CALTRAIN

ENERGY PROCUREMENT STRATEGY

FINAL REPORT UPDATE

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WSP USA

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GLOSSARY OF TERMS

AC	Alternating Current
AES	Advanced Energy Storage
BEB	Battery Electric Bus
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicle
CA	California
CA HSR	California High Speed Rail
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CCE	Community Choice Energy
CEC	California Energy Commission
CO_2	Carbon dioxide
COA	Comprehensive Operational Analysis
COD	Commercial Operation Date
CPSF	CleanPowerSF
CSP	Curtailment Service Provider
CPUC	California Public Utilities Commission
CUB	Contract Bus Fleet
DA	Direct Access
DC	Direct Current
DER(s)	Distributed Energy Resources
DRAM	Demand Response Auction Mechanism
EIR	Environmental Impact Report
EMU	Electric Multiple-Unit
ESP	Electric Service Provider
GHG	Greenhouse Gas
GRC	General Rate Case
HFTZ	High Fire Threat Zone
IOU	Investor Owned Utility(ies)
IRR	Internal rate of return
ITC	Investment Tax Credit
kW	Kilowatt
kWh	Kilowatt-hour

LCFS	Low Carbon Fuel Standard
LSE	Load Serving Entity
MACRS	Modified Accelerated Cost- Recovery System
MBTA	Massachusetts Bay Transportation Authority
MOU	Municipal Owned Utility
MW	Megawatt
MWh	Megawatt-hour
NCPA	Northern California Power Agency
NEM	Net energy metering
NFPA	National Fire Protection Association
NGOM	Net generation output meter
OCS	Overhead Control System
PCE	Peninsula Clean Energy
PCIA	Power Charge Indifference Adjustment
PG&E	Pacific Gas & Electric
PPA	Power Purchase Agreement
PSPS	Public Safety Power Shutoff
PV	Photovoltaic
REC	Renewable Energy Credit
RES-BCT	Renewable Energy Self-Generation Bill Credit Transfer
RFP	Request for Proposals
RPS	Renewable Portfolio Standard
SAID	Service Agreement ID
SGIP	Self-Generation Incentive Program
SJCE	San Jose Clean Energy
SOP	Super-Off-Peak
SVCE	Silicon Valley Clean Energy
TOU	Time of Use
UEDM	Utility expense data management
VPP	Virtual Power Plant
(v)PPA	(Virtual) Power Purchase Agreement
W	Watt
WREGIS	Western Renewable Energy Generation Information System

DEFINITIONS

Community Choice Aggregation/Energy (CCA/CCE)	CCA/CCE) are programs that allow local governments to procure power (including lower carbon power) on behalf of their residents, businesses, and municipal accounts from an alternative supplier while still receiving electricity delivery (called transmission and distribution) service from their existing utility provider (PG&E). Caltrain is currently served by a CCA/CCE providers.
Demand Reduction	Decreased demand for peak power.
Direct Access Power	Direct Access (DA) is an option available to non-residential customers that would allow Caltrain to purchase its electricity directly from a third-party supplier, including products that are exposed to wholesale market pricing. Under this option, Caltrain would be granted the ability to contract directly with any Electric Service Provider (ESP).
Distributed Energy Resources (DER(s))	DERs are decentralized, electricity-producing infrastructure located close to the consumer they supply energy to, and are connected to a local distribution system or host facility. DERs can include solar panels and battery storage systems, and can be integrated into a microgrid.
Electric Service Provider (ESP)	A non-utility entity that offers electric service to customers within the service territory of an electric utility.
Eligible Renewable Energy Resource	Energy sources that are eligible to meet the State of California's Renewable Energy Portfolio Standard (RPS). The RPS is a law that sets the minimum level of renewables utilities are required to procure. Eligible renewable resources include solar and solar thermal electric; wind; certain biomass resources; geothermal electric; certain hydroelectric facilities (energy from dams); ocean wave, thermal and tidal energy; fuel cells using renewable fuels; landfill gas; and municipal solid waste conversion, not the direct combustion of municipal solid waste. Large hydroelectric generation (e.g., Hetch Hetchy) and nuclear are excluded.
Greenhouse Gas (GHG) Emissions	Gases that trap heat in the atmosphere, including carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and fluorinated gases.
GHG-Free Energy	Electricity that does not emit carbon or other greenhouse gases. In California, GHG-free energy includes all eligible renewable energy sources plus large hydroelectric and nuclear energy.

Grid Services Programs	Distributed Energy Resources, such as batteries can participate in relatively new grid services programs such as the Demand Response Auction Mechanism (DRAM). Similar to traditional demand response programs (where customers are compensated for allowing the utility to turn off some of certain loads during certain high energy usage events), the DRAM program (as well as others) enable behind-the-meter resources to earn revenue by reducing or shifting a facility's load at specified times.
Investor Owned Utility (IOU)	Utilities owned privately by shareholders. Other types of non-IOU utilities include municipally owned utilities and community choice aggregators.
Load Serving Entity (LSE)	An organization that serves end users and has been granted authority by the state to sell electric energy to end users. Legislation would be required to allow SamTrans to become an LSE.
Low Carbon Fuel Standard (LCFS)	Designed to encourage the use of cleaner low-carbon transportation fuels in California, encourage the production of those fuels, and therefore, reduce GHG emissions and decrease petroleum dependence in the transportation sector. SamTrans will generate LCFS credits by switching from diesel fuel to electricity in proportion to the percentage of the fleet that is operated using electricity instead of diesel. The benefits provided by the alternative fuel source (e.g., grid electricity) are compared to the standard fuel source (e.g., gasoline or diesel) and the GHG emissions associated with the complete life-cycle of each fuel is compared in order to determine the reduction in GHG emissions due to the use of the alternative fuel source. The agencies can increase the value of the LCFS credits by achieving zero-carbon electricity by either (1) using DER onsite to charge the vehicles; or (2) retiring renewable energy credits (RECs).
Microgrid	A local energy grid that can be disconnected from the traditional grid and operate autonomously, which provides resilience during a power outage. A solar-battery storage system could be designed as a microgrid.
Oversubscribed	Demand for power that exceeds supply, especially in regard to a program that has capped its participation in terms of capacity.
Peak Power	In reference to electric power, the maximum power output a load serving entity can supply to load within a defined period of time.
Peak Shaving	Strategies used to proactively reduce peak power demand.
Power Purchase Agreement (PPA)	A long-term electricity supply agreement between two parties: the power producer and the power consumer. The power producer funds, constructs, owns and operates the energy generation source (e.g., solar) and charges the consumer and agreed upon rate per kWh. The energy generation source can be located either on or off the consumer's property.

Retail Electricity	Retail providers (e.g., IOUs like PG&E and CCAs like PCE) that sell power directly to end-use consumers. In California, end-use customers need legislative authority to bypass a retail provider and procure electricity directly on the wholesale market.
Renewable Energy	Electricity from a source that is not depleted when used, and that is not derived from fossil or nuclear fuel. In California, the term "eligible renewable" is used to indicate which renewable sources qualify for the Renewable Energy Portfolio Standard (RPS). The RPS is a law that sets the minimum level of renewable energy utilities are required to procure. Large hydroelectric sources are not eligible renewable sources because they result in other negative environmental impacts (e.g., to fish and aquatic communities). Low-impact hydroelectric sources have fewer negative environmental impacts and are considered to be eligible renewable energy resources. A power content label identifies the percentage of eligible renewable energy resources used by an energy provider.
Renewable Energy Credit (REC)	Credits “created” by a renewable energy generator, like a solar array, when it produces renewable energy. A REC allows the holder to claim the environmental benefits of one unit of energy generated from a renewable source. RECs can be monetized and have financial value.
Renewable Portfolio Standard (RPS)	A law mandating a minimum level of eligible renewable energy resource use by investor owned utilities (IOUs). The law is implemented at the state level. In this study the law will refer to California’s RPS; however, other states have also adopted RPS legislation.
Tariff	The rates utilities charge customers, typically differentiated by customer type and level of electricity consumption.
Time-of-Use (TOU)	A rate plan in which rates vary according to the time of day, season and day of the week. Higher rates are charged during periods of higher electricity demand, or “peak” hours, and lower rates during low demand hours (called off-peak). PG&E’s new TOU rates, which go into effect in 2021, shift the peak period, the higher cost period, to 4 to 7 PM year-round.
Wholesale Power	The wholesale electricity market is typically a market for generators and resellers (e.g., PG&E, CCAs, and ESPs), but there are some instances where large energy users are granted access to the market (e.g., BART).

EXECUTIVE SUMMARY

As Caltrain transitions from diesel- to electric-powered locomotives, electricity – and the procurement thereof – will become an increasingly important component of the agency's fuel spend, environmental impacts, and participation in revenue-generating opportunities such as the Low Carbon Fuel Standard (LCFS) market. It is also critical to consider options for power resilience in the event of a sustained power outage.

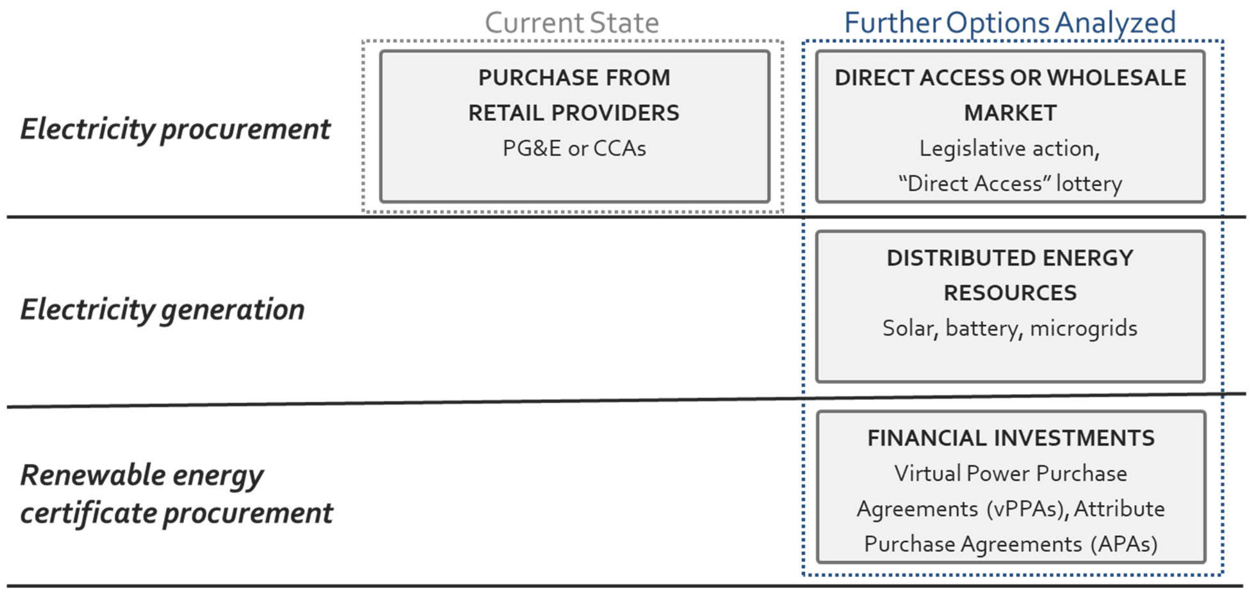
WSP and TerraVerde Energy (TerraVerde) (the Project Team) were retained to conduct a comprehensive energy procurement study to evaluate Caltrain's short- and medium-term energy procurement options. This report provides an analysis of the electricity and technology procurement options available to Caltrain, including evaluation of the associated environmental impacts, risks, trade-offs, operational impacts and financial considerations of each option. This report also includes discussion of the potential benefits associated with jointly procuring electricity with SamTrans.

Caltrain currently procures 100% greenhouse gas (GHG)-free and renewable electricity through Community Choice Aggregators (CCAs) and two municipal owned utilities (MOUs).[1] The CCA electricity is still delivered to Caltrain through Pacific Gas & Electric's (PG&E's) transmission and distribution network. Over the short-term (1 to 4 years), Caltrain has the option to choose from two types of retail electricity providers to serve its growing load: (1) an investor-owned utility (IOU) (in this case, PG&E); or (2) CCA providers available in Caltrain's jurisdiction. Caltrain also has the option to install onsite distributed energy resource (DER) systems (a solar photovoltaic system and/or battery energy storage system [BESS]) to reduce electricity procurement needs and costs.

Over the medium to long-term (4+ years), Caltrain can continue to remain a retail electricity customer and choose between currently available providers, or it could pursue expanded retailer choice through Direct Access (DA) or work to have access to the wholesale electricity market, provided DA capacity is available or Caltrain is granted legislative authority to purchase through the wholesale market. DER systems could also be installed over the medium-term as additional technology options become available or existing options become more affordable. The energy procurement and technology options evaluated in this study are summarized in Figure ES-1.

[1] Where Caltrain procures from an MOU, the agency does not have the option to switch to a CCA provider. For this reason and because the future traction load studied will be located in PG&E territory, the MOU electricity consumption is excluded from this analysis.

Figure ES-1. Energy Procurement and Technology Options



Key findings and suggestions from the study are presented below by project phase.

PHASE 1: SHORT-TERM ENERGY PROCUREMENT STRATEGY SUMMARY

Both the CCA providers and PG&E offer default rates and greener rates that have higher percentages of GHG-free and/or renewable energy. The short-term energy procurement strategy analysis demonstrates that the CCA providers have more favorable rates compared to PG&E for Caltrain's existing and future electric load under both the default and greener rates.

Table ES-1 summarizes the future annual costs associated with the new electrical services for train electrification at the Caltrain North and South substations. Caltrain will also earn LCFS credits for switching from diesel-powered trains to electric-powered trains, which will offset a large portion of Caltrain's electricity costs.[2] The potential financial benefits from the LCFS program are factored into the table, based on using grid electricity. As shown in Table ES-1, the CCA default option provides savings of approximately $267,580 over the PG&E standard rates and the CCA 100% green option provides approximately $468,146 of savings over the PG&E 100% Solar Choice rates.

Table ES-1. Future Rate Analysis Summary

Costs/Savings	Annual Electricity Cost	Total Electricity Costs with Grid Electricity LCFS Credit ($/YR)
PG&E Default Costs	$15,565,068	$1,835,959

[2] Caltrain must register with the LCFS program to participate.

Costs/Savings	Annual Electricity Cost	Total Electricity Costs with Grid Electricity LCFS Credit ($/YR)
PG&E Solar Choice Costs	$16,879,890	$3,150,781
CCA Default Costs	$15,297,488	$1,568,379
CCA 100% Green Costs	$16,411,744	$2,682,634
CCA Savings (standard)	**$267,580**	
CCA Savings (100% Green)	**$468,146**	

Caltrain can increase the value of its LCFS credits by procuring zero-carbon electricity. There are two pathways to achieving zero-carbon electricity for LCFS: (1) through onsite renewable energy sources used to directly power the vehicles; or (2) retiring qualifying renewable energy credits (RECs) from zero-carbon sources such as solar photovoltaic (PV), wind, renewable portfolio standard (RPS)-eligible hydroelectric generation, ocean wave, ocean thermal or tidal current sources. Table ES-2 summarizes the estimated difference in the value of LCFS credits generated through grid electricity versus zero-carbon electricity. Achieving zero-carbon electricity provides a projected additional LCFS credit benefit of approximately $2,952,487.

Table ES-2. Low Carbon Fuel Standard Benefits Summary[3]

Transformer	Consumption (kWh/ YR)	LCFS Using Grid Electricity ($/kWh)	LCFS Using Zero Carbon Electricity ($/kWh)	LCFS Using Grid Electricity ($/YR)	LCFS Using Zero Carbon Electricity ($/YR)
TPS-1: T1	28,536,892	$0.1232	$0.1497	$3,516,124	$4,272,277
TPS-1: T2	30,172,819			$3,717,692	$4,517,193
TPS-2: T1	30,907,744			$3,808,245	$4,627,219
TPS-2: T2	21,808,104			$2,687,048	$3,264,906
TOTALS:	**111,425,559**			**$13,729,109**	**$16,681,596**

The Project Team analyzed the feasibility of installing solar PV and/or battery energy storage (BESS) DER systems adjacent to the future Caltrain North and South traction power substations and at Caltrain stations. Based on the analysis, a solar and/or BESS system does not appear to be

[3] Assumes the LCFS credit price is $100 per ton CO^2 equivalent. The LCFS credit price varies over time. The value used is conservative based on the past two years of history showing that the lowest LCFS credit price was $150 per ton CO^2 equivalent in April of 2018 and the highest LCFS credit price was $218 per ton CO^2 equivalent in February of 2020. The LCFS value shown uses projected carbon content values from CARB for 2022 grid electricity, solar electricity and diesel. Assumes the cost per REC is $20.

viable at the South and North substations due to space limitations. Therefore, Caltrain would need to purchase RECs to realize the zero-carbon electricity LCFS value. Onsite DER systems are potentially feasible at three Caltrain stations – San Francisco, San Jose and Gilroy. However, based on future land use plans, only one of the Caltrain stations (Gilroy) is potentially feasible for a DER system in the short-term.

Short-term energy procurement findings and suggestions include:

- **Remain on the current time-of-use (TOU) rate tariffs.** PG&E introduced new TOU rate tariffs that are available now, but are not mandatory until March 2021. Staying on the current TOU rate tariffs until it becomes mandatory to switch to the new TOU rate tariffs is the best financial option.
- **Adjust select electric meters to different rate tariffs.** Caltrain can realize approximately $27,635 in annual savings by switching 40 meters to more ideal rates as described in Section 3.2.
- **Consider setting up future electric accounts that will serve large loads as primary voltage service.** Receiving service on primary voltages generally provides additional bill savings. However, the physical changes to the electric service required to achieve the annual bill savings alone do not justify the cost to complete the transition from secondary voltage service to primary voltage service for existing meters. Therefore, this should only be evaluated when infrastructure changes are already being considered for a specific site. It would be beneficial for Caltrain to review the option of setting up future electric accounts that have large loads on the highest voltage level service that makes sense, as is the case for the new electric services being installed at transmission level for the purposes of rail electrification.
- **Continue to procure electricity through CCA providers.** The CCA providers provide more cost effective rates compared to the PG&E equivalent rates. The CCA default rate is the most cost effective based on our analysis.
- **Consider purchasing RECs to increase the value of Caltrain's LCFS credits.** Achieving zero-carbon electricity provides a projected additional LCFS credit benefit of approximately $2,952,487, assuming a price of $20 per REC. Based on the estimated value of the LCSF benefits and the costs for procuring energy, Caltrain has the potential to cover a significant portion of the costs of their utility bills for the portion of the fleet that is electrified.
- **Monitor changes in the federal ITC program and state SGIP program related to incentives for stand-alone battery energy storage projects.** Without the SGIP incentives, the stand-alone battery energy storage projects explored for the San Francisco and Gilroy station sites are not anticipated to provide sufficient financial benefit to warrant proceeding with projects at these sites. Depending on the outcome of the ITC legislation for stand-alone battery energy storage systems, a third-party ownership model may be an option that

Caltrain wants to explore in the future. Caltrain could also consider financing the Gilroy onsite BESS through federal, state or local incentive programs or by issuing green bonds. As discussed in Section 4.2.3, the U.S. Department of Energy and the California Energy Commission each offer different financing and loan programs for renewable energy projects. Caltrain could also consider issuing a green bond to finance the Gilroy BESS. Green bonds are discussed in more detail in Section 4.2.3.

- **Pairing a BESS with onsite solar yields additional financial and resilience benefits.** When paired with an onsite solar PV system, a BESS can further reduce demand and provide savings value that is not available to a stand-alone BESS or solar PV system. Integrating energy storage systems with solar PV systems provides a holistic approach to renewable energy generation and financial savings. A solar PV system by itself provides per-kWh utility bill savings and some peak demand reduction but is subject to intermittency based on weather conditions and therefore plays an unreliable role in ensuring that demand charges can be effectively managed. In cases where the customer has high demand charges, solar PV and energy storage can be controlled together to provide the optimal overall bill and peak demand savings through charge/discharge management software capable of making decisions that allow for optimized financial savings based on the actual operating profile on a real time basis. This includes the ability to decide when to charge the battery system with energy provided by the solar PV system, ensuring that the battery is always charged and available for use to make up for a period of low production from the PV system. Batteries charged by solar PV also have the potential of providing "energy arbitrage," i.e., charging the batteries from the solar PV during low bill credit periods and exporting energy from the batteries during high bill credit periods. In addition, a combined solar PV and energy storage system can be configured to have the added benefit of providing an alternative source of power and resiliency in times when the grid is either unreliable or not available. Although this study did not identify any viable solar PV opportunities, any future solar PV opportunities should also consider installing a BESS system.
- **Investing in a utility expense data management (UEDM) solution will streamline electricity data collection and payment and reduce costs.** UEDM offers companies an end-to-end solution that centralizes utility information (cost and consumption), improves data accuracy, reduces costs (direct and indirect expenses), and provides for timely and insightful reporting all within a single cloud-based platform.

PHASE 2: MEDIUM-TERM ENERGY PROCUREMENT STRATEGY SUMMARY

The medium-term energy procurement strategy analysis demonstrated that there are potential financial and sustainability benefits to procuring electricity through DA or wholesale markets. Neither option is currently available to Caltrain, but the agency can take steps now to position for future opportunities. Table ES-3 summarizes the estimated savings associated with DA or wholesale procurement.

Table ES-3: Estimated annual savings from DA or wholesale procurement versus retail

Estimated Electricity Consumption When Fully Electrified (MWh)	119,000
Percent Electrified at Plan	75%
Year Plan is Met	2023
Average Blended Rate from Task 3 Report ($/MWh)	$221
Estimated Annual Spend in Year Plan is Met (2020 dollars and rates)	$26,300,000
Estimated 10% Annual Savings Wholesale v. Retail Electricity	$2,630,000

The emergency power review conducted as part of Phase 2 concluded that the traction power system designed for Caltrain is quite robust and meets all industry best practices. However, it is still vulnerable to a regional large power outage, such as one associated with a sudden and intense earthquake.

Medium-term energy procurement findings and suggestions include:

- **Caltrain should engage its CCA providers relative to any products that would provide electricity and LCFS-compliant RECs**. The CCA providers do not currently offer a product that meets the California Air Resource Board's (CARB's) requirements for zero-carbon fuel sources (which increase the value of LCFS credits). However, CCA providers could provide bundled product (i.e., electricity plus the associated RECs) that would be compliant in the LCFS program thereby leading to increased LCFS revenue.
- **Caltrain should continue to monitor the Direct Access market and consider participation.** The DA market is a market in California that allows energy buyers to have expanded choice in their service provider. For example, if a buyer is granted the ability to enter the DA market, it can choose a different Electric Service Provider (ESP) than their current options of PG&E and CCAs, the current electricity retail providers for the agencies. DA procurement is likely to result in savings for Caltrain, regardless of whether or not it pursues jointly with SamTrans. DA is only available via a lottery system and the program is currently at capacity. Additional capacity may become available in 2024, but the amount, timing, and process to apply for capacity are all in question. If sufficient capacity is added that could serve Caltrain's anticipated load, it may be worth applying.
- **Caltrain should partner with other California transit agencies (such as California High Speed Rail) to pursue legislation that would enable access to the wholesale market and conjunctive billing.** Though BART was able to gain access to the wholesale market through legislation, the process was very specific to BART's unique circumstances and took many years to finalize. Other California transit agencies have interest in gaining access to the wholesale market as well and have taken steps towards this goal. It will be important to ensure that the legislation is inclusive of (1) existing modes of transit and (2) non-rail transit (for SamTrans). By pursuing legislation, Caltrain will have the option to switch to wholesale procurement in the future if desired.

- **Caltrain should participate in CPUC, CAISO and PG&E regulatory processes that would affect future electric vehicle rates and access to Direct Access and wholesale energy markets.** The California energy market is complex and dynamic. Caltrain would benefit by actively engaging in the rulemaking process. This is another opportunity to partner with other California transit agencies, particularly those in the Bay Area, who may have similar goals.
- **Caltrain should not pursue wholesale market participation without addressing its significant risks.** Wholesale electricity prices are subject to greater variability over time as the market reacts to real-time supply and demand needs, but on the whole are lower than retail electricity prices since they are also competitive. The estimated savings from wholesale procurement will be somewhat offset by the need to engage an entity that will effectively operate as your ESP or to take management of the wholesale market electricity efforts in-house. Either management route will have both real costs, likely including consulting, legal fees, and ESP management fees or additional staff headcount plus it will have a material impact on internal staff time regardless of whether or not the management is out- or in-sourced. It is important to weigh the benefits of access to the wholesale market with these costs.
- **Caltrain would benefit from jointly procuring energy with SamTrans.** If Caltrain elects to pursue onsite DER, unique CCA products, DA or wholesale market strategies, it would benefit from procuring energy together to reduce costs and streamline management.
- **Caltrain should evaluate the feasibility of wayside power storage systems.** Wayside power storage systems, including batteries and flywheel technologies, have the potential to increase the use of regenerative braking power, operate the system more effectively (less voltage swings, faster acceleration, etc.), while earning revenue for Caltrain. In addition, they will reduce the needs for large scale back up power from other sources.
- **Caltrain stations, other facilities and systems should follow the recommendations for power reliability in National Fire Protection Association (NFPA) 130.** This includes stations, signals, communications, and more. WSP recommends Caltrain perform an evaluation of the other systems to make sure that they are prepared for large scale power outages.

OPPORTUNITIES, RISKS AND TRADEOFFS

Each energy procurement decision is associated with different opportunities and risks and may have implications on other decisions. Tables ES-4 and ES-5 present the primary risks, trade-offs and other considerations for each of the options evaluated in this study. Figure ES-2 illustrates the energy procurement options in a decision tree format and Figure ES-3 provides a high-level timeline of near-term decisions.

Table ES-4. Energy Procurement Opportunity Matrix

OPPORTUNITY	TIME HORIZON	LEVEL OF EFFORT	FINANCIAL IMPACTS	ENVIRONMENTAL BENEFIT	LOCAL ECONOMIC BENEFIT	EMERGENCY POWER POTENTIAL
Retail Electricity Options						
PG&E Default	Near-term	Low	$$	🍃		
PG&E 100% Renewable	Near-term	Low	$$$	🍃🍃🍃		
CCA Default	Near-term	Low	$	🍃🍃	✓	
CCA 100% Renewable	Near-term	Low	$$$	🍃🍃🍃	✓	
Direct Access	Medium-term	High	$-$	🍃🍃🍃	✓	
Purchasing Wholesale Electricity						
Procuring Power on the Wholesale Market	Long-term	High	$-$	🍃🍃		
Wholesale Power Purchase Agreements	Long-term	High	$-$	🍃🍃🍃		
On-Site Energy Resources						
Solar PV	Medium-term	Medium	$$$	🍃🍃🍃🍃	✓	✓
Battery Energy Storage	Medium-term	Medium	$$	🍃🍃🍃	✓	✓
Hydrogen	Long-term	High	$$$$	🍃🍃	✓	✓
Other Opportunities						
Renewable Energy Credits	Near-term	Medium	$	🍃		
Low Carbon Fuel Standard Credits	Near-term	Medium	$$$$	🍃🍃		
Grid Services Programs	Medium-term	Medium	$	🍃		

Table ES-5. Risk Analysis and Trade-off Matrix

Option	Primary Risks	Trade-offs	Impact on Other Options: how decisions effect acting on other options	Additional Considerations
Current State	Overpaying relative to other options, not maximizing LCFS revenue.	Ease; minimal effort to maintain current contracting.	DA, legislative action, and current state are all relatively mutually exclusive options.	Potential new products that create more LCFS revenue; would need comparative cost analysis.
DER: Solar PV, Batteries, & Microgrids	Regulatory changes and/or changes in energy usage at project locations could impact the savings performance from these systems.	Cost savings from avoided electricity costs and avoided costs from REC purchases, revenues earned through emerging grid services programs.	Distributed projects would pair well with each of these additional options.	With the step-down of the ITC and the fast-paced incentive funding draw down for SGIP, procurement of these projects should be prioritized.
Direct Access	Transactional costs with minimal payback; difficult negotiating for LCFS-qualifying RECs.	Ability to potentially spur new renewable energy generation; cost savings v. retail; potentially more lucrative LCFS credit generation.	DA, legislative action, and current state are all relatively mutually exclusive options.	The program is at capacity; seeking capacity at this stage may not be worth the effort; wait until it reopens.
Wholesale market	Significant effort with no guarantee of success; risks associated with being exposed to wholesale trading.	Potential cost savings.	DA, legislative action, and current state are all relatively mutually exclusive options.	This process and the results for BART are complex; encourage a debrief with BART before exploring deeply.
Financial investment: vPPA	Expensive and risk financial position relative to only receiving RECs.	Long term REC position with potentially more lucrative LCFS credit generation.	All other options, specifically relative to their REC generation impact this option.	Only should be implemented if other sources of potential LCFS revenue are unsuccessful.
Financial investment: APA	Overpaying for RECs in the long term.	Long term REC position with potentially more lucrative LCFS credit generation.	All other options, specifically relative to their REC generation impact this option.	This is a potentially good alternative to buying spot-market RECs for use in the LCFS program.

