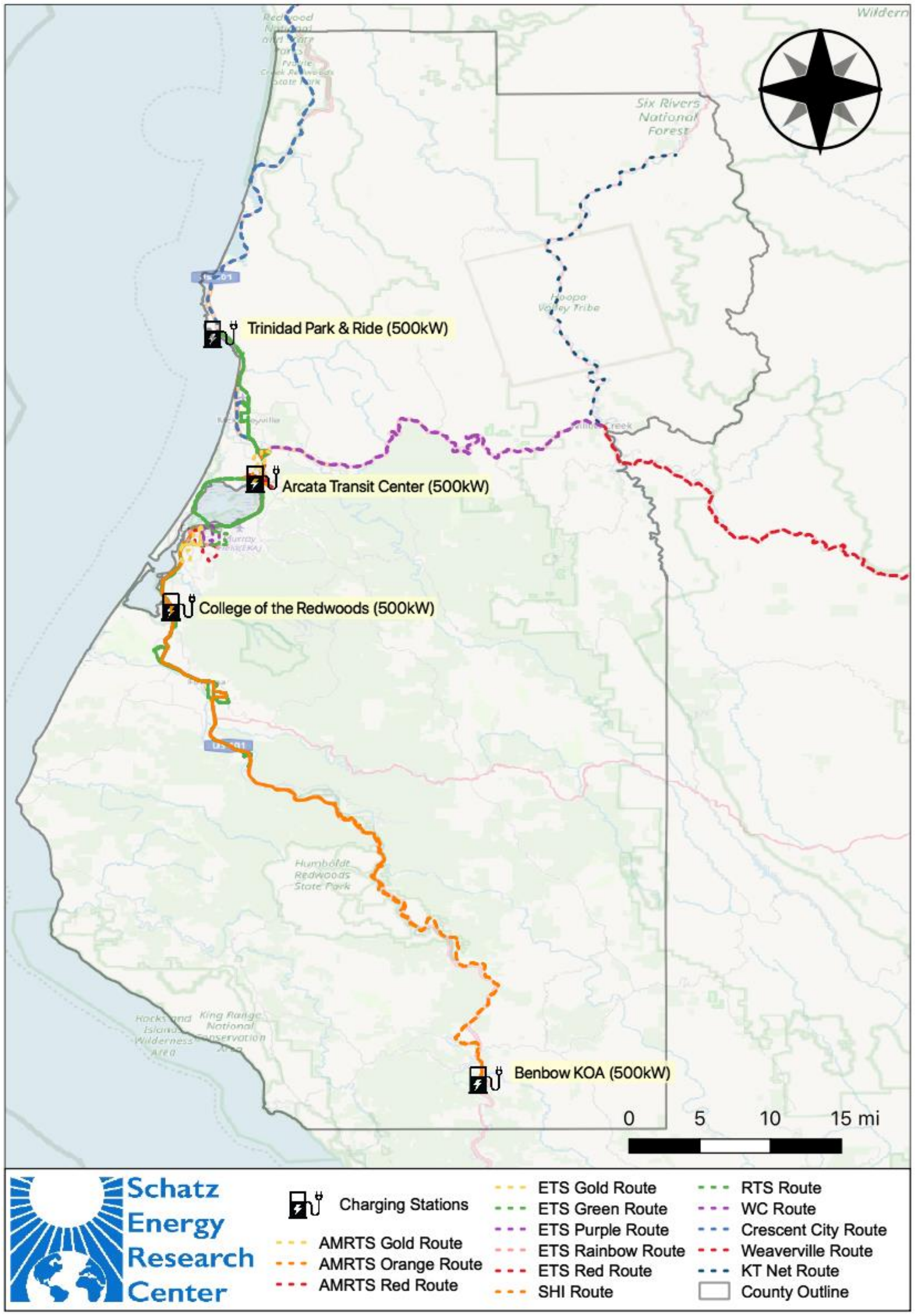

Figure 27. Modeled BEB on-route charging stations location and power rate for HTA, sensitivity analysis using efficiency value of 0.615 miles/kWh.

Using a high efficiency value results in a decrease in electricity fuel cost ($/mile), with most transit services having an average fuel cost below $0.30 per mile (Figure 28). Southern

Humboldt Intercity is the only route that reaches $0.30 per mile. The largest portion of the electricity cost for most transit services is again the depot charging energy cost. The daily cost of on-route charging is $347, while depot charging is $968. Daily total demand charges are $191 and $185 for on-route and depot charging respectively. The daily cost of on route and depot charging per transit agency is shown in Table 24.

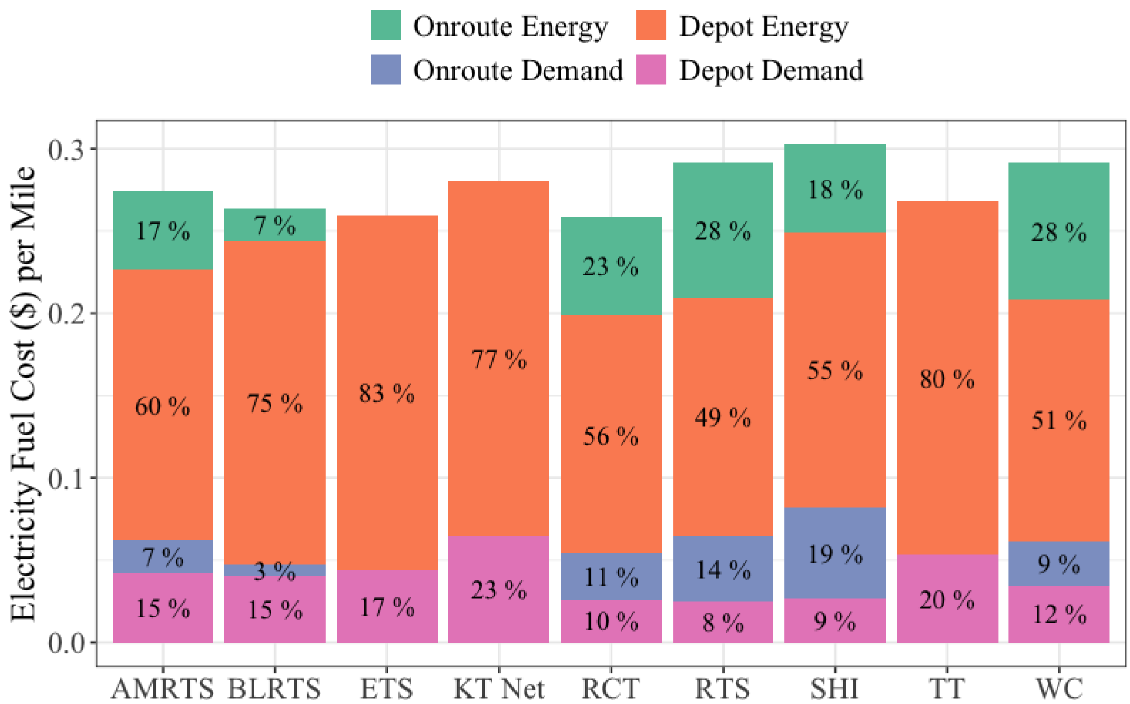

Figure 28. Average electricity cost per mile of full battery electric bus fleet for high efficiency value sensitivity analysis. The labeled numbers represent the individual cost component as the percentage of the total operation cost.

Table 24. Daily cost of on-route and in-depot charging per transit agency, high efficiency value sensitivity analysis.

Agency	On-route Energy ($/day)	On-route Demand ($/day)	Depot Energy ($/day)	Depot Demand ($/day)	Total ($/day)
AMRTS	14	6	48	12	80
BLRTS	3	1	30	6	40
ETS	0	0	121	25	146
KT Net	0	0	41	12	53
RCT	42	20	103	19	184
RTS	209	102	365	62	738
SHI	50	53	157	25	285
TT	0	0	50	12	62
WC	29	10	52	12	103

4.1: Impact of Bus Efficiency on the Number of Required On-Route Chargers

The number of on-route charging stations in the BEBOP sensitivity analysis results shows that the bus efficiency value is a sensible factor in determining the number of on-route charging stations output (Figure 29). The number of on-route charging stations increases as the bus efficiency decreases, as it is expected. A higher bus efficiency value means that the bus can travel longer distances (miles) per kWh.

The base case scenario with an efficiency of 0.528 miles per kWh results in a total of eight charging stations; the two sensitivity analyses with efficiencies of 0.465 miles per kWh and 0.615 miles per kWh result in 12 and 4 on-route charging stations respectively (removing the stations that exist outside Humboldt County). The lowest efficiency value used in the BEBOP Model that can be used to get a feasible result is 0.376 miles per kWh with a total number of twenty-three on-route charging stations (removing the stations that exist outside Humboldt County). Performance data analyzed for HTA's Proterra XR+ 330kWh 40 foot low floor bus indicates that HTA is experiencing a wide range of efficiencies from 0.33 to 0.67 miles / kWh across daily runs, with an average efficiency of 0.59. This indicates that a BEBOP Model results should be representative of the majority of daily runs each year, but there are days when electric buses may struggle to meet the demands of all transit routes in the County.

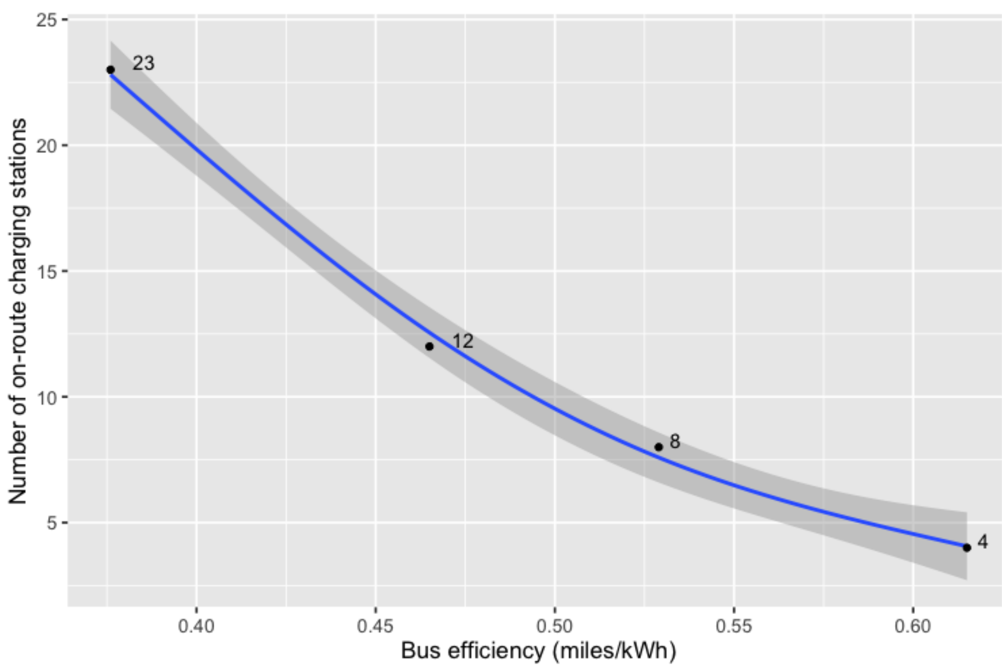

Figure 29. Bus efficiency and number of on-route charging stations results from BEBOP Model.

5: Conclusion

This report fills the gap in standardized technical support and software tools. The objective is to aid public transit systems in Humboldt County in making decisions regarding BEB management such as range predictions, utility rate analysis, and life cycle cost analyses. The results and recommendations in this report should be used as a guide to make informed decisions in consultation with informed stakeholders and consultants.

One of the main obstacles of BEB and infrastructure deployment is high capital cost. The current cost of BEBs are higher than conventional buses. However, capital costs are coming down and there are opportunities to solicit external funding to offset the high cost. Maintenance and operational cost could also reduce the BEB implementation and deployment. However, operational costs are heavily dependent on utility rates and bus performance.

The BEBOP Model results show that infrastructure needs are sensitive to the bus efficiency and route schedules. Early experience by HTA indicates that the performance of currently available buses may present a barrier to full electrification at this time. We recommend HTA focus on the electrification of the A&MRTS and ETS systems first that can be served with smaller 440kWh battery capacities. In addition, these systems can effectively operate without any on-route charging infrastructure. Electrification of these systems presents a lower risk option in an early market while operators gain experience operating electric buses. Furthermore, electrification of longer intercity routes may need to wait until larger battery capacity buses (660-kWh or larger) become available, or when the option of other technology (hydrogen fuel cell) is analyzed. This will prevent over-building on-route charging infrastructure.

In order to minimize on-route charging infrastructure and the additional headway that on-route charging introduces, small changes to route schedules that use on-route chargers with low criticality should be considered. For example, the SHI buses charging at Myers Flat or Dean Creek Resort can be charged at Benbow if the Benbow stop had additional layover time built into it. This would avoid building charging stations that have comparatively little. Note that the BEBOP Model should be run every time there are significant schedule changes in order to assess the potential impact to charging requirements, charging schedules, and costs.

To accommodate the unique operational needs of BEBs, transit agencies might have to adjust operational schedules. Layover and headway introduced from charging under the base case scenario in the presented results show that adjusting schedules could be cost effective. The charging infrastructure requirements need to be well understood and communicated between all stakeholders (original equipment manufacturers (OEMs), local utilities, construction architecture and engineering companies, public works, local and state DOTs, and local planners).

CHAPTER 5: ELECTRIFICATION STRATEGIES AND RECOMMENDATIONS

The creation of a comprehensive electrification road map can help transit agencies to transition the bus fleet from fossil fuels to BEBs. Proper planning, coupled with staged BEB infrastructure will allow transit agencies to electrify their fleets within budget requirements and without impact on current operations and service.

1: Fleet Electrification Strategy

Pilot deployments are a good way for transit agencies to gain experience with BEBs and the associated infrastructure. The BEB currently operated by HTA will be informative and scalable to allow a transition to a larger fleet deployment. Deploying a limited number of BEBs and charging equipment in a cost-effective manner can limit the disruption on current operations. Electrifying an entire fleet is a complex transition that requires appropriate planning. By first electrifying simple routes the transit agencies can experience the new technology, asses impact to operations, maintenance, training, and plan for future route electrification. HTA recommends to electrify the routes in the Arcata and Mad River Transit System (A&MRTS) and Eureka Transit System (ETS), and to track tech progress regarding electrifying other routes.

2: Near-Term Funding Opportunities

With limit funds for grant programs, stakeholders can find or suggest other financing strategies to enable HTA to afford the higher upfront cost of ZEVs by leveraging anticipated operating savings. Multiple bus manufactures have been offering leases, particularly battery leases which enable pricing for the vehicle at the same level as a diesel bus. Other proposed financing approaches such as tariffed on-bill financing and energy saving performance contract models can be used as well. Although finance alone is rarely sufficient to overcome barriers to enable investment in clean technologies, it can be a useful tool, particularly to address first cost barriers and enable further leverage of limited government funds.

Deployment planning: A program could help agencies plan electric bus deployments, including infrastructure investment plans, operations and charging management plans, route prioritization, and identify grants, financing opportunities, and utility support. Alternatively, technical assistance grants could be provided to agencies to help them hire a consultant to do this planning.

One potential funding opportunity is the PG&E EV Fleet Program. The program will help transit agencies to install EV make-ready infrastructure to support their fleets. The infrastructure is divided in 3 segments (Figure 30):

- To the meter (TTM), these are the utility upgrades, it can be brand new electric infrastructure or upgrades to the current electric infrastructure. All of these upgrades are free of charge to the transit agency if accepted into the program. PG&E pays for infrastructure upgrade cost up to the customer meter.

- Behind the meter (BTM), these are upgrades that include the meter, circuit breaker, conduit with wire going to the charger. PG&E pays an incentive $9,000 per vehicle (transit buses) up to 25 buses. The incentive is used to pay for infrastructure upgrades behind the customer meter.
- The transit agencies also qualify for charger rebates. The rebate depends on the charger rated power (Table 25) and it can offset up to 50% of the depot charger hardware.

The program allows transit agencies to incorporate back up ready systems for the public safety power shutoffs (PSPS) occurrences. Transit agencies can connect solar generation to the system, battery storage or diesel backup generators are all possible and can be connected to the EV charging infrastructure system. The transit agencies can still use and apply for grants while in the PG&E EV program, any grant funding gets stacked on top of the PG&E program.

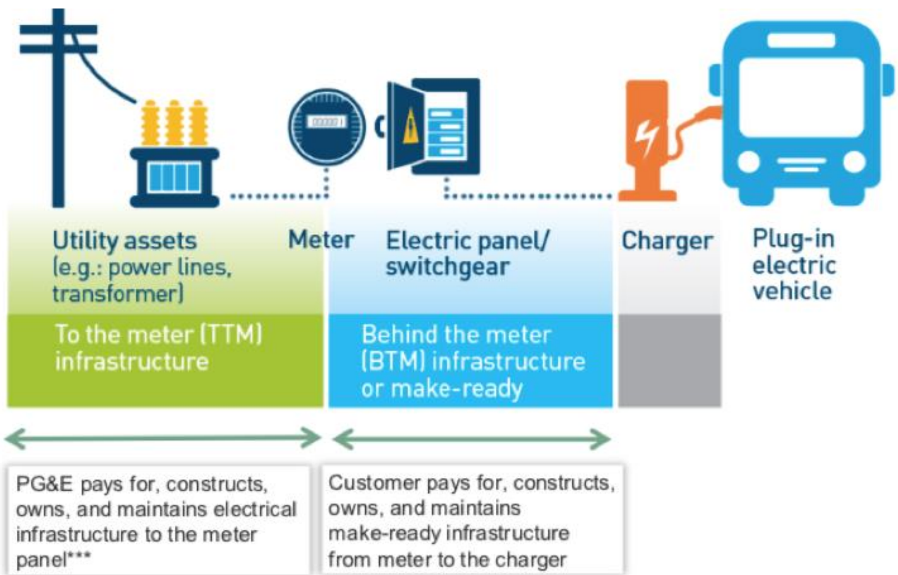

Figure 30. PG&E owned and EV fleet ownership program (PG&E, 2020).

Table 25. PG&E EV program charging equipment rebates (PG&E, 2020).

Charging equipment rebates for Schools, Transit Agencies and Disadvantaged communities	
EVSE power	**Max. rebate amount****
Up to 50kW	$15,000 per charger
50-150kW	$25,000 per charger
150kW+	$42,000 per charger

Customer-owned infrastructure	
Eligible for incentive up to capped amount based on vehicle sector	
Vehicle type	**Per vehicle incentive cap**†
Transit buses & Class 8 trucks	$9,000 per vehicle

Another funding opportunity is the Caltrans Strategic Partnership Grant. The California department of transportation has a sustainable transportation planning program to identify and address statewide, interregional, or regional transportation deficiencies on the State highway system in partnership with Caltrans. The transit component of the partnership grant will fund planning projects that address multimodal transportation deficiencies with a focus on transit.

Another funding opportunity is The Carl Moyer Infrastructure Application. It cofounds the replacement of diesel fuels heavy duty vehicles, engines and equipment, accelerates the commercialization of cleaner technology, and reduces air pollution impacts in disadvantaged and low-income communities. Eligible projects include cleaner on-road, marine, and agricultural sources. Projects may include engine re-powers, the purchase of new vehicles using alternative fuels, and engine retrofit devices approved by the California Air Resources Board (CARB). The District implements the program from funding received from CARB.

3: BEB Adoption Barriers and Limitations

Barriers to adopting battery electric buses are divided into three major elements: vehicle and batteries, agencies and operators, and grid and charging infrastructure. One of the most fundamental barriers to procuring battery electric buses is the lack of information on the technology. Given the emerging nature of BEBs it is difficult to find reliable, up to date sources of information to produce accurate analysis of the efficacy of adopting BEBs. Uncertainties remain regarding the battery life cycle and the residual value of the BEBs at their point of retirement. Almost no BEBs have been operating long enough to reach their estimated decommission date, so there is limited information on how long BEBs will actually last and how old buses will perform.

Another barrier of transit fleet electrification is the rage and power limitation of BEBs. The specifications of BEBs currently available varies widely, depending on manufacturer and model. However, BEB performance has improved over the last years. Early performance issues required two BEBs to replace the work of a diesel bus in 2011. By 2016 the rate of replacement from diesel to BEB was almost equal, with 1.03 BEBs needed on average to replace each diesel bus (WRI, 2019). Some bus routes with limited mileage such as feeder routes or downtown circulators are compatible with the range of BEBs. The current range of BEBs can be a limitation for longer mileage routes.

Range is an issue of variability of battery performance. Batteries lose effectiveness in cold weather and hot temperatures can decrease the battery range, since running air conditioning and other cooling services takes a significant amount of battery capacity. In addition to range limitations, power limitations are also a key barrier. BEBs face difficulties navigating steep topography and hilly terrain. Hi passenger loading is also an issue that revealed the power limitations of BEBs (WRI, 2019).

The adoption of BEBs also introduces the struggle to deal with charging time requirements. Conventional diesel buses have a longer range per fuel-up and can refuel faster than BEBs. BEBs in longer routes require on-route charging between hours of operation and this can present a barrier for BEB adoption. Grid and charging infrastructure are critical elements of transit fleet electrification projects. Charging stations are still an emerging technology with high cost, cumbersome physical requirements, and reliability issues.

These technological barriers represent an issue for BEB adoption. The choice of which fuel technology to use for transit buses is an important issue for transit agencies in terms of budget impact, operating performance, bus purchasing decisions, and related fueling and depot infrastructure. Alternative fuel technologies such as hydrogen fuel cell buses can be an option for longer mileage routes. A mixed fuel fleet adoption should be considered to serve the Humboldt transit needs. A combination of electric buses and fuel cell buses meets the requirements of California mandates. However, a mixed fuel fleet will introduce a higher complexity in management resources.

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APPENDIX A: SUMMARY OF ADAPTATION PLANNING STRATEGIES FOR TRANSIT AGENCIES

The main adaptation strategies for metropolitan transit agencies summarized in the FTA pilot projects (FTA, 2014) are

- Developing disaster operations plans
- Proactively designing new and more resilient facilities and infrastructure and reassessing existing facilities
- Integrating vulnerabilities to climate change impacts into asset management practices
- Working with local public works departments
- Proactively inspecting and maintaining assets
- Adding backup power/generator capacity
- Relocating critical assets prior to damage or impact
- Improving storm drain capacities
- Communicating plans and information with the public and stakeholders
- Documenting and disseminating institutional knowledge
- Integrating the adaptation and analysis solutions developed into current management practices

The implementation of the adaptation strategies should follow the five decision making principles as outlined in the PIRC report. The decisions should be guided to (Governor's Office of Planning and Research, 2017):

1. Prioritize integrated climate actions.
2. Prioritize actions that promote equity and foster community resilience.
3. Coordinate with local and regional agencies.
4. Prioritize actions that utilize natural and green infrastructure solutions and enhance and protect natural resources.
5. Base all planning and investment decisions on the best available science.
6.

APPENDIX B: FRAMEWORK FOR INTEGRATING CLIMATE CHANGING INTO PLANNING PROCESSES

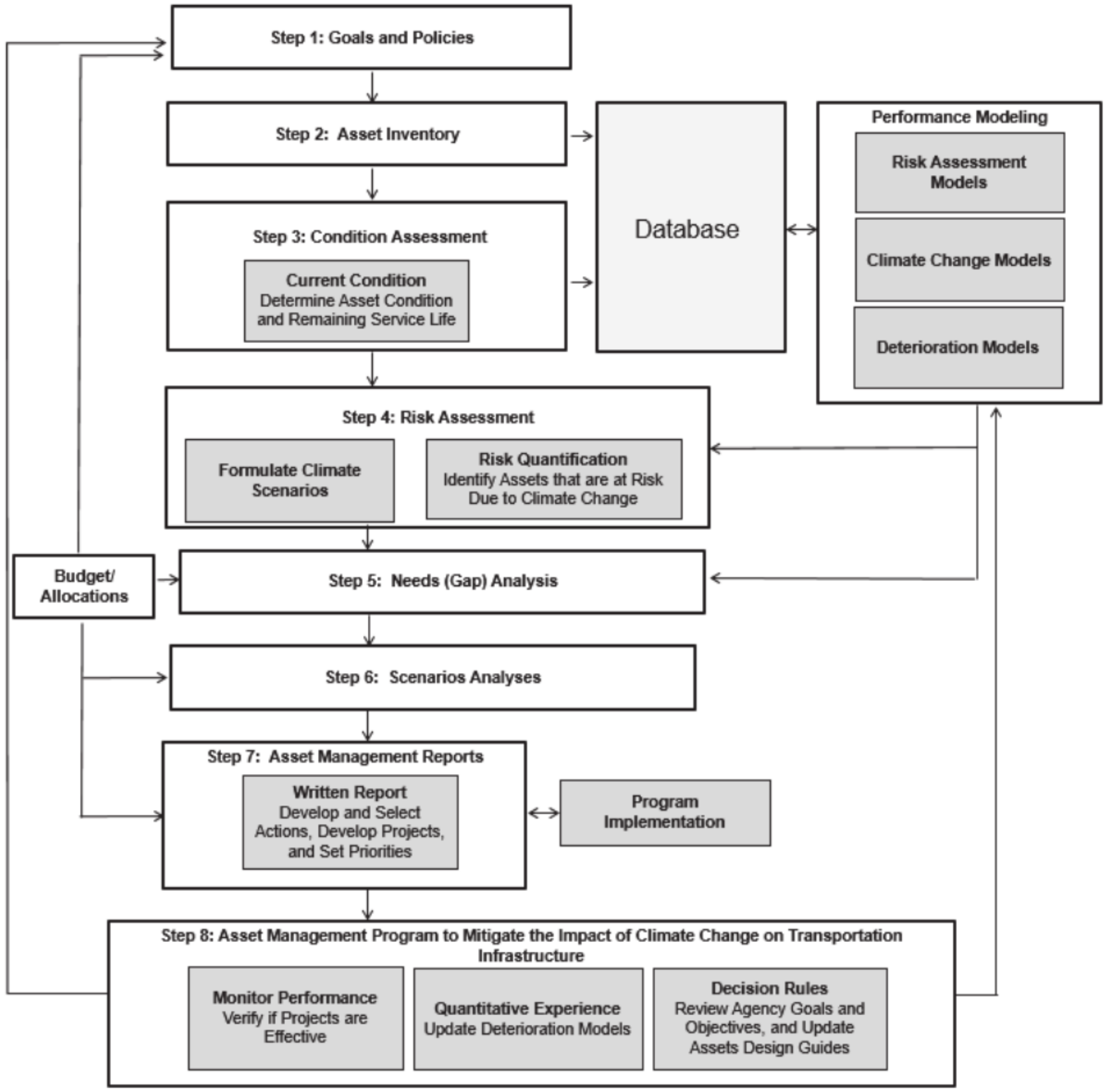


Figure 31: Framework to Integrate Climate Change Impact Analysis into TAM Practices, adopted from Ortega (2018).

APPENDIX C: DETAILED BEBOP MODEL METHODOLOGY AND RESULTS

1: Transit Route Data

Optimizing the fleet of BEBs and the system of EVCs must consider both on-route charging and in-depot charging at garages as well as the best mix of electric bus models. The optimal system solution can be obtained applying a mixed integer linear programming (MILP) model using commercial or open source solvers. The optimal solution for the system of BEBs and EVCs will identify how many charging locations are required, where they need to be located, and what the charging rate and mechanism needs to be for each location, as well as when, where, and for how long each BEB gets charged and how many BEBs of each model would be required to serve HTA without altering current schedules and routes.

In the Model's objective function, we seek to minimize the sum of the amortized capital costs over a period of 15 years for the charging infrastructure and over a period of 10 years for battery electric buses, using a 3% discount interest rate, and of the electricity operating costs associated with charging BEBs.

Transit route and schedule data were obtained from the sources below and merged to create a single input data set that includes all revenue and deadhead miles:

- Trillium Transit: the static component of the General Transit Feed Specification (GTFS) contains geographic information such as stops, routes, trips, and other schedule data (Trillium, 2019).
- Humboldt Transit Authority: bid hours which show deadhead miles and bus number corresponding to the *block_id* field in the GTFS feed.
- Blue Lake Rancheria: confirmation of no deadhead miles
- Klamath Trinity Non-emergency Transit: confirmation of no deadhead miles

The static component of the General Transit Feed Specification (GTFS) contains transit schedule and geographic information such as stops, routes, trips, and other data for the relevant agencies. GTFS datasets consist of multiple files in a comma-separated value (CSV) format. The CSV files in a GTFS dataset are relational, this means that multiple files contain related information stored as tables of rows (records) and columns (fields) and this allows a link to be established between separate files that have a matching field (Trillium, 2019).

The GTFS data fields used in the input file for the Model are (Trillium, 2019):

- ***Block_id*** – A block consists of a single trip or many sequential trips made using the same vehicle, where a passenger can transfer from one trip to the next just by staying in the vehicle. Block – refers to a vehicle schedule which is the daily assignment for an individual bus. One or more runs can work a block. A driver schedule is known as a "run".

- ***Stop_id*** – Identifies the serviced stop. A stop may be serviced multiple times in the same trip, and multiple trips and routes may service the same stop (Figure 32).
- ***Route_id*** – Represents a transit route. A route is a group of trips that are displayed to riders as a single service (Figure 32).
- ***Stop_sequence*** – Order of stops for a particular trip. The values must increase along the trip but do not need to be consecutive.
- ***Shape_distance_traveled*** – Actual distance traveled along the associated shape (a shapefile is a format for storing the geometric location and attribute information of geographic features), from the first stop to the final stop specified in the GTFS record. This field specifies how much of the shape to draw between any two stops during a trip. Values must increase; they cannot be used to show reverse travel along a route (Figure 33).
- ***Arrival/departure _time*** – Time at a specific stop for a specific trip on a route. If there are not separate times for arrival and departure at a stop, values are the same.
- ***Stop_lat & stop_long*** – Geographical coordinates (latitude and longitude) of a stop or a station. The field value must be a valid WGS 84 value from -180 to 180.
- ***Calendar*** – Represents dates for service IDs using a weekly schedule. Specify when service starts and ends, as well as days of the week where service is available.

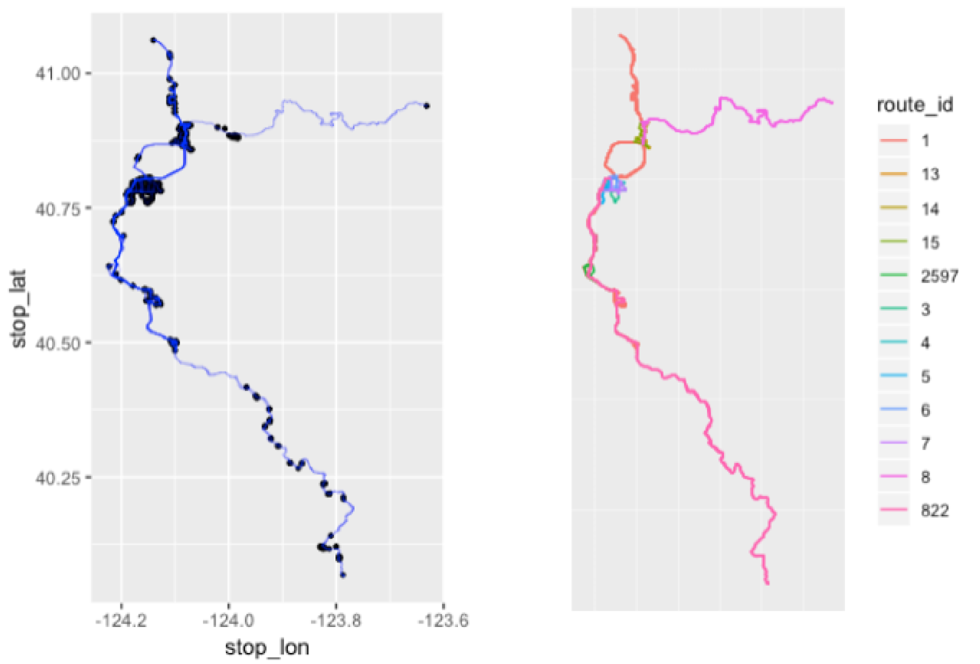


Figure 32. (Left) HTA bus stops locations. (Right) HTA routes by id. The stop location data is mapped using the relational latitude and longitude associated with each stop. The routes are mapped using the shapefile geometry data in the GTFS feed.

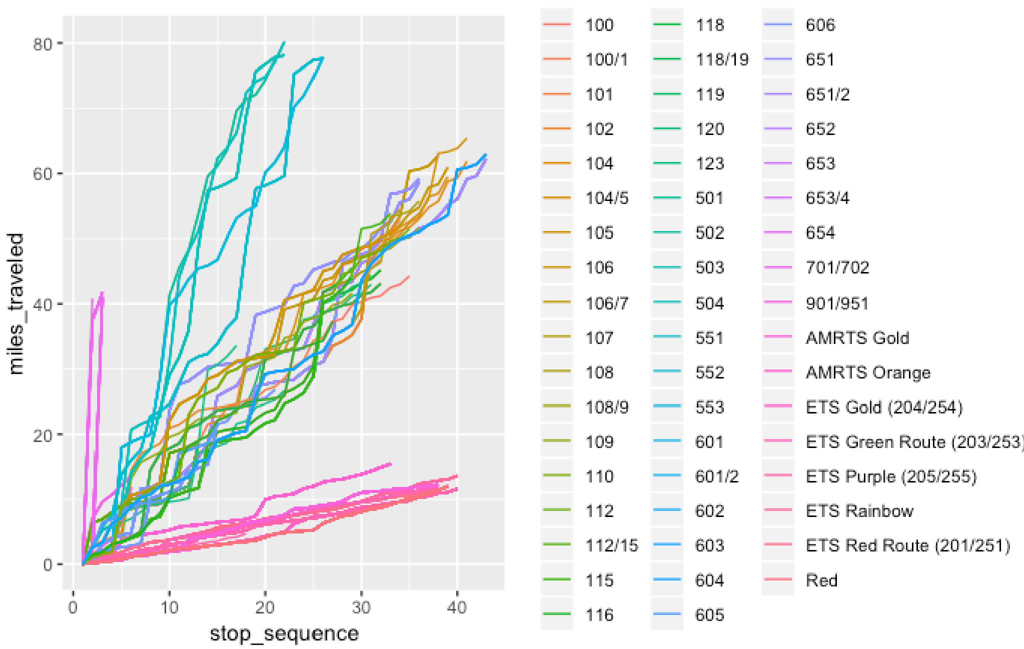


Figure 33. Distance traveled (miles) for each block-id in the Humboldt Transit Authority GTFS feed. The block_id in the GTFS does not represent the actual number of buses operated by HTA. The number of buses is less than the number of block_ids.

The GTFS data was further processed to account for:

- Bus route naming inconsistencies such as a different ***stop_name*** and/or ***stop_id*** reported from different transit agencies in their respective GTFS feed.
- The ***block_id*** field in the Humboldt Transit Authority GTFS data was modified to account for the actual bus number provided by HTA (
- Table 26).
- The ***shape_distance_traveled*** was modified as well to account for the cumulative distance of the new bus number (Figure 34).
- The ***arrival/departure_time*** in the GTFS feed had the same values, a two-minute interval time was added to the departure time column to allow on route charging in regular stops.
- Furthermore, the deadhead miles were added to the input file by using bid hours data provided by HTA. Deadhead miles are miles when the bus is traveling without fare paying customers. These miles are important to quantify from a BEB range viewpoint.
- New stop sequence, a new stop sequence was calculated match the new block_id

For future research on public transit electrification the GTFS+Runcut file from Syncromatics could be used as input for the Model (GMV, 2016). The difference between the regular GTFS feed and GTFS+Runcut feed is that GTFS uses the feed to provide information to the public for stops, routes, trips, and other schedule data. GTFS does not know how the service is operated in order to display information to the public. Syncromatics uses the Runcut GTFS file to group trips into runs, and in return it is able to provide on-time performance at various levels: trips, blocks and routes. However, the requirements of the extension would need to be adopted by the transit agencies.

Table 26. Block_id from GTFS data and bus number provided by Humboldt Transit Authority

Block_id (GTFS)	Bus Number (HTA)
Redwood Transit System	
100 & 101	889
102 & 116	888
108 & 109	891
104 & 105	894
106 & 107	890
112 & 115	892
110 & 123	886
118 & 119	896
120	893
Eureka Transit System	
204 & 254	68
201 & 251	66
203 & 253	69
205 & 255	67
Southern Humboldt Intercity	
501	512
502 & 503	514
504	410
Willow Creek	
701 & 702	714

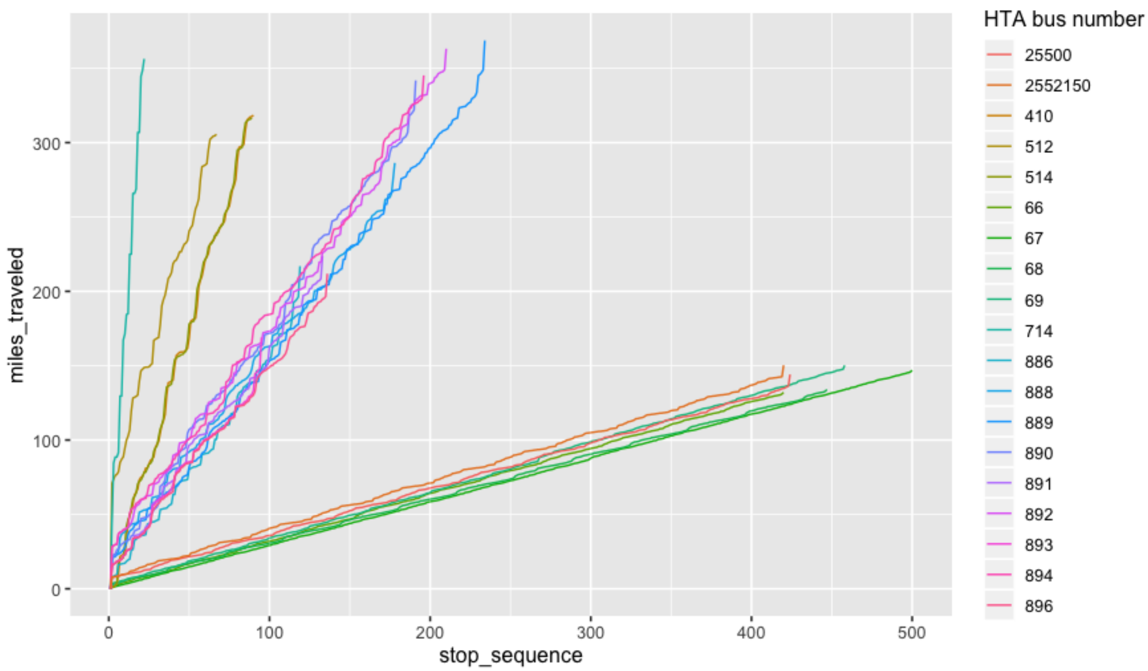


Figure 34. Miles traveled by bus number provided by HTA. The miles traveled and the total stop sequence increased with the new bus number, compared to Figure 4 data from GTFS feed.

2: Battery Electric Bus and Charging Infrastructure Specifications

Three Proterra Catalyst bus models (Table 27) are considered by the Model, each with a different battery pack capacity. This is done with the purpose of letting the Model select the optimal bus/battery size according to the route depending on the range and the cost of the bus (Table 28). The E2 max series bus is advertised in Proterra's website, however it is not yet commercially available. For Model structure constraints, a constant efficiency of 0.529 miles per kWh is assumed for all buses across all routes and seasons.

Table 27. Proterra Catalyst 40-foot bus performance specifications (Proterra, 2019).

	XR Series (XR)	E2 Series (E2)	E2 Series (E2 Max)
Nominal Range (miles)	164	305	426
Total Energy (kWh)	220	440	660
Max Overhead Charge Rate (kW)	163	331	397
Max Plug-in Charge Rate (kW)	73	120	120
Operating Efficiency (mile/kWh) – DuoPower*	0.604	0.537	0.514
Operating Efficiency (mile/kWh) – ProDrive*	0.573	0.490	0.465
*Operating efficiencies approximated from simulations based on Altoona testing results, and will vary with route conditions, weather, vehicle configuration and driver behavior.			

Table 28: Assumed electric bus costs and specifications.

Proterra Catalyst 40-foot Model	Design Battery Capacity (kWh) [a]	Effective Plug Charging Rate (kW) [a]	Effective Overhead Charging Rate (kW) [a]	Cost [b]
XR	220	73	163	$739,567
E2	440	120	331	$771,869
E2 Max	660	120	397	$804,171

a: From Proterra published specifications sheet.

b: From California GSA pricing. E2 Max price was not published, so was calculated from the XR and E2 models.

One of the constraints in the MILP Model specifies that the BEBs must always return to the depot at the end of the day with at least 15% of the advertised battery capacity as a safety reserve factor. Furthermore, since we also derate the advertised battery capacity to 80%, the BEBs are only allowed to operate with 68% (80% after derating * (1 - 15% safety reserve)) of the advertised battery capacity. The modeled operation range is impacted as consequence of the battery derating and the BEB efficiency applied in the Model. The BEB efficiency value of 0.529 miles/kWh used in the Model is the average of the DuoPower and ProDrive XR, E2, and E2 Max models.

Table 29. Battery Electric Bus assumed parameters

Proterra Catalyst 40-foot Model	Effective Battery Capacity (kWh) [a]	Effective Range (miles) [b]
XR	149	79
E2	299	159
E2 max	449	237

a: Calculated as (battery capacity * 0.8) * (1 – safety factor). The 0.8 factor accounts for a 20% battery capacity degradation. The (1 – safety factor) is a 15% safety reserve.

b: Calculated as effective battery capacity times the bus efficiency in miles per kWh.

The Model accounts for all losses from charger to battery management system (BMS) to conversion to miles traveled (Figure 35). We assume the bus efficiency values reported by the bus manufacturer (i.e. E_{bus}) are calculated using battery output current and voltage reported via on-board telematics, and therefore do not account for BMS losses (i.e. E_{BMS}) or losses from the conversion from chemical to electrical energy (i.e. $E_{battery}$).

We also assume that E_{bus} effectively uses net output current, meaning that regenerative braking during Altoona testing is captured in this efficiency number. Note also that Altoona procedures specifically do not capture HVAC loads, but do capture headlights and interior lighting. Altoona tested efficiency refers to the vehicle efficiency as reported by the Altoona Bus Research and Testing Center, which is based on dynamometer testing on simulated courses that represent driving central business district, arterial, and commuter routes (BRTC, 2019)

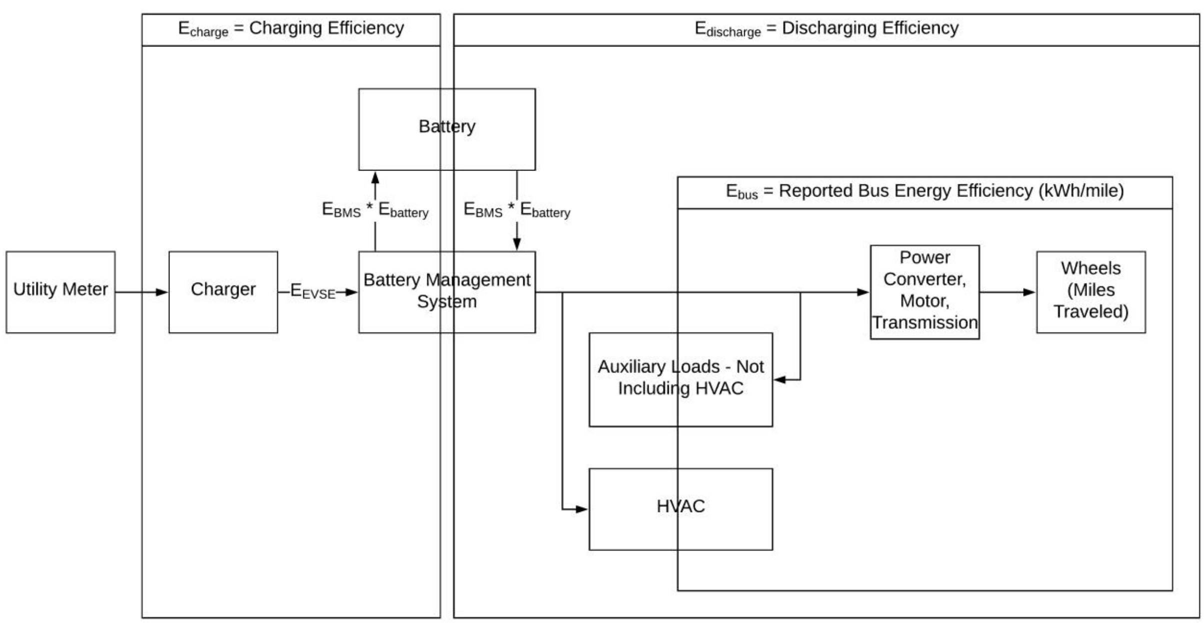


Figure 35. Energy flow diagram from utility meter to BEB, and associated various efficiency loss terms.

Table 30 summarizes assumed charger specifications and costs for the three EVCs considered by the Model.[22] Charger performance depends on the bus maximum allowed charging rate which varies by bus model. A major consideration in planning for BEBs charging infrastructure is selecting suitable locations. Fast chargers "*can only be connected to the grid where utilities can provide a dedicated supply line capable of delivering the very high currents demanded*" (Air Resources Board, 2015). Furthermore, fast chargers can only be deployed where an agency has access or rights to property to install the infrastructure.

Table 30: Assumed EV charger costs and specifications.

Charger Type	Bus model	Effective Energy Delivery Rate from the grid to the Battery (kWh / min) [a]	Cost [b]
50kW plug [c]	All	0.78	$50,000
150kW plug [d]	XR	1.05	$286,000
	E2	1.72	
	E2 max	1.72	
500kW overhead [d]	XR	2.34	$599,000
	E2	4.74	
	E2 max	5.67	

a: Effective charging rates are determined by the maximum charging rate for each bus type as shown in

Table 28.

b: Cost estimates from California Air Resources Board Fleet Cost Tool. (Installation cost included)

c: Assumes a charger efficiency of 99% (from a product specification sheet) and a battery management system efficiency of 95% (Consortium, Canadian Urban Transit Research and Innovation, June 12, 2018) for a combined efficiency of 94%. Reflects energy delivered to the battery, not energy from the grid.

d: Assumes a charger efficiency of 91% and a battery management system efficiency of 95% for a combined efficiency of 86% (Consortium, Canadian Urban Transit Research and Innovation, June 12, 2018). Reflects energy delivered to the battery, not energy from the grid.