Figure ES-2. Energy Procurement Decision Tree

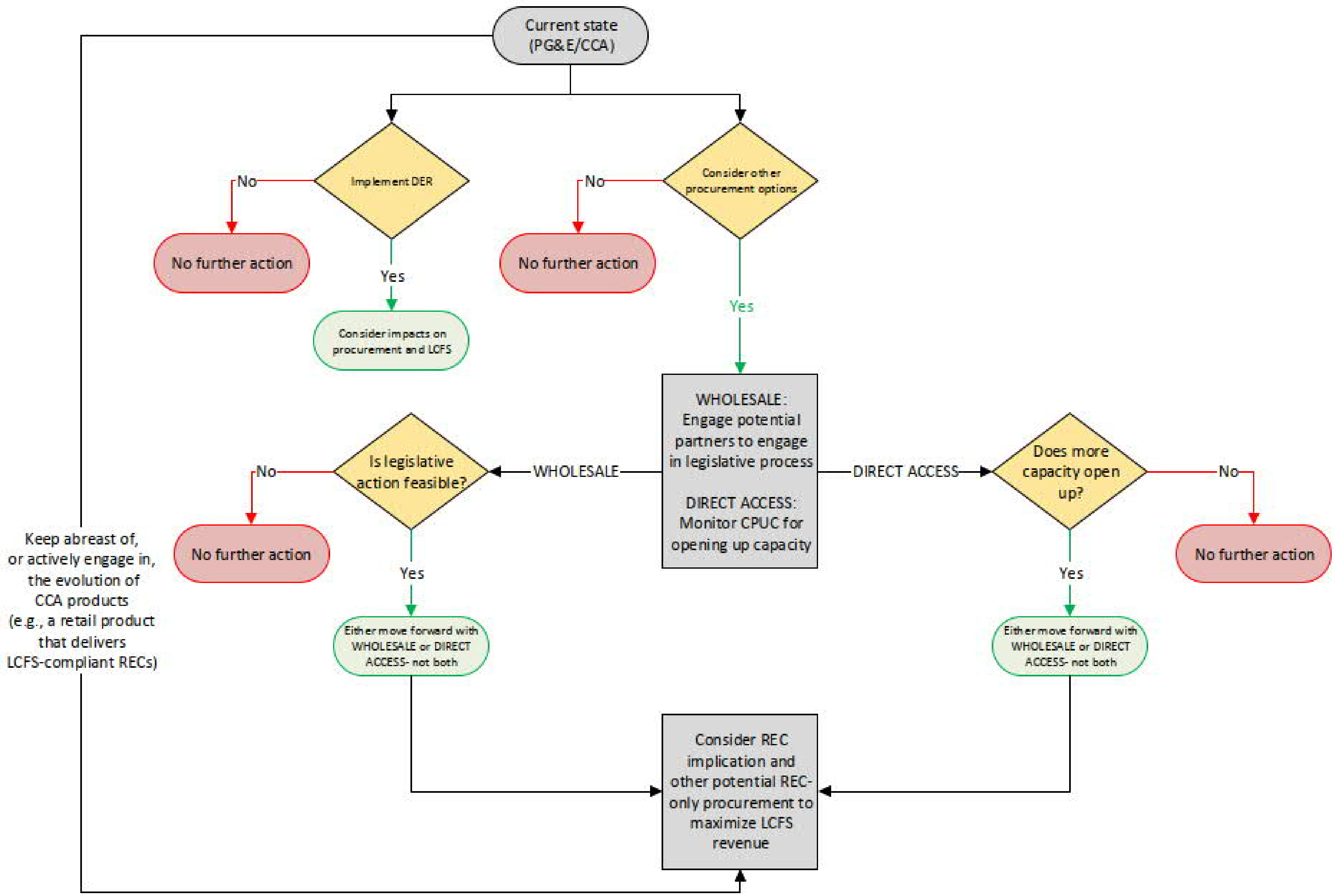
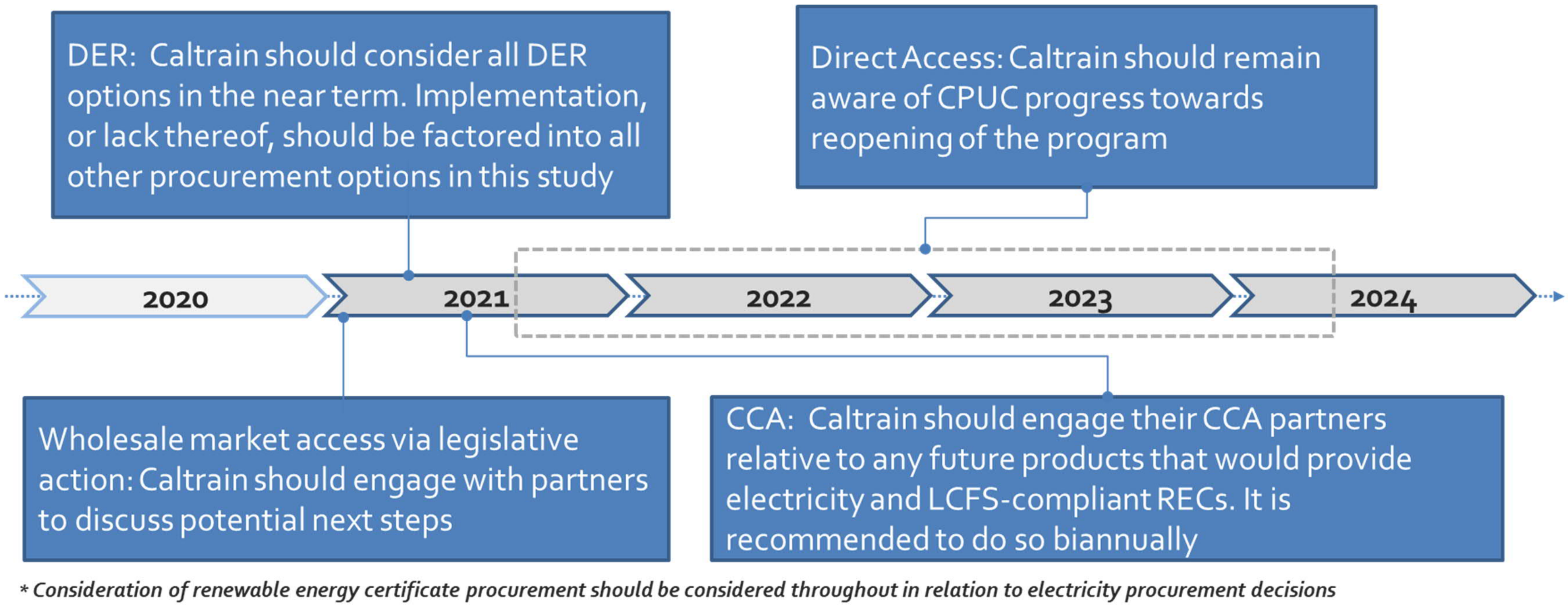


Figure ES-3. Time Horizon

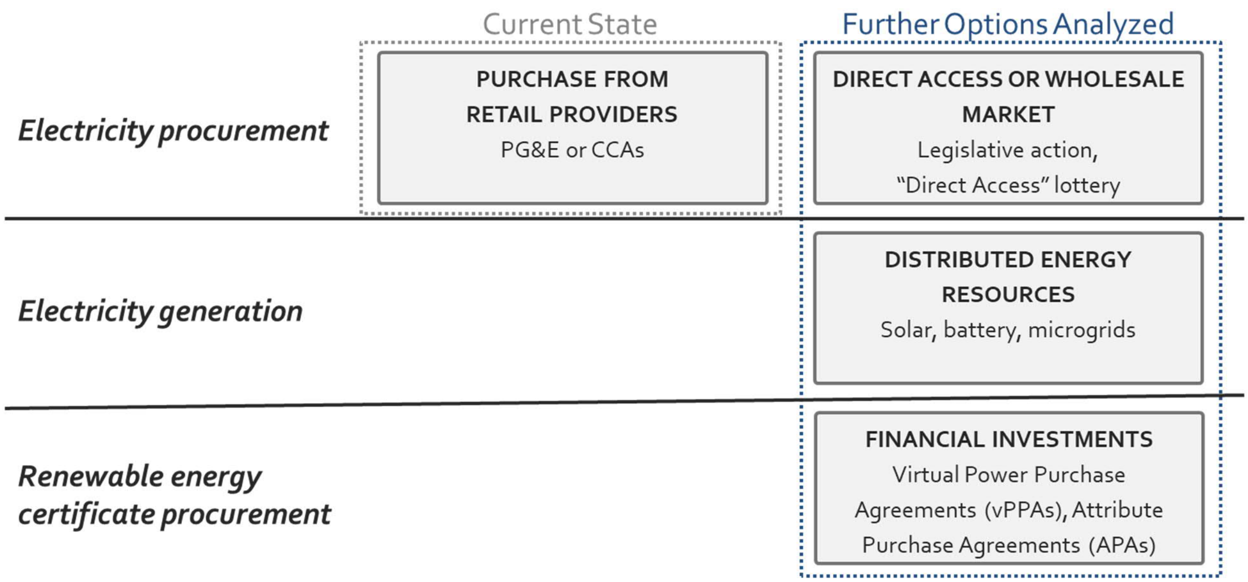


1 INTRODUCTION

As Caltrain transitions from diesel to electric-powered locomotives, electricity – and the procurement thereof – will become an increasingly important component of the agency's fuel spend, environmental impacts. Participation in revenue generating opportunities such as the Low Carbon Fuel Standard (LCFS) market will also be important. WSP and TerraVerde Energy (TerraVerde) (the "Project Team") were retained to conduct a comprehensive energy procurement study to evaluate Caltrain's short and medium-term energy procurement options. This report provides an analysis of the electricity and technology procurement options available to Caltrain including evaluation of the associated environmental impacts, risks, trade-offs, operational impacts and financial considerations of each option. This report also includes discussion of the potential benefits associated with jointly procuring electricity with SamTrans.

The energy procurement and technology options evaluated in this study are summarized in Figure 1.

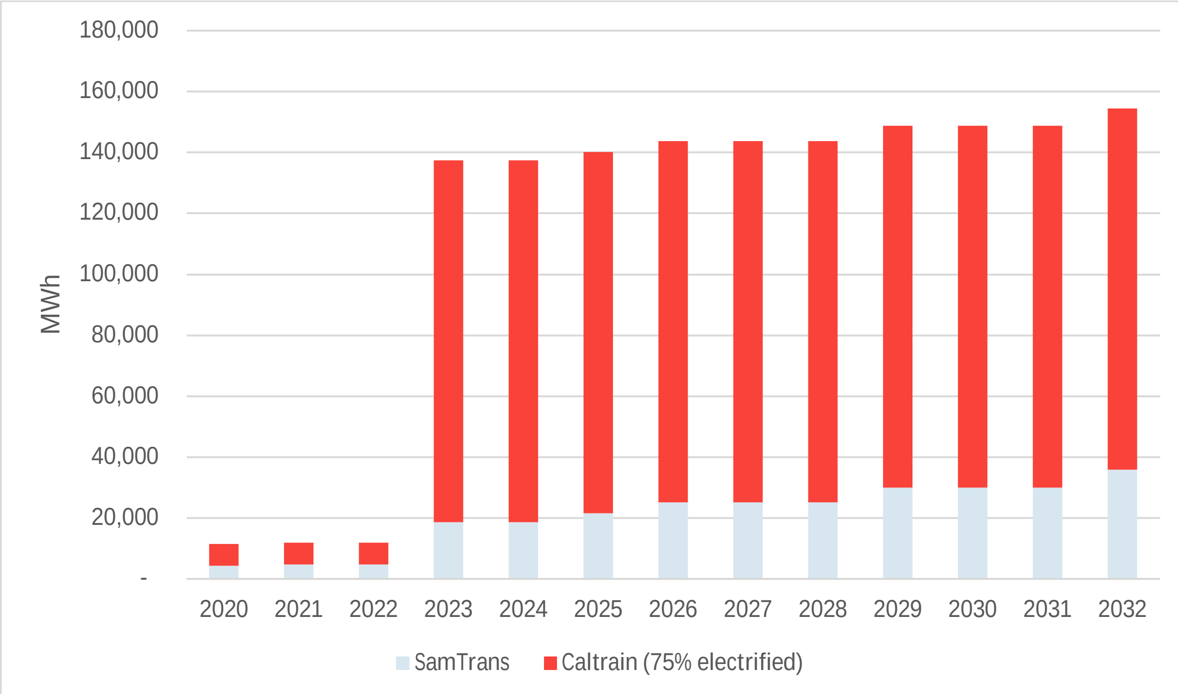
Figure 1. Energy Procurement and Technology Options[4]



The options were evaluated based on the projected electricity usage forecast for both Caltrain and SamTrans as shown in Figure 2.

[4] The options were evaluated based on the projected electricity usage forecast for both SamTrans and Caltrain.

Figure 2. Caltrain and SamTrans Electricity Consumption Projection[5]



The report is organized as follows:

- Section 2 provides a summary of relevant federal and state policies.
- Section 3 presents the findings from the short-term energy procurement strategy analysis including a discussion of the existing power demand report assumptions, comparison of historical and future electricity costs and feasibility of onsite DER systems.
- Section 4 compares Caltrain's future energy and technology procurement options. For each option considered, Section 4 describes the option, outlines steps for implementation, provides an overview of potential impacts on operations, discusses risks, barriers and trade-offs, environmental impacts and financing and revenue opportunities. Section 4 also discusses the potential benefits of district level procurement with SamTrans and provides a timeline for Caltrain to reference as the agency considers the different options available to them currently and in the foreseeable future.
- Section 5 discusses the reliability of Caltrain's future electric traction power system and provides a summary of emergency power options used by other transit agencies and discusses their potential applicability to Caltrain.

[5] Caltrain electricity consumption forecasted based on the 2015 LTK Load Flow Study. SamTrans demand projections are based on the HDR April 2020 demand study. Since this time SamTrans has adopted an ICT that extends the BEB transition timeframe to 2038 and Caltrain has pushed back the start of electrified service to 2024.

2 FEDERAL AND STATE POLICY OVERVIEW

2.1 FEDERAL

Federal incentives for renewable energy come in the form of tax credits. As a government agency, Caltrain would not be eligible for these incentives. However, Caltrain could partner with a third-party investor who is a tax paying entity that can benefit from the federal tax incentives.

2.1.1 Investment Tax Credit

Federal incentives for solar PV systems are provided in the form of investment tax credits, known as the Solar Investment Tax Credit (ITC). The ITC provides a 26% tax credit based on the capital value of the installed solar PV investment in 2020. Not all project costs are eligible for the ITC, however Internal Revenue Services (IRS) rules allow for some level of interpretation, and each organization makes an independent assessment of what costs are considered eligible based on the final project requirements, inclusions and investor risk profile. Based on new federal legislation passed in December 2020, the ITC benefit was extended and is currently set to decrease from its current 26% value at the end of 2022 to 22% starting January 1, 2023. On January 1, 2024, the ITC is currently set to decrease further to 10% and then will remain there indefinitely for commercial projects baring a policy decision to extend the ITC at the higher levels. Starting construction for a solar PV project before the designated date of change in ITC value will maintain eligibility for the relevant ITC level (i.e. to achieve the 26% credit, construction must be started prior to the end of 2022).

Battery systems that are charged by the renewable energy system at least 75% of the time can claim a portion of the ITC. Battery systems that are charged by the renewable energy system 100% of the time on an annual basis can claim the full value of the ITC. Battery systems that are charged by a renewable energy system 75% to 99.9% of the time are eligible for that portion of the value of the ITC. For example, a system installed in 2020 that is charged by renewable energy 80% of the time is eligible for the 26% ITC multiplied by 80%, which equals a 20.8% ITC instead of the full 26%.[6] On March 9, 2021, legislation was introduced to expand the ITC to apply to stand-alone battery energy storage systems.

Wind power projects are also eligible for the ITC. However, credit for large wind turbines currently expires in 2022. Small wind turbines can still receive credits for up to 22% of expenditures through December 31, 2022.

[6] The tax credit is vested over 5 years, and recapture can apply in unvested years if the percentage of renewable energy charging declines.

2.1.2 Modified Accelerated Cost-Recovery System

In addition to the ITC, the IRS allows for accelerated depreciation of solar and battery assets through the Modified Accelerated Cost- Recovery System (MACRS). The MACRS allows for a class life of five years for solar PV systems, meaning the solar PV asset may be fully depreciated in only five years. The combination of the ITC and accelerated depreciation can offset up to 31% of the system's capital cost. Without a renewable energy system installed, battery systems may be eligible for the 7-year MACRS depreciation schedule: an equivalent reduction in capital cost of about 20%. If the battery system is charged by the renewable energy system more than 75% of the time on an annual basis, the battery should qualify for the 5-year MACRS schedule, equal to about a 21% reduction in capital costs.

2.1.3 New Markets Tax Credit

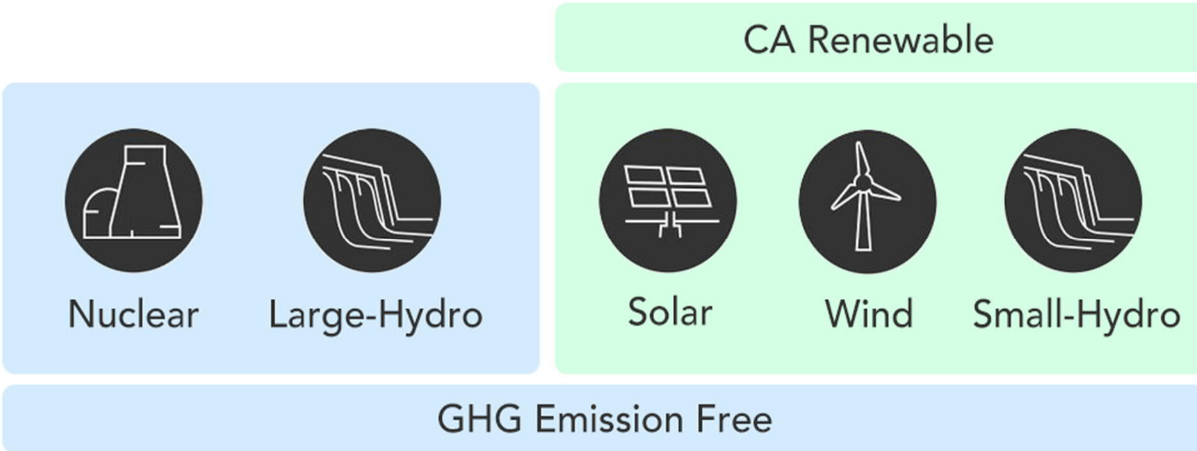
The New Markets Tax Credit (NMTC) Program was established in 2000 to incentivize community development, job creation and economic growth by attracting investment to low-income and disadvantaged communities. The program allows taxpaying entities to receive federal income tax credits in exchange for making equity investments in vehicles certified as Community Development Entities. An investor in a Community Development Entity will benefit from a 39% federal tax credit over a 7-year period, in addition to the returns on the investment. In turn, the Community Development Entity uses the capital raised to provide flexible, affordable financing for environmentally sustainable projects in low-income communities. The NMTC has been used in a limited capacity to fund renewable energy projects. For example, the City of Denver leveraged NMTC's to install 1 megawatt (MW) of solar PV on city buildings. A third party owns and operates the solar PV systems and sells electricity to the City through a Power Purchase Agreement (PPA) (NREL, 2010). The NMTC program is complex but may be worth considering.

2.2 STATE

2.2.1 Renewable Portfolio Standard

California has a Renewable Portfolio Standard (RPS), which is a mandate program designed to increase the amount of renewable energy generation sources being used by retail electricity providers. The program was established in 2002 and initially required that 20% of electricity be procured from renewable resources by 2017. California defines renewable energy by law; some resources that are GHG-free do not count as renewable because of other environmental impacts. Nuclear power is GHG-free, but is not a renewable resource. Large hydroelectric sources are not eligible renewable sources because they result in other negative environmental impacts (e.g., to fish and aquatic communities). Low-impact hydroelectric sources (small-hydro) have fewer negative environmental impacts and are considered to be eligible renewable energy resources. Figure 3 illustrates the difference between GHG-free and renewable energy eligible for the RPS.

Figure 3. GHG-Emission Free and Renewable Resources in California



In 2015, the State increased the RPS mandate to 50% renewable by 2030. Then in 2018, the State once again increased the mandate to 60% renewable by 2030 and 100% carbon-free by 2045. Therefore, by 2045, any electricity procured by Caltrain should be GHG-free regardless of provider. However, the carbon-free goal includes nuclear power, which is not a renewable resource, and large hydroelectric power, which is not considered to be a renewable resources in California.

2.2.2 Net Energy Metering

Net energy metering (NEM) is a California Public Utilities Commission (CPUC) program that enables customers to directly serve their energy needs through onsite generation and receive a financial credit on their electric bills for any surplus energy fed back to their utility. Due to the proliferation of behind-the-meter solar PV systems in California over the past ten years, the State's NEM program cap was reached, which has triggered a transition from the original net metering program tariff, known as NEM 1.0, to a new "successor" NEM tariff known as NEM 2.0. In PG&E territory the NEM 1.0 program capacity cap was reached on December 15, 2016. The NEM 2.0 program is the current program available for new renewable energy projects in PG&E territory.

The primary differences between the original NEM 1.0 tariff and the new NEM 2.0 tariff is the removal of caps on solar PV system size, and a decrease in potential cost savings due to the removal of credits for utility bill components known as non-bypassable charges. While the new NEM 2.0 tariff does not provide the same level of retail credit value as the NEM 1.0 tariff, the fact that the 1 MW CEC-AC system size cap limitation is no longer in place means solar PV systems can be sized for optimum offset of energy consumption and maximum energy cost savings potential. There are currently discussions underway regarding a new NEM 3.0 tariff which could be implemented as soon as 2021. The changes in the NEM 3.0 tariff versus the NEM 2.0 tariff are still to be determined.

The NEM tariff also includes a special condition option known as Net Energy Metering Aggregation (NEM-A). NEM-A allows a PG&E customer with multiple meters on the same property, or on adjacent or contiguous properties, to use the generation from a solar PV system interconnected behind one meter to provide NEM benefits for the other (aggregated) meters through a Utility accounting process.

A decision by the CPUC in February of 2019 has expanded the NEM 2.0 tariff to allow battery energy storage systems (BESSs) to receive net energy metering credits for energy exported to the grid when the BESS is charged 100% from a renewable generation source, such as solar PV systems, and the BESS has a power control configuration that is certified by a national recognized standard.

2.2.3 Time-Of-Use Peak Period Shift

In May 2017, PG&E completed a general rate case (GRC) filing, wherein it proposed a series of revisions to rate schedules and implemented a CPUC approved decision in January of 2017 that allowed all the California IOUs to adjust their definitions of TOU peak periods. The decision allowed PG&E to expand the definition of the on-peak period from 12:00 to 6:00 pm during the summer to all year from 4:00 to 9:00 pm. The GRC filing has currently been approved by the CPUC and the new rate schedules have been available for voluntary enrollment since November 2019. The new rate schedules will become mandatory in March of 2021 for all PG&E accounts that are not eligible for some form of grandfathering. All the Caltrain electric accounts will be subject to changes in TOU period definitions and corresponding rates beginning in March 2021.

2.2.4 Low Carbon Fuel Standard

As part of the overall strategy to reduce California's GHG emissions, Assembly Bill 32 targeted changes to transportation fuels as one of the actions that could reduce GHG emissions. The LCFS program was established in 2009 as a key part of a comprehensive set of programs in California to cut GHG emissions and other air pollutants through, in part, the promotion of the use of cleaner, low carbon alternative fuels. In 2018, Senate Bill 32 enacted California's 2030 GHG emission reduction target, which provided LCFS with the opportunity to add new crediting opportunities, including the promotion of zero emission vehicle adoption. The benefits provided by the alternative fuel source (e.g. grid electricity) are compared to the standard fuel source (e.g. gasoline or diesel) and the GHG emissions associated with the complete life-cycle of each fuel is compared in order to determine the reduction in GHG emissions due to the use of the alternative fuel source. Participation in LCFS requires that entities register and regularly report the GHG emissions reductions in order to recognize the financial benefit provided by the program. Caltrain will earn LCFS credits for switching from diesel-powered trains to electric-powered trains.

2.2.5 Power Charge Indifference Assessment

In 2002, California passed Assembly Bill 117 enabling the establishment of CCAs and thus providing customers of the California IOUs an alternative source to procure energy from. The Power Charge Indifference Adjustment (PCIA) fee is considered an "exit" fee, which IOU customers must pay for electing to purchase their energy from an alternative source, such as a CCA. The PCIA fee was established on the premise that it ensures that all electricity ratepayers pay an equal share of the costs the IOU spent on procuring energy (generation) prior to customers electing to procure energy from a CCA instead of the IOU. The PCIA charge is dependent on when a customer starts procuring their energy from a CCA and based on this a "vintage" for the PCIA charge is established.

In October of 2018, the CPUC approved a new methodology for calculating the PCIA. The decision allows the IOUs to continue charging the PCIA, with no time limitations, on all legacy IOU owned generation sources that qualify as energy procured by the IOU to meet customer needs. Beginning in 2020, the CPUC decision also placed a $0.005/kWh yearly limit on the PCIA cost and added credits for GHG-free resources, renewable resources, and capacity attributes towards the costs associated with the legacy generation sources. Under current regulation, even new electricity generation from Caltrain is subject to the PCIA.

2.2.6 Renewable Energy Self-Generation Bill Credit

When space constraints or other site logistical factors limit solar PV system size, the Renewable Energy Self-Generation Bill Credit Transfer tariff (RES-BCT) may be a viable alternative solution. RES-BCT is an "export energy" tariff that allows public agencies to install a grid-connected renewable energy generation system of up to 5 MW AC on property owned or leased by the agency within the same jurisdiction boundaries, and receive monetary bill credits for designated PG&E accounts (credits are allocated to the applicable monthly PG&E bills) for the energy generated by the system and exported to the grid. The bill credits can be applied to one or more (up to 50) PG&E accounts/meters (known as "benefitting accounts"), and their value is determined by the energy generation portion of the TOU rate schedule at the site where the renewable energy generation system is installed. The RES-BCT tariff requires that the generating account and all benefitting accounts be on a bundled service with PG&E (i.e., both generation and distribution charges are paid directly to PG&E). Meaning, these accounts/meters cannot be enrolled with a CCA or other alternative ESP for any portion of the utility bill. The RES-BCT program has a capacity limit of 105.25 MW in PG&E territory and currently has 33.046 MW of pending projects and 44.023 MW of completed projects that are counting towards the capacity limit. There are no discussions in progress at this point to extend the RES-BCT program past the point where the capacity limit is reached.

2.2.7 Self-Generation Incentive Program

The CPUC offers an incentive program, the Self-Generation Incentive Program (SGIP) (CPUC, 2021a), that provides funding to support existing, new, and emerging DERs installed on the customer's side of the utility meter. Qualifying technologies include wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells and advanced energy storage systems (including batteries). There are 5 “Steps” that categorize the funding levels for certain DER types and sizes, and the different budgets that apply to various types of customers. The rebate is administered through the local utility company, in this case, PG&E.

There are four SGIP incentive levels available for municipal battery energy storage projects, based on the facility type and geographical location of the site: SGIP Equity, SGIP Equity Resiliency, SGIP Resiliency Adder, and Large-Scale Storage. To qualify for SGIP Equity, the site must be located in a low-income designated community or a designated disadvantaged community. To qualify for SGIP Equity Resiliency, the site must qualify for SGIP Equity, qualify as a “critical facility,” and either be located in or serve a high fire threat zone (HFTZ) or have experienced more than two Public Safety Power Shutoff (PSPS) events in the past year. Qualified critical facilities include: police & fire stations, emergency response providers, emergency operations centers, 911 call centers, hospitals & health care facilities, public and private gas, electric, water, wastewater or flood control facilities, small business grocery stores or locations designated by the utility to provide assistance during power shutoffs. To qualify for the SGIP Resiliency Adder, the site must qualify as a “critical facility,” and either be located in in or serve a HFTZ or have experienced more than two PSPS events in the past year. Any site that does not meet these specifications falls into the Large-Scale Storage incentive level (SGIP base incentive). The SGIP program continues to evolve rapidly. Caltrain would qualify at the SGIP Large Scale Storage incentive level.

SGIP can offset 30 to 100% of energy storage project costs, depending on a number of factors: the eligible SGIP budget, current incentive step level, consideration for taking the ITC benefit, duration of the battery’s discharge period (2hr, 4h, etc.), overall battery capacity, cycling and GHG emission requirements and site specific installation costs. Currently, PG&E’s SGIP allocation is in step 4 for the Large-Scale Storage budget, and there is approximately $11.6M in funding remaining in step 4 as of April 23, 2021. Step 3 incentive levels start at $0.30/Whr and are adjusted downward with consideration for the factors mentioned above. The SGIP Resiliency Adder can provide an additional $0.15/Whr in incentives on top of the Large-Scale Storage incentives for eligible sites. The SGIP Equity Resiliency budget is currently waitlisted in PG&E territory. The SGIP Equity is currently oversubscribed as of May 12, 2020. Once the remaining funding available in PG&E's SGIP Step 4 is fully subscribed, there is no anticipated additional funding available within an applicable budget for the proposed projects.

In order to submit an application for an SGIP incentive, an incentive application fee of 5% of the requested incentive amount is required. The incentive application fee is required to be paid once a project is notified of incentive award and is refunded once the project is constructed.

3 PHASE 1: SHORT-TERM ENERGY PROCUREMENT STRATEGY

The Project Team evaluated Caltrain's short-term (1 to 4 years) energy procurement options. Short-term options include whether to purchase electricity from PG&E or CCA providers and whether or not to install onsite DER systems. As part of Phase 1, the Project Team reviewed the Caltrain Load Flow Study (LTK, 2015). Electric demand assumptions were developed based on this report.

3.1 EXISTING CONDITIONS ANALYSIS

The Project Team reviewed the Caltrain-only projections in the Caltrain Load Flow Study completed by LTK in 2015 in order to estimate future electric demand for the phase 1 and 2 analysis. The Project Team found the regenerative braking savings assumptions to be significantly higher than what would be expected during revenue operations, which resulted in lower energy demand numbers. Regenerative braking is the process of returning the braking energy of the electric multiple-unit (EMU) train to the EMU's auxiliary loads or to the overhead control system (OCS) through the conversion of kinetic energy to electrical energy. Regenerative braking is a feature available on most modern transit and high-speed rail vehicles. Regeneration can potentially reduce energy usage by returning the braking kinetic energy of a vehicle back to the system for use by other vehicles. In the case of ac electrification, the energy that is not used by other nearby vehicles or lost can also be supplied back into the utility grid (LTK, 2016).

However, predicted energy savings are dependent on many parameters. Some are well defined, such as traction power system components, passenger station spacing and civil layouts. Other parameters can vary in practice from those assumed in a typical computer simulation. These would include actual train behavior, schedules and the detailed vehicle operating characteristics at any particular instant of time. Therefore, actual energy savings may vary in revenue operation for these reasons.

Because the 2 x 25 kV Caltrain traction electrification system and procured Stadler EMU are designed to accept regenerated energy, the demand analysis needs to consider the energy savings of regenerative braking. The LTK load flow study showed a regenerative braking energy savings of 37.2% based on a generic EMU. However, similar 2 x 25 kV systems have a realized energy savings of around 15% (CA HSR, 2011). It appears that the energy savings of 37.2% is the ideal case of the total potential energy from a decelerating EMU returning energy to the grid but in reality the amount of energy savings is variable and is dependent on many factors such as how receptive the line is at the time the energy is put back on the system, whether there is a nearby EMU to use the energy, onboard auxiliary uses of the regenerative energy that are only specific to the EMU and other system losses. However, an updated load flow simulation and utility connection study have not been performed to analyze these details and provide more realistic energy demand numbers to confirm the preliminary regenerative energy savings.