3: Electricity Rate Structure and Cost

The cost of charging a BEB depends on both the energy costs at the time of charging and on the peak demand charges. Peak demand charges are calculated on the maximum 15-minute average power (kW) the BEB draws from the grid during a charging event, regardless of time of day. The BEBOP Model optimizes for charging events to occur during off peak and super off-peak hours. Furthermore, if there is no energy storage used to buffer the impact on the electricity grid, the associated demand charges can be high.

Potential options that would mitigate the impact of peak demand charges on the operation of electric transit buses charging on route and overnight include:

[22] Note that costs assumed by the model differ from the costs presented in the results of this report because report cost results are taken from an estimate from an electrical contractor. The cost assumed by the model is a static generic value based on literature that is used to allow identification of the optimal location of chargers.

- Increasing electric bus efficiency.
- Managing electric bus charging (increase number of charging stops, charge at lower charging power, employ demand response technologies).
- Employing energy transfer technology (battery swapping, load management system).

The BEBOP Model uses Pacific Gas and Electric's (PG&E) EV-Large electricity rate structure associated with their EV Fleet Program to calculate the demand and energy charges associated with the operation of BEBs (Table 31 & Figure 36). Note this new tariff structure replaces demand charges with new subscription pricing (PG&E, 2020).

Table 31. PG&E EV Large tariff. (PG&E, 2020).

EV-Large (over 100kW)	EV Rate	Equivalent Rate: A10
$185	Subscription Charge (per 50 kW)	
	Demand Charge (kW)	$11.26 / kW
Summer Energy Rates		
$0.31	Peak	$0.25
$0.11	Off Peak	$0.16
$0.09	SOP (Super off peak)	n/a
Winter Energy Rates		
$0.31	Peak	$0.22
$0.11	Off Peak	$0.20
$0.09	SOP	$0.19

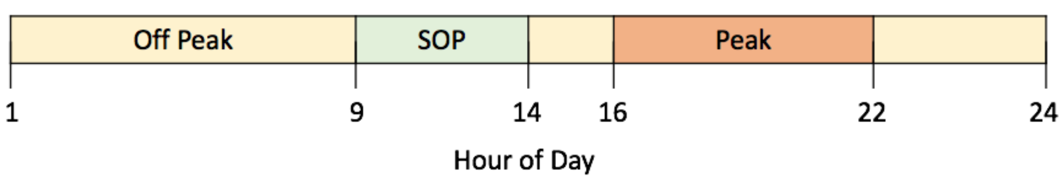


Figure 36. Hour of the day rate structure used in the Model. Rate structure hours are equivalent to tariff A-10

4: Optimization Methods

BEBOP considers a full fleet conversion to BEBs. The Model optimizes based on minimization of capital (bus & charger infrastructure) and fuel (electricity energy and demand) costs. BEBOP optimizes for the location of charging stations, the battery size of the electric buses, and the type of charger for each charging location.

4.1: Optimization Approach

The battery electric bus optimization (BEBOP) employs a mixed integer linear programming (MILP) Model. MILP is a form of programming that minimizes (or maximizes) a linear objective function subject to one or more constraints with the condition that some of the variables can only take on integer values (Chinneck, 2016). An objective function is an algebraic expression that describes the quantity that must be minimized or maximized. A constraint is restriction in the problem and is expressed as a linear inequality.

An important special case in the MILP Model is a decision variable that must be either 0 or 1 at the solution. Such variables are called binary integer variables and can be used to model yes/no decisions. Integer variables are applicable to resources that are not divisible. For example, the variables to decide on the number of charging stations or the number of buses in a fleet must be integer values. It is not possible to have 0.43 charging stations or 0.69 buses. Since integer variables make an optimization problem far more difficult to solve, the amount of memory and the solution times required may rise exponentially as the number of integer variables increases.

The BEBOP conducted for HTA is set up in the R programming language and uses an R-based optimization modeling package (*OMPR*) (Schumacher, 2019) to build the MILP Model. The Model is solver independent and thus it offers the possibility to solve the problem with different solvers. The R optimization infrastructure (*ROI*) package provides infrastructure to model optimization problems in various formats. Furthermore, ROI administers different solvers and functions to read and write optimization problems in various formats (Theußl, et al., 2017).

Once the MILP Model is built, consisting of an objective function, decision variables, and constraints, the Model then needs to be feed into a MILP solver. There are different commercial and open source solvers available; the solver used for this problem is the IBM CPLEX Optimizer (IBM, 2019). The ROI package allows an R interface to the CPLEX solver for mixed integer linear programs, the Rcplex package is available in Linux/Unix and Windows systems.

4.2: Mixed Integer Linear Optimization Algorithm

The optimization method is adapted and modified from the Liu and Wei's approach (Liu & Wei, 2018). Other reports presenting BEB research use the same methodology approach of a MILP and the similar set notation (Xylia, Leduc, Piera, Silveira, & Kraxner, 2017), (Andrews, Dogru, Hobby, Jin, & Tucci, 2012). The following notation is based on the indices used by Liu and Wei and has been expanded to include:

1) Variable bus specifications,

2) Differentiate between different types of stops, and

3) Energy and demand costs of electricity.

4.2.1: Indices:

i = index of bus in HTA territory (entire set I)

j = index of all stop categories, including long break, short break, and regular stops (entire set J)

k = index of stop sequences (entire set K)

s = index of the Proterra bus models (entire set S)

Sequenced Index

r = sequenced unique combination of bus i and stop sequence k. $\{r_{index}|index \in\}$ e.g., $r_n = (i, k)$

4.2.2: Parameters:

b_s = real operating (available?) battery capacity of bus model s (*kWh*)

c^G = daily cost associated with building an in-depot charging station *($/day/station*)

c_j^{R150kw} = daily cost associated with building a 150 kW on-route charging station at stop *j* (*$/day/station*)

$c_{j\in\Omega_j}^{R500kW}$ = daily cost associated with building a 500 kW on-route charging station at j that <u>are</u> break stops (*$/day/station*)

$c_{j\notin\Omega_j}^{R500kW}$ = daily cost associated with building a 500 kW on-route charging station at j that <u>are not</u> break stops (*$/day/station*)

$d_{i,k-1,k}$= route distance between terminal sequence $k-1$ and k for bus i (*miles*)

e_i = the maximum possible energy delivered to bus i at any stops (*kWh*)

η^B = bus electric motor efficiency (*mile per kWh*)

η^G = charging efficiency for the in-depot charger

η^R = charging efficiency for the on-route charger

f_s = daily cost of purchasing the bus model s (*$/bus/day*)

h = total available hours of in-depot charging overnight (*hr*)

g = name plate in-depot charger charging capacity (*kW*)

m_i = the total daily mileage travel by bus i (*miles*)

$o_{i,k}$= the stop duration for bus i at stop sequence k (*min*)

r_s^{150kW} = the max demand bus model s can draw from 150 kW on-route charger (*kW*)

r_s^{500kW} = the max demand bus model s can draw from 500 kW on-route charger (*kW*)

p = number of buses to be replaced with electric buses

t^G = cost of electricity for overnight depot charging (*$/kWh*)

t^D = cost of each increment of 50 kW of electricity demand

$t_{i,k}^R$ = cost of electricity at the time when bus i is at stop sequence k (*$/kWh*)

Ω_j = set of paired bus i and stop sequence k at stop j

Φ_j = set of stops that serve as a break stop for at least one bus

Ψ_{jt} = set of conflict bus terminal sequences at stop j at time t

Ϫ = set of paired bus i and last stop sequence k for each bus

4.2.3: Decision variables:

D^G = bracketed instantaneous peak electricity demand in depot in 50 kW increments

D_j^R = bracketed instantaneous peak electricity demand at the in-route charger at j in 50 kW increments

$E_{i,k,s}^{R150kW}$ = total electric energy (*in kWh*) drawn by the 150 kW in-route charger for bus i at stop sequence k by bus model s

$E_{i,k,s}^{R500kW}$ = total electric energy (*in kWh*) drawn by the 500 kW in-route charger for bus i at stop sequence k by bus model s

$E_{i,k}^R$ = total electric energy (*in kWh*) drawn by the in-route charger for bus i at stop sequence k

E^G = total electric energy (*in kWh*) drawn by in-depot chargers for all buses overnight

$A_{i,k}$ = accumulative mileage traveled by bus i at stop sequence k

P^G = peak energy demand at depot (*kW*)

P_j^R = peak energy demand at the location of stop j *(kW)*

$$X_{i,k,s}^{500kW} = \begin{cases} 1, & \text{if bus } i \text{ operating bus model } s \text{ gets charged at the on-route 500 kW charger charging stations at stop sequence } k \\ 0, & \text{otherwise} \end{cases}$$

$$X_{i,k,s}^{150kW} = \begin{cases} 1, & \text{if bus } i \text{ operating bus model } s \text{ gets charged at the on-route 150 kW charger charging stations at stop sequence } k \\ 0, & \text{otherwise} \end{cases}$$

Y^G = number of in-depot charging stations sited in depot

$Y_j^{R^{150kW}}$ = number of 150 kW on-route charging stations sited at stop j

$Y_j^{R^{500kW}}$ = number of 500 kW on-route charging stations sited at stop j

$$Z_{i,s} = \begin{cases} 1, & \text{if bus } i \text{ is replaced with bus model } s \\ 0, & \text{otherwise} \end{cases}$$

Each bus, i, operating bus model s runs through a set of stop sequence indexed by k. Each paired (i, k) is matched with a stop location indexed by j.

4.2.4: Optimization Model

The objective is to minimize the daily operation (i.e., electricity demand and energy) cost and amortized daily capital cost of operating a BEB fleet and building the supporting charging infrastructure:

Minimize the [amortized cost of buses] + [amortized cost of 150 kW charging stations] + [amortized cost of 500 kW charging stations] + [amortized cost of in-depot charging stations] + [demand charges for in-route charging] + [demand charges for in-depot charging] + [energy charges for in-route charging] + [energy charges for in-depot charging]

$$\begin{aligned} min \sum_{i\in I, s\in S} f_s Z_{i,s} + \sum_{j\in J} c_j^{R^{150kW}} Y_j^{R^{150kW}} + \sum_{j\in \Phi_j} c_{j\in\Omega_j}^{R^{500kW}} Y_j^{R^{500kW}} + \sum_{j\notin \Phi_j} c_{j\notin\Omega_j}^{R^{500kW}} Y_j^{R^{500kW}} + c^G Y^G \\ + \sum_{j\in J} t^D D_j^R + r^D D^G + \sum_{i\in I, k\in K, s\in S} t_{i,k}^R \left(E_{i,k,s}^{R^{150kW}} + E_{i,k,s}^{R^{500kW}}\right) + t^G E^G \end{aligned}$$

Subject to:

Constraint 1a mandates that each bus, i, operates only one bus model s.

Constraint 1a.alt can be used in place of 1a and in conjunction with 1b to iteratively determine the maximum feasible BEBs to be converted given a set of parameters.

Constraint 1b mandates that a total of p buses to be replaced with BEB(s).

1a) $\sum_{s\in S} Z_{i,s} = 1, \ \forall$

1a.alt) $\sum_{s\in S} Z_{i,s} \leq 1, \ \forall$

1b) $\sum_{s\in S, i\in I} Z_{i,s} = p$

Constraint 2 ensures the accumulative travel mileage before charging for each bus, i, does not exceed the actual, as opposed to nominal, model s range in miles.

2) $A_{i,k} + d_{i,k-1,k} \leq b_s * bus_{eff} + (1 - Z_{i,s})m_i,\ \forall(i,k), s$

Constraint 3 specifies only one type of charging event at most is allowed to happen.

3) $X_{i,k,s}^{150kW} + X_{i,k,s}^{500kW} \leq 1,\ \forall(i,k), s$

Constraint 4 ensures a charging event for bus model s could only happen if the i is running the corresponding bus model.

4) $Z_{i,s} \geq X_{i,k,s}^{150kW} + X_{i,k,s}^{500kW},\ \forall(i,k), s$

Constraint 5 specifies the accumulative mileage of bus i at the first stop sequence (i.e., the bus depot) is zero.

5) $A_{i,k} = 0,\ \forall(i, k = 1)$

Constraint 6 further stipulates charging events cannot happen at the first stop sequence for all buses.

6) $X_{i,k,s}^{150kW} + X_{i,k,s}^{500kW} = 0,\ \forall(i, k = 1), s$

Constraint 7a and 7b require a charging event to be happening for bus i at stop sequence k if there is any electric energy drawn. Conversely, constraint 7c and 7d require the charging event to not happen (i.e., be 0) when no electric energy was drawn.

7a) $E_{i,k,s}^{R150kW} \leq X_{i,k,s}^{150kW} e_i,\ \forall(i,k), s$

7b) $E_{i,k,s}^{R500kW} \leq X_{i,k,s}^{500kW} e_{i,}\ \forall(i,k), s$

7c) $X_{i,k,s}^{150kW} \leq E_{i,k,s}^{R150kW},\ \forall(i,k), s$

7d) $X_{i,k,s}^{500kW} \leq E_{i,k,s}^{R500kW},\ \forall(i,k), s$

Constraint 8 require the accumulative mileage for bus i at stop sequence k to be reduced by the miles equivalent of the electricity energy drawn at stop sequence k by bus i.

8) $A_{i,k} = A_{i,k-1} + d_{i,k-1,k} - E_{i,k}^{R} * bus_{eff},\ \forall(i, k \neq 1)$

Constraint 9a and 9b prohibits charging event to happen at stop sequence k for bus i unless an on-route charging station is installed at the corresponding stop j.

9a) $\sum_{s \in S} X_{i,k,s}^{150kW} \leq Y_j^{R^{150kW}},\ \forall(i,k) \in \Omega_j$

9b) $\sum_{s\in S} X_{i,k,s}^{500kW} \leq Y_j^{R^{500kW}}, \ \forall (i,k) \in \Omega_j$

Constraint 11 mandates the number of on-route charging stations built at stop j can satisfy the number of charging event happening at the same time.

11) $\sum_{(i,k)\in\Psi_{jt}} X_{i,k,s}^{150kW} + \sum_{(i,k)\in\Psi_{jt}} X_{i,k,s}^{500kW} \leq Y_j^{R^{150kW}} + Y_j^{R^{500kW}}, \ \forall j,t$

Equation 12 calculates the on-route charging peak electricity energy demand for each stop j.

12) $P_j^R \geq \sum_{(i,k)\in\Omega_j, s\in S} X_{i,k,s}^{150kW} r_s^{150kW} + \sum_{(i,k)\in\Omega_j, s\in S} X_{i,k,s}^{500kW} r_s^{500kW}, \ \forall j$

Equation 13 calculates the energy demand bracket each stop j is in.

13) $D_j^R = \lfloor P_j^R \div 50 \rfloor + 1$

Equation 14 calculates the summed in-depot electricity energy needed to fully charge the whole bus fleet.

14) $E^G = \frac{\sum_{i\in I} m_i \div \eta^B - \sum_{i\in I, k\in K, s\in S}\left(E_{i,k,s}^{R^{150kW}} + E_{i,k,s}^{R^{500kW}}\right) * \eta^R}{\eta^G}$

Equation 15 calculates the in-depot charging peak electricity energy demand.

15) $P^G = E^G \div h$

Equation 16 calculates the total amount of the in-depot chargers needed to fully charge the bus fleet in h hours.

16) $Y^G = \lfloor E^G \div h \div g \rfloor + 1$

Equation 17 calculates the in-depot electricity energy demand bracket.

17) $D^G = \lfloor P^G \div 50 \rfloor + 1$

Bounds 18a to 18f limit the electricity energy drawn at each stop sequence k by bus i to be integers greater or equal to zero and less than the maximum electricity energy that can be drawn based on the stop duration and charge rate for the corresponding bus model s.

18a) $E_{i,k,s}^{R150kW} \leq \frac{o_{i,k}}{60} \times r_s^{150kW}, \ \forall (i,k), s$

18b) $E_{i,k,s}^{R150kW} \geq 0, \ \forall (i,k), s$

18c) $E_{i,k,s}^{R500kW} \leq \frac{o_{i,k}}{60} \times r_s^{500kW}$, $\forall(i,k),s$

18d) $E_{i,k,s}^{R500kW} \geq 0$, $\forall(i,k),s$

18e) $E_{i,k,s}^{R150kW} = Integer$

18f) $E_{i,k,s}^{R500kW} = Integer$

Bounds 18g to 18k set variables $X_{i,k,s}^{150kW}$, $X_{i,k,s}^{500kW}$, $Y_j^{R^{150kW}}$, $Y_j^{R^{500kW}}$, and $Z_{i,s}$ to be binary variables.

18g) $X_{i,k,s}^{150kW} = \{0,1\}$, $\forall(i,k)$

18h) $X_{i,k,s}^{500kW} = \{0,1\}$, $\forall(i,k)$

18i) $Y_j^{R^{150kW}} = \{0,1\}$, $\forall j$

18j) $Y_j^{R^{500kW}} = \{0,1\}$, $\forall j$

18k) $Z_{i,s} = \{0,1\}$, $\forall i,s$

Bound 18l sets variable $A_{i,k}$ to be positive numbers.

18l) $A_{i,k} \geq 0$, $\forall(i,k)$

And finally, bounds 18m and 18n set variables D^G and D_j^R to be integers.

18m) $D^G = integer$

18n) $D_j^R = integer$

APPENDIX D: FLEET STATE-OF-CHARGE DETAILS

This appendix provides additional operational charging profiles for each bus in each transit system.

1: Arcata & Mad River Transit System

The two Arcata Mad River Transit System buses serving Gold and Red routes (block id 25500 & 2552150) utilize the same E2 (440 kWh) BEB model. The Red Route Bus charges 8 times at Arcata Transit Center. The Gold Route Bus charges 2 times at Arcata Transit Center. The AMRTS BEB red route keeps a relatively large remaining mileage and the end of the day (Figure 37).

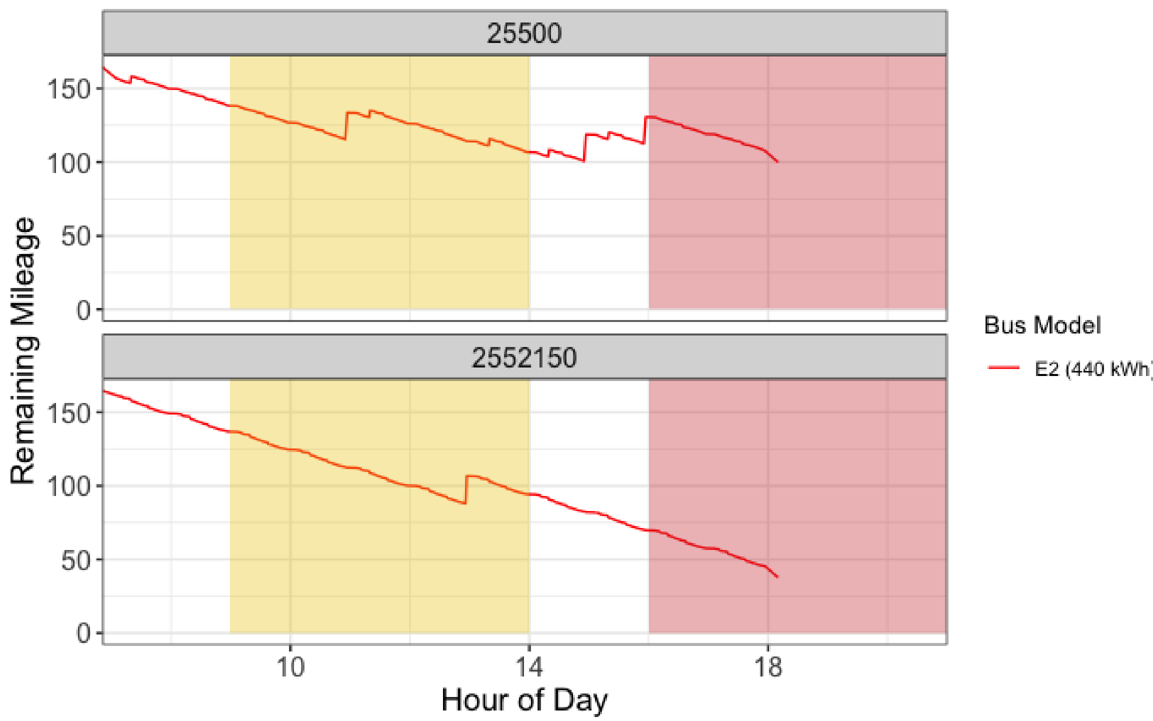


Figure 37. AMRTS Red and Gold route BEB mileage profile.

2: Blue Lake Rancheria Transit System

Blue Lake Rancheria Transit System utilizes the E2 (440 kWh) model (Figure 38) and charges 2 times at the Arcata Transit Center.

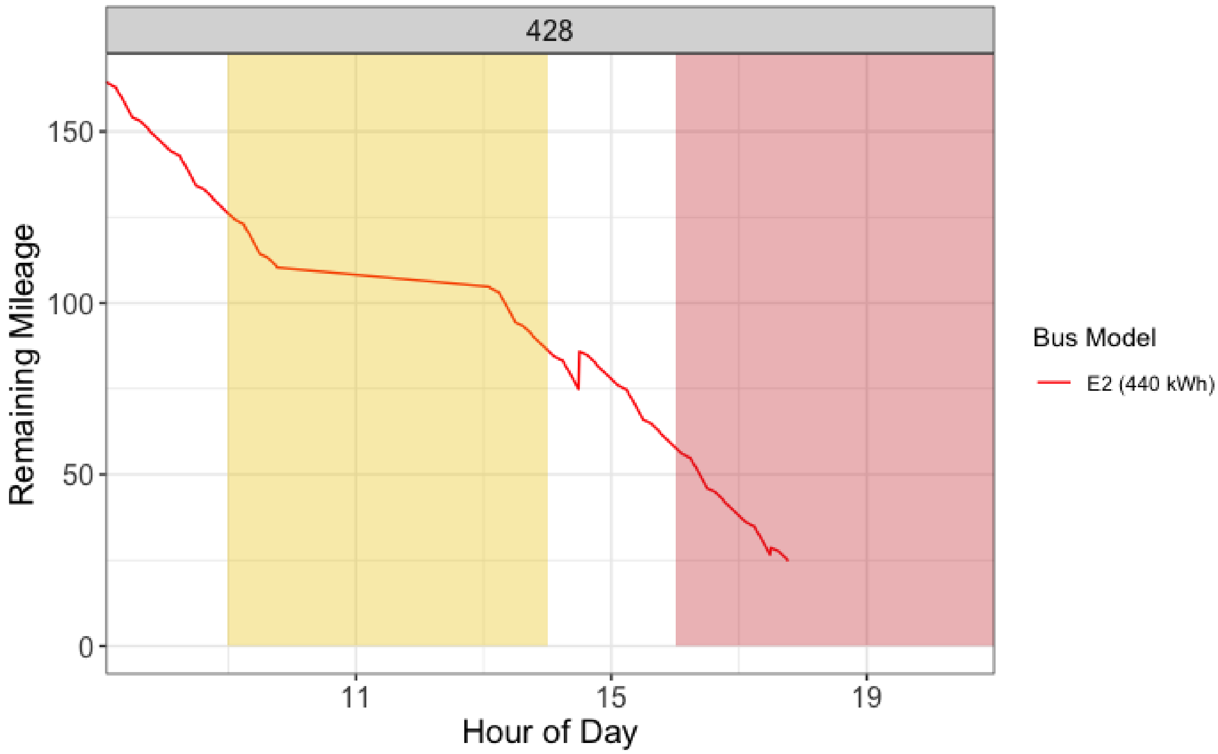


Figure 38. BLRTS E2 model BEB mileage profile

3: Eureka Transit System

The four Eureka Transit System buses utilize three E2 models and one E2 Max BEB model (Figure 39). All ETS buses charge at the Bayshore Mall. Bus 66 charges one during the day, bus 68 charges 9 times, and bus 69 charges 5 times during the day. Bus 67 do not charge at all.