Without a load flow model using the Stadler EMU and an updated model accounting for the dynamic regenerative energy characteristics, the demand numbers in the study for the case of Caltrain only with regen on are lower than can be expected during normal revenue operation. The energy savings documented in the load flow analysis also contradicts the Caltrain Environmental Impact Report (EIR) (2015) which assumed a 10% savings would be used. The California High Speed Rail (CA HSR) also used a comparable percentage of realized regenerative energy savings (CA HSR, 2011).

For these reasons, WSP adjusted the estimated regenerative braking savings to 15%. The methodology used and assumptions are described in Appendix A.

3.2 SHORT-TERM ELECTRICITY RATE ANALYSIS

The Project Team reviewed Caltrain's current energy usage and future energy usage following system electrification and conduct a rate analysis to determine the ideal (most cost effective) rates for Caltrain. The rate analysis for the existing one-hundred and forty-one (141) Caltrain electrical service accounts includes a review of potential rate changes that would minimize electricity costs, both under the existing TOU period definitions and under new TOU period definitions that are currently open for voluntary enrollment.

3.2.1 PG&E Accounts and Consumption Profile Assessment

ELECTRICITY CONSUMPTION

PG&E provides energy distribution services to the majority of the Caltrain facilities. Although Caltrain does receive electric service from two municipal utilities, those electric services were not included in this analysis given that the municipal electric service accounts must remain with the municipal utilities and have previously been evaluated for the most beneficial rate enrollment option.

A total of 141 electric utility meters served by PG&E and located throughout the Caltrain system were analyzed. Although there are a total of 162 accounts, 17 accounts are on a Traffic Control Service (TC1) rate structure that do not have alternative rate tariffs and four accounts did not have a complete year of interval data so were not investigated for any potential rate changes. The majority of the PG&E accounts are enrolled with a local CCA for electricity procurement. Appendix B provides information about the current electric accounts including rates, total consumption and maximum demand over the specified 12-month period.

Electricity consumption is measured by metering the usage of kilowatt-hours (kWh) of electricity and is updated in PG&E's meter reading system every 15 minutes (known as an interval). Electric load profile is expressed as "demand" or "load" and is measured in kilowatts (KW). Over the 12-month period (February 2019 to January 2020) used in the analysis, Caltrain consumed 6,565,466 kWh of electricity across all of the accounts listed in Appendix B.

Each PG&E service account is associated with a unique rate tariff. Each rate tariff is associated with time-of-use (TOU) charges and (for certain tariffs) demand charges. The Caltrain accounts are enrolled on a variety of rate tariffs which are shown for each account in Table 1. Which rate tariff an electrical service can enroll in is dependent on the consumption and load profile of the applicable electrical service as outlined in Table 2. Outside of these limitations, rate tariff selection should be optimized to minimize the total electrical bill, while meeting agency goals for GHG emissions reduction and renewable energy.

Table 1 provides a summary of the various TOU rate structures assigned to the Caltrain PG&E accounts based on the current TOU period definitions and the limits on demand (kW) and consumption (kWh) that dictate which rate tariffs an accounts is eligible for enrollment in. Each TOU rate structure consists of a set of three standard charges; (a) monthly customer (meter) charge which is the same each month; (b) time-of-use energy charges per kWh of consumption; and (c) time-of-use demand charges which use a rate that varies depending on the time of the day and season and are applied to the highest demand recorded during the applicable TOU periods for a given month.

Table 1. Current TOU Electric Account Rate Details

Rate Structure	Peak Monthly Demand Limit	Consumption Limits	Additional Considerations
A-1	75 kW	150,000 kWh	Demand must not exceed Monthly Demand Limit for more than 3 consecutive months or a transition to A-10 would be required. No demand charges.
A-6	75 kW	150,000 kWh	Demand must not exceed Monthly Demand Limit for more than 3 consecutive months or a transition to A-10 would be required. No demand charges. Higher rates on summer weekdays during peak periods than A-1. Slightly lower winter and off-peak kWh rates than A1.
A-10	499 kW	N/A	Demand must not exceed Monthly Demand Limit for more than 3 consecutive months or a transition to E-19 would be required. Demand charges based on maximum kW per month and

Rate Structure	Peak Monthly Demand Limit	Consumption Limits	Additional Considerations
			vary by season. Lower TOU kWh energy charges than A-1 and A-6.
E-19	999 kW	N/A	Mandatory for customers with demand higher than 500kW. Demand charges based on maximum kW per month and vary by TOU period and season. All rate components vary based on service voltage levels. Includes a special rate option called "Option R" for accounts with PV systems that provide 15% or more of their annual electricity consumption.
E-20	>1000 kW	N/A	If Demand exceeds 999 kW for any 3 consecutive months during the previous 12 months, account becomes eligible for transition to E-20. Demand charges based on maximum kW per month and vary by TOU period and season. All rate components vary based on service voltage levels. Includes a special rate option called "Option R" for accounts with PV systems that provide 15% or more of their annual electricity consumption.

Table 2 presents the limits on demand (kW) and consumption (kWh) that dictate which rate structure accounts will be enrolled for the new TOU period definitions. There are minimal changes in the rates structures related to maximum demand limits with the key differences between the current TOU and new TOU rates structures outlined below:

- All new TOU rates will contain a year-round, 7-days a week, on-peak period of 4 pm to 9 pm.
- The new TOU rates created a super-off-peak period in the months of March through May that will run between 9 am to 2 pm.
- The definition of the summer season has changed from a 6-month summer in the current TOU rates to a 4-month summer season (June through September) in the new TOU rates.
- The standby option on B-19 or B-20 rates structures (new TOU) will be the first-time daily demand charges have been implemented in California.

The new TOU rates removed the consumption limitations that was in place on A1 and A6.

Table 2. New TOU Electric Account Rate Details

Rate Structure	Peak Monthly Demand Limit	Additional Considerations
B-1	75 kW	Demand must not exceed Peak Monthly Demand Limit for more than 3 consecutive months or a transition to A-10 would be required. No demand charges. Not available for accounts with EV chargers installed.
B-6	75 kW	Demand must not exceed Peak Monthly Demand Limit for more than 3 consecutive months or a transition to A-10 would be required. No demand charges. Higher rates on summer weekdays during peak periods than A-1. Slightly lower winter and off-peak kWh rates than A1.
B-10	499 kW	Demand must not exceed Peak Monthly Demand Limit for more than 3 consecutive months or a transition to E-19 would be required. Demand charges based on maximum kW per month and vary by season. Lower TOU kWh energy charges than A-1 and A-6.
B-19	999 kW	Mandatory for customers with demand higher than 500kW. Demand charges based on maximum kW per month and vary by TOU period and season. All rate components vary based on service voltage levels. Includes a special rate option called "Option R" for accounts with PV systems that provide 15% or more of their annual electricity consumption.
B-20	>1,000 kW	If Demand exceeds 999 kW for any 3 consecutive months during the previous 12 months, account becomes eligible for transition to E-20. Demand charges based on maximum kW per month and vary by TOU period and season. All rate components vary based on service voltage levels. Includes a special rate option called "Option R" for accounts with PV systems that provide 15% or more of their annual electricity consumption.

In addition, most rate tariffs have variations in cost that are dependent on the service level voltage — i.e., whether PG&E provides service at secondary voltage (voltages less than 2,000 V), primary voltage (voltages between 2,000 V to 50,000 V), or transmission level voltages (above 50,000 V). The analysis completed showed that in all cases where existing PG&E services were on E-19, a primary voltage service would lead to additional annual bill savings. While electric services receiving service on primary voltages would provide annual bill savings, the physical changes to the electric service required to achieve the annual bill savings alone would not justify the cost to complete the transition to a primary voltage service. Importantly, there would be costs to transition from secondary service to primary service with PG&E, including infrastructure and ongoing operations and maintenance costs, so this should only be considered when infrastructure changes are already being considered for a specific site. It would be beneficial for Caltrain to review the option of setting up future electric accounts that have large loads on the highest voltage level service that makes sense, as is the case for the new electric services being installed at transmission level for the purposes of rail electrification.

3.2.2 GHG Emissions and Renewable Energy

Caltrain currently purchases 100% GHG-free and renewable energy through four CCA providers—Peninsula Clean Energy (PCE), CleanPowerSF (CPSF), Silicon Valley Clean Energy (SVCE) and San Jose Clean Energy (SJCE). Therefore, Caltrain currently generates no market-based scope 2 GHG emissions. Table 3 compares estimated GHG emissions associated with Caltrain's new electric load. The PCE default rate (ECOplus) was 95% GHG-free at the time of the analysis; as of 2021, PCE indicates that it procures 100% GHG-free electricity for the ECOplus product. Based on PG&E's 2019 Power Content Label (PCL), PG&E is currently using 100% GHG-free sources, but only 29% renewable. Therefore, SamTrans would be not generate GHG emissions under any of the scenarios evaluated, based on the current power mix reported. As shown in Table 3, Caltrain would generate approximately 2,811 tCO_2e if it were to purchase the default SJCE product (GreenSource). The rates also differ in terms of the percentage of renewable energy.

Table 3. GHG Emissions associated with Caltrain Electrification

Electricity Provider	Product	Current % GHG Emissions Free	Current % Renewable Energy	lb CO2e/ MWh	MWh/ year	Annual GHG Emissions (tCO2e)[7]
PG&E	Base Plan[8]	100%	29%	0	111,426	0
	Solar Choice	100%	100%	0	111,426	0
PCE[9]	ECOplus (default)	100%	50%	0	58,710	0
	ECO100	100%	100%	0	58,710	0
SJCE[10]	GreenSource (default)	90%	55%	188.72	52,716	451
	TotalGreen	100%	100%	0	52,716	0
			Total GHG Emissions PG&E Base Plan			**0**

[7] GHG emissions were only calculated for Caltrain's new electric load.

[8] Based on PG&E's 2019 PCL

[9] As of 2021, PCE is procuring 100% GHG-free electricity across all products by 2021 and 100% RPS-eligible renewable energy by 2025.

[10] As of June 30, 2021, based on 2019 emissions factor

Electricity Provider	Product	Current % GHG Emissions Free	Current % Renewable Energy	lb CO2e/ MWh	MWh/ year	Annual GHG Emissions (tCO2e)[7]
Total GHG Emissions PG&E Solar Choice						**0**
Total GHG Emissions PCE (ECOplus) + SJCE (GreenSource)						**451**
Total GHG Emissions PCE (ECO100) + SJCE (TotalGreen)						**0**

3.2.3 Historical Rate Analysis

The historical rate analysis compares Caltrain's current electricity costs under the existing and new TOU rates for PG&E and CCA default and 100% GHG-free and renewable rates. Based on the analysis, the Project Team identified the ideal rates under the current and future TOU rates. For this analysis, ***ideal rates*** are those that result in the lowest annual Utility bill. Table 4 provides a summary of the historical rate analysis. A more detailed version of the historical rate analysis summary is provided in Appendix C and assumptions used in the analysis are included in Appendix D.

Table 4. Historical Rate Analysis Summary

	Current TOU Current Rates	Current TOU Ideal Rates	New TOU Similar Rates	New TOU Ideal Rates
Totals PG&E Costs	$1,412,310	$1,395,845	$1,443,859	$1,416,224
PG&E Solar Choice Costs	$1,433,015	$1,416,550	$1,464,564	$1,436,929
CCA Default Costs	$1,407,014	$1,390,260	$1,438,091	$1,410,371
CCA 100% Green Costs	$1,449,078	$1,432,324	$1,480,154	$1,452,435
CCA Default Rate Savings	$5,296	$5,584	$5,767	$5,852
CCA Savings (100% Green)	($16,062)	($15,774)	($15,591)	($15,506)
Ideal Rate Savings	$16,466		$27,635	

3.2.4 Future Rate Analysis

The future rate analysis compares Caltrain's projected traction power electricity costs under different PG&E and CCA rate structures. In order to create a cost projection for the four new electric services that are to be installed solely for the purposes of electrification of the Caltrain rails between San Francisco and San Jose, TerraVerde used 15-minute interval files created and provided by LTK for each substation/PG&E meter as a result of the LTK Traction Power System Modeling and Simulations of the Caltrain Electrification Project study. Using the final annual consumption profile, we then analyzed the costs under the only available rate tariff based on the projected energy and load profile (B-20-T) at each PG&E service point.

The analysis also factors in estimated value of the LCFS credits Caltrain will generate, which will offset total electricity costs. LCFS credits are discussed further in Section 3.2.5. Table 5 provides a summary of the future rate analysis. Assumptions used in the analysis are provided in Appendix D.

Table 5. Future Rate Analysis

		PROJECTED COSTS				LCFS CREDITS	
SITE NAME[11]	Bundled PG&E Rate	Bundled PG&E Costs	PG&E Solar Choice Costs	PG&E + CCA Default Rate Costs	PG&E + CCA Costs (100% clean)	Using Grid Electricity	Using Zero Carbon[12] Electricity
TPS-1: T1	B-20-T	$3,931,289	$4,268,024	$3,809,982	$4,095,351	$3,548,456	$4,331,615
TPS-1: T2	B-20-T	$4,452,854	$4,808,894	$4,308,048	$4,609,776	$3,751,877	$4,579,932
TPS-2: T1	B-20-T	$4,462,133	$4,826,845	$4,453,926	$4,763,004	$3,843,263	$4,691,486
TPS-2: T2	B-20-T	$2,718,792	$2,976,127	$2,725,532	$2,943,613	$2,711,756	$3,310,252
	TOTALS:	**$15,565,068**	**$16,879,890**	**$15,297,488**	**$16,411,744**	**$13,855,352**	**$16,913,285**
CCA RATE SAVINGS:				**$267,580**	**$468,146**		

[11] TPS-1 is located in South San Francisco and TPS-2 is located in San Jose (per the LTK Traction Power System Modeling and Simulations of the Caltrain Electrification Project report.

[12] Zero carbon electricity is an LCFS term. Zero carbon electricity can be achieved using onsite renewable energy generation or through the retirement of REC.

Based on this analysis, there are savings from being enrolled in the CCA standard rates under all scenarios. On average for the historical rate analysis, the PG&E Solar Choice option provides bill savings over the equivalent CCA 100% green program, although this will vary by account and CCA (see Appendix B for a summary of each account). The costs to purchase energy in the PG&E Solar Choice option varies between $0.0048/kWh for rates such as A-1 and A-6 to $0.0118/ kWh for B-20-T rates. CCAs also typically charge a variable rate per kWh based on the rate tariff for their 100% green option, although within a specific CCA there is lower variability in the rate per kWh between rate tariffs. For the CCAs that Caltrain is enrolled in, the CCA 100% green option rate adder can vary between $0.005/ kWh to $0.01/kWh. Enrollment in the CCA has the additional benefit of supporting procurement of local renewable energy resources, and in some cases, a mix of renewable energy resources that provide green energy 24-hours a day. As can be clearly seen in the future rate analysis results below in Section 3.2.5, the CCA 100% green program provides financial savings over the PG&E Solar Choice option. The CCA default option provides savings of $267,580 over the PG&E standard rates and the CCA 100% green option provides $468,146 of savings over the PG&E 100% Solar Choice rate.

Additionally, there is a small amount of savings to be made by making an immediate switch to the rate shown for the PG&E Rate (the CCA rate will be adjusted accordingly) under ***Current TOU, Ideal Rates and Cost section*** for the associated SAID in Appendix C. By switching to the PG&E Rate shown in the Ideal Rate and Costs section under the Current TOU, Caltrain could save up to $16,466 in annual utility bill costs versus costs under the current rate that the accounts are enrolled in. Similarly, by switching to the rate shown for the PG&E Rate under the ***New TOU, Ideal Rates and Cost section*** Caltrain could save up to $27,635 in annual utility bill costs versus simply transitioning to the rates shown under the ***New TOU, Projected Rate and Costs section***. The ideal rate savings shown assume enrollment in the CCA as this provides the highest level of savings. The full annual savings will not be able to be realized given that the current TOU rates are only available through March of 2021.

3.2.5 Low Carbon Fuel Standard Analysis

The potential financial benefits from the LCFS program were also investigated and provided for both the standard grid-electricity procurement option as well as the zero-carbon electricity purchase option which are summarized in Table 6.

Table 6. Future Rate Analysis Summary

Costs/Savings	Electricity Cost	Total Electricity Costs with Grid Electricity LCFS Credit ($/YR)
PG&E Default Costs	$15,565,068	$1,835,959
PG&E Solar Choice Costs	$16,879,890	$3,150,781

Costs/Savings	Electricity Cost	Total Electricity Costs with Grid Electricity LCFS Credit ($/YR)
CCA Default Costs	$15,297,488	$1,568,379
CCA 100% Green Costs	$16,411,744	$2,682,634
CCA Savings (standard)	**$267,580**	

When using electricity as transport fuel, the carbon content of grid electricity must be accounted for. There are two pathways to achieving zero-carbon electricity for the purposes of LCFS:

- Onsite renewable energy sources used to directly power the vehicles; or,
- Retiring qualifying RECs from zero-carbon sources such as solar photovoltaic, wind, RPS eligible hydroelectric generation, ocean wave, ocean thermal or tidal current sources in order for electricity usage to be treated as zero-carbon.

RECs are managed in California on the Western Renewable Energy Generation Information System (WREGIS), the regional independent tracking system. A unique identifier is assigned to each MWh of reported renewable energy generation. RECs can be transferred between parties and are regularly purchased by LSEs as a means of complying with the RPS, commercial enterprises with sustainability goals, and LCFS market participants. Currently, RECs can be purchased for between $20-$25/REC. Table 7 provides an overview of the additional costs of procuring RECs to achieve zero-carbon electricity for the purposes of LCFS.

Onsite renewable energy generation provides an alternative to procuring RECs on the market. Electricity generated by the proposed solar PV system would be used to generate RECs. Given that the available space for the installation of the proposed solar PV system within the Caltrain system is limited, and projected consumption from the electrified load is large, the solar PV system would allow Caltrain to avoid a projected cost of about $34,721/yr in REC market purchases as shown in Table 8.[13] The financial analysis completed for the solar PV and BESS and presented in Section 3.3 did not include any consideration for the LCFS benefit so the projected avoided costs provided by the solar PV system related to purchasing RECs on the market should be considered as an additional benefit above the costs savings already provided in the financial analysis.

Table 7: Low Carbon Fuel Standard Zero-Carbon Options Summary

	Projected Consumption (kWh/YR)	Projected Solar PV Production (kWh/YR)	REC Cost without Solar PV Systems ($)[1]	REC Cost with Solar PV System ($)	Annual Reduction in REC Cost ($)
TOTALS	111,425,559	1,736,056	$2,228,511	$2,193,790	**$34,721**

[13] Assumes the market cost is $20/REC.

Table 8. Low Carbon Fuel Standard Benefits Summary[14]

Transformer	Consumption (kWh/ YR)	LCFS Using Grid Electricity ($/kWh)	LCFS Using Zero Carbon Electricity ($/kWh)	LCFS Using Grid Electricity ($/YR)	LCFS Using Zero Carbon Electricity ($/YR)
TPS-1: T1	28,536,892	$0.1232	$0.1497	$3,516,124	$4,272,277
TPS-1: T2	30,172,819			$3,717,692	$4,517,193
TPS-2: T1	30,907,744			$3,808,245	$4,627,219
TPS-2: T2	21,808,104			$2,687,048	$3,264,906
TOTALS:	**111,425,559**			**$13,729,109**	**$16,681,596**

As can be seen from Table 8, achieving zero-carbon electricity provides a projected additional LCFS credit benefit of approximately $2,952,487 based on the comparison of available annual benefits for LCFS Using Grid Electricity versus LCFS Using Zero Carbon Electricity. Using the values provided in Table 7, achieving zero carbon electricity content for the purposes of LCFS would provide an additional annual benefit of $723,976 without onsite solar (equivalent to approximately 4.7% of total electricity cost under the CCA default rate), and $758,697 with onsite solar (approximately 5% of total electricity cost under the CCA default rate), after consideration for retiring and purchasing RECs, as applicable. Based on the estimated value of the LCSF benefits and the costs for procuring energy, Caltrain has the potential to cover the majority of the costs of their utility bills.

3.3 DISTRIBUTED ENERGY RESOURCES

TerraVerde analyzed the feasibility of installing solar and/or BESS systems adjacent to the future Caltrain North and South traction power substations and at Caltrain stations. Based on the analysis, a solar and/or BESS system does not appear to be viable at the future South and North traction power substations due to space limitations. Onsite DER systems are potentially feasible at three Caltrain stations – San Francisco, San Jose and Gilroy. However, based on future land use plans, only one of the Caltrain stations (Gilroy) is potentially feasible for a DER system in the short-term.

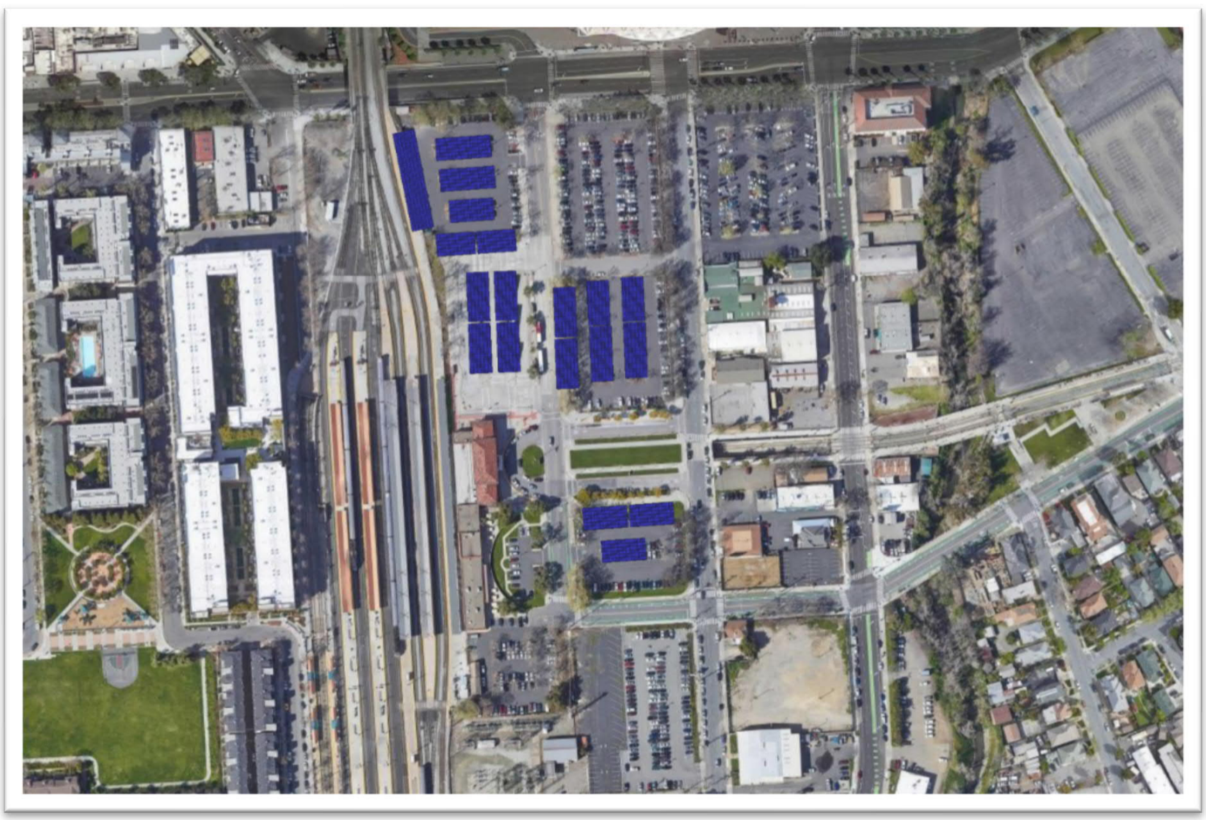
[14] Assumes the LCFS credit price is $100 per ton CO^2 equivalent. The LCFS credit price varies over time. The value used is conservative based on the past two years of history showing that the lowest LCFS credit price was $150 per ton CO^2 equivalent in April of 2018 and the highest LCFS credit price was $218 per ton CO^2 equivalent in February of 2020. The LCFS value shown uses projected carbon content values from CARB for 2022 grid electricity, solar electricity and diesel. Assumes the cost per REC is $20.

3.3.1 Facility Information

Caltrain currently has operations at 32 stations and a number of maintenance facilities. In addition, a number of the PG&E electrical meters service railway crossing and traffic signals. With the exception of the San Francisco and Gilroy stations, the DER analysis only considered sites where Caltrain owns the property.

Although there is physical space at a number of the Caltrain stations for the installation of small to moderately sized solar PV systems, the energy consumption at the stations is relatively low, leading to low financial savings to offset the cost of the installation. TerraVerde reviewed the option of offsetting the consumption at a number of stations together in a NEM-A arrangement, which should be feasible based on the contiguous nature of the properties along the ROW. This arrangement would allow for a single larger solar PV system installation at one of the stations while providing financial benefit through an accounting process at other stations that are included as part of the NEM-A arrangement. Despite the more optimal financial arrangement, the proposed projects did not show financial viability with the exception of a proposed solar PV carport installation installed at San Jose station to offset the consumption at the station as well as the consumption at CEMOF. The proposed solar PV system location is show in Figure 4.

Figure 4. Proposed Solar PV Layout at San Jose Station



The Project team used two main resources to evaluate Caltrain operations for siting solar PV arrays: aerial reviews using Google Earth (including the provided ROW maps) and a location-based production analysis tool known as Helioscope. All Caltrain locations were investigated for solar PV and battery energy storage installations given the following factors:

- Physical space for the installation of solar PV systems;
- Potential for sufficient local consumption to offset the production from the proposed PV systems; and
- Load profiles that provided sufficient financial savings to offset the cost of installation of BESSs.

When reviewing these sites for solar PV array placement, areas available for solar shade structures were identified as the preferred installation method. Although solar PV shade structures are typically more expensive to build than rooftop arrays, they provide the additional benefit of shading Caltrain customer parking spaces and thus tend to be a preferred arrangement when parking lot space is available. Rooftop solar PV can also be considered under the right conditions including on buildings with new and/or recently replaced roofs and that have sufficient structural capacity to handle the additional loading created by a solar PV system. Given that most Caltrain stations have a limited amount of rooftop space and the low electrical consumption at most station sites, rooftop solar was not considered in detail in this analysis.

Based on PG&E's soon to be mandatory TOU peak period definitions (4:00 pm to 9:00 pm), the orientation of solar PV systems should be in a south to south-west direction to provide optimized financial savings while maximizing production yield.

At the two new electrified load substations, only a very small amount of land is available and will primarily be used for the installation of the PG&E infrastructure necessary to provide electricity to the electrified loads. The electrical consumption at both of the substations is high and even if space were available it would be insufficient to offset even a small percentage of the consumption. Although RES-BCT projects may be a viable alternative to offset a portion of the consumption at the TPS stations, RES-BCT projects are limited to 5 MW AC for each project and must be located in the same jurisdiction as the facilities that they are providing benefits to. Given that limited land availability in the general vicinity of the TPS stations this option may also have limited viability. Should Caltrain be able to identify land that may be suitable for a RES-BCT project in the same jurisdiction as the TPS station, the land requirement would be approximately forty (40) acres to allow for the installation of a 5 MW AC solar PV system.

Alternatively, should Caltrain determine that pursuing the option to become an load-serving entity (LSE) is viable, a large remotely located ground-mounted solar PV system should be considered in the future. A financial analysis would need to be completed at the time based on the details of the project to determine the financial benefits of this option.

The proposed BESSs at San Jose station, at the San Francisco station location and at the Gilroy station location would be located as close as possible to the existing PG&E services and will take up an electrical pad area of between 15 feet and 30 feet in length and 10 feet in width. Although Caltrain does not own the property at the Gilroy station or at the proposed San Francisco location, given the limited impact to the site for a BESS and the potential bill savings available, it may be worth pursuing the option to install a BESS at these sites.

3.3.2 Solar Photovoltaic Systems Procurement

This section explores the different ownership and financing options available for the solar PV installations (see examples in Figure 5), including direct ownership and third-party ownership.

Figure 5: Example Solar Installations

Source: Image from iStock

SOLAR PV OWNERSHIP AND FINANCING

Direct Ownership: Under the direct ownership scenario, the solar PV system is purchased with available cash, or is financed using different loan structures. There are several options that can be used individually or collectively to achieve full project funding under a direct ownership scenario.

- **Cash Purchase:** PV systems can be purchased outright when the facility owner/operator has the capital available in reserves or other liquid assets. For tax-paying entities with tax liabilities, this procurement path allows the use of the Federal ITC, which can currently offset of the gross capital cost of the project in the form of a direct tax credit in the tax year the system(s) is completed and commissioned. See Section 2.1.1 for more information about the ITC credit value. Purchasing a solar PV system using cash can have the additional benefits: (1) allows for a faster and more streamlined installation process that sidesteps the potentially time-consuming third-party financing approval process; and (2) provides for improved project economics by avoiding loan costs and interest expenses associated with debt servicing. It is also important to consider operating costs when comparing project financing options. In particular, projects purchased through direct procurement options require the system owner perform all necessary operation maintenance and equipment replacement for the PV system over the anticipated effective useful life of the system (25 years or more). Operations, maintenance and warranty support can be self-performed, or a third-party asset management firm can be contracted to perform these services.

- **Loans:** For facility owners/operators interested in owning a solar PV system, but lacking the upfront capital for the purchase, a loan can provide the necessary funding. Loans can be obtained from a preferred lender, or alternatively many solar PV system vendors have approved lending partners that are familiar with financing solar PV projects.

Third-Party Ownership: Under a third-party ownership scenario, an outside entity (typically a private sector tax paying entity that can benefit from the ITC) finances and owns the solar PV asset(s), thus requiring little or no up-front capital cost by the facility owner/operator. Most third-party financing strategies also provide an optional path to direct ownership over the term of the contract. In any third-party ownership agreement, we suggest that Caltrain negotiate to keep all associated RECs.

- ***Power Purchase Agreements (PPA)***: Under a PPA contract, the customer enters into an agreement with a private company who finances, installs, owns, operates and maintains the PV system for a set contract term (typically 20, 25, or 30 years). The customer agrees to purchase all of the energy generated by the system for a negotiated PPA rate. Typically, the PPA rate (expressed as cents per kWh or "$/kWh") is lower than the utility cost of electricity (referred to as the avoided cost, or what the energy would otherwise cost to purchase from PG&E in the absence of the solar PV system). PPA rates can be either fixed (0% annual escalation) for the term of the agreement or can use annual escalators to keep the PPA rate artificially lower in the early years of the agreement. Historically, the cost of purchasing energy from PG&E has escalated over time; thus, a PPA rate with a 0% escalator provides a hedge against the anticipation of rising energy prices.

  A performance guarantee aligned with the term of the PPA is typically included to ensure that if the solar PV project does not perform as expected potentially reducing the expected savings to the facility owner/operator (the PV system host), a payment will be made by the third-party owner to address a portion of the lost savings based on the shortfall in production on an annual basis.

  For public agencies (and non-profit entities) who do not possess tax-liability or sufficient tax-appetite to monetize the available tax credits, a PPA financing strategy allows the third-party financier/system owner to monetize the tax incentives, and pass a portion of the savings benefit to the host customer in the form of a lower PPA rate(s). All PPA contracts should include certain buyout provisions that allow the host customer to purchase the PV system at a depreciated value ("fair market" value) after the financiers have consumed the tax benefits (typically at the end of the sixth year of operation, or at other pre-defined periods of the PPA contract term. Exercising a buyout option during the PPA can provide added savings potential, however the added cost of maintenance, warranty support, insurance, and other owner-related costs (along with the cost of capital or financing) should be closely evaluated when considering taking over ownership.

At the end of the term of the PPA, the customer has the option to purchase the system, renew the PPA for additional years (typically in 5-year increments), or have the system removed.

- ***Leases*:** Equipment leasing is a common method for facility owners/operators to finance certain hard assets associated with the PV system. Similar to the PPA, there is a monthly payment to the equipment owner, but unlike a PPA the monthly payment is tied to the system installation cost versus the operation of the system over time. Typically, the lease payment is offset by the savings on the customer's electricity bills. At the end of the lease agreement (typically 15-20 years), the customer has the option to purchase the system, renew the lease, or have the system removed.

Under a third-party ownership project scenario, project agreements can be structured to include a buyout options at specified price points and intervals (typically beginning no sooner than the 6th year of project operation) and in some cases can present better financial benefits than continuing under the third-party ownership structure.

SOLAR INCENTIVES

- ***Investment Tax Credit:*** Federal incentives for solar PV systems are provided in the form of investment tax credits, known as the Solar ITC. See Section 2.1.1 for more detail.
- ***Modified Accelerated Cost-Recovery System (MACRS):*** The MACRS allows for a class life of five years for solar PV systems, meaning the solar PV asset may be fully depreciated in only five years. The combination of the ITC and accelerated depreciation can offset up to 31% of the system's capital cost. See Section 2.1.2 for more detail.
- ***Renewable Energy Credits (RECs):*** RECs are the environmental attributes associated with the production of electricity from a renewable resource. One REC represents the environmental attributes associated with 1.0 MWh of electricity generated by a qualified and registered renewable energy source. A REC generated from an onsite solar PV can be sold into a REC trading market either "bundled" with its underlying energy or "unbundled" as a separate commodity from the energy itself. Once unbundled, the energy associated with the unbundled RECs may no longer be claimed as renewable or "green" energy. RECs can be traded in the Voluntary Market, which includes RECs purchased by private and public entities in fulfillment of sustainability goals. An example would be a corporation reducing their carbon footprint by purchasing RECs to offset nonrenewable energy supplied to their facilities by local energy retailers. Currently, the value of selling RECs from Distributed Generation projects in California is approximately $7.00 to $10.00 per REC. Due to the relatively low value, especially for smaller projects, the administrative costs of registering,

certifying, and taking RECs to market are generally cost prohibitive in California but can provide additional benefit for Caltrain associated with the LCFS credits, as discussed further in Section 3.2.5.

3.3.3 Battery Energy Storage System Procurement

The primary financial benefits from BESS projects are electric demand reduction and peak shaving. For energy usage profiles that have significant jumps in demand over a billing period, a battery can be used to provide an alternative source of power that ensures that the peak amount of power drawn by an individual operation/meter from PG&E never exceeds a set threshold, thereby allowing the customer to remain on a more cost-effective rate structure, and/or to reduce demand charge costs. Battery storage systems can also provide a number of other benefits including energy arbitrage and resiliency.

BESS OWNERSHIP AND FINANCING

Direct Ownership: Under a direct ownership scenario, the customer finances and owns the BESS asset(s). There are several options that can be used individually or collectively to achieve full project funding for direct ownership.

- **Cash Purchase:** BESS can be purchased outright when the facility owner/operator possesses available capital in reserves or other liquid assets. Similar to purchasing a solar PV system, purchasing a BESS project using cash can have the additional benefits: (1) allows faster and more streamlined installation process that sidesteps potentially time-consuming third-party financing approval processes; and (2) provides the potential for greater savings by avoiding third-party financing expenses and interest costs. It is important to also consider estimated operations and maintenance costs when comparing project financing options. In a cash purchase scenario, the facility owner/operator is responsible for the scope and cost of system operation, maintenance, warranty support and equipment replacement over the anticipated EUL of the system (typically 10 to 15 years).
- **Loans:** For facility owners/operators who do not possess upfront capital, a loan can provide the necessary funds to allow for a direct purchase. Loans can be obtained directly from a preferred lender or alternatively many BESS vendors also have approved lending partners that are familiar with BESS projects.

Third Party Ownership: Much like a solar energy PPA, the third-party ownership model for battery systems provides direct demand cost savings to the customer without capital investment or operation and maintenance responsibilities. In this scenario all applicable SGIP incentives are retained by the third-party owner, who uses the incentives to help offset the cost of installation and on-going maintenance. In addition to SGIP incentives, the system owner may receive revenues by requiring the customer to pay for a portion of the kW demand reduction based on a $/kW rate determined at the time of contract signing, or through an arrangement where the monthly utility demand cost savings are shared ("split") between the customer and the system owner. The customer's monthly demand savings payments made to the system owner is analogous to the monthly PPA payments for electricity procured through a solar PV PPA.

In addition, projects that combine solar PV and BESS together (with a single third-party Owner/Provider) allow the Owner/Provider to receive ITC benefits for the battery system in addition to the solar PV project. IRS rules allow the ITC to be claimed for BESS when the batteries are charged directly by the solar PV system. This combined system approach reduces the overall cost of the battery system, which in turn provides increased savings from the project. New legislation has been introduced as of March 9, 2021 to allow the ITC to be claimed for stand-alone BESS.

BESS INCENTIVES

- **SGIP:** The CPUC offers an incentive program that provides funding to support existing, new, and emerging DERs installed on the customer's side of the utility meter. See Section 2.2.7 for more information.

3.3.4 Solar Photovoltaic and BESS System Financial Results

The Project Team's financial analysis begins with a comprehensive data collection process and operations profile analysis and concludes with a financial projection of project economics using proprietary rate tariff and financial modeling programs. The analysis was completed for two different financing strategies: a PPA and a cash-purchase for each system scenario considered.

METHODOLOGY

Solar PV system costs and PPA rates used in the analysis are estimated "market" rates informed by known recent proposals and completed solar energy projects of similar size, scope, financing, and customer profile. Solar PV system costs and PPA rates are influenced by many factors, including: project size (kW), scope complexity, equipment & installation costs, number of sites (if project is a portfolio of separate sites), system(s) configuration, location, ITC eligibility & availability, other incentives availability and value (SGIP for example), project schedule, project risk (primarily site conditions), interconnection scope/cost, technology type, contract terms (unique or non-standard requirements), O&M and monitoring requirements, performance guarantee terms and bonding and insurance requirements. Solar PPA rates are influenced by additional factors including the use of PPA rate annual escalators, the credit rating of the energy off-taker (customer), prevailing interest rates, the internal rate of return (IRR) required by the investors/financiers and buyout options.

The electricity consumption and billing analysis for each meter requires at least one complete year of operational billing and usage data to be used as a baseline for defining future consumption, and as an input for modeling a projection of financial savings over time. For existing PG&E services, data is collected in the form of 15-minute interval data files, billing and usage data, and paper (pdf) bills. Billing data summarizes the metered energy, max demand values, and the corresponding charges that Caltrain incurs during each billing period. In the case of future loads where historical consumption data is not available, load profiles are created by a firm familiar with the proposed new loads, which in this case was LTK. The projected electrical load interval data provided by LTK for each of the proposed new electrical services at the North and South substations was used to complete the solar PV and battery energy storage financial analysis.

Interval data is comprised of metered kWh and kW values at 15-minute intervals and shows the shape and load profile of a specific operation/facility (meter/site). Using the interval data along with most current rate information (PG&E tariff periods and costs), it is possible to construct monthly bills to establish an accurate basis for comparing expected energy and demand reductions associated with proposed solar PV systems.

To ensure that billing assumptions and tariff related variables are correct for each meter prior to modeling project cash flows and net savings, 12 months of billing for each proposed meter is calculated by calendarizing the 15-minute interval data and applying the applicable rate tariffs. Factors that can affect the calculated baseline billing assumptions include: voltage levels, demand response programs, standby charges, and exported energy production.

The cost savings attributed to solar energy production are based on calculated avoided cost that describes the cost of electricity provided by the utility and that is replaced by credits generated by the proposed PV. The value is measured in $/kWh and derived by dividing bill savings attributable to solar energy generation by total solar energy production. Calculated bill savings are the difference between the projected (or actual) billing before installation of the solar PV systems, and projected (or actual) billing after the PV systems are operating for a 12-month period. Assumptions used in the analysis are provided in Appendix D and pro formas are included in Appendix E.

PEAK DEMAND SHAVING AND ENERGY ARBITRAGE

When paired with an onsite solar PV system, a BESS can further reduce demand and provide savings value that is not available to a stand-alone BESS or solar PV system. Integrating energy storage systems with solar PV systems provides a holistic approach to renewable energy generation and financial savings. A solar PV system by itself provides per-kWh utility bill savings and some peak demand reduction but is subject to intermittency based on weather conditions and therefore plays an unreliable role in ensuring that demand charges can be effectively managed. In cases where the customer has high demand charges, solar PV and energy storage can be controlled together to provide the optimal overall bill and peak demand savings through charge/discharge management software capable of making decisions that allow for optimized financial savings based on the actual operating profile on a real time basis. This includes the ability to decide when to charge the battery system with energy provided by the solar PV system, ensuring that the battery is always charged and available for use to make up for a period of low production from the PV system. Batteries charged by solar PV also have the potential of providing "energy arbitrage," i.e., charging the batteries from the solar PV during low bill credit periods and exporting energy from the batteries during high bill credit periods. In addition, a combined solar PV and energy storage system can be configured to have the added benefit of providing an alternative source of power and resiliency in times when the grid is either unreliable or not available.

Under current policy and utility tariffs, it is necessary to install either a net generation output meter (NGOM) or a non-export relay when installing a combined battery energy storage and solar PV system unless the BESS is charged 100% from the solar PV system. When a BESS is charged from the grid, an NGOM is a meter required by the utility to ensure that only production from the renewable energy generation system receives net metering credits (i.e., to ensure only the solar PV system receives export credits and not the energy storage system given that it has been charged using grid electricity). A non-export relay functions to prevent the BESS from discharging energy when the load at the utility meter is zero or negative (i.e., the relay ensures batteries do not discharge at a time when the discharge would result in exporting energy to the grid). If Caltrain decides to pursue BESSs, we suggest the installation of NGOMs to provide the option for the facilities to participate in energy storage net energy metering programs while maintaining the flexibility to charge the BESS from the grid should circumstances change. When an energy storage system is charged 100% from a renewable energy source, the NEM program allows energy exported from the BESS to receive export credits from the utility.

FINANCIAL ANALYSIS RESULTS

As discussed in Section 3.3.1, TerraVerde identified three potentially viable DER projects:

- Solar and BESS system at the San Jose Station
- BESS system at the San Francisco Station
- BESS system at the Gilroy Station

Table 9. Solar PV and BESS System Specifications and Estimated Savings

Site	Rate Tariff	Est. Solar PV Annual Production (kWh)	Est. Solar PV Size (KW DC)	BESS Size (kW/kWh)	Solar PV Savings ($/kWh)	BESS Savings from Demand Reduction ($/kW)	BESS Arbitrage Savings ($/kWh)

San Jose Station	B-19	1,736,056	1,150	116/464	$0.0929	$51.46	$0.030
San Francisco Station	B-19	N/A	N/A	464/1,856	N/A	$26.28	$0.030
Gilroy Station	B-19	N/A	N/A	580/2,320	N/A	$30.29	$0.018

summarizes the solar and/or BESS system specifications for each site and the associated cost savings per kWh.

Table 9. Solar PV and BESS System Specifications and Estimated Savings

Site	Rate Tariff	Est. Solar PV Annual Production (kWh)	Est. Solar PV Size (KW DC)	BESS Size (kW/kWh)	Solar PV Savings ($/kWh)	BESS Savings from Demand Reduction ($/kW)	BESS Arbitrage Savings ($/kWh)
San Jose Station	B-19	1,736,056	1,150	116/464	$0.0929	$51.46	$0.030
San Francisco Station	B-19	N/A	N/A	464/1,856	N/A	$26.28	$0.030
Gilroy Station	B-19	N/A	N/A	580/2,320	N/A	$30.29	$0.018

Table 10 summarizes summarizes solar and/or BESS system specifications for each site and associated cost savings per kWh. Table 10 summarizes estimated costs and savings for the San Jose solar plus BESS project under a third-party ownership and cash purchase scenarios based on construction in 2022.[15] Table 11 summarizes estimated costs and savings for the San Francisco and Gilroy BESS projects under a third-party ownership and cash purchase scenarios based on construction in 2022. Pro formas for each scenario are included in Appendix E.

[15] The pro-formas for the San Jose solar PV project were completed using the December 2020 legislation extending the 26% ITC tax credit.

Table 9. Solar PV and BESS System Specifications and Estimated Savings

Site	Rate Tariff	Est. Solar PV Annual Production (kWh)	Est. Solar PV Size (KW DC)	BESS Size (kW/kWh)	Solar PV Savings ($/kWh)	BESS Savings from Demand Reduction ($/kW)	BESS Arbitrage Savings ($/kWh)
San Jose Station	B-19	1,736,056	1,150	116/464	$0.0929	$51.46	$0.030
San Francisco Station	B-19	N/A	N/A	464/1,856	N/A	$26.28	$0.030
Gilroy Station	B-19	N/A	N/A	580/2,320	N/A	$30.29	$0.018

Table 10: San Jose Station Solar PV plus BESS Projected Utility Cost Impacts

Site/Scenario	Est. Capital Cost ($)/ PPA Rate ($/kWh)	Est. Yr 1 Utility Gross Benefits ($)	Est. Yr 1 Expenses ($)	Est. Yr 1 Net Benefits ($)	Cumulative Cash Position (Yr 25) ($)
Third-Party Ownership	$0.1240 PPA + 99% Savings to BESS Provider	$186,719	$258,831	($72,112)	($220,552)
Cash Purchase	$3,655,357	$186,719	$49,660	$137,058	$151,417

Table 11: Stand-Alone BESS Projected Utility Cost Impacts

Site/Scenario	Est. Capital Cost ($)/ BESS Rate (%)	Est. Yr 1 Utility Gross Benefits ($)	Est. Yr 1 Expenses ($)	Est. Yr 1 Net Benefits ($)	Cumulative Cash Position (Yr 15) ($)
SF Meter Third-Party Ownership	204%	$44,000	$94,116	($50,116)	($870,002)

Site/Scenario	Est. Capital Cost ($)/ BESS Rate (%)	Est. Yr 1 Utility Gross Benefits ($)	Est. Yr 1 Expenses ($)	Est. Yr 1 Net Benefits ($)	Cumulative Cash Position (Yr 15) ($)
SF Meter Cash Purchase	$1,164,770	$44,000	$5,077	$38,923	($434,362)
Gilroy Station Third-Party Ownership	120%	$90,924	$113,725	($22,801)	($348,879)
Gilroy Station Cash Purchase	$1.417,775	$90,924	$5,315	$85,610	$181,320

3.3.5 Back-up Power Benefits

Solar PV and BESS systems also have the potential to provide back-up power generation during a grid outage with the installation of additional equipment, such as a microgrid controller and a transfer switch (these costs were not considered in the financial analysis but typically cost between $50,000 to $100,000 per site).

The total cost for the additional equipment needed to establish the capability for the solar PV and BESSs to operate during a grid outage can vary on a site-by-site basis mostly due to load management techniques and any associated electrical rewiring required. Assuming that no load management technique is used, the anticipated number of hours that each of the proposed systems could provide is shown in Table 12.

Table 12: Projected Hours of Backup Power Provided

Site	Hours of Backup Power[16]
San Jose Station	6.75
San Francisco Station	18.75
Gilroy Station	23.75

3.3.6 Virtual Power Plant, Demand Response Revenue and LCFS Opportunities

Virtual Power Plants (VPPs) are networks of local energy storage devices that may be centrally controlled by a LSE to dispatch power as an alternative to purchasing power in wholesale electricity markets. VPPs can also dispatch excess power to sell into the wholesale markets at times when wholesale prices are high. In addition, VPPs can store excess generation as an alternative to selling into wholesale markets when prices are low. When paired with renewable generation, VPPs can dispatch clean energy in real-time as an alternative to the dirtier power dispatched through a wholesale auction process. VPPs are being deployed across California to generate additional revenue to owners of behind-the-meter BESSs. By participating in wholesale energy markets, BESS owners have the opportunity to shift load when demand for energy is high (i.e., during peak hours) and thereby receive financial incentives from the independent grid operator for providing balance to the electric grid.

[16] Represents the anticipated number of hours that the battery and solar PV system or stand-alone BESS will provide back-up power for based on each site's worst-day energy consumption over the 12-months of data used (February 2019 to January 2020), and assumes that the battery is 100% charged at the start of the outage and the applicable solar PV system will produce between 80% of its anticipated production.

VPPs benefit LSEs, such as PG&E or the local CCA, by providing ramping flexibility through frequency control (by ramping up and down power production and consumption on short notice, as needed), better management of high penetrations of renewable resources, and improved grid resilience. VPPs provide revenue opportunities for its participants by entering into contracts to provide spinning reserve and resource adequacy (RA) and participating in wholesale energy markets to balance energy procurement shortfalls for the participating LSE. VPPs benefit communities by reducing an LSE's need to purchase costly and hydrocarbon-based energy. Additionally, communities also benefit from reduced risk of blackouts as the VPP provides greater grid resilience.

An evolving source of added financial benefits associated with energy storage systems are utility level demand response programs offered through direct contracts with local LSEs and the CAISO. For example, in regions where existing LSE substations and distribution networks are experiencing high demand conditions and are deemed "unreliable" to support late afternoon/early evening demands for electricity, and/or are in locations where additional grid infrastructure is contemplated to resolve reliability concerns, energy storage systems may be contracted for use through an LSE demand response program. In practice, the LSE or grid operator issues a call for demand response services; the operator of the energy storage systems commits to provide a certain amount of kW to the grid and issues a control signal to the battery system to discharge at the appropriate time to meet the demand response commitment. In return for this service, the LSE or grid operator provides a $/kW payment for the energy discharged to the grid. In situations where the utility demand response program depletes the energy storage system capacity to a point where it must be re-charged to support on-going behind the meter services, any third-party agreements for the installation of BESS must have provisions to ensure protection of the Customer's guaranteed demand savings.

When coupled with behind the meter services such as demand shaving and peak load shaping, the additional revenue from participation as a VPP may significantly increase the overall project returns. There may also be future opportunities for additional VPP revenue from participation in LSE peak load shaping.

Although these additional revenue streams are currently available, VPP have not evolved to the point where there is certainty around the amount and timing of the additional revenue streams, and hence have not been considered in our financial analysis. A limited number of vendors in the industry currently consider these alternative revenue streams as reliable enough to justify the cost of a BESS under a third-party ownership model, although this is also rapidly changing. Given the current evolution of the market, the ideal way to find a partner that is willing to consider all potential revenue streams for a BESS is through a competitive solicitation process that clearly outlines the revenue streams to be considered by participants.

For Caltrain, LCFS credits are another opportunity for offsetting costs or generating additional revenue from a solar PV system. The RECs generated by the solar PV system can be retired to obtain zero-carbon LCFS credits.

3.3.6 DER Financial Analysis Results Summary

In summary, the financial benefits of potentially feasible DER systems are higher for Caltrain based on a cash purchase option in all scenarios. The cash purchase option does require the upfront capital to pay for the project, whereas the third-party ownership does not require any upfront capital and instead annual energy and/or services procurement payments are made to the third-party provider. The proposed solar PV and BESS will only offset a portion of the annual utility bills in either a cash purchase or third-party ownership model.

SAN JOSE STATION SOLAR PV PLUS BESS

- Year 1 Net Benefits for ***CASH PURCHASE*** -Solar PV + BESS project: **$137,058**
- 25yr Cumulative Cash Position for ***CASH PURCHASE*** - Solar PV + BESS project: **$151,417**

SAN FRANCISCO AND GILROY STATIONS BESS

- Without the SGIP incentives, the stand-alone battery energy storage projects explored for the San Francisco and Gilroy station sites are not anticipated to provide sufficient financial benefit to warrant proceeding with projects at these sites. Depending on the outcome of the ITC legislation for stand-alone battery energy storage systems, a third-party ownership model may be an option that Caltrain wants to explore in the future.

Further site-specific due diligence would be required to confirm physical/technical feasibility and to verify project cost assumptions.

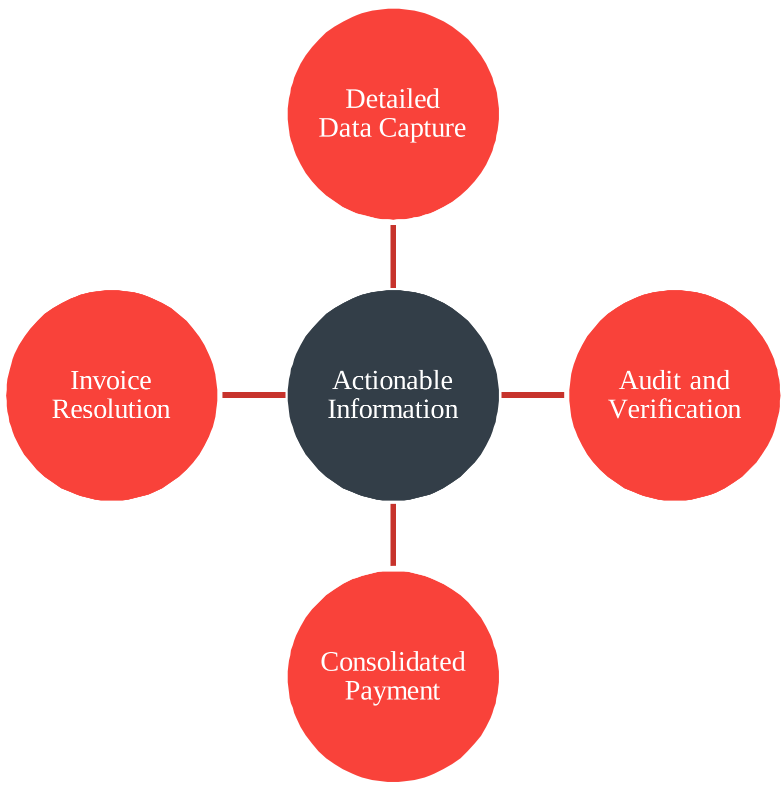
3.4 ENERGY EFFICIENCY

Opportunities to improve facility and vehicle energy efficiency should be pursued whenever feasible. As part of this study, the Project Team conducted a desktop review to evaluate potential energy efficiency opportunities at Caltrain stations and facilities. Caltrain has already completed or scheduled LED retrofits at all stations. In addition, Caltrain station design specifications mandate LED lighting with lighting controls that use photocell controls with a timeclock and override functionality. Based on the information provided and a desktop review of select Caltrain stations, most are not expected to include any other energy-consuming systems. The CEMOF and the San Francisco and San Mateo stations have the greatest electricity consumption and could yield energy efficiency opportunities. However, given the complex ownership structure and plans for upgrading CEMOF and the San Francisco Station, Caltrain did not elect to pursue further evaluation of potential energy efficiency opportunities.

UTILITY EXPENSE DATA MANAGEMENT

Utility expense data management (UEDM) offers companies an end-to-end solution that centralizes utility information (cost and consumption), improves data accuracy, reduces costs (direct and indirect expenses), and provides for timely and insightful reporting all within a single cloud-based platform (Figure 6). A UEDM can perform the following key functions:

Figure 6. UEDM Process



- **Utility bill processing and analysis:** eliminates the accounts payable burden with a fully outsourced processing and payment solution that includes detailed line-item data capture, robust reporting and sophisticated analysis capabilities.
- **Open and close:** management of the time-consuming task of site-by-site utility account opening and closing while ensuring your savings are maximized by being on the correct rate schedule and negotiating deposits.
- **Natural gas, water and waste bill processing and analysis:** natural gas would be collected alongside electricity data. Water and waste could be added to provide cost-and-time-efficient gathering and processing of Caltrain waste and water bills utilizing the most up-to-date optical data capture, electronic data transfers and data management techniques in the industry.

Benefits include:

- Cloud-based reporting and analytic platform enables evaluation of spend, consumption and trending
- Provides quick, reliable access to bill data and invoices
- Eliminates the accounts payable burden of processing and paying utility expenses
- Positions utility expenses as a controllable operating cost
- Pre-payment auditing of invoices, ensuring accurate payments producing expense savings through bill auditing and exception analysis
- Cost savings

Estimated Costs

Table 13 summarizes the estimated costs to implement a UEDM for Caltrain based on the current number of meters (174). Caltrain would need to obtain a quote from a UEDM provider to confirm actual costs.

Table 13. Estimated UEDM Costs

Implementation Fees			Caltrain Costs
Implementation	**Account Setup Fee:** One-time fee for account setup	$6.00 per account (one-time setup fee)	$1,044.00
Historical Data Load Fee	Up to 12-months of electric and/or natural gas historical data	$18.00 per account	$3,132.00
Expense and Data Management Solutions			
Utility Bill Processing and Analysis	**Monthly Bill Processing/Payment Fee:** Monthly fee for processing, auditing, and payment of all utility invoices	$3.50 per account, per month	$7,308
	On-Going Account Setup Fee: One-time fee for new accounts setup	$6.00 per account	$1,044.00
	Custom General Ledger (G/L) Files: Hourly fee (standard G/L files included at no additional fee)	TBD	TBD, if needed
Open and Close	Site-by-site utility account opening and closing	$75.00 per account request	TBD – likely minimal
		Total Estimated First Year Costs	$12,528
		Total Estimated Annual Costs	$8,352

Estimated Savings

A UEDM system would result in the following savings:

- **Processing labor:** estimated around $8,700 annually[17]
- **Annual GHG inventory report cost savings:** approximately $3,000 for data collection and processing
- **Other savings:** bill error resolution

UEDM providers claim an average return-on-investment of **285%** beyond the eliminated costs associated with bill validation, reconciliation and processing.

3.5 CONCLUSION

As can be seen by the results of the historical and future rate analyses shown in Section 3.2, there are savings from being enrolled in the CCA standard rates under all scenarios. The CCA default rates provide the greatest financial benefit to Caltrain based on the projected electrified load. The CCA 100% GHG-free and 100% renewable rates are more costly, but lower than the equivalent PG&E rate (Solar Choice).

Additionally, there is a small amount of savings to be made by switching select electric meters referenced in Section 3.2 to ideal rate tariffs. By switching to the recommended rates, Caltrain could save up to $27,635 in annual utility bill costs versus simply transitioning to the rates shown. The ideal rate savings shown assume enrollment in the CCA as this provides the highest level of savings.

Caltrain will earn LCFS credits for transitioning from diesel-powered trains to electric-powered trains. Even using the lowest LCFS credit value (grid electricity), LCFS credits will enable Caltrain to offset a large portion of its electricity costs. Caltrain can increase the value of its LCFS credits by purchasing RECs. If Caltrain is able to install an onsite solar system, this will offset a portion of the REC purchase necessary to attain the higher LCFS credit value. TerraVerde identified potentially viable DER projects at three Caltrain stations: San Jose, San Francisco and Gilroy. However, Caltrain staff have indicated that future land use plans will prohibit installation of onsite DER at the San Jose and San Francisco stations in the near-term.

Key suggestions based on the Phase 1 analysis are summarized below:

- The Project Team recommends that Caltrain stay with the regional CCA for its accounts at this time.

[17] This assumes that it takes approximately 5 minutes to review and process each meter every month and estimates a $50 per hour labor rate (174 accounts x 12 months of bills x 5 minutes/meter)/60 minutes x $50/hour).

- LCFS can provide significant benefit in terms of offsetting the increased electricity costs for the new electrified loads.
- The installation of the proposed solar PV and BESS are projected to provide financial savings for Caltrain based on utility bill savings alone at the San Jose station, although the savings are relatively low before consideration for the LCFS benefits.
- When further considering zero-carbon LCFS credits, the solar PV system has the ability to reduce the need to procure RECs through a retirement of the RECs associated with the solar PV energy generation.
- Stand-alone BESSs at one of the San Francisco station meters and at the Gilroy station were projected to provide financial savings for Caltrain based on utility bill savings alone with consideration for Step 3 SGIP incentives. Without the SGIP incentives, the stand-alone BESS projects do not show sufficient financial benefit to warrant consideration. This may change should the legislation to approve ITC for stand-alone BESS be approved.
- When considering the installation of DERs it is best to coordinate with PG&E as early as possible in the process.
- In order to maximize the ITC benefits for the proposed solar PV systems under a third-party financing option, it would be in Caltrain's best interest to commence construction of the proposed solar PV project (in compliance with IRS requirements for ITC eligibility) prior to the end of 2022.
- A RES-BCT solar PV project is an option that could be explored to provide renewable energy and utility bill savings for the Caltrain electricity accounts not included in the onsite solar PV systems proposed in this report but given the large amount of consumption at the new substations and the anticipated difficulty in siting a 5 MW AC project in the same jurisdiction as the substation(s), this may not be a viable approach. At the time of writing, there are approximately 27 MW of 105.25 MW of capacity remaining in the PG&E RES-BCT program. Participation in the PG&E RES-BCT tariff also requires that all participating electrical accounts receive both distribution and generation service from PG&E (i.e., are not enrolled with a CCA).
- Given the large amount of electricity consumption at the TPS stations, should Caltrain determine that it is viable to establish as an LSE, a large remotely located solar PV project should be investigated as an alternative to onsite DERs or a RES-BCT project. Further investigation of the economics would need to be completed based on additional details that would be available once Caltrain establishes themselves as an LSE.
- A UEDM offers companies an end-to-end solution that centralizes utility information (cost and consumption), improves data accuracy, reduces costs (direct and indirect expenses), and provides for timely and insightful reporting all within a single cloud-based platform.