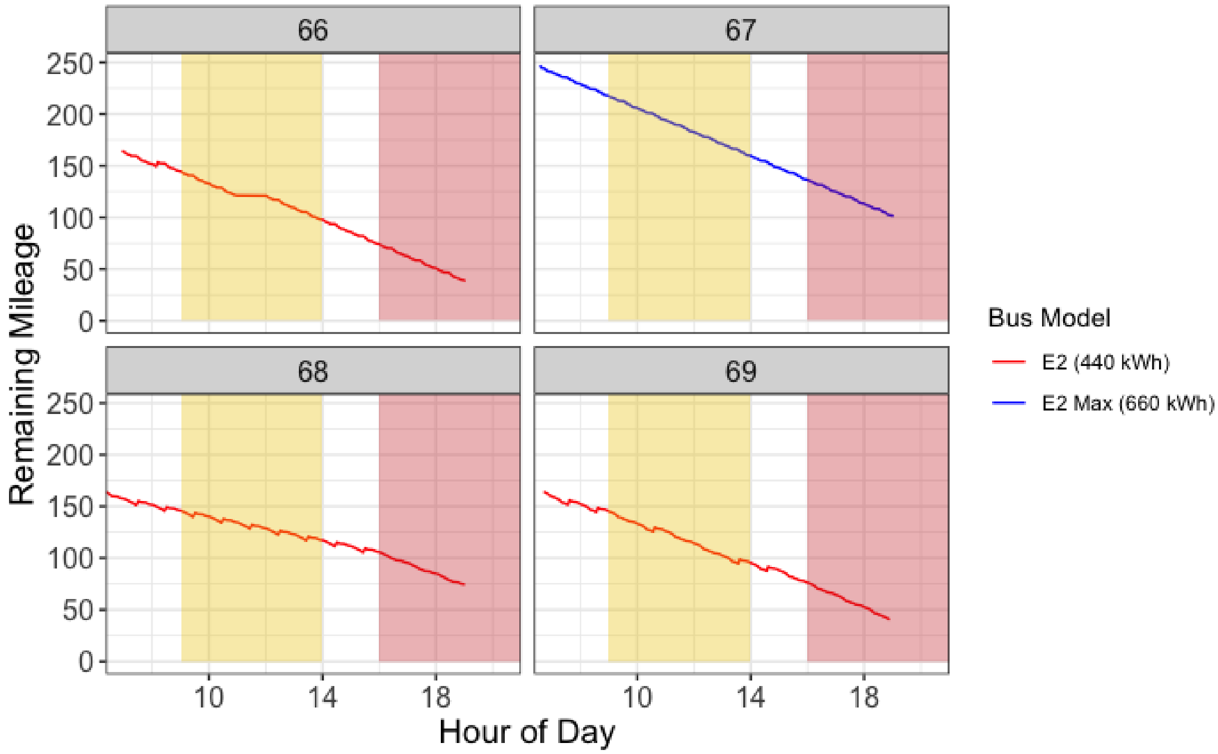


Figure 39. ETS E2 and E2 max models BEB mileage profile.

4: Klamath Trinity Non-Emergency Transportation

The one KT-Net bus utilizes an E2 model (Figure 40) and charges 2 times a day at Willow Creek.

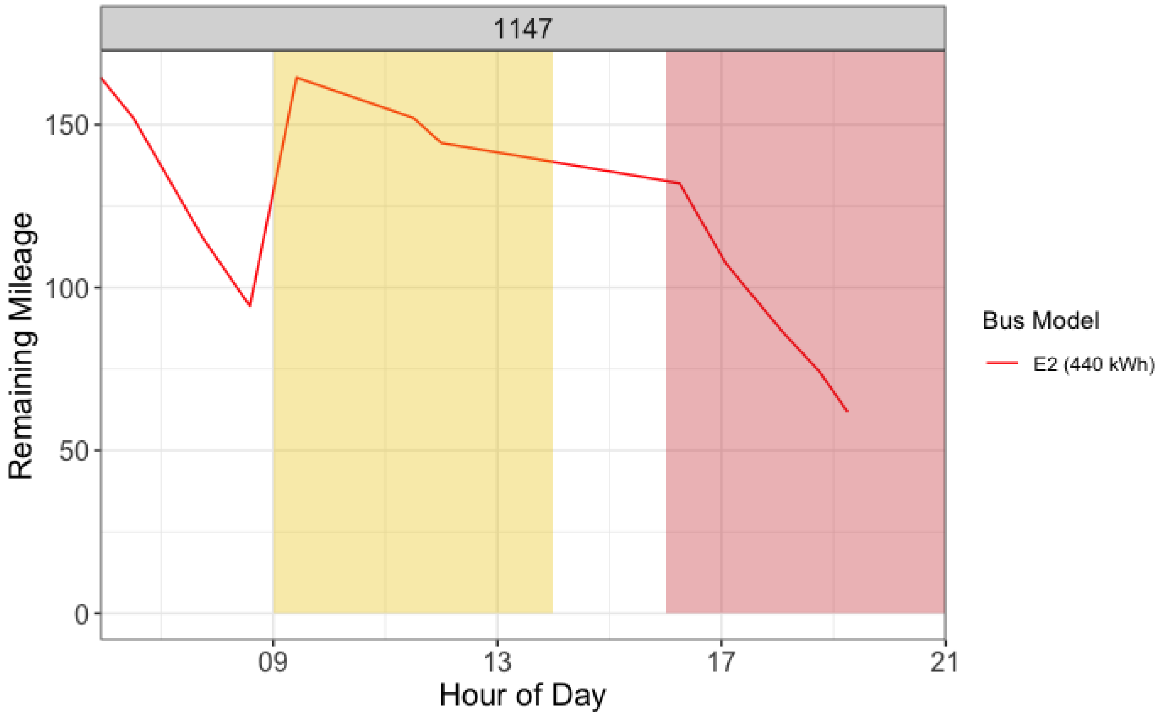


Figure 40. KT Net E2 Max model BEB mileage profile.

5: Redwood Transit System

The nine Redwood Transit System buses utilize two E2 and seven E2 Max model BEBs (Figure 41). The BEBs charge at Arcata Transit Center, Bayshore Mall, College of the Redwoods, and Trinidad Park and Ride (Table 32).

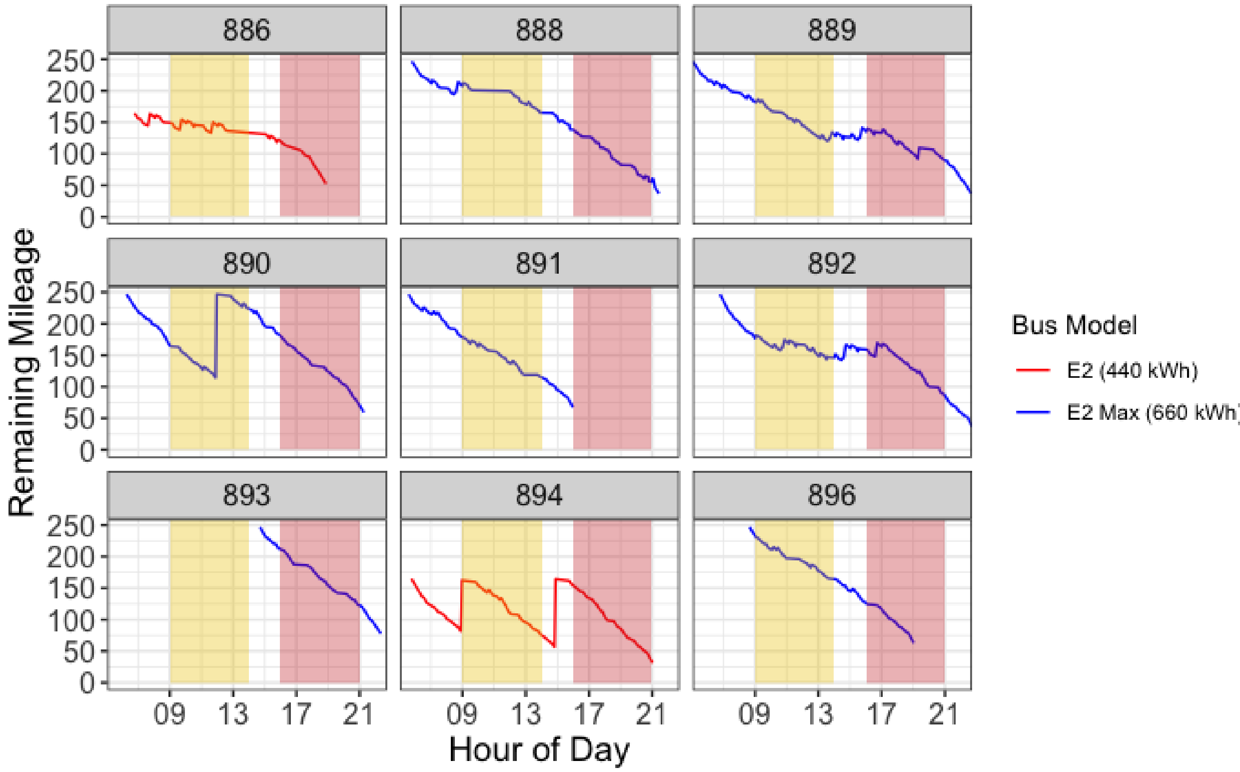


Figure 41. RTS. E2 and E2 Max models BEB mileage profile.

Table 32. Redwood Transit System number of charging events at each charging station.

Bus	Arcata Transit Center	Bayshore Mall	College of the Redwoods	Trinidad Park & Ride
886	2	4	4	0
888	1	5	5	0
889	7	8	5	1
890	2	0	2	1
891	2	3	3	0
892	6	7	4	0
893	0	0	0	0
894	1	0	3	2
896	0	3	2	0

6: Southern Humboldt Intercity

The three Southern Humboldt Intercity buses utilize a E2 Max model BEBs (Figure 41). The BEBs charges at Bayshore Mall, Benbow KOA, College of the Redwoods, Dean Creek Resort, and Myers Flat (Table 33).

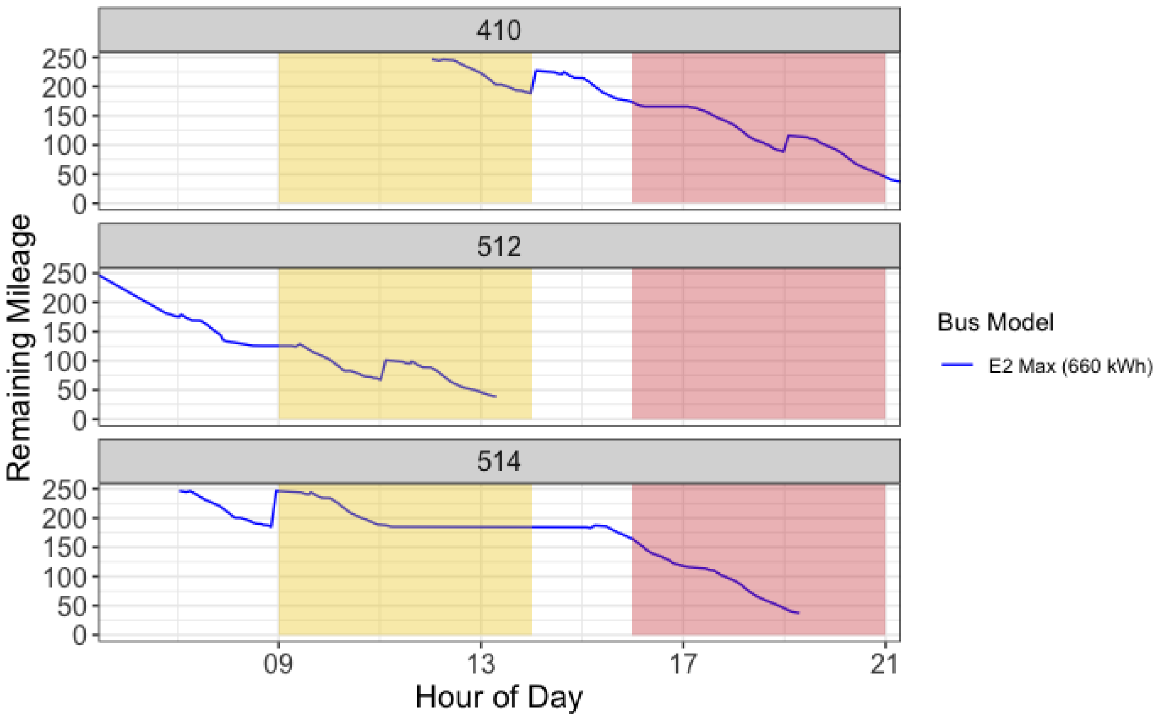


Figure 42 Southern Humboldt Intercity and E2 Max models BEB mileage profile.

Table 33. Southern Humboldt Intercity number of charging events at each charging station.

Bus	Bayshore Mall	Benbow KOA	College of the Redwoods	Dean Creek Resort	Myers Flat
410	1	2	2	2	2
512	2	2	2	3	3
514	3	2	1	2	2

7: Willow Creek

Finally, Willow Creek service utilizes E2 Max model BEB and chargers four times at Arcata Transit Center and two times at Willow Creek.

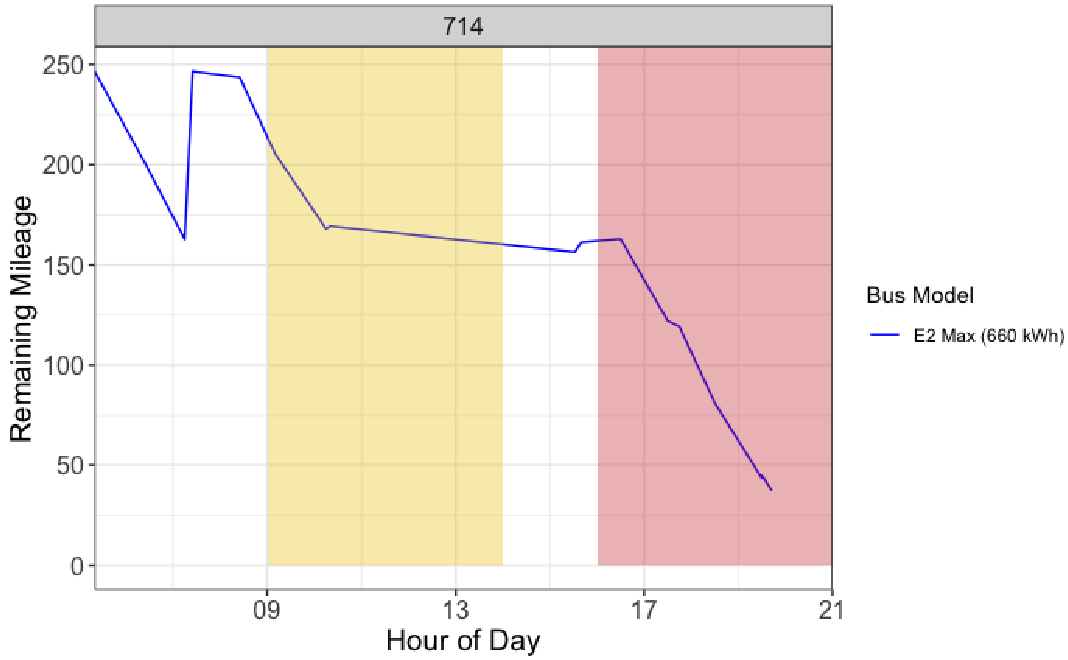


Figure 43. Willow Creek and E2 Max model BEB mileage profile.

APPENDIX E: CHARGING STATION POWER PROFILES

This appendix provides detailed electrical demand profiles for all recommended on-route charging locations, and summary demand estimates of depot charging.

1: In-depot charging

Excluding Redwood Coast Transit (RCT) and Trinity Transit (TT), there are three separate bus depots for the public bus fleet in Humboldt County.

4. Humboldt Transit Authority bus yard at 113 V Street, Eureka
5. Blue Lake Rancheria office building at 426 Chartin Road, Blue Lake
6. Hoopa Tribal Police station at 12637 CA-96, Hoopa

To avoid adding additional personnel to manage overnight charging, each bus is recommended to have an electric bus charger. A 62.5 kW in-depot charger is assumed (equivalent to the ChargePoint CPE250[23] or the ChargePoint Express Plus system[24]). Details of recommended charging infrastructure requirements are shown in Table 34. Note this represents a recommended minimum quantity of chargers.

Table 34. Recommended in-depot charging infrastructure requirements.

Bus Depots	# of Operating Buses	Max Instantaneous Expected Demand (kW)	# of Chargers Needed	Average Expected Overnight Load (kW)
HTA Bus Yard	19	1187.5	19	857
Blue Lake Rancheria Office	1	62.5	1	62.5
Hoopa Tribal Police Station	1	62.5	1	62.5

For the HTA Bus Yard, the total nameplate load is significant considering PG&E interconnection. If this load appears to present a significant barrier, discussions with HTA would be needed regarding the feasibility and schedule associated with rotating buses through a limited number of chargers. Note, however, that actively managed bus charging could only achieve a few hundred kW reduction in nameplate load, as indicated by the average expected overnight load. Hence, it may simply be the case that the total nameplate load that must be served by PG&E presents a significant interconnection challenge.

[23] https://www.chargepoint.com/products/guides/#cpe250_a

[24] https://www.chargepoint.com/products/commercial/express-plus/

2: On-Route Charging

With the baseline assumptions, eight on-route charging stations were identified. We assume two possible chargers: a 150kW and a 500kW nameplate charger of unknown manufacturer (consider the ChargePoint Express Plus system[24] or the ABB Pantograph solutions[25]). There are a small handful of commercial options with these power ratings, and expect these nameplate ratings to become increasingly common. Figure 44 through Figure 59 below show the 15-minute average demand and instantaneous demand for each charging station location.

Note that actual demand for each charging event depends on the bus manufacturer (see

Table 35). Therefore, the actual peak demand depends on both the charger nameplate and which buses end up charging at each location. Note that for a given charger the maximum demand at each charging station could increase (up to the rated nameplate of the charger) as the bus charging capacity increases either as the result of technological improvement or procuring buses from different bus manufacturers. Also, it is recommended to consider allowing for additional load associated with public DC fast chargers co-located with the bus charging infrastructure. Co-locating public chargers would take advantage of the fact that significant electrical infrastructure is already being installed. We recommend a rule of thumb of two DC fast charger plugs per site with a nameplate rating of 62.5kW per plug (consider the ChargePoint CPE250[23] or the ABB Terra 54 CJ[26]).

Table 35. Maximum Grid to Charger Demand at 150kW and 500kW in-route chargers by different Proterra Bus Models.

Bus Model	150kW Charger (kW)	500 kW Charger (kW)
XR	73	163
E2	120	331
E2 Max	120	397

[25] https://library.e.abb.com/public/09cd5a7dc3434ee399c0cbb531716773/4EVC901704-BREN_HeavyVehicleCharging%20solutions%20portfolio_11_19.pdf

[26] https://new.abb.com/ev-charging/products/car-charging/multi-standard/terra-54-cj

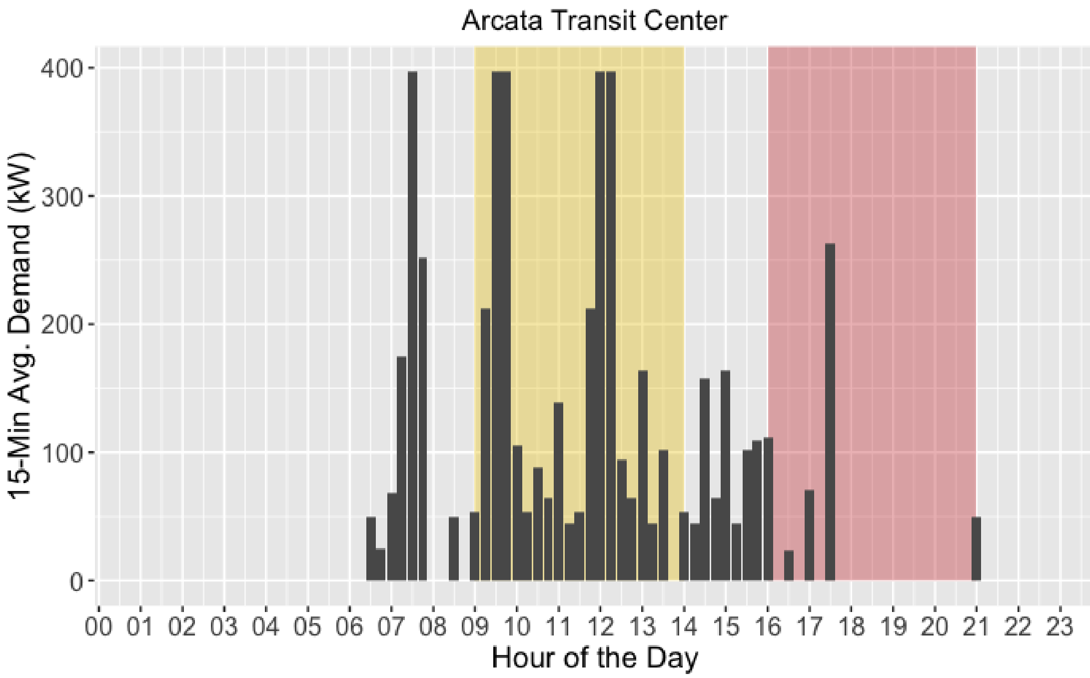


Figure 44. Arcata Transit Center (40.8685, -124.0841) daily 15-minute average demand from electric bus charging. Yellow highlighted segment represents the solar over production time-of-use rate. Red highlighted segment represents the peak time-of-use rate. Non-highlighted segments represent off-peak time-of-use rate.