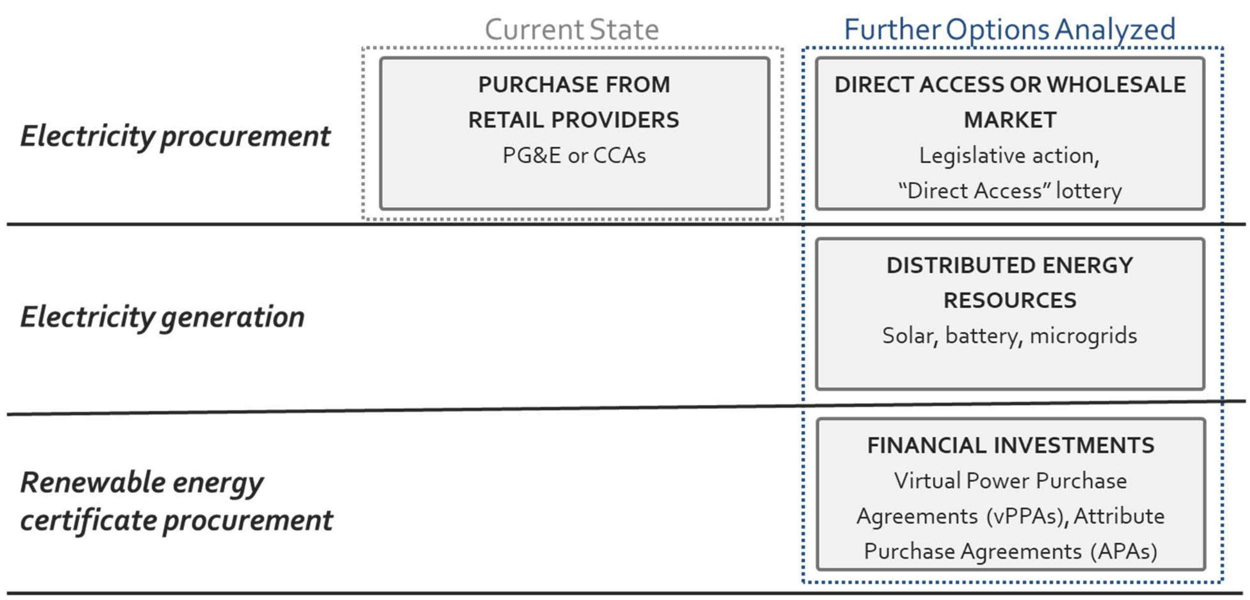
4 PHASE 2: MEDIUM-TERM ENERGY PROCUREMENT STRATEGY

The Project Team evaluated Caltrain's medium-term (4+ years) energy procurement options, which include participation in the direct access or wholesale markets, installation of DER systems and energy financial investments. This section discusses the electricity and technology procurement options available to Caltrain and includes an evaluation of the associated environmental impacts, risks, trade-offs, operational impacts and financial considerations of each option. This section also discusses the potential benefits associated with jointly procuring electricity with SamTrans.

4.1 PROCUREMENT AND TECHNOLOGY OPTIONS

Caltrain currently procures electricity from four CCAs –PCE, SJCE, CleanPowerSF and SVCE, which is delivered through PG&E – and two MOUs—the City of Palo Alto Utilities and Silicon Valley Power. Over the medium to long-term (4+ years), Caltrain can continue to remain a retail electricity customer and choose between the available providers, or Caltrain could pursue procurement through the Direct Access (DA) or wholesale markets. DER systems could also be installed over the medium-term as additional technology options become available or existing options become more affordable. The energy procurement and technology options evaluated in this study are summarized in Figure 7.

Figure 7. Procurement and Technology Options



Caltrain should also continue to monitor, or proactively engage in, the evolution of their CCA partners' product offerings. For example, PCE may consider a future product that could include

LCFS-qualifying RECs, thus potentially providing Caltrain with a larger revenue stream associated with participating in the LCFS market via creating and selling LCFS credits.

4.1.1 Solar and Battery Storage Distributed Energy Resources

Section 3.3 discusses the feasibility of installing solar and/or BESS DER systems at Caltrain facilities. This section provides a description of the current technology, summary of implementation steps, discussion of potential impacts on operations, barriers to implementation and a risk analysis.

TECHNOLOGY DESCRIPTION

Solar PV systems provide clean, renewable energy generation, and are a commonly deployed project type by California Public agencies as a means of generating energy cost savings benefits. These systems commonly include arrays of solar panels, that generation Direct Current (DC) electricity, which are converted to Alternating Current (AC) electricity via inverters. These solar PV systems are then interconnected to the electrical systems of a facility to meet electricity demand. Under NEM programs, these systems are also allowed to export from the facility to the grid and generate credits against those times when energy is being consumed from the retail electricity provider.

BESSs are able to store and discharge electricity at a facility. As such, these batteries are able to provide value in several different ways, including:

- *Providing Backup Power*: When paired with the proper switching and controls, BESSs are able to provide backup power support at facilities in the event of grid outages.
- *Demand Charge Management*: Demand charges are the portion of an electricity bill that is charged by the utility for a facility's peak power demand. This amount is typically set by the highest peak 15-minute interval over a billing period (month). For facilities that have significant demand charges, and the right load profile, batteries can discharge to meet a portion of that peak demand, reducing the utility demand charges and generating savings. This is also referred to as "peak shaving."
- *Time-Of-Use Energy Arbitrage*: For facilities on time-of-use rates, batteries can charge when energy rates are at their lowest and discharge when rates are their highest, thereby reducing energy costs.
- *Grid Services & CCA Program Revenue*: Increasingly, batteries are being provided with revenue opportunities through participating in grid services and community choice energy programs. For example, batteries can participate in a relatively new grid services program known as the Demand Response Auction Mechanism (DRAM). Similar to traditional demand response programs (where customers are compensated for allowing the utility to turn off some of certain loads during certain high energy usage events), the DRAM

program enables behind-the-meter batteries to earn revenue by reducing a facility's load at specified times *without* requiring facility loads to be turned off.

These programs are described in more detail in Sections 2.2 and 3.3.

IMPLEMENTATION

Solar PV and/or BESS are typically implemented via the following 4-stage process:

Stage 1 – Feasibility Assessment

In order to understand whether projects are technically and financially feasible, a detailed study is typically required. This process begins with a collection and thorough evaluation of facility energy usage and costs, site infrastructure & drawings, available programs and incentives. From there, an analysis is performed to determine the optimal sizing of the solar and battery systems to meet backup power requirements and/or deliver peak financial benefits. Next, the assessment should include an evaluation of the costs and benefits of these projects under both a purchase and third-party ownership scenario. A desktop feasibility assessment was conducted as part of Task 3 and is summarized in Section 3.3. If Caltrain elects to move forward with any of the identified DER projects, a more detailed onsite assessment would need to be conducted.

Stage 2 – Project Solicitation

Once a project or projects have been identified as viable, projects are then typically procured through a competitive Request for Proposals (RFP process) in order to secure offers from potential installers and/or providers for these projects. This solicitation process typically includes the development of the RFP package (including technical specifications for the projects and a contract), the release of the RFP to qualified respondents, site walks with the respondents, a questions and answers period for the respondents, a qualitative and quantitative review of the responses, shortlist interviews, and ultimately the selection of a respondent. Once a respondent has been selected, the project enters the very critical stage of contract negotiations, where it is of utmost importance to ensure that terms and conditions properly mitigate risk and set the project up for success.

Stage 3 – Project Implementation

Upon entering a contract for the projects, the installer will then begin their design, permitting, and utility interconnection application processes. As applicable, the installer may initiate incentive application processes. Once designs are completed and permits are in place, the projects then begin construction. The conclusion of the construction phase includes receiving Permission to Operate from the electric utility provider, and a commissioning of the systems to begin operation.

Stage 4 – On-going Operation

Upon commissioning, these systems enter their operational phase, during which it is imperative that performance is monitored on a daily, active basis. Studies show that the average commercial scale solar PV system is expected to experience between 4 to 5 significant performance impacting events each year. Early detection and resolution of these performance issues ensures that these systems deliver on their pre-deployment expectations. In addition to system monitoring, these systems require regular preventive maintenance and inspections. If these systems are enrolled in revenue generating programs, such as the monetization of RECs, ongoing financial management of these programs will also be required. Finally, it is important that the energy and financial performance of these systems be analyzed and reviewed on a regular basis.

IMPACT ON OPERATIONS

The construction of these systems typically takes 4 to 6 months from commencement to completion. Coordination with your installer is essential to ensure that site access, material deliveries & storage, and construction activities align with expectations. In many cases, these projects require the facility to be without power for a period of a few hours to complete the final interconnection of the new energy systems.

During the operational phase of these systems, best practices include daily active performance monitoring, performance issue detection and resolution, warranty tracking and enforcement, regularly scheduled preventive maintenance and inspections, revenue program management, solar PV panel washing, and ongoing energy & financial performance analysis and reporting. Under a third-party ownership scenario, maintenance is the responsibility of the owner. Under both a cash purchase and third-party ownership scenario, the agency has the option to engage a third-party to provide these management services which is common practice.

BARRIERS TO IMPLEMENTATION

Implementation barriers for solar PV and battery projects include energy usage profiles/rate structures and space limitations. Given the costs for these systems, projects may not prove to be viable unless there is sufficient energy usage, demand, and costs. Facilities that use relatively low amounts of energy, and have low or no energy demand charges, are unlikely to benefit financially from the installation solar or battery systems. Solar PV systems require significant amount of rooftop, parking lot, or other space availability. The amount of space required varies greatly based on the target system sizing. BESSs are designed to be installed as close to the facility's main switch gear as possible, and typically require an equipment pad of approximately 10' x 30' to be installed. In some cases, these space requirements may present barriers.

RISK ANALYSIS

Risks for solar and battery projects include both regulatory risks and operational risks. From a regulatory perspective, the financial benefits of these systems are tied to the programs, rules, and rate structures as defined by the CPUC. As changes in these rules take place, the financial benefits of these projects can be impacted. For example, the recent adoption of new TOU rates by the CPUC, significantly reduced the value of mid-day solar exports, thereby reducing the avoided cost benefit performance of installed solar facilities. From an operational perspective, significant changes in energy usage, especially a substantial drop in energy usage undermines the value being delivered by these energy systems.

4.1.2 Microgrids

TECHNOLOGY DESCRIPTION

Considering the recent rolling blackouts and the emergence of wildfire related PSPS events, California Public agencies are increasingly evaluating means of securing backup power resources. One answer to this challenge is deploying solar PV + battery energy storage microgrids, which, when combined with the proper switching, load management systems, and controls, are able to (in some cases) provide both financial and backup power benefits. During normal operating conditions (while the electricity grid is up), these resources can operate and provide the benefits as outlined in Section 3.3.5 of this report. In the event of a grid outage, an automatic transfer switch can be automatically triggered to isolate these resources and specified loads from the grid, creating an "island" that is able to continue to operate in the absence of grid provided electricity.

IMPLEMENTATION

The implementation process for these projects is similar to the steps outlined in Section 4.1.1 of this report. However, to deploy solar + battery microgrids, a few additional considerations come into play. To understand the potential scope of the microgrid, there will need to be an assessment of the loads that will be supported by the microgrid. In an effort to minimize costs, and optimize the efficiency of resiliency projects, in many cases, a sub-set of the total facility's loads will be identified as "critical loads" to be supported by the microgrid. The identification of these loads includes determining which loads are to be considered as critical, and then evaluating both the energy consumption (kWh) and power demand (kW) profiles for those loads.

For facilities where there is already existing on-site electricity generation, such as solar PV, the expected performance, potential re-configuration requirements, and contract implications must be carefully considered. To understand the expected performance, there should be a detailed assessment of as-built drawings and recent performance records. It is important to note that the historic performance of the system will need to be accounted for in the process of building the energy use profile for a facility (i.e., the historic generation data will need to be evaluated in comparison to the historic electric utility meter data to determine the actual historic facility electricity usage). In addition, based on the intended level of backup support to be provided by the microgrid, there will need to be an evaluation of the physical interconnection configuration for the existing on-site generator, as it is likely that all or a portion of the system will need to be re-configured to operate in island mode (to continue to generate power in the event of a grid outage). Finally, the terms and conditions of the contracts related to the on-site generator will need to be examined closely to understand what implications there may be for incorporating this resource into the microgrid.

From an energy perspective, the resiliency (or backup power) benefits of a microgrid are generally described by the amount of load (or power capacity) that it can support, and the duration of support that it can provide. The power capacity and duration of energy resiliency provided by a microgrid are determined by several factors. The size of the on-site generation and energy storage resources is one variable. The loads and usage profiles that will be supported by the microgrid are another factor. The time of year when a power outage might occur also comes into play, as that typically impacts assumptions of both power generation from solar PV as well as the load support that may be required.

The operational impacts, barriers to implementation, and risks for these projects are similar to those outlined in Section 4.1.1 of this report.

4.1.3 Direct Access and Wholesale Market

The primary reason to seek access to engage in Direct Access (DA) or the wholesale electricity market – thereby not having to go through the current channel of contracting electricity through an IOU or CCA – is savings on electricity spend. The wholesale electricity market is typically a market for generators and resellers (e.g., PG&E, CCAs and ESPs), but there are some instances where large energy users are granted access to the market (e.g., BART).There are two primary mechanisms for the SamTrans and Caltrain to go this route: (1) entering California's "Direct Access" lottery, and (2) being granted a legislative exception (analogous to how Bay Area Rapid Transit (BART) gained access to the wholesale market). Both mechanisms come with several considerations that would be thoroughly contemplated before beginning to expend resources – particularly including the impact on staff time to lead such efforts.

Addressed below, one critical consideration is economies of scale (i.e., the amount of electricity being procured) because attempting to gain access to DA or the wholesale market – and the resulting impact on implementing any subsequent electricity contracting and management – come with material transaction and management costs outlined below. By accessing the wholesale market the agency would be classified as a LSE. This designation comes with increased market risk and more complex energy procurement needs, as described below. The benefits of cost and market flexibility should be carefully considered against these ongoing risks. For example, SamTrans has a relatively small electricity load and, therefore, the potential transaction costs may outweigh the potential benefit should it endeavor to gain, and ultimately are granted, access to DA or the wholesale market.

To contextualize the savings opportunity, Table 14 provides an estimate of the potential savings for Caltrain in the year each agency plans to meet their electrification goal. The potential savings estimate is based on our understanding of the California market wherein procuring electricity from DA or the wholesale market versus purchasing through any of the current retailers, which should generate roughly 10% savings. This savings forecast does not include any transactional and management costs highlighted above. Should Caltrain consider DA or the wholesale market access a viable option, it is recommended that it engage a market partner, such as Northern California Power Agency (NCPA) to better understand potential savings and costs to achieve those savings.

Table 14: Estimated annual savings from DA or wholesale procurement versus retail

Estimated Electricity Consumption When Fully Electrified (MWh)	119,000
Percent Electrified at Plan	75%
Year Plan is Met	2023
Average Blended Rate from Task 3 Report ($/MWh)	$221
Estimated Annual Spend in Year Plan is Met (2020 dollars and rates)	$26,300,000
Estimated 10% Annual Savings Wholesale v. Retail Electricity	$2,630,000

DIRECT ACCESS LOTTERY

TECHNOLOGY DESCRIPTION

Direct Access is an option available to non-residential customers that would allow the SamTrans and Caltrain to purchase their electricity directly from a competitive provider called an ESP, including products that are exposed to wholesale market pricing. An ESP is a non-utility entity registered with the CPUC that provides electrical service to end customers within the service territory of an electric utility (CPUC, 2021b). Under this option, Caltrain would be granted the ability to contract directly with any ESP. If granted access to the DA market, the agencies would have greater control in selecting providers who offer renewable energy products. PG&E would remain their utility provider for transmission and delivery of the electricity. One scenario of being granted Direct Access is the ability to have the ESP back the supply agreement with an underlying renewable energy PPA contract. In such a scenario and for context, SamTrans when at full electrification would need an approximately 20 MW_{ac}[18] solar farm to serve their full load, and

[18] MW_{ac} is the output the solar array is designed to deliver to the grid.

Caltrain would need an approximately 70 MW_{ac} solar farm to serve their full load at their planned 75% electrification.

IMPLEMENTATION

California limits the amount of energy that can be provided through DA. The DA program is currently fully subscribed, meaning there is no new capacity – measured in megawatt-hours (MWh) – available to new potential participants. However, some capacity does open up from time to time and the CPUC has submitted a recommendation to "reopen" capacity starting in 2024 (which would likely mean service beginning in 2025 or 2026) (CPUC, 2020). This implementation section assumes Caltrain consider submitting for the lottery in the event it is granted capacity that opens up within the current capacity cap.

California allows enrollment in the DA market based on a lottery system which is typically open each year in June. An application must be submitted during the one-week enrollment period, and applications are entered into a lottery to determine priority position on a wait list for the upcoming year. The DA program in California is currently limited to 11,393 GWh of load, and approval to pursue Direct Access from the wait list is dependent on available market capacity, position on the wait list, and requested capacity. If an applicant is granted access, they must complete the application process and confirm their intent to participate in the market within six months.

After selecting an ESP to work with – likely through a competitive solicitation, DA service with their chosen ESP can begin the following year on January 1. For example, an application that was submitted in June 2020 would establish a lottery position for the 2021 calendar year. If access is granted within the year, direct access service may begin on January 1, 2022. Applications are valid on the wait list for one calendar year. If DA is not granted within that year, all participants on the wait list are discarded and a new application must be submitted in the next lottery process to determine a new priority for the wait list. Subsequent applications do not impact an applicant's position on the wait list from one year to the next.

FINANCIAL CONSIDERATIONS

Cost impacts are dependent upon the specific ESP chosen for DA, if granted. Nevertheless, access to the market would allow for competitive sourcing of renewable electricity and is expected to result in a beneficial cost structure over time. As an ESP may be able to provide a cost structure that more closely follows wholesale market pricing, a reasonable expectation for savings on electricity spend by buying accessing the wholesale market through ESPs versus retail contracting (i.e., status quo) is conservatively 10% as shown in Table 14.

IMPACT ON OPERATIONS

The impact on electrical service to Caltrain's operations is similar to the current contracting as PG&E would remain the transmission and delivery provider, and operations would be subject to the uptime and availability of the electric grid. Potential incremental management and transaction costs beyond current state:

- Management: Caltrain would need to expend resources on: monitoring the DA regulation; engage potential ESPs; participating in the lottery (if the lottery persists in the new phase of opening up more capacity).
- Transaction: Once capacity is granted, Caltrain would need to create, facilitate and evaluate an RFP process to select an ESP potentially including evaluation of any associated underlying renewable generation facility.

BARRIERS TO IMPLEMENTATION

Capacity in the DA market is currently very limited, and availability is subject to an annual lottery system. Additional capacity may become available in 2024, but the amount, timing, and process to apply for capacity are all in question.

POLICY CONSIDERATIONS

As stated above, DA is currently at capacity. Therefore, the critical policy consideration is whether or not more capacity is added to the DA program. Another policy consideration is the potential interplay between a DA agreement wherein Caltrain is able to leverage the associated RECs as a part of their LCFS credit creation. To achieve this end several steps would have to be implemented, including the following high-level steps (CARB, 2019):

- Negotiating that Caltrain has exclusive rights to at least some portion of the RECs associated with the supply contract and that said RECs are compliant within the LCFS program
- The ESP would need to become a "Fuel Pathway Applicant" to obtain a certified carbon intensity and retire RECs in Western Renewable Energy Generation Information System (WREGIS)
- Caltrain would become a "Fuel Reporting Entity"

RISK ANALYSIS

Capacity is very limited so access through this option is unlikely to meet 100% of Caltrain's growing electricity needs in the near term. The most material risk may be that of expending resources – both staff time and expenses – associated applying for a lottery position and solicitation for an ESP partner with no guarantee of material electricity cost savings or increased revenue via the LCFS market.

LEGISLATIVE EXEMPTION

TECHNOLOGY DESCRIPTION

With the DA lottery system inherently limited and unpredictable, organizations are seeking alternatives to be granted similar market access. One option is through an amendment to existing legislation, where there is precedent for the Public Utilities Code to allow for a transit organization to access the market in this way. In September 2019 Assembly Bill No. 923 was signed into law, allowing Bay Area Rapid Transit (BART) District unrestricted access to the wholesale electricity market, essentially bypassing the DA lottery. The bill also allows BART to aggregate its load from multiple meters (known as "conjunctive billing[19]") and requires annual reporting of the electricity that is sourced. With similar access to the wholesale electricity market, SamTrans and Caltrain would have the ability to source electricity from multiple generation sources on the open market. This method of sourcing provides greater visibility to the source of generation, as well as real-time fluctuations in price for wholesale energy trading.

IMPLEMENTATION

Access to the wholesale electricity market would require an amendment to existing legislation, where there is precedent for an amendment to the Public Utilities Code to allow for a transit organization to access the market in this way. In December 2016, FERC approved CAISO's revised definition of a LSE to add a new class of end user LSE that (1) are ultimate consumers of electricity; and (2) have legal authority to serve load through the purchase of energy form an entity that is not an LSE; and (2) have exercised their right to purchase electricity from a party that is not serving as the LSE for the transaction (FERC, 2016). Then in September 2019 Assembly Bill No. 923 was signed into law, allowing BART unrestricted access to the wholesale electricity market. The bill also allows BART to aggregate its load from multiple meters and requires annual reporting of the electricity that is sourced. BART arrived at this position through an unusual history beginning with the federal Reclamation Project Act of 1939, which qualified BART as a preference entity to purchase and receive hydropower from the Central Valley Project (CVP) that was generated as a byproduct of the federal irrigation project. PG&E was responsible for delivering CVP to BART under a wheeling agreement it had with the Western Area Power Administration (WAPA). During this time, BART was not responsible for managing their energy portfolio. As the energy market evolved, it became necessary for BART to take on some of the energy management responsibilities handled by PG&E in order to continue to purchase wholesale power. BART took initial steps towards becoming an LSE in 1995 and received incremental additional authorization to access the wholesale market leading up to AB 923.

[19] Conjunctive billing is a method of pricing all of the power sold to electric rail systems as if it were delivered through a single meter. Without conjunctive billing, demand accumulates as the train passes through each injection point rather than remaining constant along the length of the track.

Our understanding is efforts are underway to have AB 923 amended to provide other California transit agencies the same legislative authority to access the wholesale market; it is unclear if such an effort would cover just Caltrain or both Caltrain and SamTrans. It is our recommendation that Caltrain work with other transit agencies (e.g., CA HSR, LA Metro, VTA) to collectively get this amendment through the legislative process.

FINANCIAL CONSIDERATIONS

Wholesale electricity prices are subject to greater variability over time as the market reacts to real-time supply and demand needs, but on the whole are lower than retail electricity prices since they are also competitive. A wholesale sourcing option for Caltrain would allow for competitive sourcing of renewable electricity and is expected to result in a beneficial cost structure over time. Based on our understanding of the market, a reasonable expectation for electricity spend savings by buying on the wholesale market versus retail contracting (i.e., status quo) is conservatively 10% (see Table 14). It is important to note that these savings will be somewhat offset by the need to engage an entity that will effectively operate as your ESP or to take management of the wholesale market electricity efforts in-house. Either management route will have both real costs, likely including consulting, legal fees, and ESP management fees or additional staff headcount plus it will have a material impact on internal staff time regardless of whether or not the management is out- or in-sourced. These costs are highly specific to the individual project and transaction, but they will be material. It is important to weight the benefits of access to the wholesale market with these costs.

Finally, if a similar legislative exemption is granted for the Caltrain, it would be required to report their energy consumption and source information annually to the Energy Commission.

IMPACT ON OPERATIONS

The impact on electrical service to the Caltrain's operations is similar to the current contracting as PG&E would remain the transmission and delivery provider, and operations would be subject to the uptime and availability of the electric grid.

Due to potential incremental management and transaction costs pursuing the wholesale market is expected to have a material impact on agency finances and staff time, required to manage the demands of procuring and scheduling power through the wholesale market. Some of this management expertise can be outsourced at cost but will still necessitate a central coordinator within the agency.

BARRIERS TO IMPLEMENTATION

A legislative change is needed to pursue this sourcing option. Caltrain would need to identify a bill sponsor, outline the public benefits of this approach and receive approval from the governor.

POLICY CONSIDERATIONS

Consider adopting an Energy Policy to outline the specific benefits that access to the wholesale market would provide to Caltrain and to the public.

Other policy considerations are similar to those in under DA.

RISK ANALYSIS

Legislative action is inherently unpredictable, but the precedent from BART has the potential to streamline this process.

4.1.6 Financial Instruments for Renewable Energy Claims

In the context of Caltrain's procurement strategy, the financial instrument options outlined below are fundamentally aimed at procuring RECs associated and, as such, the options are presented to provide a holistic representation of procuring renewable energy and the associated claims. It is assumed the only reason to potentially engage in either of the two options outlined is if such RECs would qualify for LCFS credits because voluntary renewable energy claims are already covered with procuring electricity from CCAs or through the wholesale market. provided such procurement was from renewable resources.

VIRTUAL POWER PURCHASE AGREEMENT

TECHNOLOGY DESCRIPTION

A PPA is a contractual arrangement between a buyer and a renewable project developer for delivery of renewable energy. These contracts can take on many forms, but the most common is a financial arrangement, often called a Virtual PPA or vPPA. In a vPPA the project developer would build and operate the project and sell the electricity on the wholesale market. The buyer, or offtaker, would guarantee a certain strike price for each MWh of electricity produced by the project. If the wholesale market price is settled above this strike price, then the buyer would receive the difference as a payment. If the wholesale price is settled below the agreed-upon strike price then the buyer would owe the developer for the difference. In exchange, the buyer also receives the environmental benefits from the project, typically RECs.

IMPLEMENTATION

Caltrain would need to engage a developer to identify a specific renewable energy project that it would like to pursue. Typically, this project and developer are identified through an RFP process. Contract terms are negotiated between the buyer and seller, which includes details of REC delivery, financial settlement, and term length of the agreement. Renewable energy delivery would typically begin on the agreed upon Commercial Operation Date (COD) of the project.

Stage 1 – Feasibility Assessment

Caltrain would need to determine if a virtual PPA and educate internal stakeholders on the structure of such deals.

Stage 2 – Project Solicitation

Once the business case has been approved, projects are then typically procured through a competitive Request for Proposals (RFP process) in order to secure offers from potential counterparties. The RFP process would be similar to that of a PPA.

Stage 3 – Contracting

For PPAs (virtual or otherwise), the contracting phase is typically protracted and requires outside legal counsel who has experience in these contracting structures.

Stage 4 – On-going management

Once the project is operating, there will also be the on-going management of invoicing and RECs

FINANCIAL CONSIDERATIONS

Pricing for vPPAs are subject to the agreed upon strike price and contract terms, as well as fluctuation in the market for the settlement price of electricity. Proper terms and financial modeling can result in cost-effective sourcing of RECs from a high quality new renewable energy project. Given virtual PPAs are financial contracts, at times, they can be used to hedge against future energy prices, such a strategy is beyond the scope of this study.

IMPACT ON OPERATIONS

Since a vPPA delivers only RECs, electricity would still need to be contracted and delivered from current retail sources or access to the wholesale market addressed elsewhere in this report.

BARRIERS TO IMPLEMENTATION

Sourcing of a vPPA can be a time-consuming and expensive process, typically taking 12-18 months for identification, data collection, analysis, negotiation, and contracting. Depending on the specific project chosen the COD for the beginning of power production can follow 2 to 5 years after the contract is signed.

POLICY CONSIDERATIONS

The critical policy consideration is likely assuring that any such contracting would provide incremental LCFS revenue. If either agency opts to further explore this path, it is critical to establish these criteria up front with any potential vendors. For example, the RECs would need to qualify under the LCFS program, and each party would need to adhere to the requirements of the program.

RISK ANALYSIS

Virtual PPAs are inherently risky. There is the risk that the generation may not perform as expected due to either weather or operations. There is pricing risk associated with spot-market electricity pricing. There is curtailment risk meaning the buyer may not receive the quantity of RECs anticipated.

ATTRIBUTE PURCHASE AGREEMENT

TECHNOLOGY DESCRIPTION

An Attribute Purchase Agreement (APA) is a contractual arrangement between a buyer and a renewable project developer for delivery of renewable energy attribute certificates, or RECs from the project over a multi-year portion of a project's lifetime. In an APA the project developer would build and operate the project and sell the electricity on the wholesale market. The buyer, or offtaker, would agree to a specific price for a portion of the RECs that are generated from the project over a specified term. The price could be fixed or could escalate over time, and the portion of the project RECs and the term length are variable and are agreed upon by both parties during contract negotiation.

IMPLEMENTATION

SamTrans would need to engage a developer to identify a specific renewable energy project that it would like to pursue. Typically, this project and developer are identified through an RFP process, but an RFP is not necessary. Contract terms are negotiated between the buyer and seller, which includes details of REC delivery, financial settlement, and term length of the agreement. REC delivery would begin on the date agreed upon in the contract.

FINANCIAL CONSIDERATIONS

Pricing for APAs are subject to the agreed upon REC price and contract terms. This structure results in a set price for each REC that the project generates, so it would always result in a cost to the agency, but it provides greater certainty in these costs over time as it is not dependent on fluctuations in energy prices or in the REC commodity market. This differs from a vPPA in that contracting an APA does not expose the buyer to electricity pricing as a vPPA does.

IMPACT ON OPERATIONS

Since an APA delivers only RECs, electricity would still need to be contracted and delivered from current retail sources or access to the wholesale market addressed elsewhere in this report.