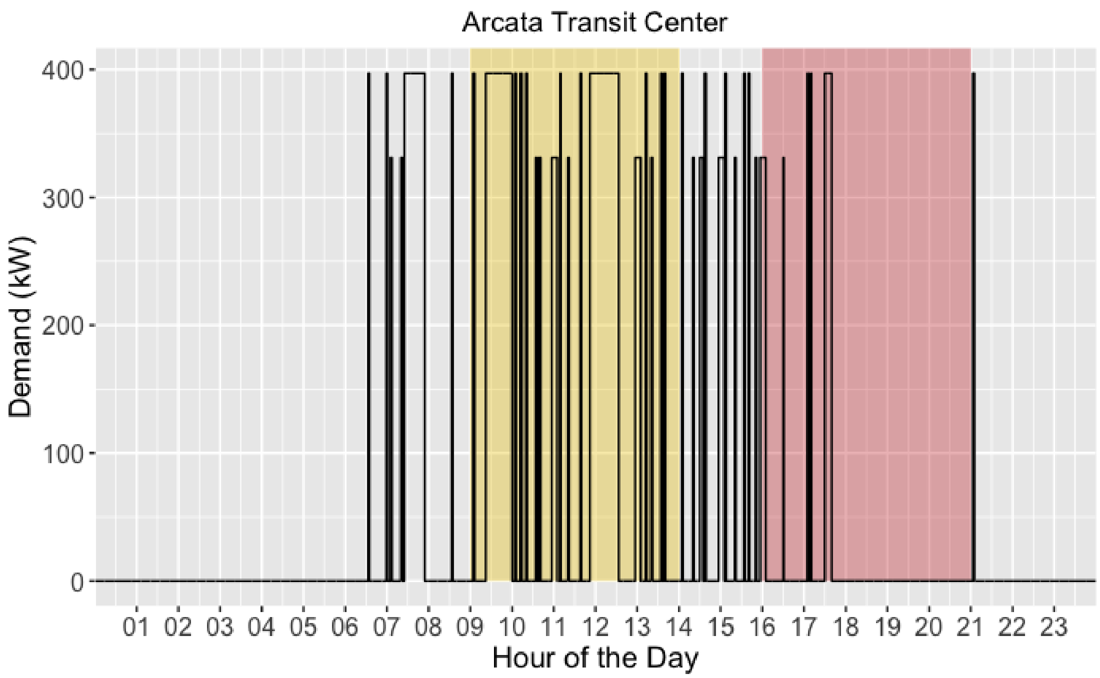


Figure 45. Arcata Transit Center (40.8685, -124.0841) daily instantaneous demand from electric bus charging. Yellow highlighted segment represents the solar over production time-of-use rate. Red highlighted segment represents the peak time-of-use rate. Non-highlighted segments represent off-peak time-of-use rate.

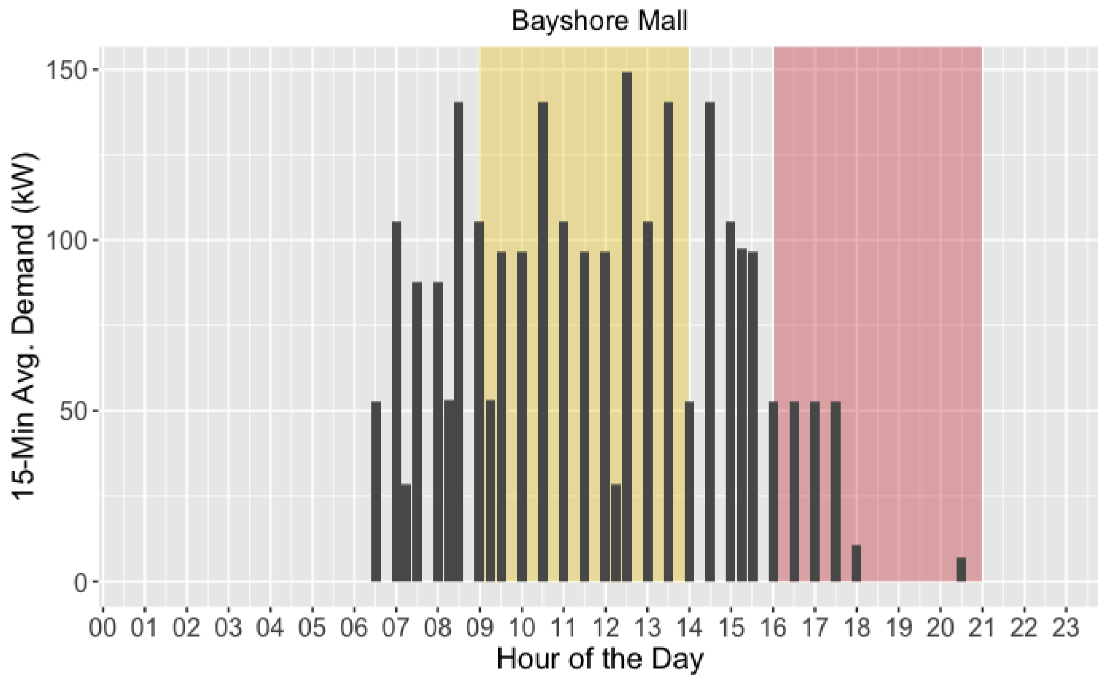


Figure 46. Bayshore Mall (40.7804, -124.1888) daily 15-minute average demand from electric bus charging. Yellow highlighted segment represents the solar over production time-of-use rate. Red highlighted segment represents the peak time-of-use rate. Non-highlighted segments represent off-peak time-of-use rate.

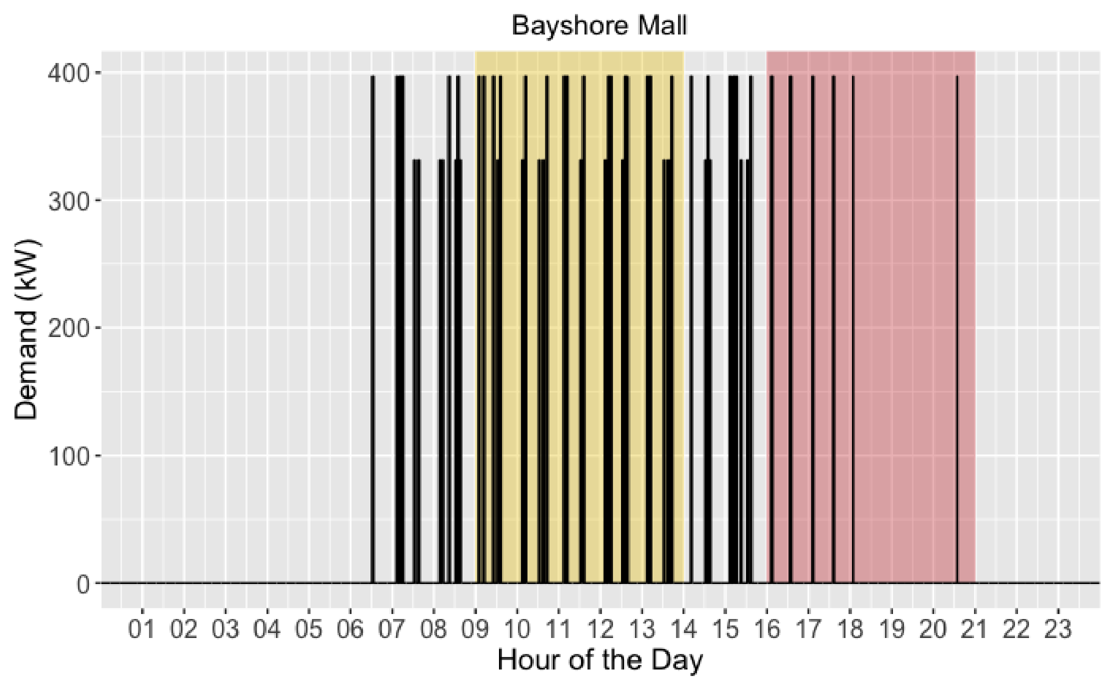


Figure 47. Bayshore Mall (40.7804, -124.1888) daily instantaneous demand from electric bus charging. Yellow highlighted segment represents the solar over production time-of-use rate. Red highlighted segment represents the peak time-of-use rate. Non-highlighted segments represent off-peak time-of-use rate.

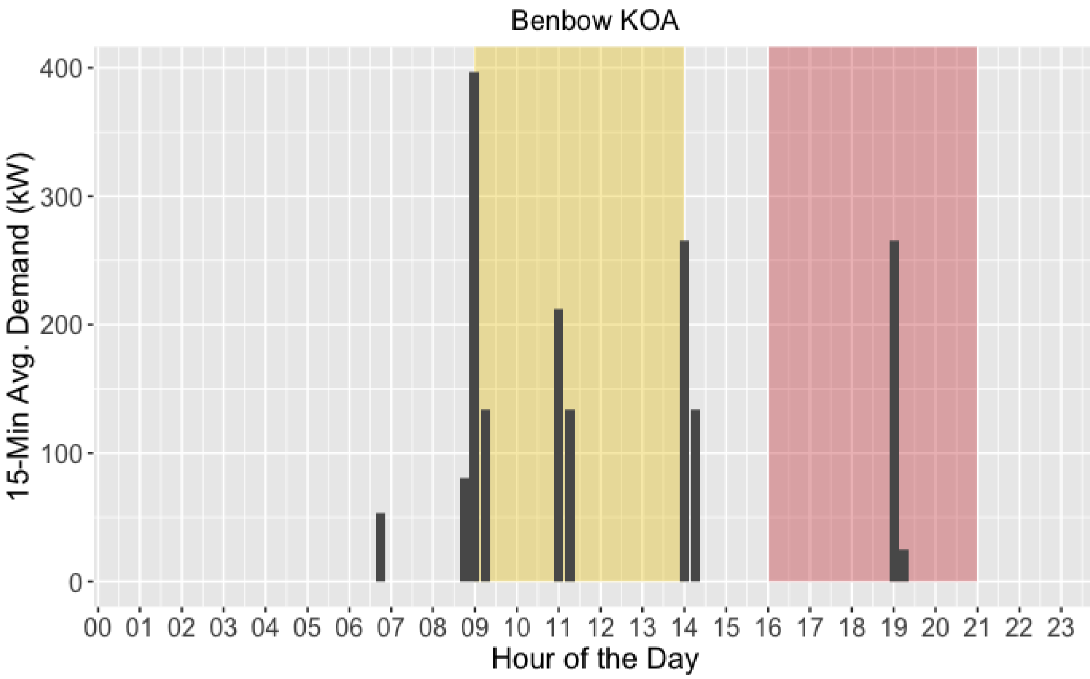


Figure 48. Benbow KOA (40.0681, -123.7874) daily 15-minute average demand from electric bus charging. Yellow highlighted segment represents the solar over production time-of-use rate. Red highlighted segment represents the peak time-of-use rate. Non-highlighted segments represent off-peak time-of-use rate.

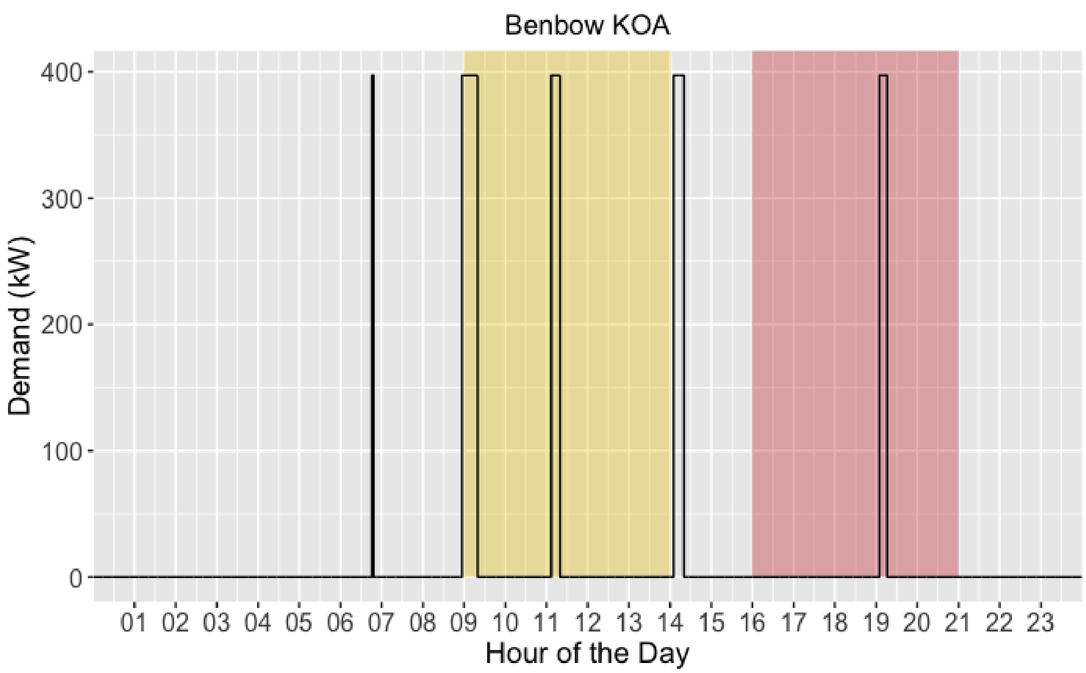


Figure 49. Benbow KOA (40.0681, -123.7874) daily instantaneous demand from electric bus charging. Yellow highlighted segment represents the solar over production time-of-use rate. Red highlighted segment represents the peak time-of-use rate. Non-highlighted segments represent off-peak time-of-use rate.

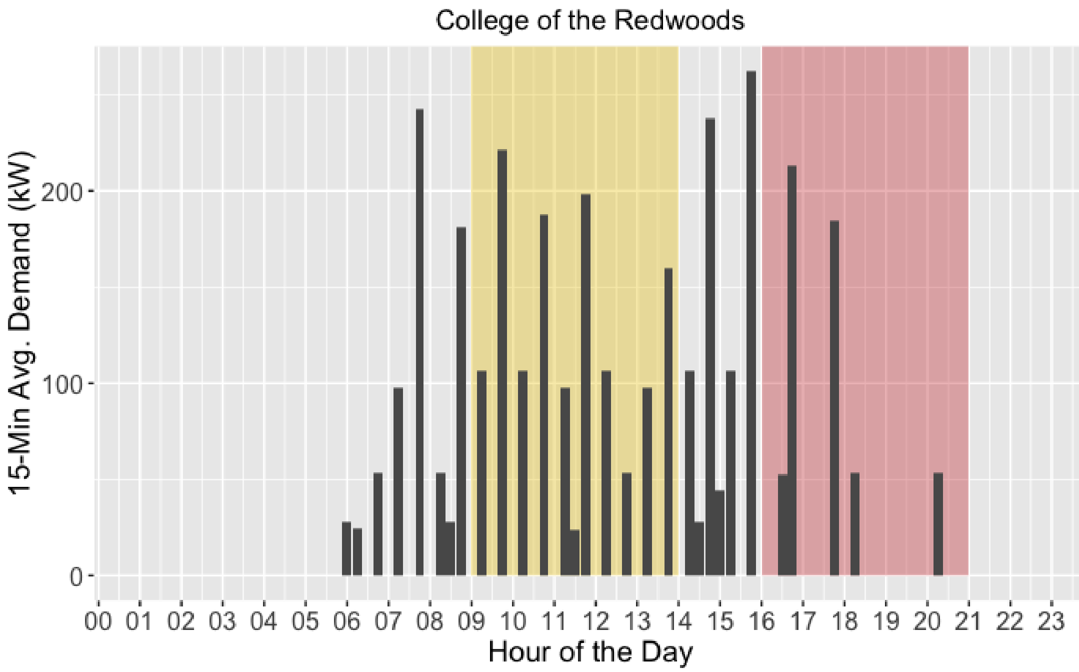


Figure 50. College of the Redwoods (40.69807, -124.1959,) daily 15-minute average demand from electric bus charging. Yellow highlighted segment represents the solar over production time-of-use rate. Red highlighted segment represents the peak time-of-use rate. Non-highlighted segments represent off-peak time-of-use rate.

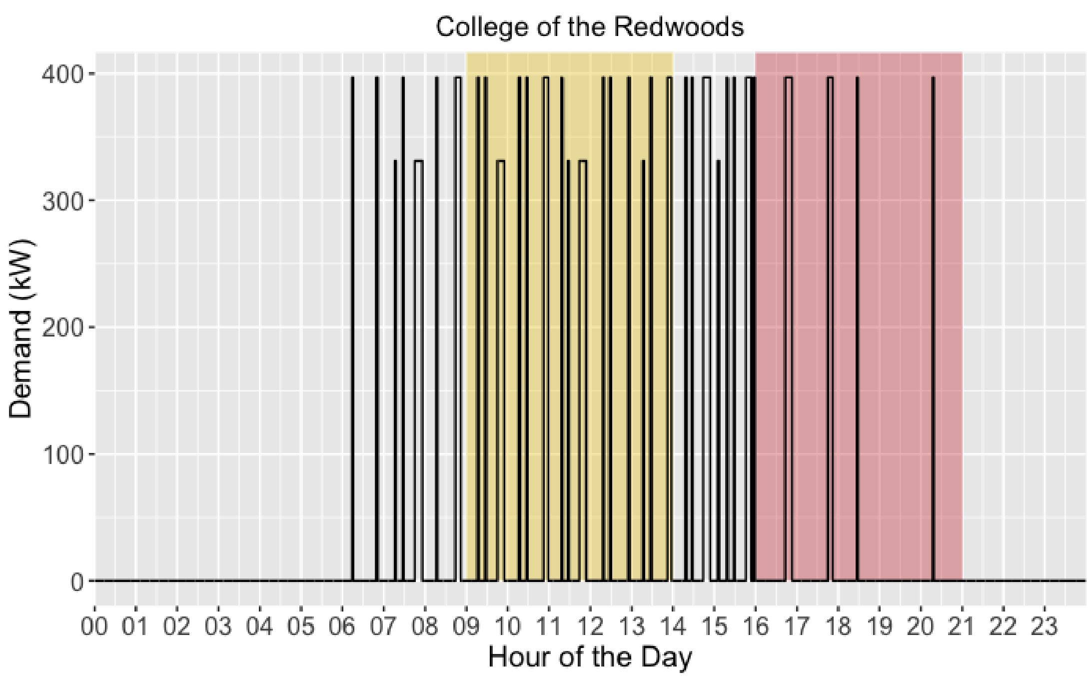


Figure 51. College of the Redwoods (40.69807, -124.1959,) daily instantaneous demand from electric bus charging. Yellow highlighted segment represents the solar over production time-of-use rate. Red highlighted segment represents the peak time-of-use rate. Non-highlighted segments represent off-peak time-of-use rate.

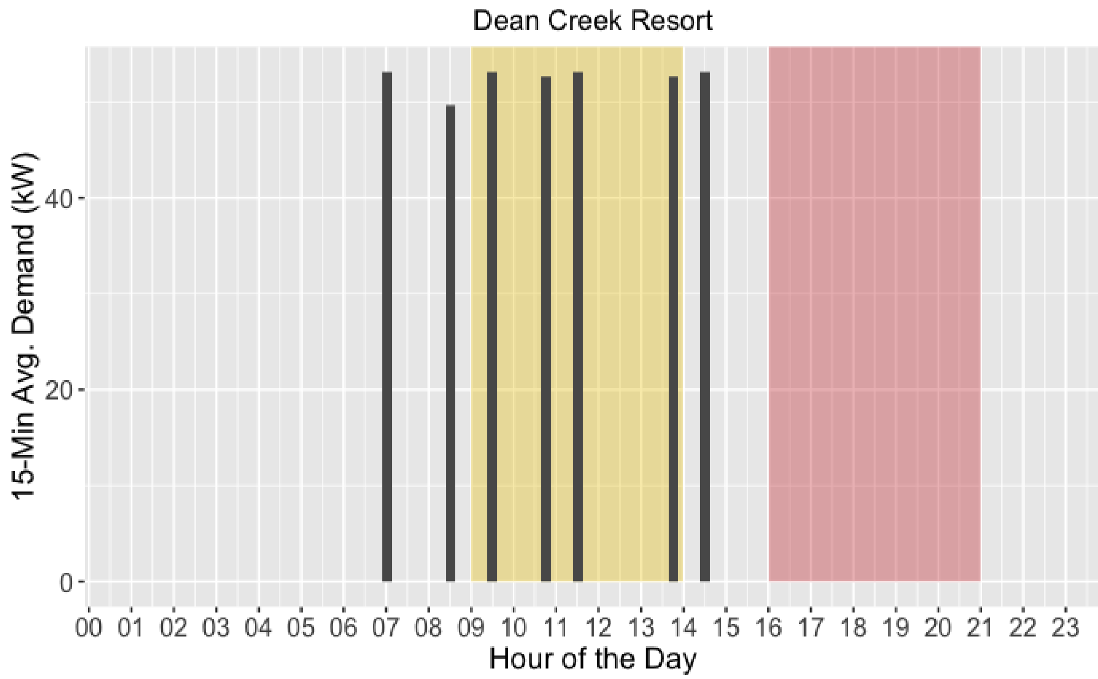


Figure 52. Dean Creek Resort (40.14085, -123.8102) daily 15-minute average demand from electric bus charging. Yellow highlighted segment represents the solar over production time-of-use rate. Red highlighted segment represents the peak time-of-use rate. Non-highlighted segments represent off-peak time-of-use rate.

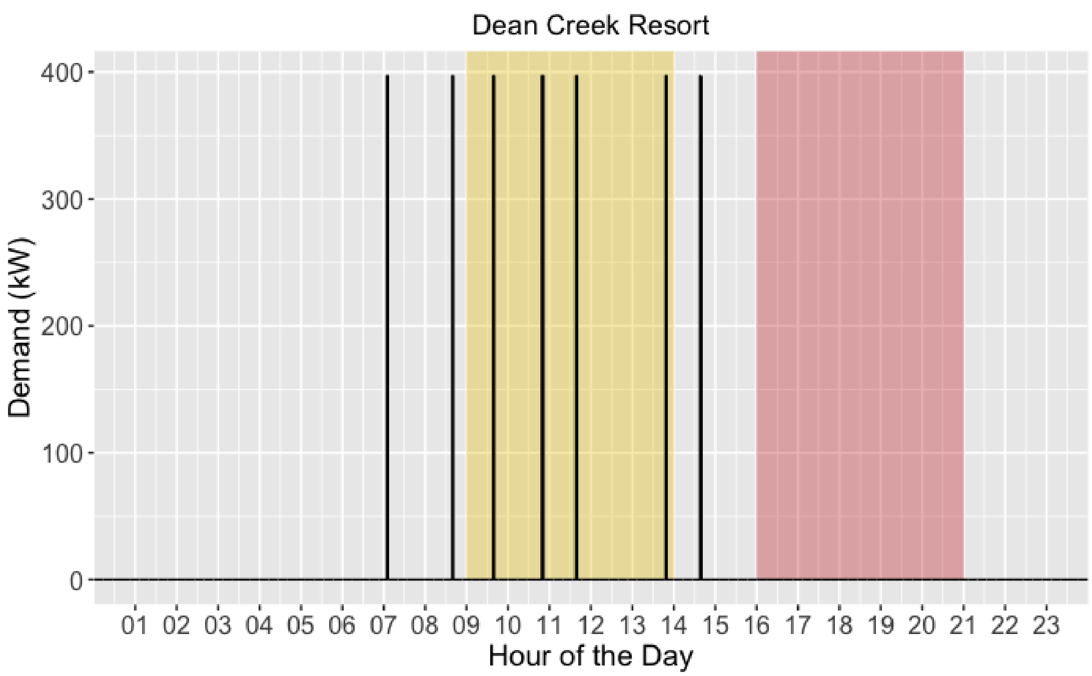


Figure 53. Dean Creek Resort (40.14085, -123.8102) daily instantaneous demand from electric bus charging. Yellow highlighted segment represents the solar over production time-of-use rate. Red highlighted segment represents the peak time-of-use rate. Non-highlighted segments represent off-peak time-of-use rate.

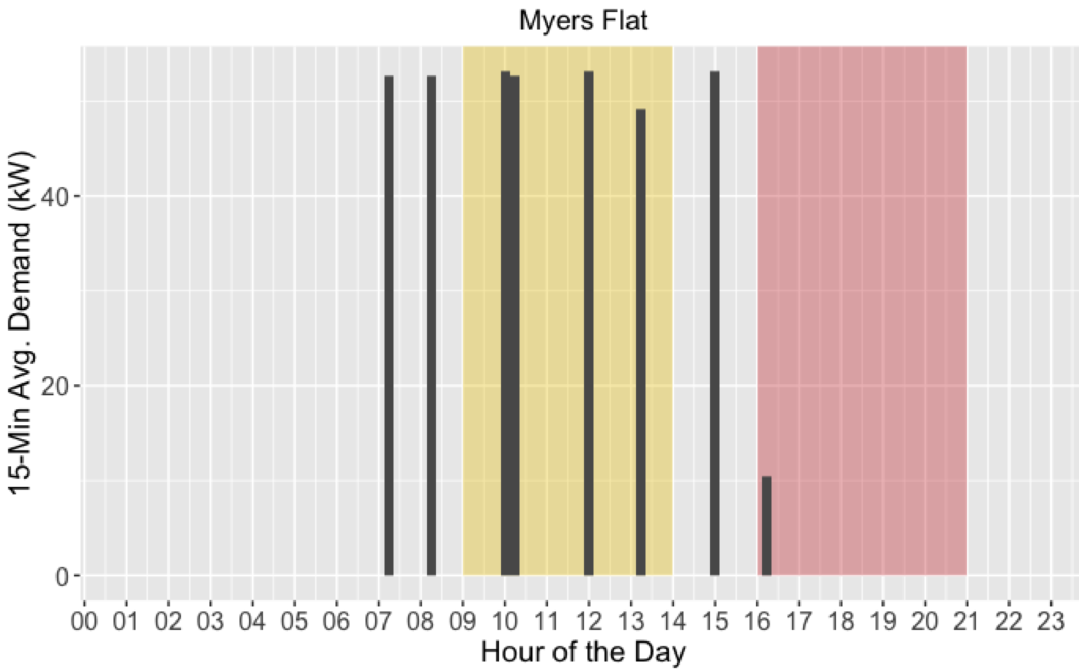


Figure 54. Myers Flat (40.26610, -123.8708) daily 15-minute average demand from electric bus charging. Yellow highlighted segment represents the solar over production time-of-use rate. Red highlighted segment represents the peak time-of-use rate. Non-highlighted segments represent off-peak time-of-use rate.

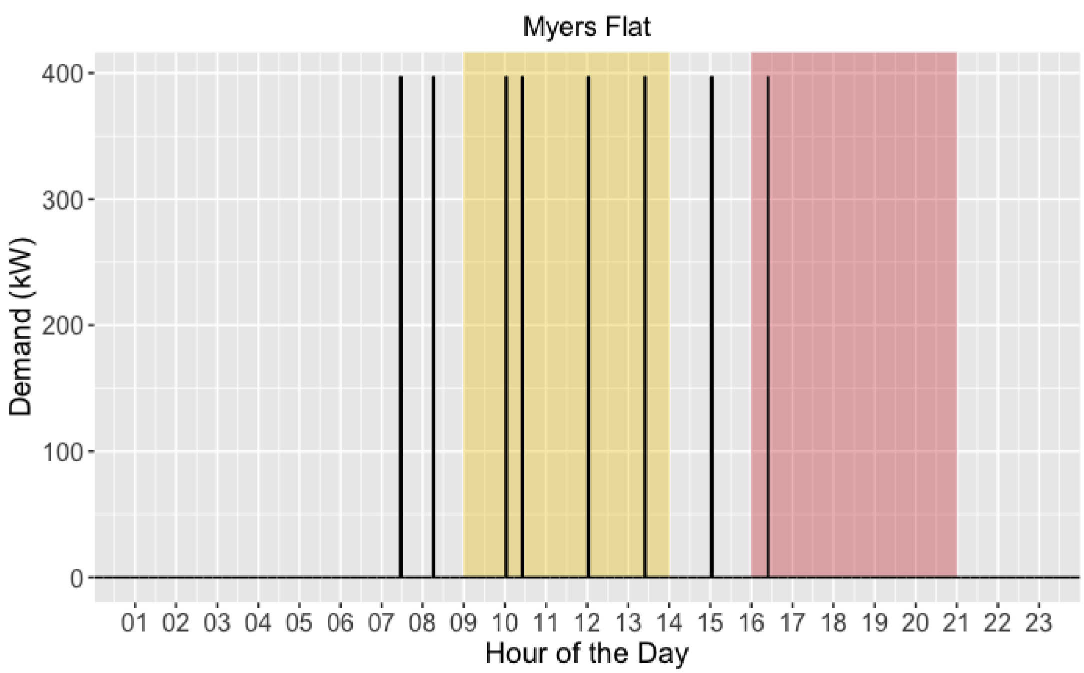


Figure 55. Myers Flat (40.26610, -123.8708) daily instantaneous demand from electric bus charging. Yellow highlighted segment represents the solar over production time-of-use rate. Red highlighted segment represents the peak time-of-use rate. Non-highlighted segments represent off-peak time-of-use rate.

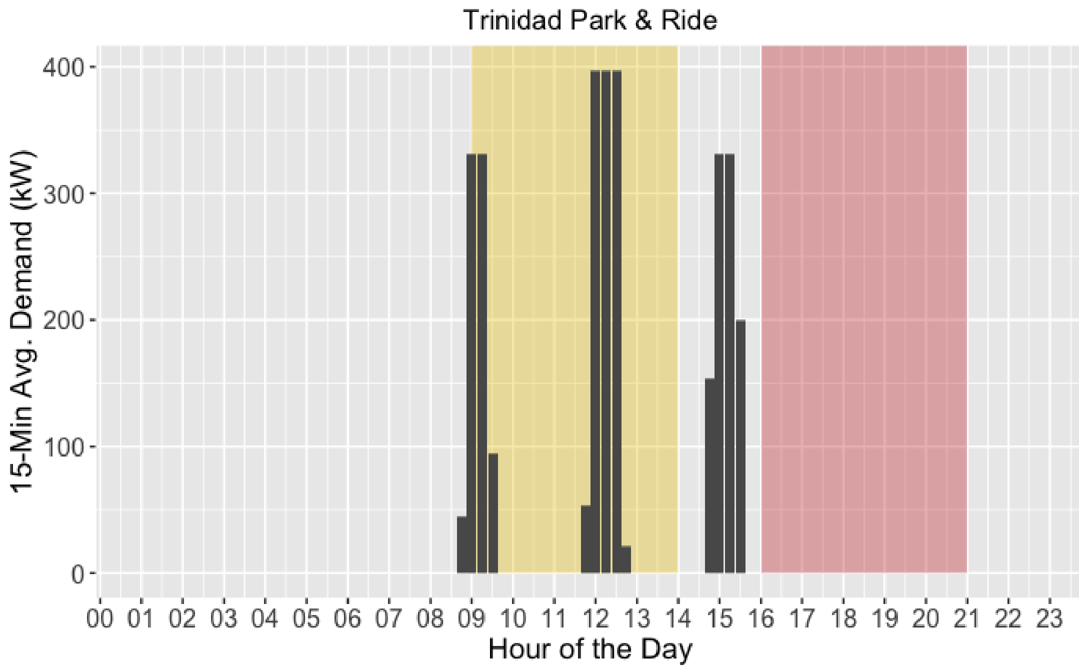


Figure 56. Trinidad Park & Ride (41.0615, -124.1406) daily 15-minute average demand from electric bus charging. Yellow highlighted segment represents the solar over production time-of-use rate. Red highlighted segment represents the peak time-of-use rate. Non-highlighted segments represent off-peak time-of-use rate.

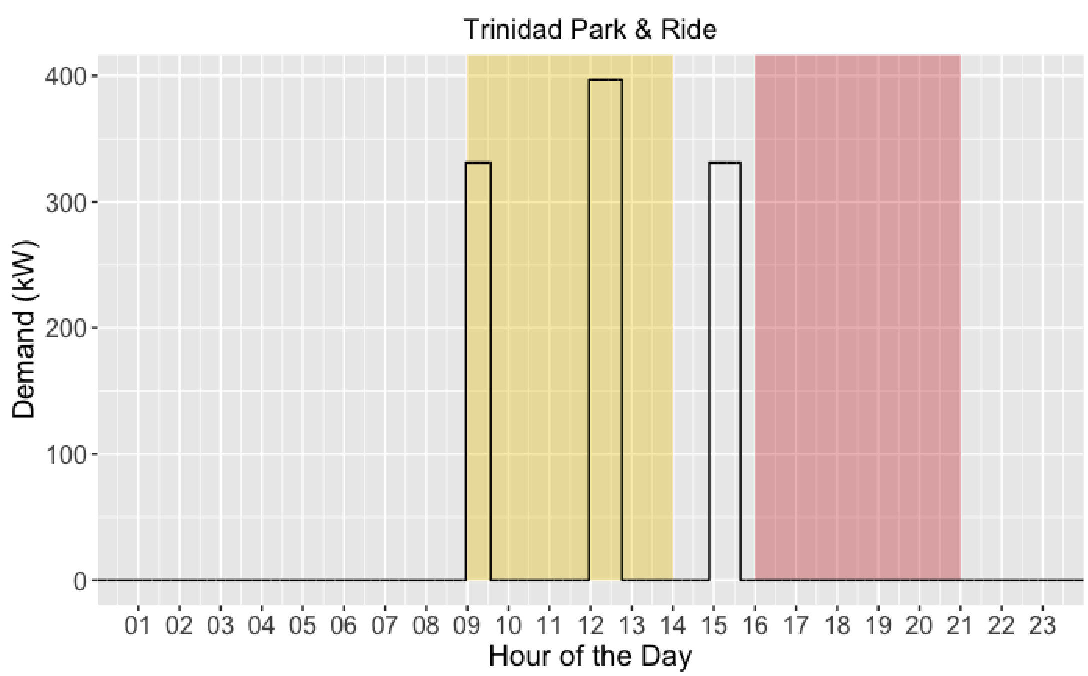


Figure 57. Trinidad Park & Ride (41.0615, -124.1406) daily instantaneous demand from electric bus charging. Yellow highlighted segment represents the solar over production time-of-use rate. Red highlighted segment represents the peak time-of-use rate. Non-highlighted segments represent off-peak time-of-use rate.

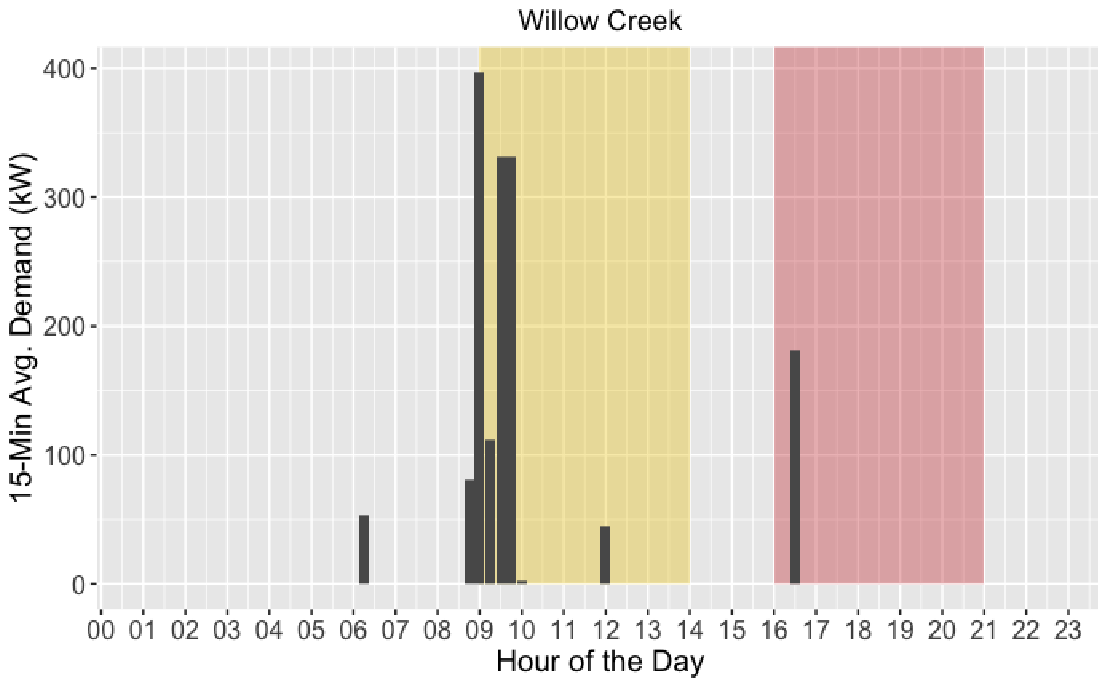


Figure 58. Willow Creek (40.9397, -123.6316) daily 15-minute average demand from electric bus charging. Yellow highlighted segment represents the solar over production time-of-use rate. Red highlighted segment represents the peak time-of-use rate. Non-highlighted segments represent off-peak time-of-use rate.

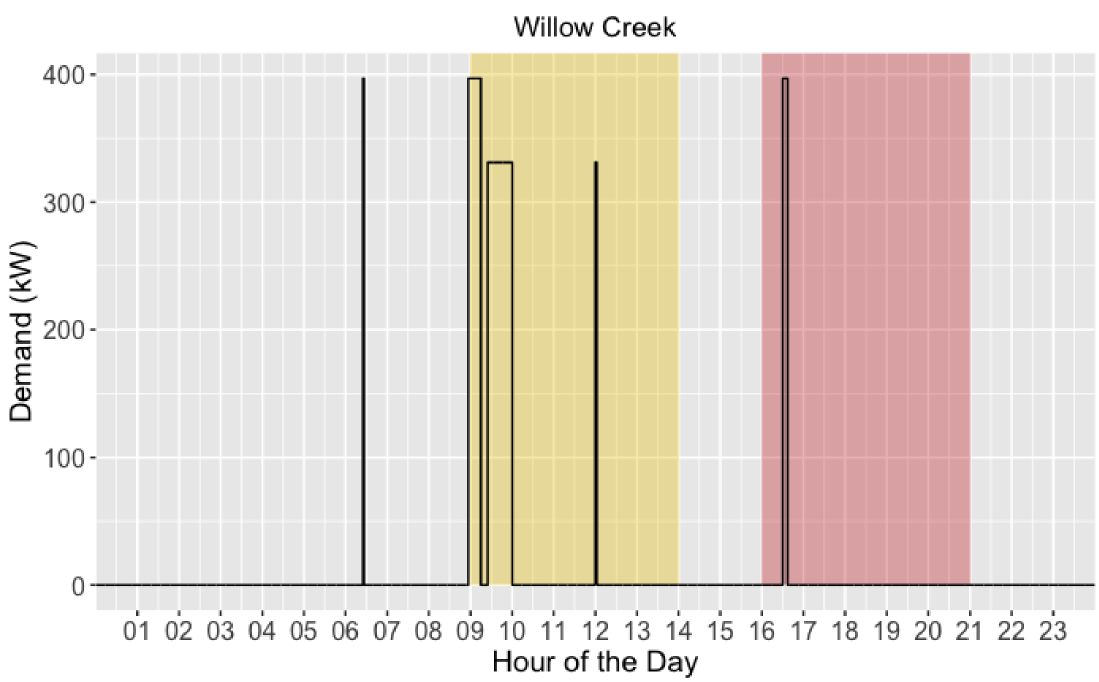


Figure 59. Willow Creek (40.9397, -123.6316) daily instantaneous demand from electric bus charging. Yellow highlighted segment represents the solar over production time-of-use rate. Red highlighted segment represents the peak time-of-use rate. Non-highlighted segments represent off-peak time-of-use rate

APPENDIX F: PERFORMANCE ANALYSIS OF HTA’S BATTERY ELECTRIC BUS

The following sections present initial analysis results of performance data on HTA’s Proterra XR+ 330kWh 40 foot low floor bus. Data used came from two different sources: 1) hand written logs of bus mileage coupled with kWh consumption data from HTA’s ChargePoint CPE200 50kW depot charger accessed through ChargePoint’s Dashboard management software, and 2) on-board data logger via bus telematics accessed through Proterra’s beta version of their Apex system, version 0.08.19.

1: Bus Charger kWh with Bus Mileage Logs

Performance data from HTA’s BEB in service was used to estimate the efficiency of the current Proterra bus in operation. HTA's BEB is an XR+ model with a battery capacity of 330 kWh. The advertised operating efficiency for this model from the Proterra specification sheet ranges between 0.549 miles per kWh and 0.671 miles per kWh.

The data from HTA consisted of distance traveled and grid energy consumption during charging from June 2019 through February 2020. The charging data from HTA’s ChargePoint depot charger is “meter-to-miles” and the efficiency value includes the charger and other losses. The distance traveled data for the bus comes from Proterra’s maintenance software which collects data via an onboard data logger.

The data was compiled and analyzed to get an average efficiency value in miles per kWh from the cumulative distance traveled and the energy consumption during the data collection period. The average efficiency found for the Proterra XR+ model is 0.561 miles per kWh (Figure 60), which is within the range of the advertised operating efficiency. Note the progressive decline in the slope of the distance vs. energy curve which indicates a decline in the average efficiency from 0.596 kWh per mile initially to 0.510 kWh per mile (86%, or a 14% decrease).

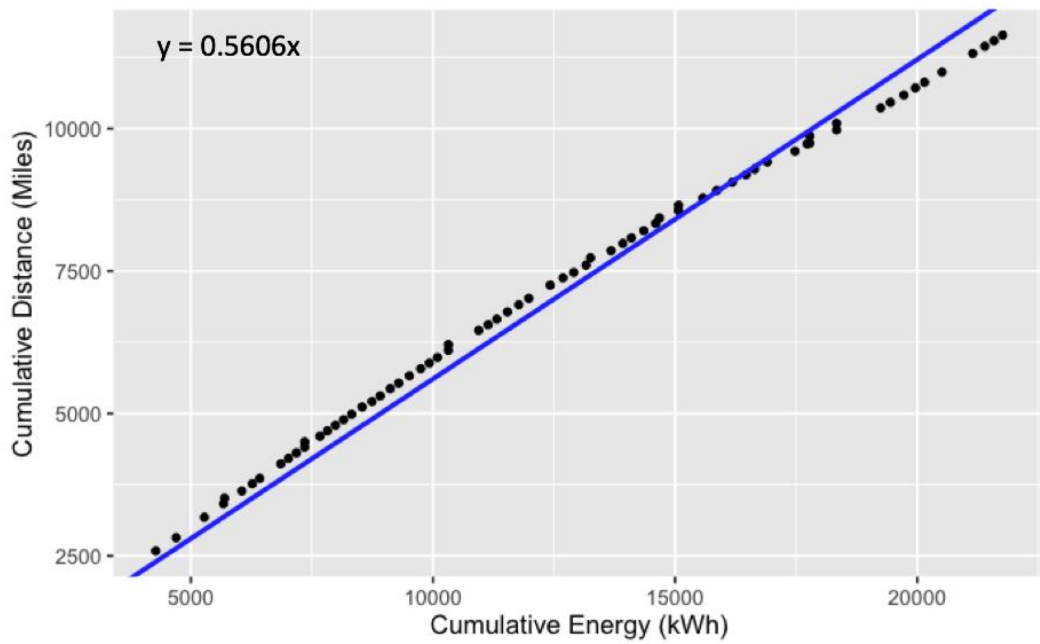


Figure 60. Cumulative miles and utility meter energy reported from HTA for the Proterra XR+ BEB model.

2: Bus Telematics Data

The BEB energy consumption was also reported by individual load: powertrain, power steering, HVAC, defroster, etc. For trips of at least 10 miles, 97% of the energy was consumed while the bus was in motion. On average, almost all of that energy was consumed by the power train (89%). On average, the remaining energy consumption was primarily by the HVAC, defroster, and the battery temperature management systems (7%) (Figure 61). These loads varied substantially from trip to trip depending on ambient temperature and related weather conditions. For starting ambient temperatures above 16°C (about 60°F), the HVAC, defroster, and the battery temperature management system loads average 50 miles traveled per kWh consumed by the HVAC system, while for temperatures below 16°C (about 60°F) those loads are about ten times higher (about 5 miles traveled per kWh consumed by the HVAC system). See Figure 61 and Figure 62.

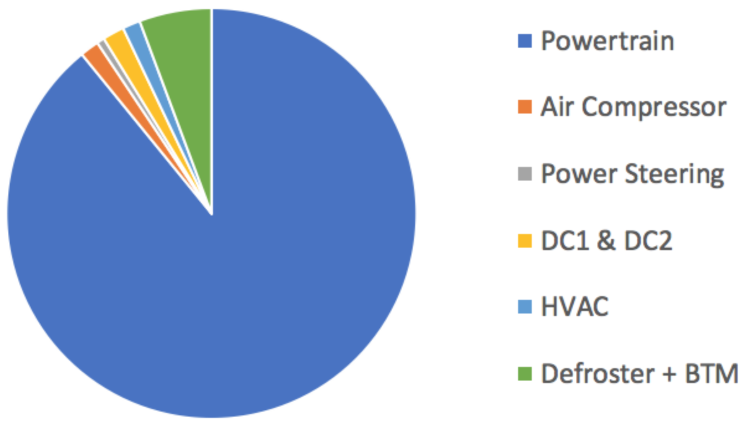


Figure 61. Average total BEB energy consumption by load.

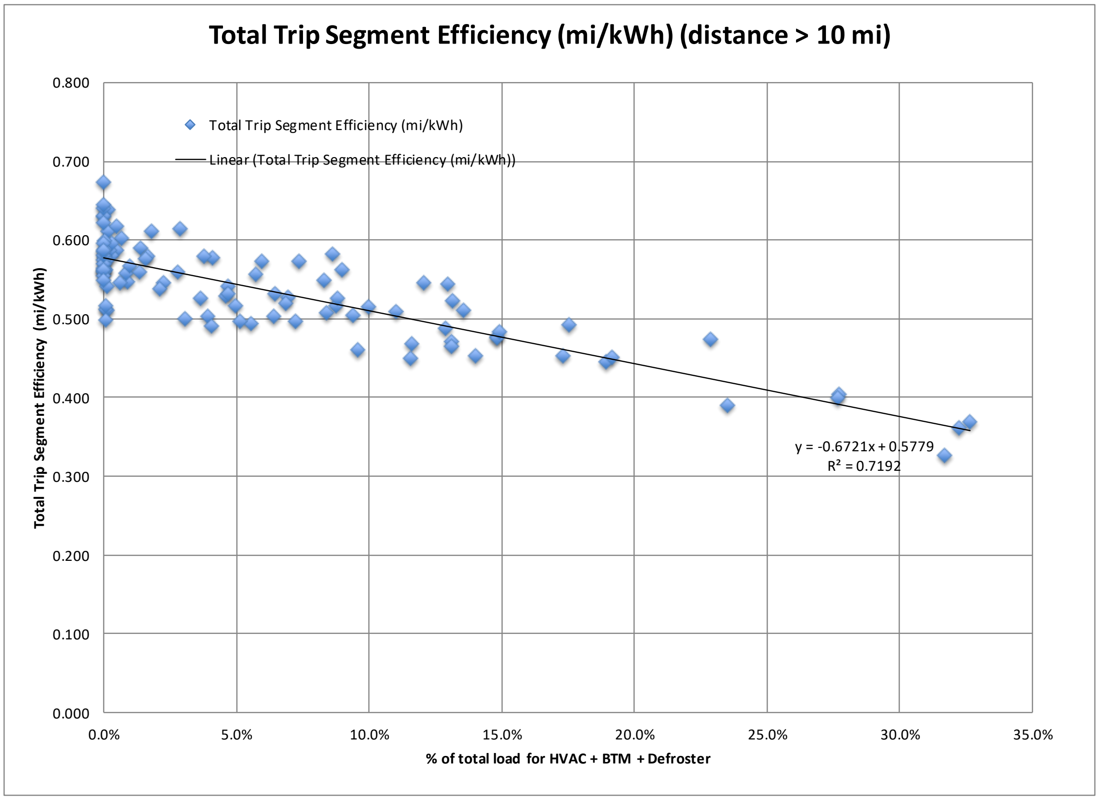


Figure 62: Proterra XR+ efficiency compared to fraction of total battery loads from HVAC, battery management (BTM), and battery defroster systems.