BARRIERS TO IMPLEMENTATION

Contracting for an APA is much simpler than a vPPA process since the financial analysis is much more straightforward, but still involves a sourcing effort to identify projects and negotiate a contract. Since projects need to secure an offtaker for electricity in order to support their project financing, it may be more challenging to find a renewable project willing to contract for only the RECs.

POLICY CONSIDERATIONS

Policy considerations are the same as those outlined in the VPA discussion above.

RISK ANALYSIS

The financial risk to the agency is low in an APA, since a typical contract would only require payment for each MWh generated. If the project encounters operational challenges, the agency could be at risk of falling short on the project RECs that it is expecting in a given year which may place them short of a sustainability ambition.

4.2 FINANCING AND REVENUE OPPORTUNITIES

4.2.1 Solar PV and Battery Storage

Financing and revenue opportunities associated with solar PV and BESS are discussed in Section 3.3.

4.2.2 Low Carbon Fuel Standard Credits

California's LCFS program designed to reduce carbon intensity of fuel in California. Caltrain is able to generate credits for the use of low carbon fuels, like electricity or renewable energy, and sell those credits to companies that need to reduce emissions. As a result Caltrain can use LCFS credit to generate revenue. Based on the volume of electricity that will be consumed by those of these systems as it electrifies, the revenue opportunities from monetizing LCFS credits represents millions of dollars in annual recurring revenue. The value of these credits can be increased by Caltrain sourcing their electricity from renewable sources and/or purchasing RECs in similar vintages and volumes. Section 3.2.5 describes the anticipated value of LCFS credits that Caltrain is expected to generate.

4.2.3 Financing Opportunities

The following section discusses some of the financing options for the purchase of the Gilroy BESS, as described in Section 3.3, which was identified by Caltrain staff as the only potentially feasible DER option at this time. This analysis is based on the 2019 annual financial reports provided by the agency. It does not account for the operating and financial impact of the COVID-19 pandemic in the year 2020.

As discussed in the previous sections, direct ownership of the BESS at the Gilroy Station provides the best long-term financial return for JPB, as well as other benefits such as direct control over the asset, retention of RECs and environmental attributes. However, the purchase of the BESS alone does not allow the agency to indirectly leverage some of the federal incentives discussed in this report, such as the ITC, which currently only apply to solar PV or BESS that are charged by solar PV but may apply to stand alone BESS in the future depending on the outcome of legislation to consider this change . As shown in Appendix E, the analysis shows a total initial project cost of $1,417,775. A financing strategy for this initial investment needs to be discussed internally to evaluate which of the following options (alone or combined) fit with the agency's strategic goals and financial constraints:

CASH PURCHASE

The agency could consider purchasing the battery system in cash, to avoid time-consuming financing approval processes and interest costs, however that depends on whether available funds are committed and what internal policies are in place for capital expenditures. A common source of funds includes farebox revenues and potential revenues from other operations, such as property leasing and advertising—and, potentially, taxes. In the context of the 2019 Annual Financial Report for JPB, the initial projects costs for the Gilroy BESS would correspond to about 2.82% of the unrestricted cash and cash equivalents for JPB, which amounted to $50,338,170, as indicated in the 2019 Annual Financial Report, and about 1.26% of the total operating revenues for the fiscal year 2019, which amounted to $112,777,140.

COMMERCIAL LOANS

These include traditional commercial loans as well as concessional loans, which are provided by a financier at flexible lending conditions, such as lower interest rates and/or longer repayment schedules. The emerging finance market for energy storage projects is evolving, with new options still developing in terms of either structures, sizes, or partnerships. JPB can directly approach traditionally preferred lenders and compare the conditions they offer for the BESS financing. Alternatively, some new-to-market lending agencies, such as Culbertson Bonding and IronOak, have been developing their expertise specifically on financing BESSs. The major BESS vendors also developed agreements with lending partners that are familiar with the new technology and the risks that come with it. At the end of fiscal year 2019, the JPB had $55.4 million in outstanding farebox revenue bonds, so the initial projects costs for the Gilroy BESS would correspond to about 2.56% of the total JPB debt. This represents a marginal change in total debt, however it must undergo the agency's approval process for issuing new loans, and it will impact future payments of capital debt, interests, and debt capacity.

FEDERAL, STATE AND LOCAL FINANCIAL INCENTIVES AND SPECIAL LOANS

Caltrain, as a public agency, has the option to explore and leverage a variety of incentives available for solar projects that can greatly reduce the investment's financial burden. These include:

- **U.S. Department of Energy - Loan Guarantee Program:** Under Section 1703, The U.S. Department of Energy (DOE) is authorized to issue loan guarantees for projects with high technology risks that "avoid, reduce or sequester air pollutants or anthropogenic emissions of greenhouse gases; and employ new or significantly improved technologies as compared to commercial technologies in service in the United States at the time the guarantee is issued." Through its Title 17 Innovative Energy Loan Guarantee Program, the Loan Programs Office (LPO) can help finance catalytic, replicable, and market-ready renewable energy and efficient energy technologies with $4.5 billion of available loan guarantees. LPO can provide first-of-a-kind projects and other high-impact, energy-related ventures with access to debt capital that private lenders cannot or will not provide.

  Renewable Energy & Efficient Energy projects must satisfy all four of the following basic eligibility requirements to be considered for the Title 17 Innovative Energy Loan Guarantee Program:

  - Innovative Technology
  - Greenhouse Gas Benefits
  - Located in the United States
  - Reasonable Prospect of Repayment

  LPO has more than $40 billion in remaining loan and loan guarantee authority and is accepting applications under its Innovative Energy Loan Guarantee Program (Title 17). Potential applicants are encouraged to contact LPO for no-fee, no-commitment, pre-application consultations prior to submitting a formal application. Pre-application consultations allow potential applicants to begin a dialogue directly with LPO staff to help LPO learn more about the project and to help ensure that applicants fully understand DOE's requirements and processes.

- **Energy Efficiency Financing for Public Sector Projects:** Cities, counties, public care institutions, public hospitals, public schools and colleges and special districts in California can apply for low-interest loans from the California Energy Commission for energy efficiency projects in their buildings and facilities. Entities eligible for 1% loans include cities, counties and special districts. There is no minimum loan amount, but the maximum loan amount per application is $3 million. The loan term cannot exceed the useful life of loan-funded equipment, and will be determined on a case-by-case basis based on the estimated annual energy cost savings from the projects. The exact loan term will be determined such that the energy savings will cover the loan payments. For a project to be considered, it must have proven energy savings and meet the eligibility requirements of the loan program. Examples of projects include energy generation including renewable energy and combined heat and power projects. The loan can fund 100 percent of the project cost within a 17-year (maximum) simple payback. The loan must be repaid from energy savings (including principal and interest) within a maximum of 20 years. The repayment schedule is based on the estimated annual energy cost savings from the aggregated projects, using energy costs and operating schedules at the time of loan approval. Loans will be amortized on the estimated annual energy cost savings achieved by the loan-funded project. Applicants will be billed twice a year, in June and December, after the projects are completed.

GREEN BONDS

Green bonds have emerged as a new tool over the past decade for the municipal and corporate markets to directly connect environmentally conscious capital market investors with climate action projects. There is no legal definition for a what constitutes a green bond. However, from a credit, structural and legal standpoint, municipal green bonds mirror traditional bonds but are expressly earmarked to raise capital for — or refinance — vital public projects with positive environmental and climate benefits. Globally, green bond issuance increased by 49 percent from 2018 to 2019 with roughly $255 billion in green bonds being issued in 2019. The U.S. alone accounted for a $76 billion, or a 30 percent, share of the global green bond market last year. The type of project that could benefit is wide ranging, including renewable energy, energy efficiency, sustainable waste management, sustainable land use, biodiversity conservation, clean transportation, and clean water projects. Eligible projects and assets relating to solar energy generation also include supporting infrastructure such as energy storage systems. Green bonds generally offer the same returns as other types of bonds. The difference is that green bonds attract new investors who are interested in climate friendly projects funded by all types of companies. JPB can use green bonds as a positive public relations tool. Promoting the use of green bonds demonstrates that an agency is actively engaging in, and delivering on, vital projects that address climate change and keep the community’s health and vitality at the forefront of planning.

The green bond issuance process is similar to that of a regular bond, with an added emphasis on governance, traceability and transparency designed to increase investors’ confidence in the green credential of the bond. When considering issuing a green bond, Caltrain should be aware of the heightened scrutiny of environmental credentials and reputational risks associated with ‘greenwashing’ accusations. However, many issuers, especially repeat green bond issuers, offset this initial cost with the benefits of highlighting their green assets/business, positive marketing story, and diversifying their investor base. Caltrain should review the business case for green bond issuance, consider how it matches with their financing objectives and sustainability strategy, and weigh the benefits against the specific challenges

4.3 ECONOMIES OF SCALE/DISTRICT LEVEL PROCUREMENT

4.3.1 DER Procurement

As discussed in Section 3.3, Caltrain could generate energy cost savings through the deployment of DER. Given the larger size of the of the evaluated SamTrans DER projects, Caltrain is likely to see better pricing on the San Jose project if the project was included in the same procurement process as the SamTrans projects.

4.3.2 Electricity and Renewable Energy Credit Procurement

As highlighted in Section 4.1, the aggregated load after electrification is predominantly based on Caltrain's load. Therefore, Caltrain has the most buying power and all options presented in the study are viable for the agency. Detailed considerations are outlined below. SamTrans is likely to realize additional energy cost savings by jointly procuring energy and/or RECs with Caltrain, which has a much higher load and achieved at a faster scale. Caltrain is not likely to realize additional energy/REC cost savings through joint procurement beyond administrative savings.

Current State

If Caltrain and SamTrans intend to remain with their CCAs, approaching the CCAs as a joint entity may provide a better chance of success in having the CCAs create a bundled product (i.e., electricity plus the associated RECs) that would be compliant in the LCFS program thereby theoretically leading to more LCFS revenue. SamTrans load – and the relatively protracted timeline for electrification – may not be as compelling to, for example, PCE.

Electricity and Renewable Energy Credit Procurement

Whether being granted DA capacity, achieving a legislative amendment and thereby gaining access to the wholesale market, or engaging vendors for a potential REC contracting, there are material transactional and management costs associated with either route. While there will likely be efforts each agency needs to put forth, combining those actions that would be duplicative will streamline the process and minimize costs. For example, the process of running RFPs for a DA ESP or management of the wholesale market access.

4.4 ENVIRONMENTAL IMPACT ANALYSIS

4.4.1 Permitting/regulatory considerations/risks

OFFSITE ENERGY RESOURCES

Utility-scale solar PV and wind power facilities have extensive federal, state, tribal and local environmental permitting requirements. The federal permitting process may include U.S. Army Corp of Engineers (USACE) Section 404 consultation for projects requiring work in navigable waters of the U.S., National Historic Preservation Act (NHPA) Section 106 cultural resource consultation and Section 7 endangered species act consultation. If the project crosses federal lands or involves federal funding, National Environmental Policy Act (NEPA) consultation would also be required. State and local permitting requirements will vary based on location and potential resource impacts. Solar and wind projects are subject to California Environmental Quality Act (CEQA) review. The County will determine the type of environmental review document required – whether the project qualifies under a negative declaration (ND), mitigated negative declaration (MND) or would require a full EIR. The County will also specify the biological, cultural resource, hydrology and visual impact studies that are necessary to evaluate the project. Depending on the type of environmental document required, public review and comment may be required. The County will either adopt the mitigated negative declaration or certify the EIR. The County will also likely need to grant a Conditional Use Permit (CUP) (PlaceWorks, 2017).

Utility-scale projects also require a transmission interconnection study to determine if there is sufficient capacity to integrate the project. Typically additional transmission and distribution infrastructure is needed. The developer or group of developers needing the same infrastructure upgrades are usually responsible for the cost of interconnection. An interconnection agreement is needed between the local IOU, MOU or with CAISO depending on the transmission voltage. There are different interconnection study processes depending on the project size and transmission voltage. The process could take as little as three months for small projects and low transmission voltage and up to two years for larger projects at higher transmission voltage.

The biggest schedule drivers are typically the California CEQA process and the local CUP process. Biological and cultural resources studies will likely be needed as part of the CEQA process and often have seasonal limitations. A project that pursues a MND could complete the permitting process in around 3 years while a project requiring a full EIR may require 4 to 5 years, including biological and cultural resource studies. Permitting risks will vary based on location but could include threatened or endangered species or cultural resource concerns, public opposition. It is likely that projects to Caltrain would be developed in the Central Valley or Antelope Valley. Some jurisdictions also have a Community Benefit Program requiring developers to contribute towards local programs.

Hydroelectric power in California is considered either large hydro (facilities larger than 30 MW) or small hydro (facilities under 30 MW). Hydropower facilities include dams, which raise the water level of a stream or river to achieve the necessary elevation difference; run-of-river, which divert water from a natural channel to a course with a turbine and usually return the water to the channel downstream of the turbine; or pumped storage, which pump water during off-peak demand periods from a reservoir at lower elevation for storage in a reservoir at higher elevation (California Energy Commission, 2021).

Only small hydro plants qualify as renewable energy under the RPS. Large hydropower projects are not counted towards California's RPS because they result in significant impacts to aquatic ecosystems. However, new hydroelectric generation in California is unlikely due to high costs, environmental impacts, and uncertain water availability. If Caltrain were to procure hydroelectric power, it would almost certainly be sourced from an existing hydroelectric facility. For example, PCE currently sources a portion of its renewable energy from four small hydroelectric projects, which were all constructed in the 1980s. The permitting and licensing process for hydroelectric facilities takes years to decades. Even a small hydroelectric project would take longer to permit compared to solar or wind facilities. Any new hydroelectric facilities in California would likely be pumped storage or nascent technologies such as installation of small turbines in agricultural irrigation channels (subject to seasonality and droughts and transmission interconnection) or wastewater treatment plant or water distribution system pipelines.

4.4.2 Onsite Distributed Energy Resources

Onsite distributed solar PV and battery projects require interconnection approval from the electric utility, in this case PG&E, which is received through an application process specific to the program under which the project is designed to operate (i.e. NEM, NEM Aggregation, RES-BCT). In addition, these projects would approvals from the appropriate Authority Having Jurisdiction (AHJ). In some cases, projects may require environmental review under the CEQA, as described in the section above for offsite energy resources.

4.4.3 Land Use, Habitat and Water Quality Impacts

ONSITE DISTRIBUTED ENERGY RESOURCES

Onsite solar and battery systems would have minimal to no land use impacts. Solar PV systems at Caltrain Stations would also be designed as custom parking canopy structures and would not be anticipated to reduce the available number of parking spaces. Battery storage systems would require a minimal footprint on a concrete pad in close proximity to the electric infrastructure.

OFFSITE ENERGY RESOURCES

Offsite solar or wind power procured through a PPA or wholesale energy would require a significant footprint (see Figure 8 and Figure 9 for context). Total land area requirements vary, depending on factors such as the technology used, site topography, and solar intensity. Utility-scale solar PV systems are expected to require approximately 4 to 6 acres per MW for the panels and associated equipment. Unlike wind energy projects, there is more limited opportunities for shared use of the land occupied by solar projects such as agricultural uses. Approximately 360 to 540 acres would be needed to provide enough power to serve SamTrans and Caltrain's combined electric load.

Figure 8. Photo of the 200 MW PCE Write Solar PPA in Mercer County, CA

Figure 9. PCE Buena Vista 38 MW Wind Power Facility

Wind power facilities require more land area compared to solar; however, the footprint of each turbine and the associated infrastructure occupy a small percentage of the total acreage. The total acreage varies considerably depending on site conditions such as topography. According to the National Renewable Energy Laboratory, onshore wind power facilities in the United States range between 30 to 141 acres per MW, but less than 1 acre per MW is permanently disturbed and less than 3.5 acres per MW is temporarily disturbed during construction (Union of Concerned Scientists, 2013a). The land surrounding the turbines can be used for other purposes such as agriculture, recreation and to support other infrastructure. Approximately 2,700 to 12,960 acres would be needed to serve SamTrans and Caltrain's combined load, but the permanently disturbed area would be closer to 90 acres. In addition to habitat loss, wind turbines lead to some level of bird and bat collisions. Proper siting can help to minimize these impacts as well as management techniques such as keeping wind turbines motionless during times of low wind speeds when bat collisions are more likely.

Large hydropower projects require significant amounts of land while small hydropower projects may require as little as 0.25 acre per MW in hilly locations (Union of Concerned Scientists, 2013b). For example, the SF Power Hetch Hetchy Reservoir is approximately 1,972 acres in size and produces around 216[20]. Damming a river to create a reservoir for a large hydropower project results in significant land use and habitat impacts. Initially, this involves flooding land, which may include forestland, agricultural land or vacant land, which destroys wildlife habitat and may also displace or affect residential communities and cultural resources. The dam and reservoir system significantly impact aquatic ecosystems by changing natural water flow and sedimentation processes and altering water temperature and dissolved oxygen levels. These changes alter patterns in plant and animal lifecycles, disrupt and kill fish species, change patterns of trigger increased algal (Union of Concerned Scientists, 2013b). Impacts to water quality and fish passage are the key issues that must be considered during the hydropower licensing process. Mitigation measures can reduce some of these impacts, but the river system will be forever

Small hydroelectric facilities have shorter dams and much smaller reservoir storage space. This reduces impacts to water temperature and dissolved oxygen, which are critical to avoiding or minimizing impacts to aquatic species. Smaller dams also enable easier mitigation of upstream and downstream fish passage. Run-of-river projects are leveraging in-flow so do not rely on reservoirs.

4.4.4 Disposal

Solar PV panels, wind turbines and battery storage systems must ultimately be reused, recycled or disposed of at the end of their useful lifespan. Solar PV panels and wind turbines have a lifespan of about 20 years while lithium-ion batteries have a lifespan of about 10 years. There are currently limited options to recycle any of these technologies. However, end-of-life disposal is a recognized problem in the industry and there is significant investment into developing recycling solutions.

Solar PV panels contain heavy metals that can contaminate soil and water if not properly disposed. A solar PV is typically about 75 percent glass, 10 percent polymer, 8 percent aluminum, 5 percent silicon and 1 percent copper with small amounts of heavy metals in the PV panels or components (silver, tin, lead and other metals such as arsenic, cadmium, chromium, and selenium) (Shaibani, 2020). Lead and tin pose environmental hazards if leached into groundwater. Copper, silver and silicon present good recycling opportunities. Solar PV panels typically have a lifespan of about 20 years. Used solar PV panels are currently characterized as hazardous waste unless the generator tests the material and confirms levels of toxic chemicals that are below hazardous waste regulation thresholds. However, California recently passed legislation (effective January 2021) that allows the State to classify used solar panels as universal waste, which is expected to support solar PV recycling programs (CA DTSC, 2021). There are currently limited (and expensive) recycling

[20] Combined with Cherry Lake and the Lake Eleanor Reservoir, the Hetch Hetchy system generates up to 380.5 MW of large hydroelectric power

opportunities; however, the market for solar PV recycling is expected to be more mature by the time a project initiated by Caltrain would need to be dismantled.

Approximately 90 percent of a wind turbines parts can be recycled or sold (Stella, 2019). However, wind turbine blades, which are constructed of resin and fiberglass and designed to withstand hurricane-force winds and cannot be easily crushed, recycled or repurposed (Martin, 2020). The blades are also difficult to transport to landfills due to their size. Once landfills, the blades are essentially there forever, though they do not leach hazardous chemicals. Current research is evaluating processes to separate resins from fibers or create pellets or boards from the used fiberglass blades. Wind turbine companies are actively looking into solutions to improve the lifecycle sustainability of wind turbines. For example, a new company based in the U.S., Global Fiberglass Solutions, has developed a method that recycles over nearly 100 percent of the blades into pellets and fiber boards. It is likely that the wind turbine recycling industry will be more mature by the time a project initiated by Caltrain would need to be dismantled.

Battery storage systems contain heavy metals such as lithium, cobalt, nickel, and manganese that can contaminate soil and groundwater when landfilled. While many lithium-ion battery materials would be valuable to recover, little recycling occurs today. Those that are recycled are typically smelted in large commercial facilities, which is a very energy intensive process that generates harmful emissions that then need to be treated. The electric vehicle market is driving considerable focus on improving the recyclability of lithium ion batteries. In 2019, the U.S. Department of Energy created a Lithium ion battery recycling R&D center and announced a $5.5 million battery recycling prize.

Under a third-party ownership structure, recycling, repurposing or disposal of the equipment is the responsibility of the owner. Under a cash purchase scenario, Caltrain would be responsible for removal and recycling/disposal.

4.4.5 GHG and Air Quality Impacts

Solar, wind and hydroelectric resources do not emit any GHG emissions or other harmful air emissions during operation. However, there are modest lifecycle GHG emissions associated with mining, manufacturing and transportation associated with these resources. Table 15 identifies the estimated lifecycle GHG emissions associated with renewable energy compared to non-renewable energy (Union of Concerned Scientists, 2013c).

Table 15. Estimated Lifecycle GHG Emissions for Renewable and Non-Renewable Sources

Electricity Source	Lifecycle GHG Emissions (lbs. of CO_2e per kWh)
	Renewable
Wind turbines	0.02 to 0.04

Electricity Source	Lifecycle GHG Emissions (lbs. of CO_2e per kWh)
Solar PV	0.07 to 0.18
Small hydroelectric	0.01 to 0.03
Large hydroelectric	0.06
	Non-Renewable
Natural gas	0.6 to 2
Coal	1.4 to 3.6

Source: Union of Concerned Scientists, 2013c.

As part of Phase 1, the Project Team evaluated estimated GHG emissions associated with Caltrain's retail electricity options through PG&E and CCA programs. Table 3 compares estimated GHG emissions associated with Caltrain's new electric load.

As shown in Table 3, Caltrain would generate approximately 2,811 tCO2e if it were to purchase the default SJCE product (GreenSource). PG&E and the other CCA providers use 100% GHG-free electricity in their base plans. While CCA providers are currently procuring greater amounts of GHG-free and renewable electricity, IOUs like PG&E will need to increase their percentage of renewable sources to meet California's 2045 target of 100% GHG-free electricity (60% of which must be from RPS-eligible sources).

4.5 RISK ANALYSIS AND TRADE-OFF MATRIX AND DECISION FLOW

Table 16 and Table 17 present the primary risks, trade-offs and other considerations for each of the options in this study. Figure 10 illustrates the energy procurement options in a decision tree format.

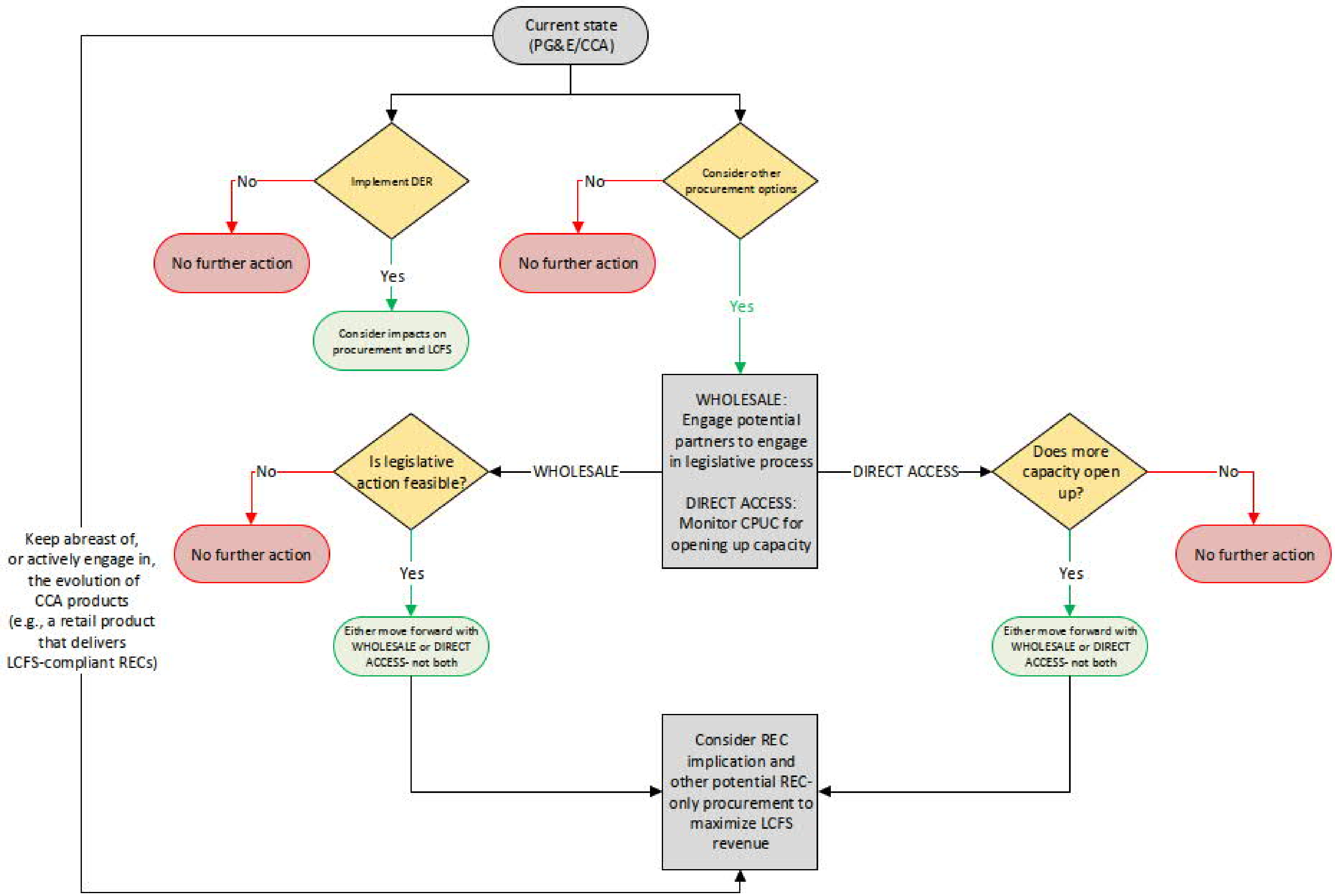
Table 16. Energy Procurement Opportunity Matrix

OPPORTUNITY	TIME HORIZON	LEVEL OF EFFORT	FINANCIAL IMPACTS	ENVIRONMENTAL BENEFIT	LOCAL ECONOMIC BENEFIT	EMERGENCY POWER POTENTIAL
Retail Electricity Options						
PG&E Default	Near-term	Low	$$	🍃		
PG&E 100% Renewable	Near-term	Low	$$$	🍃🍃🍃		
CCA Default	Near-term	Low	$	🍃🍃	✓	
CCA 100% Renewable	Near-term	Low	$$$	🍃🍃🍃	✓	
Direct Access (DA)	Medium-term	High	$-$	🍃🍃🍃	✓	
Purchasing Wholesale Electricity						
Procuring Power on the Wholesale Market	Long-term	High	$-$	🍃🍃		
Wholesale PPA	Long-term	High	$-$	🍃🍃🍃		
On-Site Energy Resources						
Solar PV	Medium-term	Medium	$$$	🍃🍃🍃🍃	✓	✓
Battery Energy Storage	Medium-term	Medium	$$	🍃🍃🍃	✓	✓
Hydrogen	Long-term	High	$$$$	🍃🍃	✓	✓
Other Opportunities						
REC	Near-term	Medium	$	🍃		
LCFS Credits	Near-term	Medium	$$$$	🍃🍃		
Grid Services Programs	Medium-term	Medium	$	🍃		

Table 17. Risk Analysis and Trade-off Matrix

Option	Primary Risks	Trade-offs	Impact on Other Options: how decisions effect acting on other options	Additional Considerations
Current State	Overpaying relative to other options, not maximizing LCFS revenue.	Ease; minimal effort to maintain current contracting.	DA, legislative action, and current state are all relatively mutually exclusive options.	Potential new products that create more LCFS revenue; would need comparative cost analysis.
DER: Solar PV, Batteries, Microgrids	Regulatory changes and/or changes in energy usage at project locations could impact the savings performance from these systems.	Cost savings from avoided electricity costs and avoided costs from REC purchases, revenues earned through emerging grid services programs.	Distributed projects would pair well with each of these additional options.	With the step-down of the ITC and the fast-paced incentive funding draw down for SGIP, procurement of these projects should be prioritized.
Direct Access	Transactional costs with minimal payback; difficult negotiating for LCFS-qualifying RECs.	Ability to potentially spur new renewable energy generation; cost savings v. retail; potentially more lucrative LCFS credit generation.	DA, legislative action, and current state are all relatively mutually exclusive options.	The program is at capacity; seeking capacity at this stage may not be worth the effort; wait until it reopens.
Wholesale market	Significant effort with no guarantee of success; risks associated with being exposed to wholesale trading.	Potential cost savings.	DA, legislative action, and current state are all relatively mutually exclusive options.	This process and the results for BART are mixed; encourage a debrief with BART before exploring deeply.
Financial investment: vPPA	Expensive and risk financial position relative to only receiving RECs.	Long term REC position with potentially more lucrative LCFS credit generation.	All other options, specifically relative to their REC generation impact this option.	Only should be implemented if other sources of potential LCFS revenue are unsuccessful.
Financial investment: APA	Overpaying for RECs in the long term.	Long term REC position with potentially more lucrative LCFS credit generation.	All other options, specifically relative to their REC generation impact this option.	This is a potentially good alternative to buying spot-market RECs for use in the LCFS program.