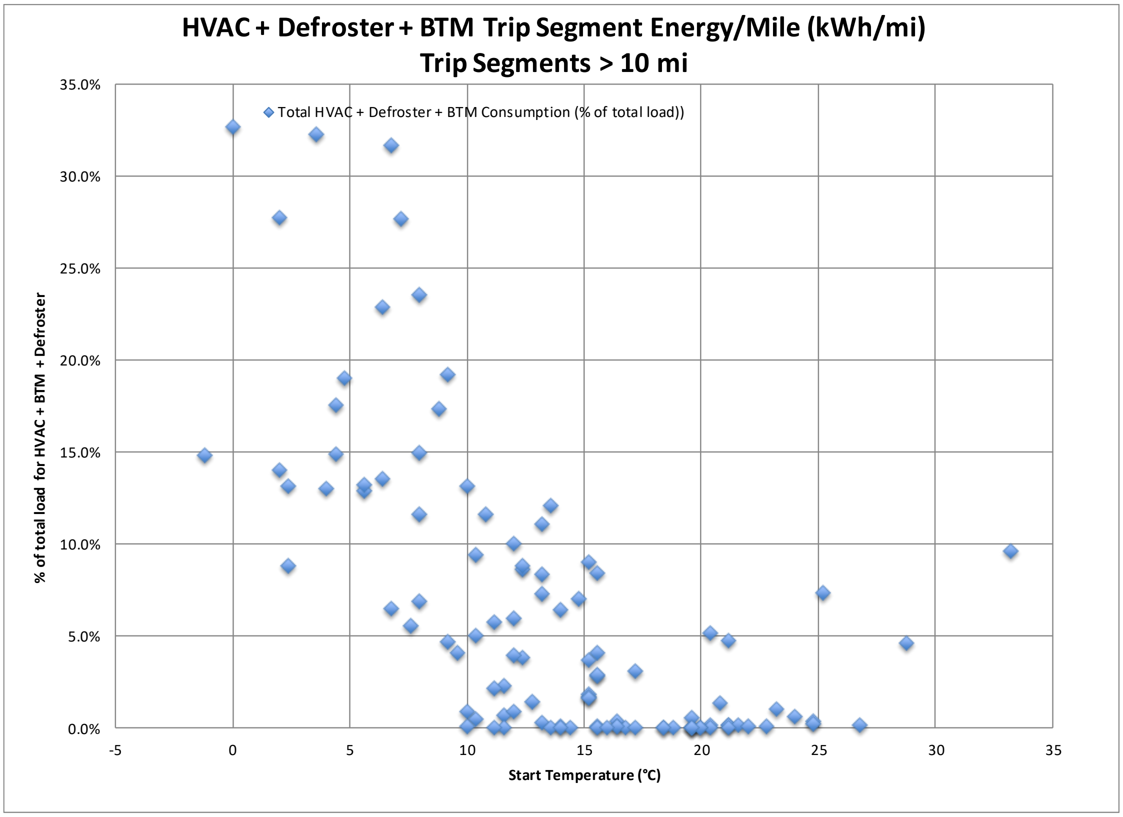


Figure 63: Proterra XR+ ambient temperature vs. fraction of total battery loads from HVAC, battery management (BTM), and battery defroster systems.

For trips of at least 10 miles, the powertrain efficiency (measured from battery to load) saw a mean of 0.585 miles per kWh across a large majority of trips, but with a substantial spread with a low of 0.326 for a handful of trips (Figure 64). Efficiency also appears to be declining at a rate of about 5% per year.

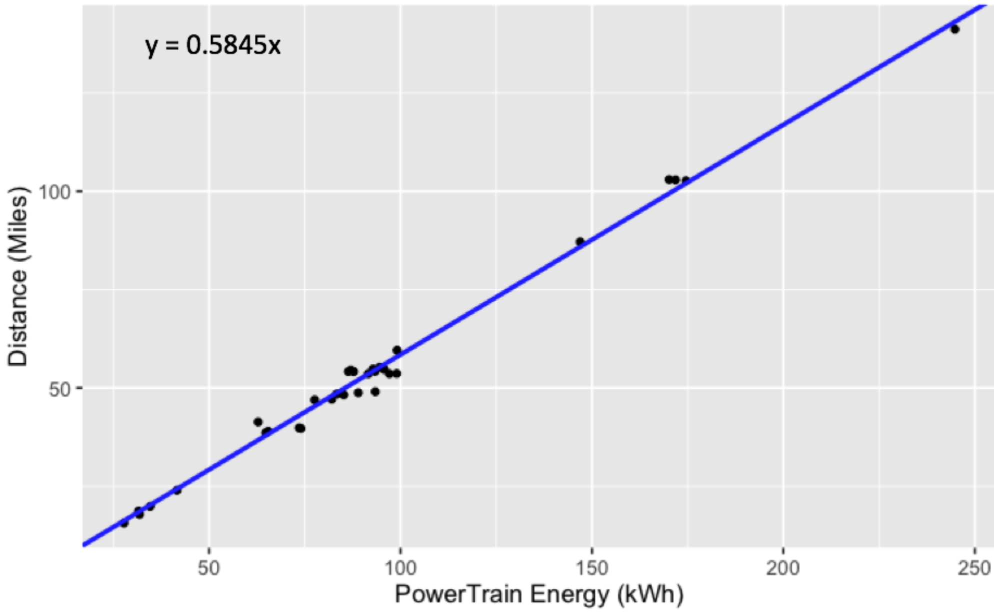


Figure 64. Powertrain efficiency (measured from battery to load)

Based on 32 trips that started with the battery at 100% state of charge (SOC), the reported starting battery energy storage averaged 319 kWh and ranged from 280 to 344 kWh. Over the period from June 2019 through March 2020, the reported starting battery energy storage at 100% SOC declined at a rate of 55 kWh per year (17%/yr) (Figure 65).

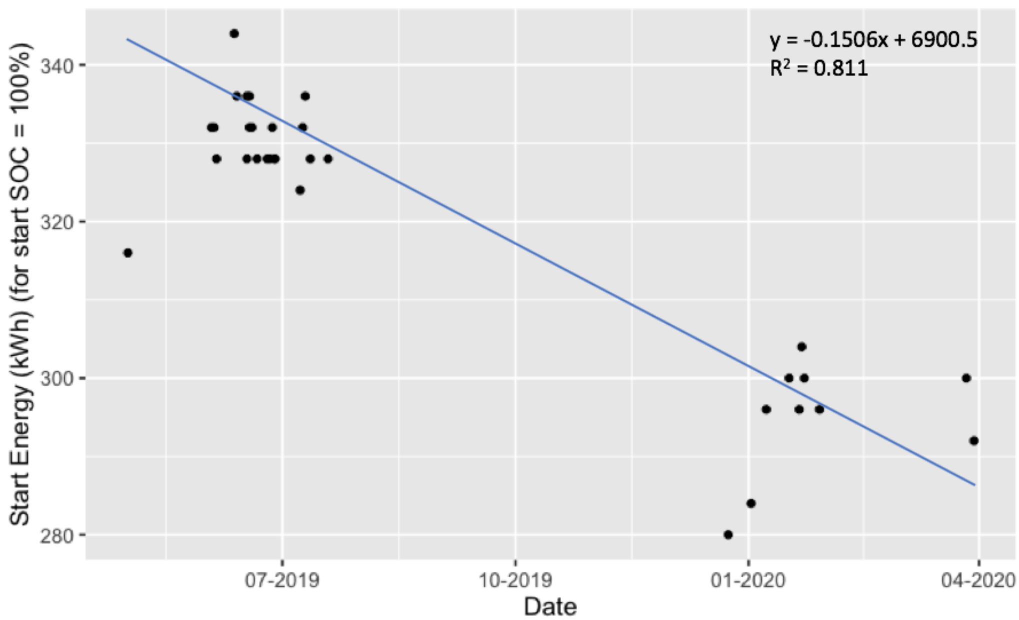


Figure 65. Time trend in battery energy storage at 100%. SOC.

APPENDIX G: COMMERCIALLY AVAILABLE BATTERY ELECTRIC BUSES

Table 36 provides specifications of known commercially available electric transit buses. Note that cut-away options are not included here, yet there are a few commercially available options.

Table 36: Specifications for some commercially available battery electric buses.

Bus Manufacturer	Model	Length	Energy Storage (kWh)	Efficiency (kWh/mile)	Range (miles)
Proterra	XR - DuoPower	40'	220	1.49 - 1.82	97 - 118
	E2 - DuoPower	40'	440	1.53 - 2.19	161 - 230
	E2 Max - DuoPower	40'	660	1.61 - 2.28	232 - 328
	XR - ProDrive	40'	220	1.58 - 1.91	92 - 111
	E2 - ProDrive	40'	440	1.73 - 2.35	150 - 204
	E2 Max - ProDrive	40'	660	1.82 - 2.48	213 - 290
New Flyer	Xcelsior	35' & 40'	311	1.94	160
		35' & 40'	388	1.99	195
		40'	466	2.07	225
		60'	466	3.45	135
Gillig		40'	444	N/A	N/A
BYD	K9S	35'	352	2.43	145
	K9	40'	324	2.08	156
	K11	60'	578	2.63	220
GreenPower	EV250	30'	210	1.20	175
	EV300	35'	260	1.49	175
	EV350	40'	320	1.27	185
	EV400	45'	320	1.73	185
	EV550	45'	478	1.99	240

Note the shaded cells are calculated values from parameters in the manufacture’s specification sheet.

APPENDIX H: ON-ROUTE CHARGER CAPITAL AND INSTALLATION COST ESTIMATES

The following cost estimates for all identified on-route charging locations are provided in the following attached report.

McKeever
ENERGY & ELECTRIC
CA C10 965286

Charging Infrastructure Price Estimation

Climate Resilient Electrified Transit Plan for Humboldt County

May 28, 2020

May 28, 2020

Humboldt Transit Authority
133 V Street
Eureka, California 95501

Subject: Estimate for On-Route Charging Infrastructure| Climate Resilient Electrified Transit Plan for Humboldt County

Dear,

Thank you for giving us the opportunity to submit our estimate for the above-mentioned project.
Please see the attached cost estimates and layouts of the proposed project for each site.
The estimate includes Design-Build for an EV infrastructure at the following sites:

Phase 1
- Arcata Transit Center
- Bayshore Mall
- College of the Redwoods

Phase 2
- Willow Creek
- Trinidad Park & Ride

Phase 3
- Myers Flat
- Dean Creek Resort
- Benbow KOA

With best regards,

Gaurav Kumar
Construction Manager
707.822.0100 x2 | 707.267.8728
gaurav@mckeeverenergy.com

Arcata Transit Center		
Scope of Work	Description	Price
Design Price		
	a. Site and existing underground survey b. Complete primary and secondary utility/electrical design c. Set of drawings for building permit and PG&E submittal	$52,000.00
Pre-Construction & Procurement Phase		
	During Pre-Construction & Procurement: a. Issue Product Submittals & Shop drawings to owner's representative. b. Prepare a Site Specific Safety Plan (SSSP) c. Issue certificates of insurance d. Construction administrative tasks & schedule	$2,280.00
Construction Phase		
	a. Project Management & Administration i. We will appoint a key-staff member as project lead during construction. ii. We will host and attend Project Management meetings during the course of construction as and when required.	$5,000.00
	b. Mobilization & Demobilization	$2,000.00
	c. Civil & site work	$50,000.00
	d. Furnish & install 500 kW Pantograph Charger	$336,000.00*
	e. Electrical i. Furnish and install of 12kV 600A Switch Interrupting Switch ii. Furnish & install a 750kVA transformer and a transformer pad iii. Pull 12 kV line from the existing vault iv. Furnish and install NEMA 3R 800 Amp, 480/277Vac Switchgear with 800 Amp distribution section. v. Furnish and install all necessary underground conduits, conductors, over-current protection devices, grounding & bonding, etc.	$246,000.00
	Total	**$693,280.00**

**Please see attached the price list of the charger.*

There is a 600 A 12kV PG&E vault near the proposed charger location (please see the layout 1), but it requires a new vault and a 600 A 12kV switch interrupting switch. The feeder has available power to feed the proposed charger. Two existing parking spaces near to the proposed location are required to mount a new 750 kVA transformer, 800 Amp switchgear and the charger panel.

Additionally, right of way is required for trenching. The estimate does not include any cost related to right of way or permitting.

Bayshore Mall		
Scope of Work	Description	Price
Design Price		
	a. Site and existing underground survey b. Complete primary and secondary utility/electrical design c. Set of drawings for building permit and PG&E submittal	$55,000.00
Pre-Construction & Procurement Phase		
	During Pre-Construction & Procurement: a. Issue Product Submittals & Shop drawings to owner's representative. b. Prepare a Site Specific Safety Plan (SSSP) c. Issue certificates of insurance d. Construction administrative tasks & schedule	$2,500.00
Construction Phase		
	a. Project Management & Administration i. We will appoint a key-staff member as project lead during construction. ii. We will host and attend Project Management meetings during the course of construction as and when required.	$5,000.00
	b. Mobilization & Demobilization	$3,500.00
	c. Civil & site work	$75,000.00
	d. Furnish & install 500 kW Pantograph Charger	$336,000.00*
	e. Electrical i. Furnish & install a 750kVA transformer and a transformer pad ii. Furnish & install conduits for 12 kV line iii. Furnish and install NEMA 3R 800A, 480/277Vac Switchgear with 800A distribution section. iv. Furnish and install all necessary underground conduits, conductors, over-current protection devices, grounding & bonding, etc.	$244,000.00
	Total	$721,000.00

**Please see attached the price list of the charger.*

There is a 600 Amp 12kV PG&E express system near the existing Tesla chargers (please see the layout 2), and it has available power to feed the proposed charger. The existing PG&E vault is around 750 feet from the proposed location. Since the site is very congested two existing parking spaces near to the proposed location are required to mount a new 750 kVA transformer, 800 Amp switchgear and the charger panel.

Additionally, right of way is required for trenching. The estimate does not include any cost related to right of way or permitting.

College of the Redwoods		
Scope of Work	Description	Price
Design Price		
	a. Site and existing underground survey b. Complete primary and secondary utility/electrical design c. Set of drawings for building permit and PG&E submittal	$50,000.00
Pre-Construction & Procurement Phase		
	During Pre-Construction & Procurement: a. Issue Product Submittals & Shop drawings to owner's representative. b. Prepare a Site Specific Safety Plan (SSSP) c. Issue certificates of insurance d. Construction administrative tasks & schedule	$2,500.00
Construction Phase		
	a. Project Management & Administration i. We will appoint a key-staff member as project lead during construction. ii. We will host and attend Project Management meetings during the course of construction as and when required.	$5,000.00
	b. Mobilization & Demobilization	$4,500.00
	c. Civil & site work	$75,000.00
	d. Furnish & install 500 kW Pantograph Charger	$336,000.00*
	e. Electrical i. Furnish & install vault ii. Furnish & install a 750kVA transformer and a transformer pad iii. Furnish & install conduits for 12 kV line iv. Furnish & install NEMA 3R 800A, 480/277Vac Switchgear with 800A distribution section v. Furnish & install all necessary underground conduits, conductors, over-current protection devices, grounding & bonding, etc.	$240,000.00
	Total	$713,000.00

**Please see attached the price list of the charger.*

At present, there is no PG&E vault available near the proposed location, so a new vault is required. PG&E express system near the existing Tesla chargers (please see the layout 3), and it has available power to feed the proposed charger. The proposed new PG&E vault is around 1000 feet from the proposed charger location. There are some parking lots adjacent to the proposed site that can be used to mount a new 750 kVA transformer, 800 Amp switchgear and the charger panel.

Additionally, right of way is required for trenching. The estimate does not include any cost related to right of way or permitting.

Willow Creek		
Scope of Work	Description	Price
Design Price		
	a. Site and existing underground survey b. Complete primary and secondary utility/electrical design c. Set of drawings for building permit and PG&E submittal	$35,000.00
Pre-Construction & Procurement Phase		
	During Pre-Construction & Procurement: a. Issue Product Submittals & Shop drawings to owner's representative. b. Prepare a Site Specific Safety Plan (SSSP) c. Issue certificates of insurance d. Construction administrative tasks & schedule	$2,300.00
Construction Phase		
	a. Project Management & Administration i. We will appoint a key-staff member as project lead during construction. ii. We will host and attend Project Management meetings during the course of construction as and when required.	$5,000.00
	b. Mobilization & Demobilization	$5,500.00
	c. Civil & site work	$45,000.00
	d. Furnish & install 500 kW Pantograph Charger	$336,000.00*
	e. Electrical i. Furnish & install a 750kVA transformer and a transformer pad ii. Furnish & install conduits for 12 kV line iii. Furnish & install NEMA 3R 800A, 480/277Vac Meter Main Service with 800A distribution section. iv. Furnish & install all necessary underground conduits, conductors, over-current protection devices, grounding & bonding, etc.	$196,000.00
	Total	$624,800.00

**Please see attached the price list of the charger.*

There is a PG&E vault available within 200 feet of the proposed location (please see the layout 4), and it has available power to feed the proposed charger. There is a space adjacent to the proposed location that can be used to mount a new 750 kVA transformer, 800 Amp switchgear and the charger panel.

Additionally, right of way is required for trenching and land acquisition may be required.
The estimate does not include any cost related to right of way or permitting.

Trinidad Park & Ride		
Scope of Work	Description	Price
Design Price		
	a. Site and existing underground survey b. Complete primary and secondary utility/electrical design c. Set of drawings for building permit and PG&E submittal	$35,000.00
Pre-Construction & Procurement Phase		
	During Pre-Construction & Procurement: a. Issue Product Submittals & Shop drawings to owner's representative. b. Prepare a Site Specific Safety Plan (SSSP) c. Issue certificates of insurance d. Construction administrative tasks & schedule	$2,300.00
Construction Phase		
	a. Project Management & Administration i. We will appoint a key-staff member as project lead during construction. ii. We will host and attend Project Management meetings during the course of construction as and when required.	$5,000.00
	b. Mobilization & Demobilization	$4,500.00
	c. Civil & site work	$30,000.00
	d. Furnish & install 500 kW Pantograph Charger	$336,000.00*
	e. Electrical i. Furnish & install 600 A Switch Interrupting Switch. ii. Furnish & install a 750kVA transformer and a transformer pad iii. Pull 12 kV line from the existing vault iv. Furnish and install NEMA 3R 800A, 480/277Vac Meter Main Service with 800A distribution section. v. Furnish and install all necessary underground conduits, conductors, over-current protection devices, grounding & bonding, etc.	$206,000.00
	Total	**$618,800.00**

**Please see attached the price list of the charger.*

There is a PG&E vault available within 50 feet of the proposed location (please see the layout 5), and it has available power to feed the proposed charger, but a 600 Amp switch interrupting switch is required. There are couples of parking spaces adjacent to the proposed location that can be used to mount a new 750 kVA transformer, 800 Amp switchgear and the charger panel.

Additionally, right of way is required for trenching and land acquisition may be required.
The estimate does not include any cost related to right of way or permitting.

Myers Flat		
Scope of Work	Description	Price
Design Price		
	a. Site and existing underground survey b. Complete primary and secondary utility/electrical design c. Set of drawings for building permit and PG&E submittal	$50,000.00
Pre-Construction & Procurement Phase		
	During Pre-Construction & Procurement: a. Issue Product Submittals & Shop drawings to owner's representative. b. Prepare a Site Specific Safety Plan (SSSP) c. Issue certificates of insurance d. Construction administrative tasks & schedule	$2,300.00
Construction Phase		
	a. Project Management & Administration i. We will appoint a key-staff member as project lead during construction. ii. We will host and attend Project Management meetings during the course of construction as and when required.	$5,000.00
	b. Mobilization & Demobilization	$7,500.00
	c. Civil & site work	$75,000.00
	d. Furnish & install 500 kW Pantograph Charger	$336,000.00*
	e. Electrical i. Furnish & install a new vault ii. Furnish & install 600 A Switch Interrupting Switch. iii. Furnish & install a 500kVA transformer and a transformer pad iv. Pull 12 kV line from the new vault v. Furnish and install NEMA 3R 800A, 480/277Vac Meter Main Service with 800A distribution section. vi. Furnish and install all necessary underground conduits, conductors, over-current protection devices, grounding & bonding, etc.	$295,000.00
	Total	$770, 800.00

**Please see attached the price list of the charger.*

There is a PG&E facility available within 1000 feet of the proposed location (please see the layout 6), but the existing facility is only single phase and need to be upgraded to three phase. A 12kV vault and a 600 Amp switch interrupting switch will be required once the upgrade happens. There are spaces available adjacent to the proposed location that can be used to mount a new 500 kVA transformer, 800 Amp switchgear and the charger panel.

Additionally, right of way is required for trenching and land acquisition may be required. The estimate does not include any cost related to right of way or permitting.

Dean Creek Resort		
Scope of Work	Description	Price
Design Price		
	a. Site and existing underground survey b. Complete primary and secondary utility/electrical design c. Set of drawings for building permit and PG&E submittal	$45,000.00
Pre-Construction & Procurement Phase		
	During Pre-Construction & Procurement: a. Issue Product Submittals & Shop drawings to owner's representative. b. Prepare a Site Specific Safety Plan (SSSP) c. Issue certificates of insurance d. Construction administrative tasks & schedule	$2,500.00
Construction Phase		
	a. Project Management & Administration i. We will appoint a key-staff member as project lead during construction. ii. We will host and attend Project Management meetings during the course of construction as and when required.	$5,000.00
	b. Mobilization & Demobilization	$8,500.00
	c. Civil & site work	$55,000.00
	d. Furnish & install 500 kW Pantograph Charger	$336,000.00*
	e. Electrical i. Furnish & install a 750kVA transformer and a transformer pad ii. Pull 12 kV line from the new vault iii. Furnish and install NEMA 3R 800A, 480/277Vac Meter Main Service with 800A distribution section. iv. Furnish and install all necessary underground conduits, conductors, over-current protection devices, grounding & bonding, etc.	$190,000.00
	Total	**$642,000.00**

**Please see attached the price list of the charger.*

There is a PG&E facility available within 500 feet of the proposed location (please see the layout 7), but the existing circuit is heavily loaded. PG&E will have to upgrade the circuit. Once the circuit is upgraded, a 12kV vault and a 600 Amp switch interrupting switch will be required. There are spaces available adjacent to the proposed location that can be used to mount a new 750 kVA transformer, 800 Amp switchgear and the charger panel.