Figure 10. Energy Procurement Decision Tree



4.6 TIME AND INVESTMENT HORIZON ANALYSIS

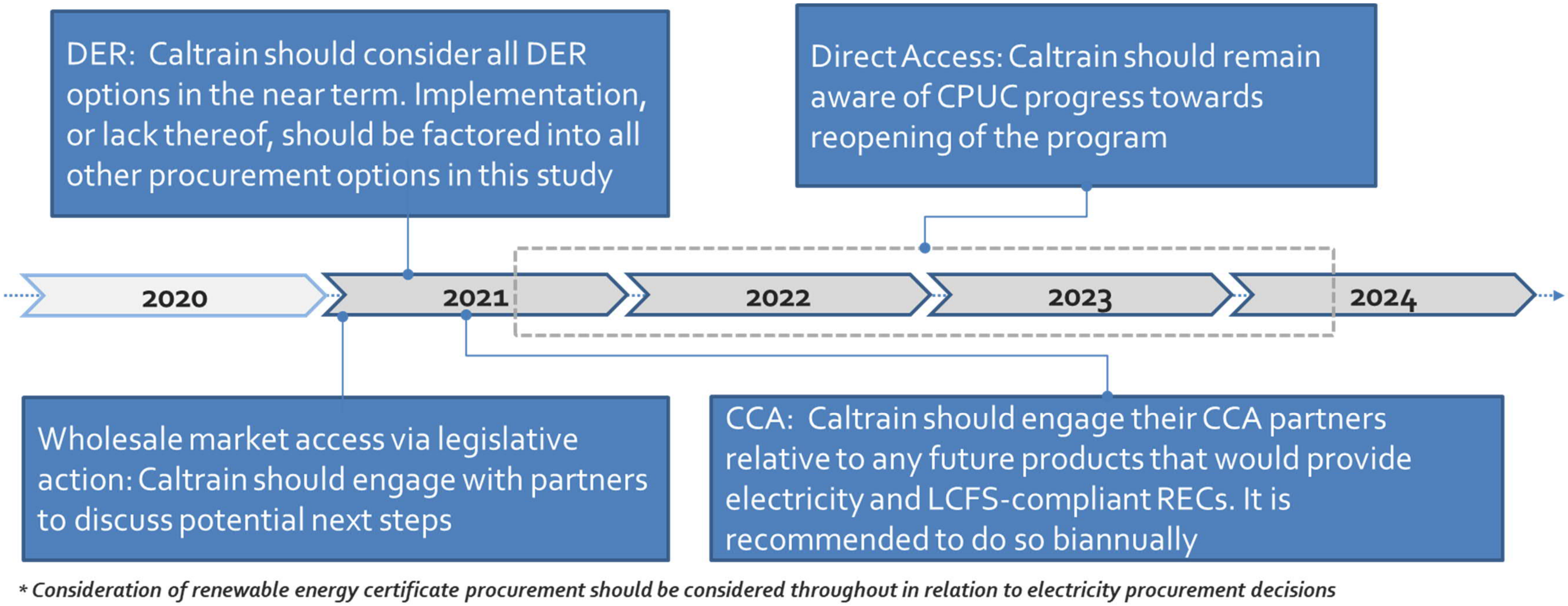
This study evaluates options for Caltrain's energy strategy based on viable options including currently available technologies for electricity generation and potential near-term supply and REC procurement options. Therefore, this study is valid for as long as those options exist. Per the time horizon and decision process map below, the useful life of each of the main three categories of options are:

- *Distributed Energy Resources*: Implementation of DERs remains a viable option in perpetuity, with a couple of important considerations:
  - If Caltrain enters into long-term electricity supply or renewable energy claims contracting, it is important to contemplate existing and/or potential future DER generation as to not lock in more supply than would be necessary.
  - The pricing and technology of DERs changes rapidly, particularly for batteries. Therefore, it is recommended that in the absence of implementing DERs, the DER portion of the study should be revisited every two years or if new federal or state incentive programs are implemented that would significantly affect costs and benefits.
- *Electricity* procurement: The time horizons within which Caltrain should consider revisiting their electricity procurement strategy, based on the options presented herein, are:
  - Status quo and CCA: Given our understanding that the CCAs are currently working to develop new products that could potentially serve the needs of Caltrain's LCFS market participation, it is recommended to revisit current contracting with CCAs on a biannual basis, provided that Caltrain has not left the CCA via gaining access to the wholesale market.
  - Direct Access: Given the complexity of the DA market, associated lottery, and capacity constraints of the program, it is recommended that Caltrain monitor the potential reopening of DA biannually to stay abreast. The CPUC staff report referenced in this study recommends reopening in 2024.
  - Gaining access to the wholesale market via legislative action: The time horizon of this is unknown. It is recommended that Caltrain coordinate with other transit agencies to understand any current efforts and determine at that point if the desire is to collaborate on joint efforts to get the necessary legislation to codify their ability to access the wholesale market. Based on that decision, Caltrain can then determine next steps and the frequency at what they should revisit legislative action.
- REC procurement via financial instruments:
  - These options have been presented in an attempt to provide a holistic picture of the options available, but they are admittedly not options we recommend Caltrain contemplate as a first next step. These options should only be considered when:
    - It is determined to not act on attempting to gain access to DA or the wholesale market.

        - It is clear that the CCAs will not have a bundled electricity plus REC product that satisfies the LCFS program.
        - A long-term supply contract is executed and that contract does not improve the generation of LCFS credits above and beyond the baseline assumptions from the Section 3.2.5 (i.e., LCFS credits are generated based on the standard retail grid mix in California).
    - Therefore, these options should be revisited at the decision points addressed above.

The consideration of relative knowns over the next four years are outlined in Figure 11.

Figure 11. Energy Procurement Time Horizon



4.7 CONCLUSION

As stated in the introduction, electricity procurement is becoming an ever more important component of Caltrain's fuel spend and environmental impacts. How each agency decides to procure that electricity will also have ramifications on revenue opportunities via the participation in California's LCFS market and other programs.

This section has provided an analysis of the medium-term electricity procurement options available to Caltrain categorized into three buckets:

- Electricity procurement, including maintain current state of purchasing through PG&E, CCAs and Municipal Owned Utilities and the additional options of gaining access to the wholesale market through legislative action or via Direct Access,
- Onsite electricity generation, including solar PV, batteries, and microgrids, and
- REC procurement via financial investments in virtual PPAs and APAs.

Key medium-term energy procurement findings and suggestions include:

- **Caltrain should engage its CCA providers relative to any products that would provide electricity and LCFS-compliant RECs:** The CCA providers do not currently offer a product that meets the California Air Resource Board's (CARB's) requirements for zero-carbon fuel sources (which increase the value of LCFS credits). However, PCE could provide bundled product (i.e., electricity plus the associated RECs) that would be compliant in the LCFS program thereby leading to increased LCFS revenue.
- **Caltrain should continue to monitor the Direct Access market:** The DA market is a market in California that allows energy buyers to have choice in their service provider. For example, if a buyer is granted the ability to enter the DA market, they can choose a different ESP than their current options of PG&E and CCAs, the current electricity retail providers for the agencies. DA procurement is likely to result in savings for Caltrain, regardless of whether or not they pursue jointly with SamTrans. DA is only available via a lottery system and the program is currently at capacity. Additional capacity may become available in 2024, but the amount, timing, and process to apply for capacity are all in question. If sufficient capacity is added that could serve Caltrain's anticipated load, it may be worth applying.
- **Caltrain should partner with other California transit agencies (such as CA HSR) to pursue legislation that would enable access to the wholesale market and conjunctive billing:** Though BART was able to gain access to the wholesale market through legislation, the process was very specific to BART's unique circumstances and took many years to finalize. Other California transit agencies have interest in gaining access to the wholesale market as well and have taken steps towards this goal. It will be important to ensure that the legislation is inclusive of 1) existing modes of transit and 2) non-rail transit (for SamTrans).

By pursuing legislation, Caltrain will have the option to switch to wholesale procurement in the future if desired.

- **Caltrain should participate in CPUC, CAISO and PG&E regulatory processes that would affect future electric vehicle rates and access to Direct Access and wholesale energy markets:** The California energy market is complex and dynamic. Caltrain would benefit by actively engaging in the rulemaking process. This is another opportunity to partner with other California transit agencies, particularly those in the Bay Area, who may have similar goals.
- **Access to the wholesale market comes with significant risks:** Wholesale electricity prices are subject to greater variability over time as the market reacts to real-time supply and demand needs, but on the whole are lower than retail electricity prices since they are also competitive. The estimated savings from wholesale procurement will be somewhat offset by the need to engage an entity that will effectively operate as your ESP or to take management of the wholesale market electricity efforts in-house. Either management route will have both real costs, likely including consulting, legal fees, and ESP management fees or additional staff headcount plus it will have a material impact on internal staff time regardless of whether or not the management is out- or in-sourced. It is important to weigh the benefits of access to the wholesale market with these costs.
- **Caltrain and SamTrans would benefit from jointly procuring energy:** If Caltrain elects to pursue onsite DER, unique CCA products or DA, wholesale market, it would benefit from procuring energy with SamTrans to reduce costs and streamline management.

5 EMERGENCY/BACKUP POWER OPTIONS

This section discusses the potential need for emergency power generation for Caltrain once the system is electrified.

5.1 THE CALTRAIN SYSTEM

The Caltrain system after electrification will have an expanded set of assets that require electrical power, including:

- Two traction power substations (TPSS): South San Francisco and San Jose
  - Incoming Power
    - Two 115-kilovolt (kV) transmission feeds
    - Two 60-megavolt-ampere (MVA) transformers
  - Outgoing Power
    - A 25kV 60-hertz (Hz) alternating current (AC) traction power system
  - Seven paralleling stations to boost voltage, no incoming feeds from utility: San Francisco, Brisbane, Burlingame, San Mateo, Redwood City, Palo Alto, Sunnyvale and San Jose
- 32 train stations, which are fed by:
  - Existing PG&E (or other) feeds
  - Low voltage distribution feeds
  - 10kW assumed for most stations
- Tunnel systems: the Caltrain system includes four tunnels, all located between Bayshore Station and San Francisco Station
- Train controls, including: track circuits, wayside signals, interlockings, radio towers, and wayside intrusion devices. Most of the train controls are existing and will be unaffected by the Caltrain electrification project.
  - Most of the train controls are small, less than 1kW. Interlockings require the largest power supplies, 5-10kW
  - Train controls either have their own independent feeds from PG&E or are connected to train station feeds or others

5.2 RATIONALE FOR BACKUP POWER

When transitioning to electric train service, it is important to consider options for power resilience in the event of a sustained power outage, such as climate-related or natural disaster emergency.

Although diesel supply chains were usually not correlated with electrical power outages, new electrified service might be affected. Ensuring dependable delivery of service from an operational standpoint or evacuations of vulnerable populations are of critical concern to a transit agency.

Caltrain must undertake a review of the value of resilience for its infrastructure and operations. It may be possible to monetize backup power infrastructure through reduced insurance premiums, although this would require additional study.

By documenting the risks associated with electric operations, Caltrain will be able to make informed decisions on vital infrastructure and plan holistically for new and emergent technologies.

NATURAL DISASTERS AND EMERGENCY PREPAREDNESS

Caltrain's service area has experienced a number of different disasters over the last 50 years, including numerous earthquakes, floods, droughts, wildfires, energy shortages, landslides, and severe storms. The most significant disaster impacting the district was the Loma Prieta earthquake. Based on a district-wide mitigation plan and instances of past disasters impacting Caltrain (SamTrans, 2010), the most significant hazards to Caltrain's facilities are earthquake shaking and liquefaction, and wildland-urban-interface fire is a secondary concern. Tsunami evacuation planning also needs to be addressed. For instance, the entire district lies along the San Andreas fault, and evacuation planning also must be addressed. Potential natural disasters that Caltrain facilities may be subject to are summarized below.

- Earthquake: None of these facilities are in an Alquist-Priolo Fault Rupture Study Zone. The Caltrain stations are exposed to lower (but still high) levels of shaking. None are in areas of expected earthquake-triggered landslides.
- Tsunamis: No threats of tsunamis to Caltrain infrastructure.
- Flooding: None of these facilities are in the 100-year flood plain.
- Landslides: None of these facilities are in an area of existing landslides.
- Wildfire: None of these facilities are in areas subject to higher than average wildfire threat, but the Menlo Park Caltrain station is in a wildland-urban interface threat area.
- Dam-Failure Inundation: Two Caltrain stations (the Santa Clara and San Jose Diridon stations) are subject to dam inundation.
- Delta Levee Failures: The Caltrain facilities are not in an area protected by a levee or in the Delta.
- Drought: The operations of Caltrain are not significantly impacted by drought conditions.

5.3 POWER RELIABILITY

Power reliability is a vital factor when considering the transition to electric rail. Without an understanding of existing reliability, Caltrain cannot properly understand the value of resiliency and the costs of mitigation.

The CPUC monitors reliability for regulated, investor-owned utilities around the state to ensure performance. CPUC uses four main reliability indices (see Table 18). The Project Team gathered information from CPUC as it relates to PG&E, the local distribution utility. However, Caltrain intends to get power directly from PG&E 110kV transmission lines, which are more reliable than the distribution network.

Table 18. Electric Power Distribution Reliability Indices

INDEX	MEASURE	UNITS
System Average Interruption Duration Index (SAIDI)	Average outage duration per customer	Minutes per outage (per customer)
System Average Interruption Frequency Index (SAIFI)	How often a customer can expect to experience an outage	Number of outages a year (average)
Customer Average Interruption Duration Index (CAIDI)	Average outage duration if an outage is experienced, or average restoration time	Minutes Per Year (per customer)
Momentary Average Interruption Frequency Index (MAIFI)	The frequency of momentary interruptions	Number of instantaneous outages per year (average)

Source: CPUC

5.3.1 PG&E Reliability

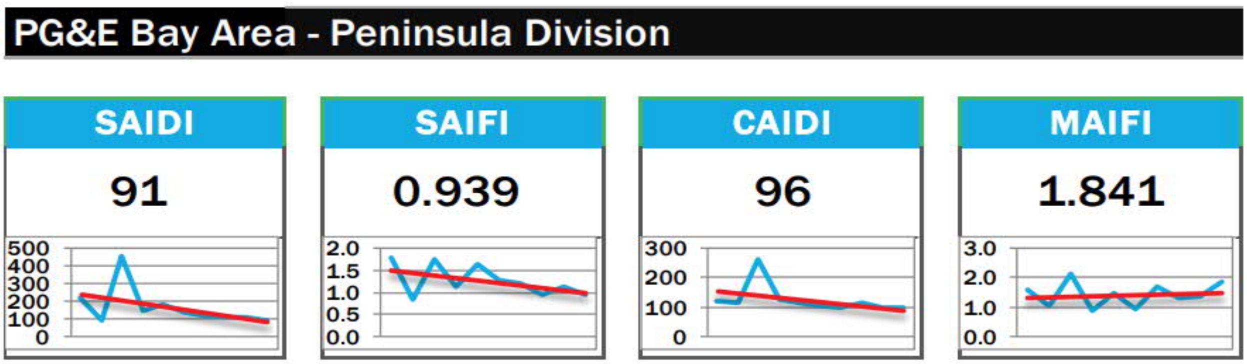
Because reliability metrics oscillate from year to year based on large power outage events, such as the Camp Fire in Paradise, California, in 2018 or the Southwest Blackout of 2011, CPUC generally uses 10-year rolling averages to show improvements over time. After PG&E's transmission lines caused the deadliest fire in California history (the Camp Fire), CPUC and regulated utilities began to implement public safety power shutoffs (PSPS) in fall of 2019. The resulting harm to PG&E's reliability has not been publicly reported yet.

PG&E reliability in the "Peninsula" division (region) is of average performance as measured by the four reliability indices. For all four metrics (Table 18), lower numbers indicate more reliability. For example, if an average outage duration (CAIDI) is experienced, the number represents the number of minutes of the outage, so an outage of only 10 minutes shows a more robust system then an average outage of 45 minutes.

Figure 12 presents metrics for the PG&E Peninsula Division. The left side of each chart is the year 2006, and the end of each chart is the year 2015, when this comprehensive overview was completed. The blue line represents the calculated metric on a year by year basis, while the red line is the 10-year rolling average, which is far more stable than each individual year's data.

Each customer within PG&E's Peninsula Division can expect just less than one power outage per year, and it will probably last an average of 96 minutes (multiplying 0.939 average outages per year * 96 minutes per outage = 91 minutes of average outage minutes per year). Similarly, there are 1.84 momentary outages per year; these, may cause nuisance resetting of electric chargers.

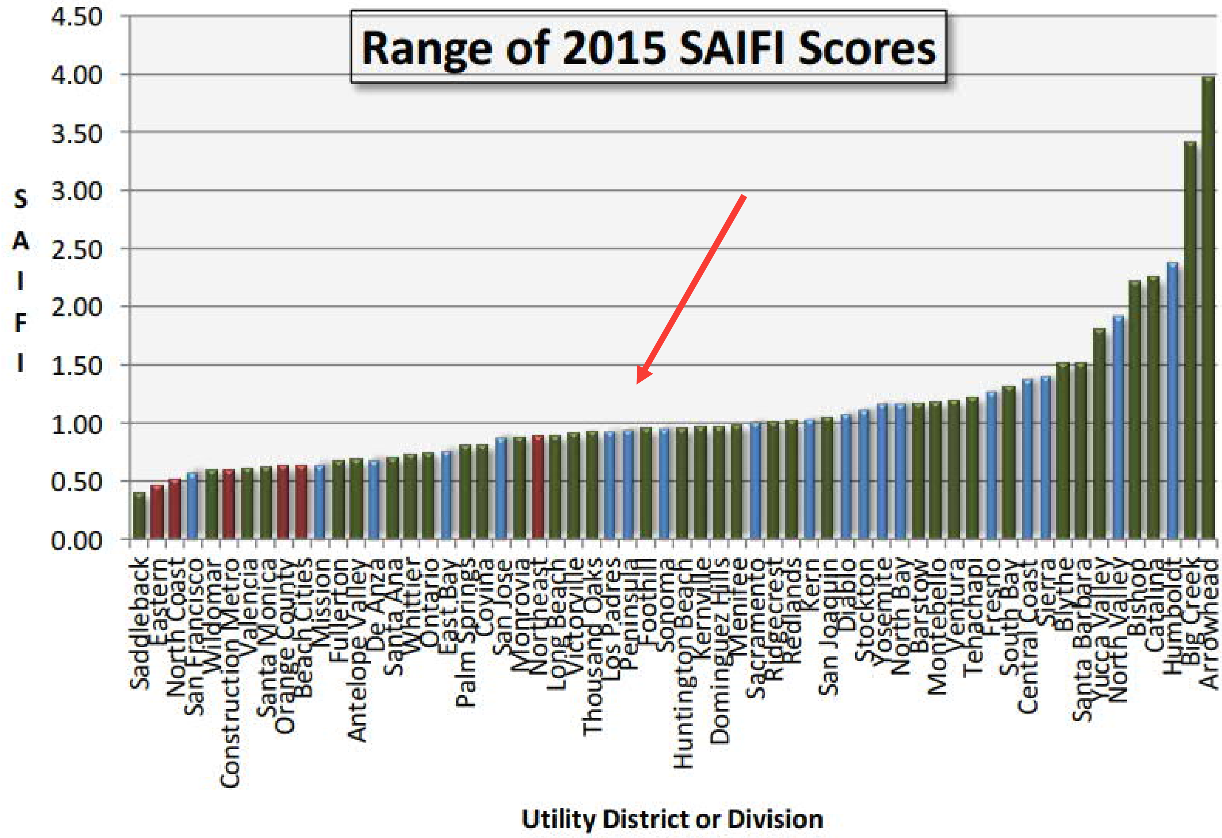
Figure 12. Peninsula Division Metrics (2006-2015)



Source: CPUC

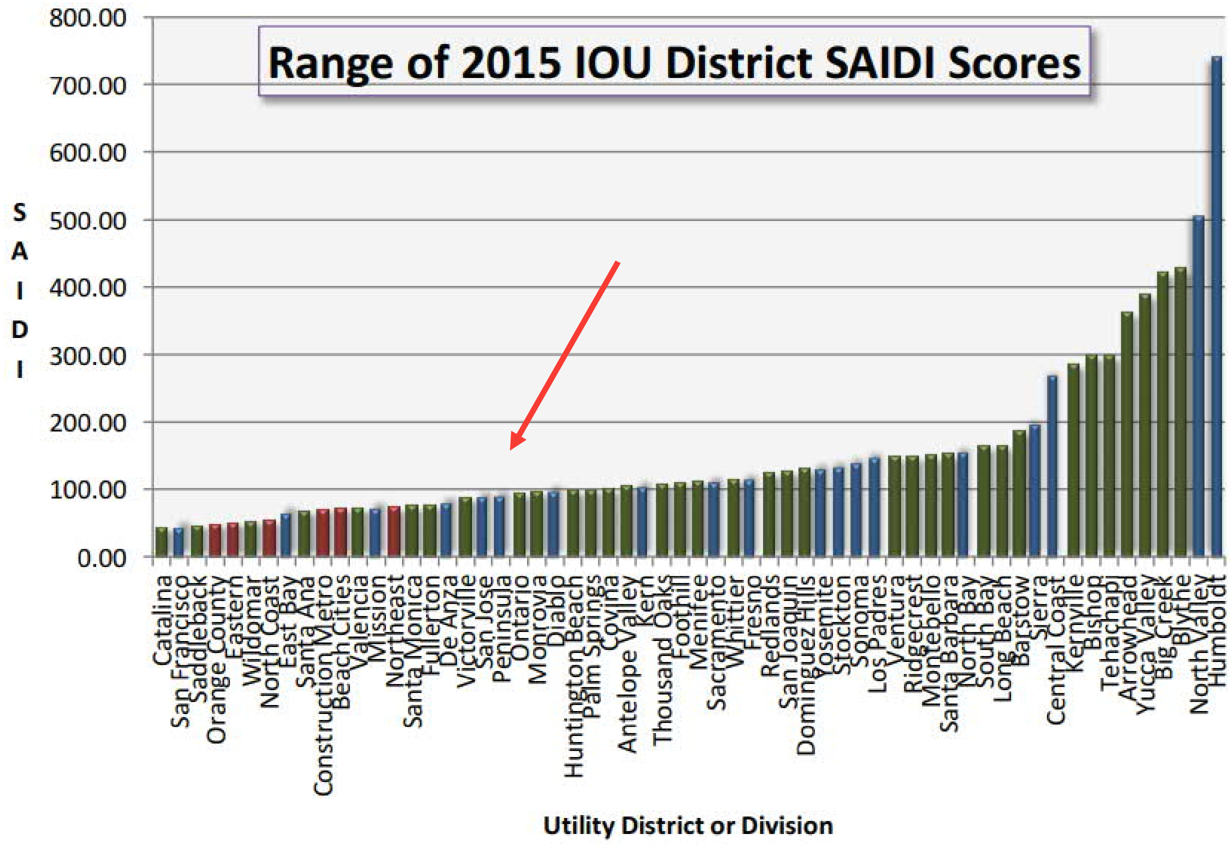
As indicated above, these statistics place PG&E's Peninsula Division squarely in the middle of performance across California, as shown in Figure 13 and Figure 14.

Figure 13. California SAIFI Scores by Utility Division (2006-2015)



Source: CPUC

Figure 14. California SAIDI Score by Utility Division (2006-2015)



Source: CPUC

5.3.2 PG&E Rotating Outages

During times of great stress on the grid, PG&E can enact rolling blackouts to conserve energy (PG&E, n.d.). Although a rare occurrence, this happened during the heat wave in August 2020. PG&E divides its distribution circuits up into blocks and shuts them off for an hour at a time. Essential uses are labeled “Block 50” and are unlikely to be affected by rotating block outages.

Caltrain’s electric rail is already listed on PG&E’s essential uses list as a “rail transit systems as necessary to protect public safety, to the extent exempted by the Commission”; however, it is unclear whether the existing other electrical systems that serve Caltrain are exempted from rotating block outages. A more detailed study of the train stations and signal power sources would be required to confirm.

5.4 BACKUP POWER OPTIONS

The following section outlines potential emergency backup power technologies that could provide Caltrain with adequate supply in the event of an extended disruption or disaster. Potential strategies are broken up as follows:

- TPSS, including paralleling stations and switching station (this is the most critical system)
- Train stations
- Train controls
- Tunnel-specific systems

In addition, this section also describes BART's power supply and backup capabilities.

5.4.1 BART Back Up Power

BART is the geographically closest electrified train system to compare to Caltrain, but has a very different design. PG&E provides high voltage 34.5kV service feeders to 12 switching stations feed the traction power system. The trains run on a third rail with 1,000V DC traction power. BART has no back up power source for their traction power system. In the event of a large scale power outage, the trains will not run. However, with twelve separate switching stations receiving power from PG&E, BART can withstand a power outage at any one switching station.

There are 48 passenger stations which get power from PG&E separately and are not connected to the 1,000VDC traction power system. These stations use a combination of installed and portable diesel generators to keep critical functions during a power outage.

The final component of the BART system is the tunnel fans, radio communications, and other train controls. These also have a combination of installed and portable diesel generators to provide backup power.

The system was stress tested in October 2019 during a large scale PG&E PSPS event. A decision was made to keep all normal service operational during the PSPS event. More than 15 locations received portable generators and more than 30 people staffed the Emergency Operations Center (EOC). Fuel deliveries were coordinated around the clock to ensure generators were operational. Some escalators were shut off to conserve loads, but all stations continued to have elevators, ticket machines, and other normal station functions (Bay Area Rapid Transit, 2019). Figure 15 shows one of the portable generators located next to Rockridge Station.

Figure 15. Portable Generator Adjacent to Rockridge Station

Source: BART, 2021.

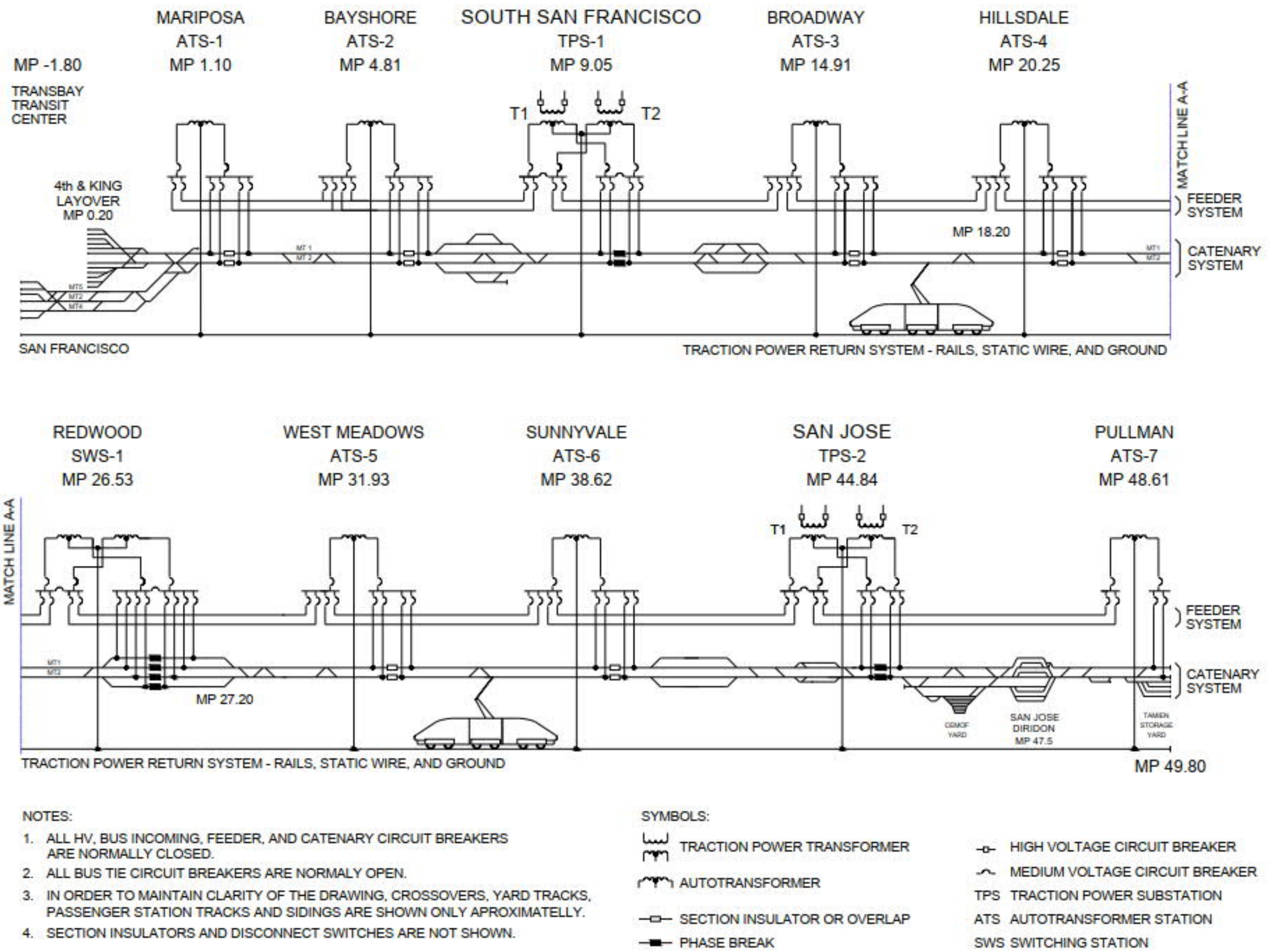
The lesson for Caltrain is that operations can continue during PSPS events as long as traction power is un-interrupted.

5.4.1 Traction Power Substations

The new electrification project uses a standard configuration to get two sets of full redundancy from the local utility. Figure 16 shows the system as designed, including the paralleling substations (also called autotransformer stations), and the switching station at Redwood City. This section of the memo includes recommendations for the following assets:

- Two TPSS: South San Francisco and San Jose
- Seven paralleling stations to boost voltage, no incoming feeds from utility
- One switching station at Redwood City

Figure 16. Caltrain Traction Power System Schematic



Source: LTK Traction Power System Modeling and Simulations (2015)

The electric redundancy provided in the current electrification project works as follows. The South San Francisco TPSS serves the northern half of the electrified tracks, while San Jose serves the southern half. The switching station at Redwood City keeps each half of the system independent during normal operations. Each TPSS has redundant feeds from 2 PG&E 115kV transmission lines and contains 2 fully redundant 60MVA transformers. The expected maximum loads on the transformers are approximately 46MVA.

During abnormal service from either TPSS, Caltrain has the option to close the switching station and feed the entire system from either north or south TPSS, with limited capacity. According to a report by Rail Power Systems, only 4 Caltrain trains per hour can travel under this emergency condition.