Additionally, right of way is required for trenching and land acquisition may be required. The estimate does not include any cost related to right of way or permitting.

Benbow KOA		
Scope of Work	Description	Price
Design Price		
	a. Site and existing underground survey b. Complete primary and secondary utility/electrical design c. Set of drawings for building permit and PG&E submittal	$35,000.00
Pre-Construction & Procurement Phase		
	During Pre-Construction & Procurement: a. Issue Product Submittals & Shop drawings to owner's representative. b. Prepare a Site Specific Safety Plan (SSSP) c. Issue certificates of insurance d. Construction administrative tasks & schedule	$2,500.00
Construction Phase		
	a. Project Management & Administration iii. We will appoint a key-staff member as project lead during construction. iv. We will host and attend Project Management meetings during the course of construction as and when required.	$5,000.00
	b. Mobilization & Demobilization	$9,500.00
	c. Civil & site work	$35,000.00
	d. Furnish & install 500 kW Pantograph Charger	$336,000.00*
	e. Electrical v. Furnish & install a 500kVA transformer and a transformer pad vi. Furnish and install NEMA 3R 800A, 480/277Vac Meter Main Service with 800A distribution section. vii. Furnish and install all necessary underground conduits, conductors, over-current protection devices, grounding & bonding, etc.	$155,000.00
	Total	**$578,000.00**

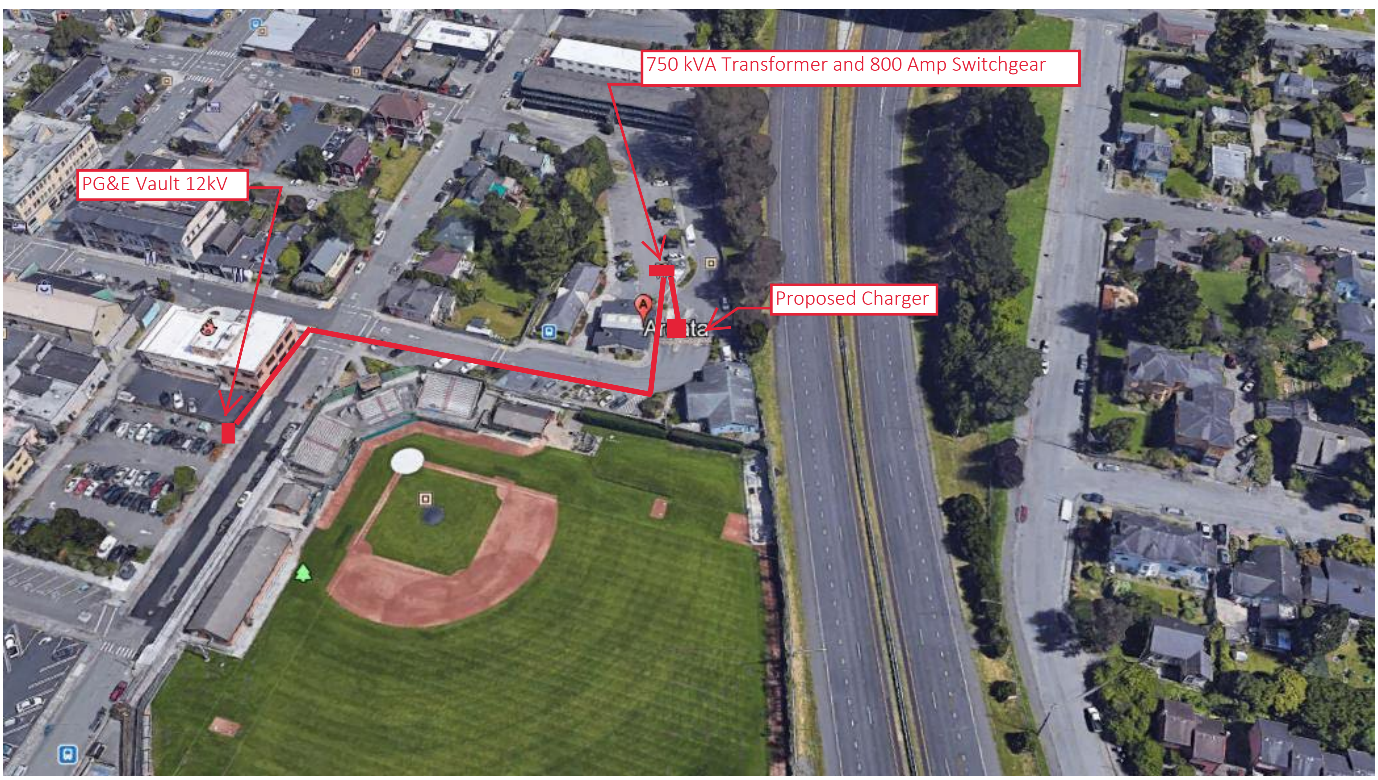
**Please see attached the price list of the charger.*

There is a PG&E facility available within 100 feet of the proposed location (please see the layout 8) and there is an existing transformer which supplying power to a facility. The cost estimate has assumed the upgradation (500 kVA) of the existing transformer. Further, there are spaces available adjacent to the proposed location that can be used to mount a new 500 kVA transformer, 800 Amp switchgear and the charger panel.

Additionally, right of way is required for trenching and land acquisition may be required. The estimate does not include any cost related to right of way or permitting.

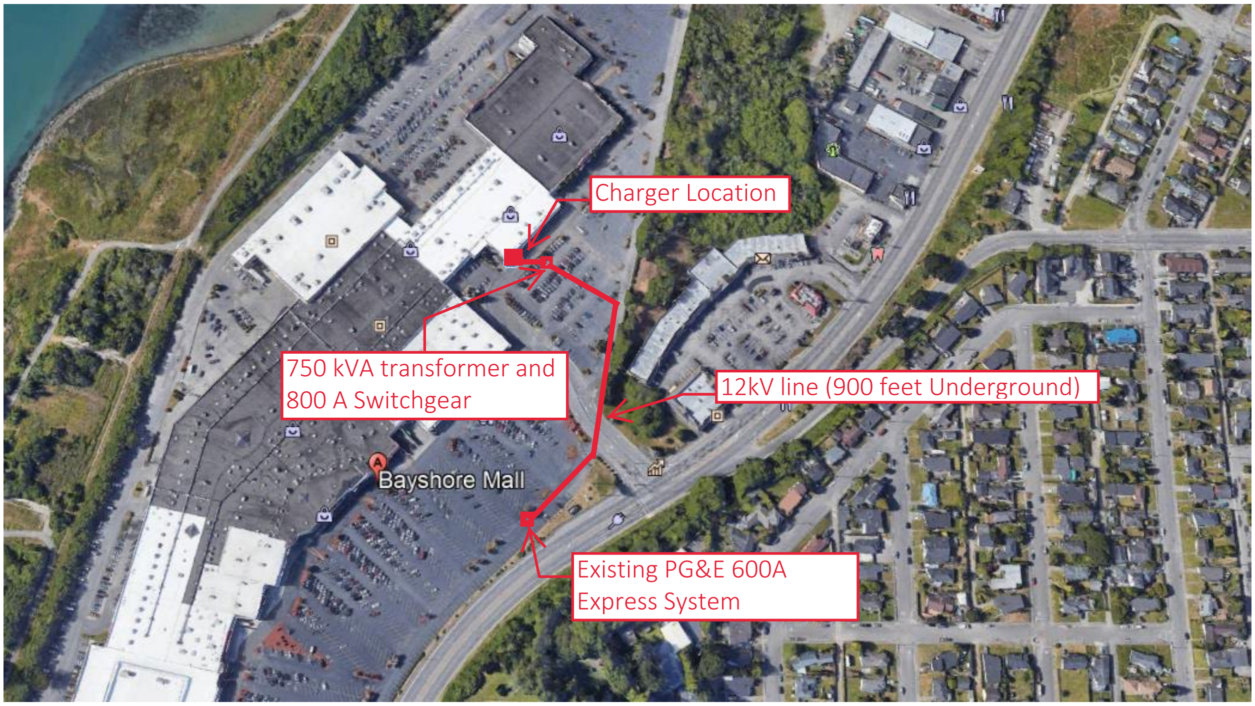
Appendix A

Arcat Transit Center



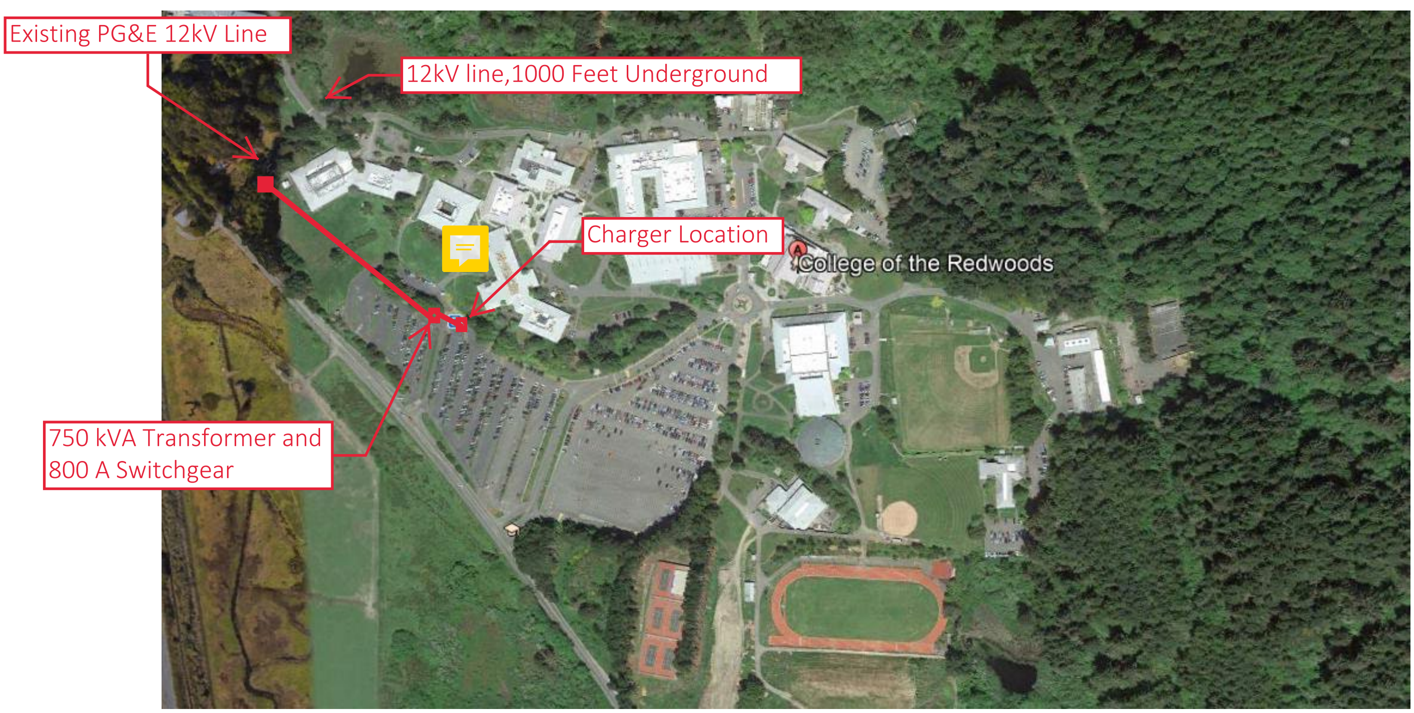
Layout 1

Bayshore Mall



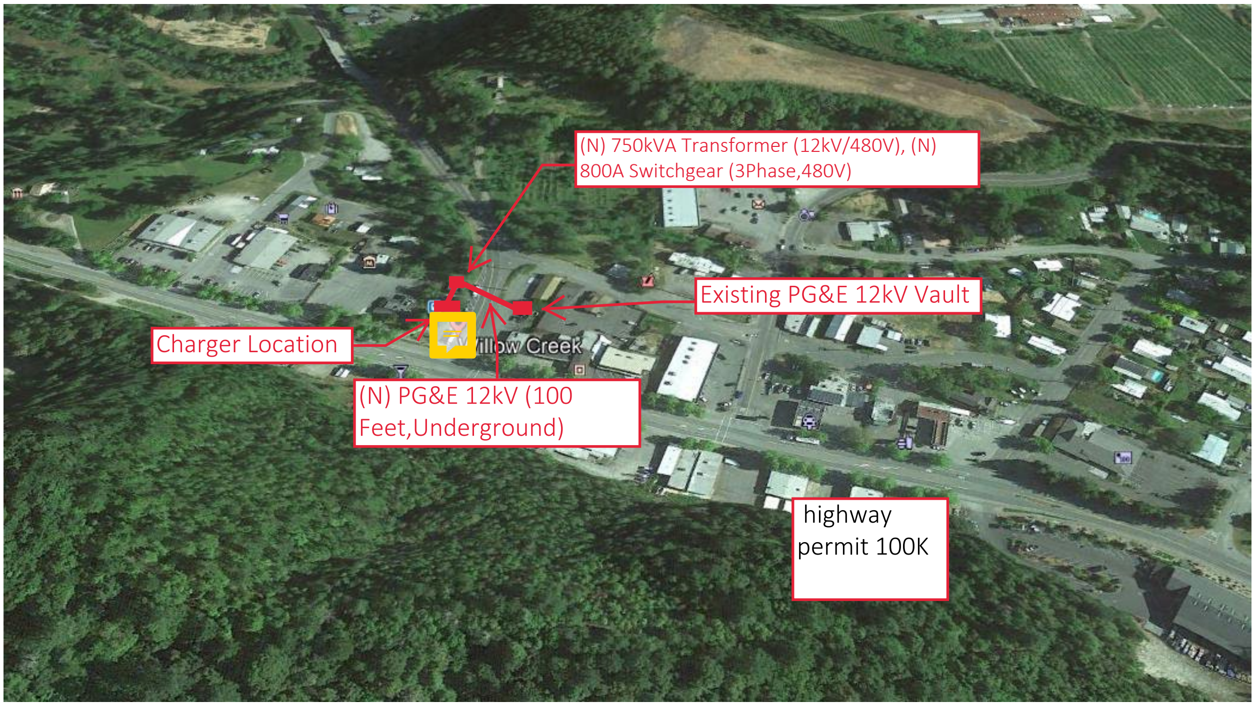
Layout 2

College of the Redwoods



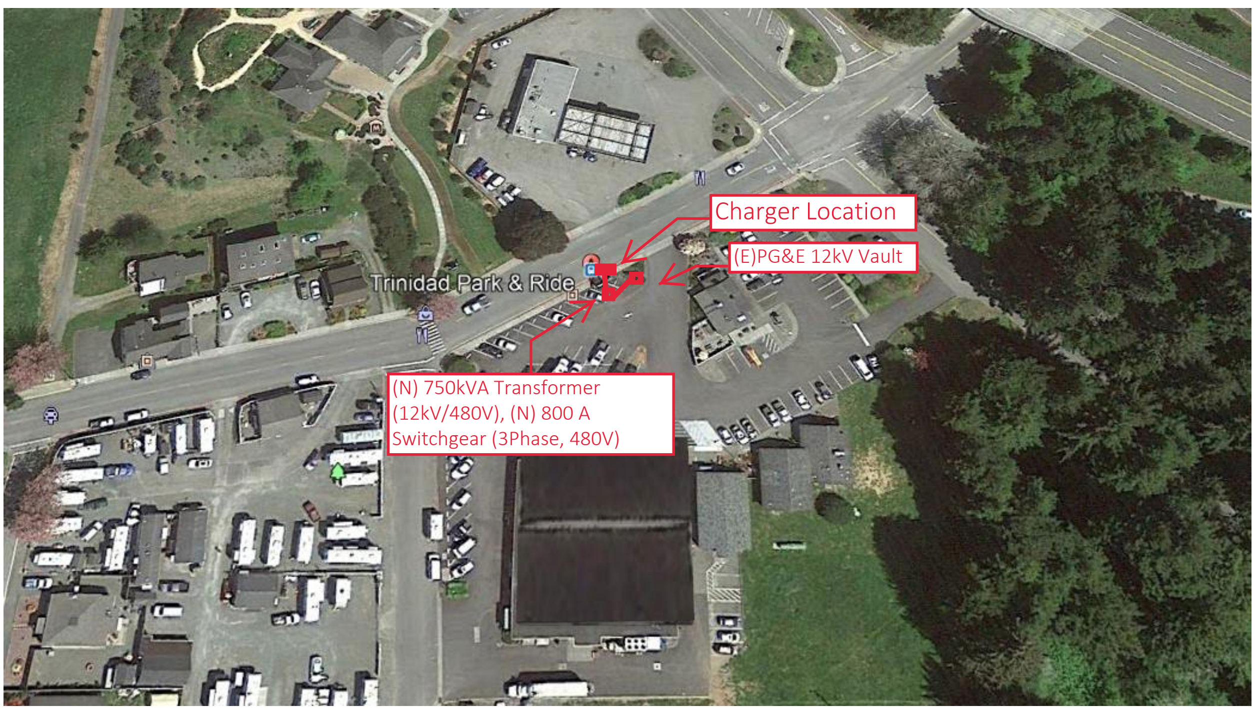
Layout 3

Willow Creek



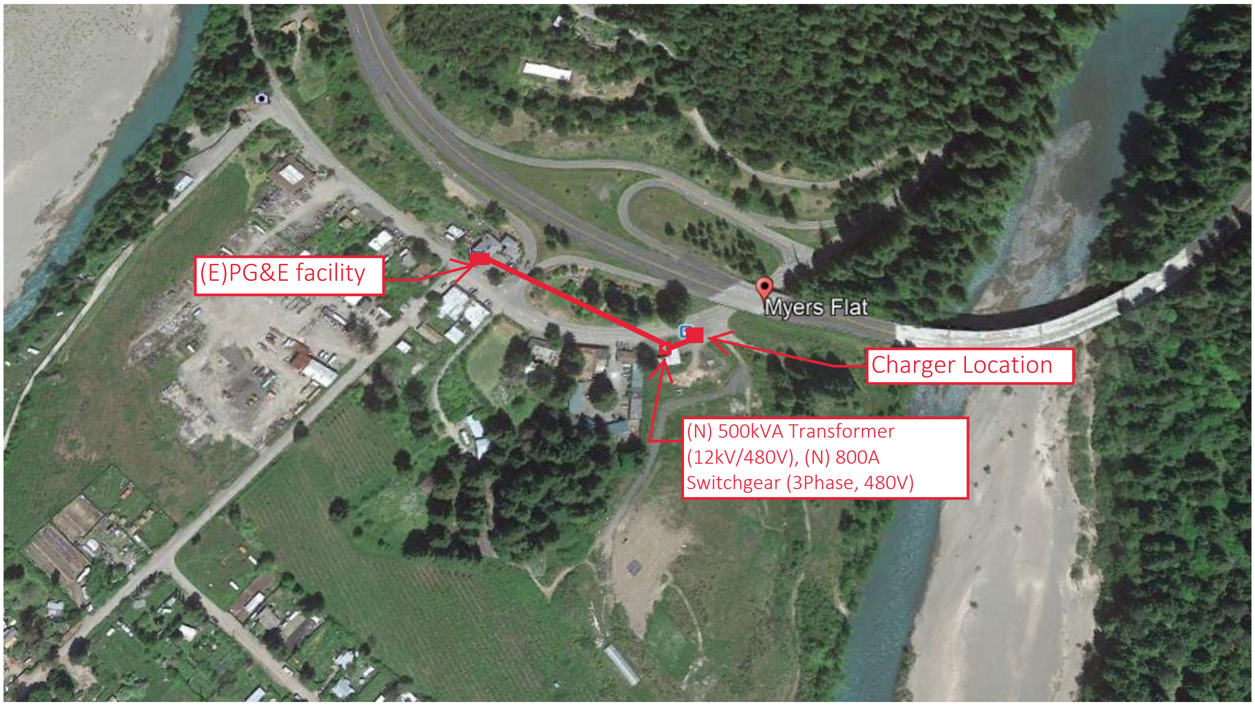
Layout 4

Trinidad Park & Ride



Layout 5

Myers Flat



Layout 6

Dean Creek Resort

Layout 7

Benbow KOA

Layout 8

GENERAL SERVICES ADMINISTRATION

Federal Supply Service

Authorized Federal Supply Schedule Price List

On-line access to contract ordering information, terms and conditions, up-to-date pricing, and the option to create an electronic delivery order are available through GSA Advantage!, a menu-driven database system. The INTERNET address GSA Advantage! is: GSAAdvantage.gov

Schedule Title: 23V - Automotive Superstore

Contract Number: GS-30F-026BA

For more information on ordering from Federal Supply Schedules click on the FSS Schedules button at fss.gsa.gov.

Contract Period: April 18, 2014 through April 17, 2019

Proterra Inc
1 Whitlee Ct
Greenville, SC 29607-3791
Phone: 801-953-9539

Email: awestenskow@proterra.com

Contractor's internet address/web site where schedule information can be found www.proterra.com

Business Type: Small business

1. Table of awarded special item number(s) with appropriate cross-reference to

item descriptions and awarded price(s).

Special Item Number (SIN)	Part ID	Item Description	Single Unit GSA Price Including IFF, Freight, & FET
SIN 272-105 Buses (40 Ft. E2)	40catalyste2	40 Ft. Catalyst Transit Bus including E2 Batteries	$771,869.02
SIN 272-105 Buses (35 Ft. E2)	35catalyste2	35 Ft. Catalyst Transit Bus including E2 Batteries	$694,488.66
SIN 272-105 Buses (40 Ft. FC)	40catalystfc	40 Ft. Catalyst Transit Bus, Fast Charge Batteries	$739,566.75
SIN 272-105 Buses (35 Ft. FC)	35catalystfc	35 Ft. Catalyst Transit Bus, Fast Charge Batteries	$660,574.31
SIN 272-105 Buses (40 Ft. XR)	40catalystxr	40 Ft. Catalyst Transit Bus, Extended Range Batteries	$739,566.75
SIN 272-105 Buses (35 Ft. XR)	35catalystxr	35 Ft. Catalyst Transit Bus, Extended Range Batteries	$660,574.31
SIN 272-105 Chargers	FC500KW	500 KW Overhead fast charger	$316,473.55
SIN 272-105 Chargers	MC050KW	50 KW Manual Shop Charger	$36,937.03
SIN 272-105 Chargers (60kW)	MC060KW	60 KW PCS Charger, Dispenser, Cord Rack and Labor	$44,750.63
SIN 272-105 Chargers (125kW)	MC125KW	125 KW PCS Charger, Dispenser, Cord Rack and Labor	$61,324.94
SIN 272-105	DIAGTOOLS	Bus Diagnostic Tools	$6,559.00
SIN 272-105	OUTSKN	Exterior Outskin for Charger Use	$10,086.00
SIN 272-105 Buses (ITS)	PrimaryITS	Intelligent Transportation System	$38,115.87