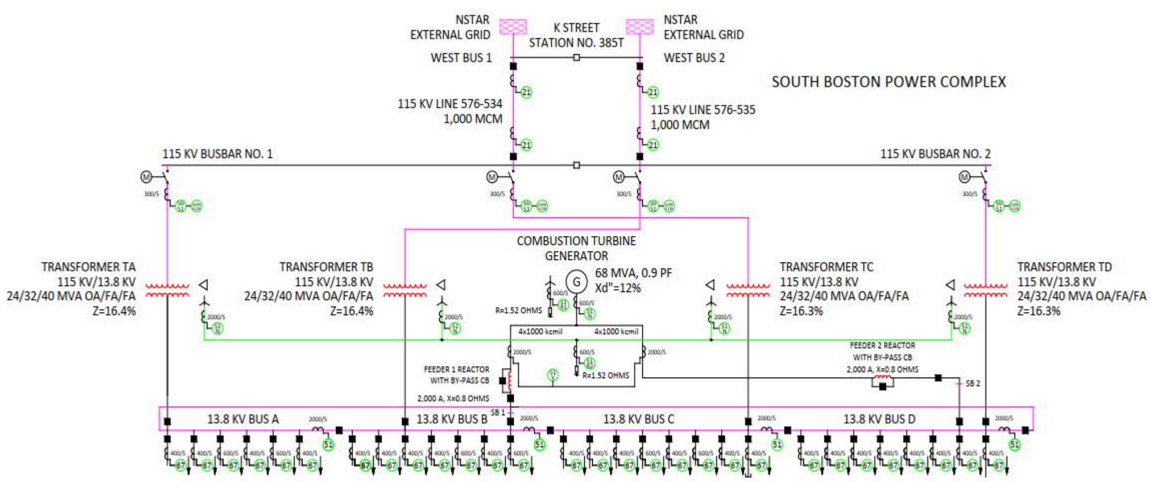
The following three sections of the memo compare the backup power strategies for traction power in three different train systems. Based on our online research and professional experience, most electrified train systems do not have any back up power supplies. Three electric traction power systems were found to have or are planning to install power backup systems and are described below.

MBTA SOUTH BOSTON POWER COMPLEX

The Massachusetts Bay Transportation Authority (MBTA) has owned and operated a backup power plant for its “T system” since the 1960s. The plant consists of two turbines that are rated around 32MW maximum. The backup power plant is on cold standby and can be connected to the microgrid or Eversource (formerly NStar) utility grid as needed. However, due to environmental permitting, the turbines cannot be run as the primary power source throughout the year, but can sell power back to the grid during periods of high demand, as requested by the Independent System Operator-New England.

The electrical feed system from the local utility has a very similar configuration to Caltrain, with two 115kV transmission feeders from Eversource. The main difference is that MBTA only has one main connection to the grid, where Caltrain will have two separate feeder/conversion systems. MBTA drops the power down to 13.8kV voltage and owns its own complex distribution system (Figure 17).

Figure 17. MBTA South Boston Power Complex Single Line Diagram



Source: Rauceo, R. and Kneschke, T. (2014).

The electrified MBTA train system uses 750V DC as the traction power source, which is a different configuration than Caltrain. There are 26 separate traction power substations throughout the MBTA 13.8kV distribution system.

The most important lesson learned from MBTA that can be applied to Caltrain is that, although fossil turbines and other assets can perform adequately for the backup power application, they may no longer be the best choice. A clean power plant would be able to earn revenues throughout the year, without being restricted due to environmental permits.

The site is around 4 acres in size for the turbines, back up oil tank, transformers, and switchgear.

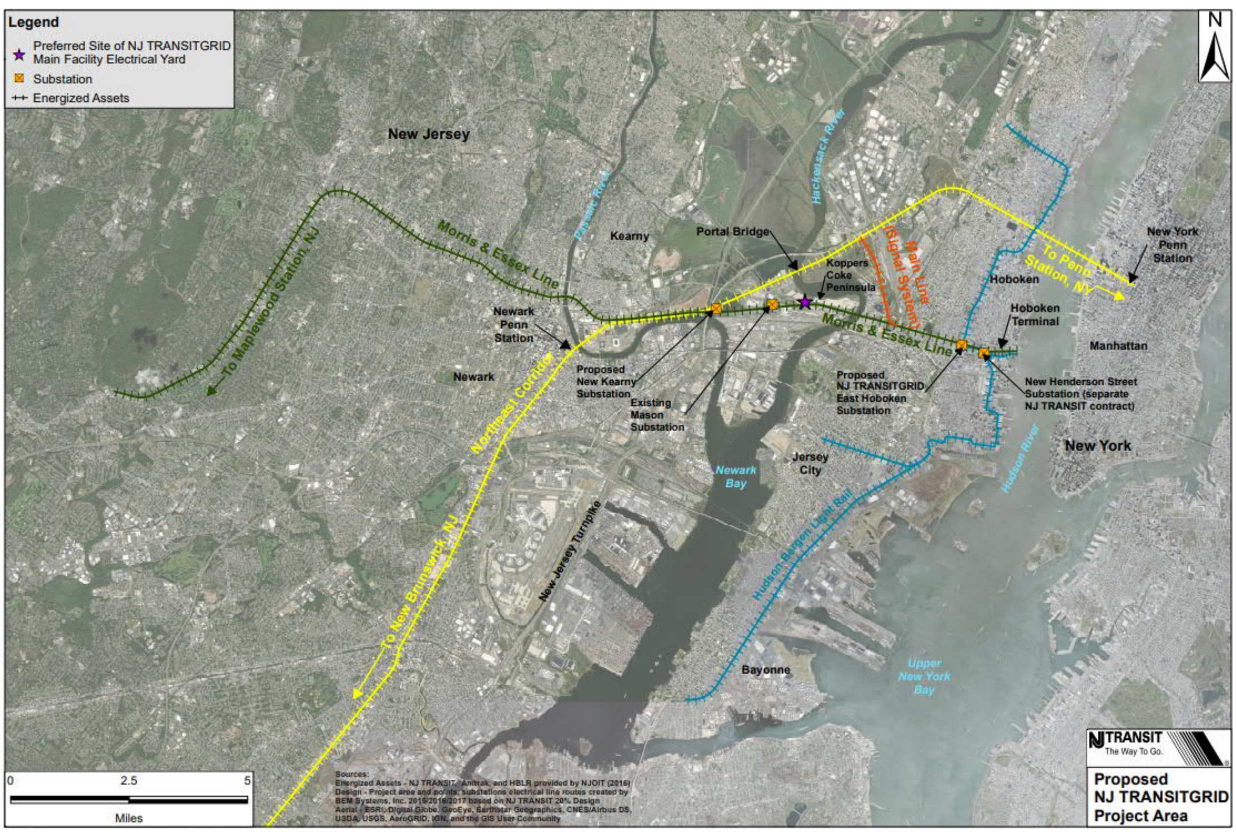
NJ TRANSITGRID PROJECT

NJ Transit was highly impacted by Hurricane Sandy in October 2012, from flooding of buses, to electric outages, to diesel supply line issues. As a result, NJ Transit began to work with Sandia National Lab and others to come up with a set of projects that can enhance resilience for NJ commuters during the next storm or power outage.

The goal of the transitgrid project is to provide resilient power to three separate NJ Transit train lines with three different electrical needs, as well as some signals for the Main Line (Figure 18):

- Northeast Corridor, tracks owned by Amtrak - 138kV 25Hz
- Morris & Essex Line - 25kV 60 Hz (same as Caltrain)
- Hudson Bergen Light Rail Transit System - 750V DC

Figure 18. NJ Transitgrid Map



Source: NJ Transit

The total amount of traction power needed is approximately 140MW. NJ Transit was able to secure a grant from FTA in the Emergency Relief Program in response to Superstorm Sandy for nearly $410M. Total expected costs are currently projected at $577M.

The design included a centralized natural gas fired power plant as well as new transmission lines to key substations though out the systems. However, as per the end of October 2020, NJ Transit announced that it was looking to increase the amount of renewable energy feeding into the resilient power system. This was designed to be more in line with the NJ Energy Master Plan (2019). The final updated design was not determined yet, but is expected to largely rely on solar and batteries for the bulk of the energy supply (Higgs, 2020).

The area required for the centralized natural gas system was 26 acres in total. It is not yet known how much space would be required for the renewable energy solution, but the new plan will require significantly more space.

In addition, the scope also includes separate on-site resilient power generators to key train stations, maintenance facilities, bus garages, and other buildings identified by NJ Transit as key to operations.

CALIFORNIA HIGH SPEED RAIL

The CA HSR Authority has committed to 100% renewable energy. The intent is to build 50 MW solar blocks on parcels of land procured as part of the right-of-way acquisition and use the power generated in a resilient microgrid configuration. These blocks of power would require approximately 250 acres of land each at 5 acres per megawatt. This is far more space than is available for Caltrain in the urban environment. Plans have not been publicly announced yet for this portion of the project.

5.4.2 Wayside Power Storage Systems

Several projects are not designed to provide backup power, but instead provide some energy storage at wayside substations, which has multiple benefits including increased use of regenerative braking and improved acceleration out of the stations. This technology is emerging and could provide additional resilience by lowering the peak energy needs and storing energy during periods of low demand. Several technologies have all been built and operated around the country:

- SEPTA in Philadelphia installed BESSs at nine wayside substations for its 600V DC trolley. This system was funded by private partners and earns revenue from the PJM Reg D Frequency Response BESS market (T&D World, 2016).

- MDOT MTA in Maryland installed ultracapacitors at one substation for its 750V DC light rail. This system was funded by private partners under an energy performance contract (Winslow, 2020).
- LA Metro installed flywheels on two of the subway lines (Morant, 2017).

5.4.3 Train Stations and Other Facilities

The Caltrain train stations are not fed from the electrified traction power system, but instead have existing power independent feeds. Most of the smaller stations are less than 25 kW each for lighting and other loads, but some of the large train stations are significantly larger. Both San Francisco and San Jose have sites that use over 100 kW peak loads.

The train stations are fed from the low-voltage distribution system, mostly owned and operated by PG&E, although some might be on municipal electric utilities. The distribution feeds are less reliable than the transmission system that feeds the traction power substations and should follow the average reliability measurements described in Section 2 of this memo.

Most of the time, backup power is not required for train stations. National Fire Protection Association (NFPA) 130 provides a guide to life safety measures required for subsystems, such as elevators, lights, and fire pumps. Larger train stations may act as a hub for emergency management services, or as a shelter for travelers. Caltrain may want to invest in further backup power options for those train stations similar to the NJ Transit project, which also included some maintenance facilities. Section 3.3 discusses the potential for battery back-up systems at the San Jose, San Francisco and Gilroy Stations.

5.4.4 Train Signals and Controls

Train signals and controls are critical to life safety and are guided by NFPA 130. Train controls include track circuits, wayside signals, interlockings, radio towers, and wayside intrusion devices and either have their own independent feeds from PG&E or are connected to train station feeds.

The CA HSR project has many more remote sets of train controls, which it defines as more than 2.5 miles away from utility power supplies. Although Caltrain is much more urban, the chart shown in Appendix D still provides a good guide to alternative power supplies for train signals and controls.

Solar power and batteries continue to come down in cost and should be re-evaluated as back up supply for small loads, even when in an urban environment. During discussions with Caltrain staff, it was indicated that there are several train crossings that are powered from the local distribution system. Sometimes these lose power and are not currently backed up with batteries, generators, etc., which should be explored further.

5.4.5 Tunnel Backup Power

The Caltrain system includes four tunnels, all located between Bayshore Station and San Francisco Station. These are shown below on Figure 19 and Figure 20.

Figure 19. Caltrain Existing Tunnels

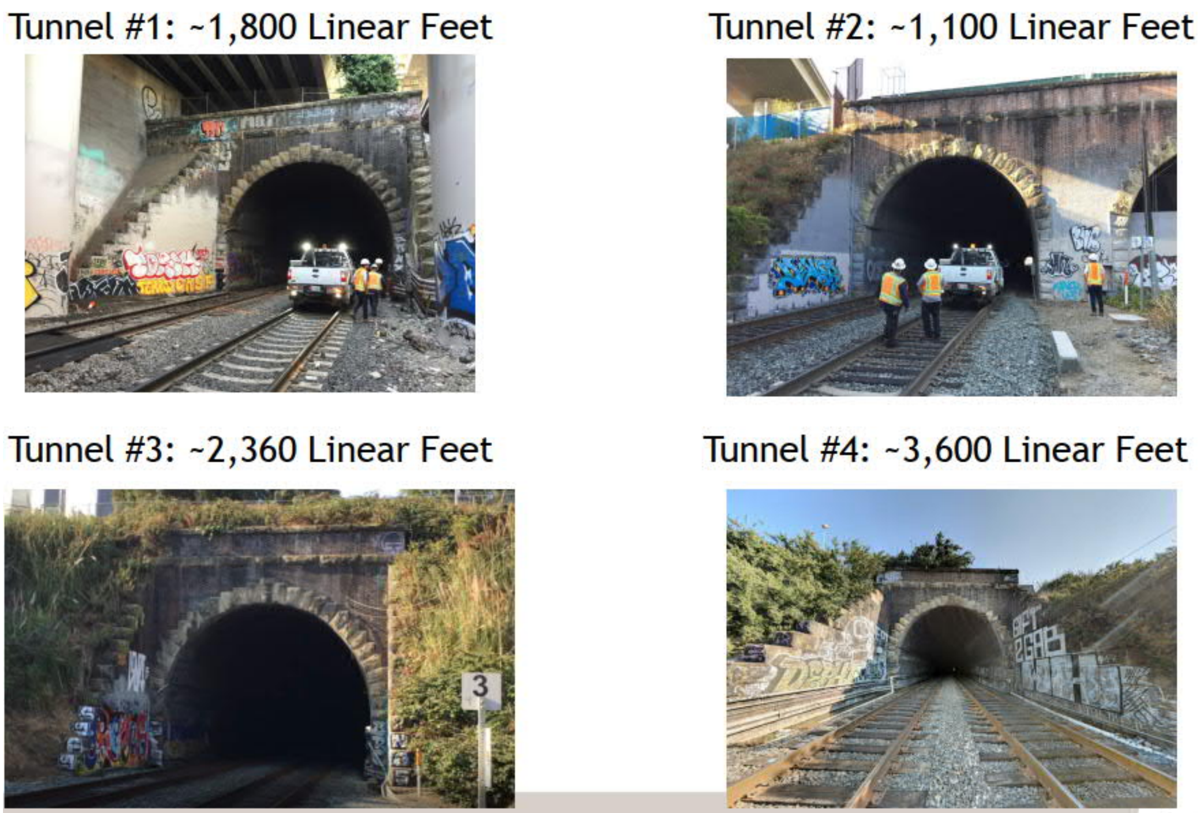


Figure 20. Caltrain Existing Tunnel Locations

As described above, NFPA 130 is required for life safety for all passenger train systems. Specifically within tunnels, lighting and signals will normally be backed up using UPS systems. The following systems may or may not be present and require backup power systems:

- Emergency smoke purge fans to pressurize stairways for emergency evacuations
- Public address systems
- Elevators

5.4.6 Conclusion

The traction power system designed for Caltrain is quite robust and meets all industry best practices. However, it is still vulnerable to a regional large power outage, such as one associated with a sudden and intense earthquake. It is unclear what Caltrain should do in those situations, but it is likely that regular Caltrain service would be suspended during that type of crisis.

Unfortunately, Caltrain does not have the land currently available to provide full backup power of the traction power system, even if powered by fossil fuels. Fossil-fueled infrastructure does take up significantly less land than renewable infrastructure, but also comes with risks of stranded or uneconomic assets.

Caltrain should look further into wayside power storage systems, including batteries and flywheel technologies. They have the potential to increase the use of regenerative braking power, operate the system more effectively (less voltage swings, faster acceleration, etc.), while earning revenue for Caltrain. In addition, they will reduce the needs for large scale back up power from other sources.

The other Caltrain systems should all follow the recommendations for power reliability in NFPA 130. This includes stations, signals, communications, and more. The Project Team recommends Caltrain perform an evaluation of the other systems to make sure that they are prepared for large scale power outages.

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APPENDIX A CALTRAIN TRACTION POWER ENERGY DEMAND ADJUSTMENT

CALTRAIN TRACTION POWER ENERGY DEMAND ADJUSTMENT

As discussed in Section 3.1, the Project Team adjusted the Caltrain demand profile to account for a lower percentage of regenerative energy savings. The methodology used is described below.

Methodology

The regenerative energy savings was removed from the demand values to get a baseline energy demand and compared to the adjusted data in the 2015 LTK Load Flow Report, Appendix F values which was the case of Caltrain only service with regen off. A 15% regen savings factor was then applied to the demand values which is comparable to other 2 x 25 kV systems. Since the samples are over a total runtime of 20 hr and 47 minutes and the samples are taken every second and averaged in 15 min intervals there is a high probability that some of the samples are higher and in some cases lower than actuality given the applied regenerative braking adjustment would not be seen at that particular instance. However, the cumulative energy demand over the total run cycle with the adjusted regenerative savings is valid since the average of the regenerative energy can be reflected in the cumulative demand numbers.

In absence of an updated load flow model that incorporates the Stadler EMU and vehicle regenerative braking characteristics it is recommended that the adjusted demand numbers be used as the current energy demand with regen ON is lower than can be expected during normal revenue operations and does not capture the actual energy savings that can be realized from regenerative braking.

The following is a list of assumptions in regard to the load flow demand study:

- The study will only consider Caltrain service (not CA HSR blended service).
- The study will only evaluate the regenerative braking option.
- The study will be based on the 2015 LTK traction load study, which evaluated electric demand for when 75% of the fleet is converted to EMUs.
    - The study is based on a generic EMU, not the Stadler EMU
    - A generic regenerative braking model was used in the study
    - Regenerative braking was assumed to provide energy savings of approximately 37.2%
    - The schedule detailed in the LTK study for Caltrain is out of sync with the 15 minute interval data (e.g., the load in the interval data file starts at 4:35 AM); we will use the interval data as provided as the source of truth for the initial modeling.
    - The 15-minute interval data provided only covers a typical weekday and does not adjust for seasonal or weekend/holiday variations.

APPENDIX B ELECTRIC ACCOUNT OVERVIEW

The cells highlighted in light blue in Table B-1 indicate accounts where we either could not get a complete year of data from PG&E, or a complete year of data was not available because the account was opened less than a year ago. The cells highlighted in green indicate accounts that should be further investigated because the accounts do not appear to be in active use.

Table B-1: Electric Account Overview

Index	Meter Number	SAID (Service Agreement ID)	Rate Tariff	Annual Consumption (kWh) Feb. 2019-Jan. 2020	Highest Monthly Load (kW) Feb. 2019-Jan. 2020	Demand Charges on Current Rate?
1	1006767578	1293436165	LS3	3,439	N/A	NO
2	1006767626	1293436154	TC1	7,654	N/A	NO
3	1006767519	4623707158	TC1	2,472	N/A	NO
4	1010208408	7284200610	TC1	7,990	N/A	NO
5	1010208410	5797160770	TC1	2,975	N/A	NO
6	1005542361	260896363	TC1	9	N/A	NO
7	1006767478	1293436369	TC1	6,802	N/A	NO
8	1006652567	1293436160	TC1	2,144	N/A	NO
9	1008883790	8440550005	TC1	9,786	N/A	NO
10	1005382987	502468158	TC1	2,119	N/A	NO
11	1008888090	9400025768	TC1	5,177	N/A	NO
12	1008872755	3600605870	TC1	3,839	N/A	NO
13	1006767459	1293436191	TC1	3,504	N/A	NO
14	1008888113	6437786822	TC1	13,178	N/A	NO
15	1009250142	6889621070	TC1	5,783	N/A	NO
16	1008888112	5337461152	TC1	12,384	N/A	NO
17	1008888088	6621217241	TC1	4,515	N/A	NO
18	1010555565	1293436435	A1	3,116	N/A	NO
19	4M5838	1293436457	A1	8,313	N/A	NO
20	5P0146	9111797178	A1	2,233	N/A	NO
21	1010579998	2382971190	A1	7,942	N/A	NO
22	1010580003	2070340127	A-1	3,291	0.8	NO
23	1008993034	5751564849	A-1	2,717	0.4	NO
24	1010280387	4552610271	A-1	33,937	12.4	NO
25	1008999268	1293436265	A-1	12,706	2.9	NO
26	1008887095	452437843	A-1	12,162	12.3	NO
27	1010382692	1293436220	A-1	21,195	4.9	NO
28	1010469462	4553578325	A-1	3,160	0.4	NO
29	1010356816	776309766	A-1	1,319	0.6	NO
30	1008980534	43122525	A-1	5,616	2.1	NO
31	1008795927	5752628645	A-1	9,522	3.2	NO
32	1010288399	9963923221	A-1	6,022	3.2	NO
33	1009968203	1293436609	A-1	173	3.7	NO
34	1010408601	8442870991	A-1	18,745	5.7	NO

Index	Meter Number	SAID (Service Agreement ID)	Rate Tariff	Annual Consumption (kWh) Feb. 2019-Jan. 2020	Highest Monthly Load (kW) Feb. 2019-Jan. 2020	Demand Charges on Current Rate?
35	1010466960	4559881867	A-1	2,024	0.4	NO
36	1010208627	4557297422	A-1	2,968	0.4	NO
37	1010555567	1293436015	A-1	7,463	2.0	NO
38	1010332398	2766823167	A-1	5,265	1.6	NO
39	1010145407	1778944562	A-1	9,224	2.1	NO
40	1008778282	7973267983	A-1	2,595	0.8	NO
41	1010333736	9744092963	A-1	5,822	1.0	NO
42	1009034817	1293436020	A-1	1,563	1.6	NO
43	5000005192	1737291614	A-1	4,273	1.8	NO
44	1010097662	9935462116	A-1	3,023	1.7	NO
45	1006767464	6069076118	A-1-TOU	1,565	1.0	NO
46	1006786565	1293436489	A-1-TOU	30,334	9.8	NO
47	1006528016	4647695064	A-1-TOU	7,970	1.6	NO
48	1005446887	1293436729	A-1-TOU	12,898	4.1	NO
49	1009517896	1293436518	A-1-TOU	3,660	4.8	NO
50	1005382266	7025364417	A-1-TOU	2,844	1.4	NO
51	1005549790	9885130441	A-1-TOU	6,637	2.2	NO
52	1006531868	3616579455	A-1-TOU	3,762	1.1	NO
53	1006759362	1293436314	A-1-TOU	6,910	1.5	NO
54	1006767179	1596555478	A-1-TOU	2,774	1.2	NO
55	1006767547	1233772208	A-1-TOU	3,906	6.3	NO
56	1009661621	1293436113	A-1-TOU	0	0.0	NO
57	1005828848	1293436537	A-1-TOU	29,370	4.8	NO
58	1005382893	1293436548	A-1-TOU	3,931	2.3	NO
59	1009517072	9360756434	A-1-TOU	9,045	4.9	NO
60	1007288286	9303994118	A-1-TOU	1,747	2.1	NO
61	1005382536	1293436765	A-1-TOU	7,305	3.2	NO
62	1005428275	2092604321	A-1-TOU	7,034	3.1	NO
63	1005529194	41495856	A-1-TOU	2,380	0.5	NO
64	1008724050	1293436760	A-1-TOU	5,570	1.5	NO
65	1006758404	2319472137	A-1-TOU	10,066	2.3	NO
66	1005828304	2352092220	A-1-TOU	2,443	1.1	NO
67	1005427547	1293436809	A-1-TOU	910	5.0	NO
68	1006707077	9349520251	A-1-TOU	20,548	22.1	NO
69	1005372996	1293436159	A-1-TOU	2,434	1.4	NO
70	1006727299	9136010298	A-1-TOU	370	11.2	NO
71	1008775894	1293436521	A-1-TOU	7,013	2.4	NO
72	1006729846	1293436049	A-1-TOU	13,013	1.9	NO
73	1010381997	1293436323	A-1-TOU	2	0.0	NO
74	1005382456	1293436819	A-1-TOU	2,414	0.4	NO

Index	Meter Number	SAID (Service Agreement ID)	Rate Tariff	Annual Consumption (kWh) Feb. 2019- Jan. 2020	Highest Monthly Load (kW) Feb. 2019- Jan. 2020	Demand Charges on Current Rate?
75	1005382454	1293436517	A-1-TOU	8,150	1.2	NO
76	1006758702	5718985787	A-1-TOU	6,633	2.4	NO
77	1008817924	1293436023	A-1-TOU	9,926	2.9	NO
78	1006767532	1293436976	A-1-TOU	3,297	1.4	NO
79	1006758131	8869195870	A-1-TOU	2,354	1.0	NO
80	1006528515	7980138350	A-1-TOU	6,981	3.1	NO
81	1006526718	292016465	A-1-TOU	5,693	2.1	NO
82	1008698132	423352474	A-1-TOU	2,973	0.8	NO
83	1009130314	1293436298	A-1-TOU	5,571	1.3	NO
84	1009077581	1293436206	A-1-TOU	431	0.2	NO
85	1009169132	7616356837	A-1-TOU	3,964	0.6	NO
86	1010579784	5751564634	A-1-TOU	5,222	1.4	NO
87	1005447198	1293436634	A-1-TOU	1,760	1.3	NO
88	1006758567	848285961	A-1-TOU	2,846	0.7	NO
89	1006767135	209772704	A-1-TOU	363	1.0	NO
90	1009856640	5168859377	A-1-TOU	36,955	11.2	NO
91	1005383119	1293436484	A-1-TOU	5,587	4.6	NO
92	1005428259	9267959434	A-1-TOU	33,220	9.4	NO
93	1006767114	1293436965	A-1-TOU	5,145	1.3	NO
94	1006767470	1961160076	A-1-TOU	6,061	1.5	NO
95	1006767593	1293436672	A-1-TOU	1,829	0.8	NO
96	1004472536	1293436036	A-1-TOU	0	0.0	NO
97	1005428779	8581704782	A-1-TOU	2,723	0.6	NO
98	1005428234	1293436189	A-1-TOU	2,977	0.9	NO
99	1006767446	7616356592	A-1-TOU	0	0.0	NO
100	1009275034	7616356293	A-1-TOU	0	0.0	NO
101	1005446569	1293436689	A-1-TOU	2,882	1.4	NO
102	1005447204	2178337696	A-1-TOU	2,022	1.6	NO
103	1008922888	8479612659	A-1-TOU	3,591	1.2	NO
104	1010348826	5756253498	A-1-TOU	8,605	4.2	NO
105	1005529752	3305181364	A-1-TOU	3,968	1.3	NO
106	1005382939	1297587432	A-1-TOU	6,213	1.5	NO
107	1006768055	5039253980	A-1-TOU	5,687	1.5	NO
108	1009285216	1293436194	A-1-TOU	7,051	2.5	NO
109	1006483857	1293436178	A-1-TOU	11	0.1	NO
110	1006527100	3578012254	A-1-TOU	2,532	0.8	NO
111	1009190761	2847057957	A-1-TOU	1,114	0.8	NO
112	1005383168	292016743	A-1-TOU	1,815	1.1	NO
113	1006767530	1717382926	A-1-TOU	2,032	0.8	NO
114	1006767627	1293436257	A-1-TOU	5,944	2.2	NO

Index	Meter Number	SAID (Service Agreement ID)	Rate Tariff	Annual Consumption (kWh) Feb. 2019- Jan. 2020	Highest Monthly Load (kW) Feb. 2019- Jan. 2020	Demand Charges on Current Rate?
115	1006767028	1293436732	A-1-TOU	55	0.0	NO
116	1006767026	6582523760	A-1-TOU	2,421	0.6	NO
117	1006767165	1293436704	A-1-TOU	1,303	0.3	NO
118	1008678733	7616356187	A-1-TOU	5,005	1.1	NO
119	1009077720	1428067137	A-1-TOU	12,383	2.9	NO
120	1005428260	1293436322	A-1-TOU	1,641	0.8	NO
121	1006767709	1293436019	A-1-TOU	637	0.1	NO
122	1006767546	7517379118	A-1-TOU	2,418	0.9	NO
123	1005428254	3397012401	A-1-TOU	3,884	1.3	NO
124	1010581927	1293436588	A-1-TOU	0	0.0	NO
125	1006759328	1293436872	A-1-TOU	2,070	0.8	NO
126	1006767697	1293436769	A-1-TOU	2,403	0.8	NO
127	1009288395	5249520333	A-1-TOU	0	0.0	NO
128	1007139008	1293436898	A-1-TOU	0	0.0	NO
129	1005446164	4552324955	A-1-TOU	31,591	7.8	NO
130	1005428525	1293436739	A-1-TOU	7,845	3.0	NO
131	1005529208	650794714	A-1-TOU	8,190	2.0	NO
132	1006767117	1293436568	A-1-TOU	7,214	1.6	NO
133	1008695803	4383293771	A-1-TOU	3,259	4.5	NO
134	1009661311	2538415392	A-1-TOU	0	0.0	NO
135	1006767586	2473747687	A-1-TOU	5,152	2.3	NO
136	1010576196	9744092683	A-1-TOU	13,852	3.1	NO
137	1006766947	7681075064	A-1-TOU	760	0.2	NO
138	1009314038	1293436983	A-1-TOU	11,924	3.6	NO
139	1009606036	3865426092	A-1-TOU	29,654	7.6	NO
140	1005529243	1293436790	A-1-TOU	6,220	1.7	NO
141	1010127999	4550888824	A-6	46,152	11.2	NO
142	1010283786	1832904139	A-10-TOU-P	562,668	197.3	YES
143	1010239054	5347339954	A-10-TOU-P	112,349	134.4	YES
144	1010124825	4552324646	E-19-P-V	116,798	468.0	YES
145	1007074343	1837233652	E-19-P-V	1,861,262	412.8	YES
146	1010058983	4552324771	E-19-S-V	112,585	30.2	YES
147	1005428504	1293436638	E-19-S-V	95,416	21.6	YES
148	1006727549	1293436182	E-19-S-V	708,659	132.8	YES
149	1003873311	4552324421	E-19-S-V	85,099	25.3	YES
150	5000118675	8356183296	E-19-S-V	296,165	63.4	YES
151	1010057385	4552324506	E-19-S-V	46,443	7.4	YES
152	1010124628	4552324834	E-19-S-V	83,182	33.0	YES
153	1009776784	4552324757	E-19-S-V	66,169	15.5	YES

Index	Meter Number	SAID (Service Agreement ID)	Rate Tariff	Annual Consumption (kWh) Feb. 2019- Jan. 2020	Highest Monthly Load (kW) Feb. 2019- Jan. 2020	Demand Charges on Current Rate?
154	1010018923	4552324481	E-19-S-V	254,741	618.2	YES
155	1006910794	4552324080	E-19-S-V	188,554	41.3	YES
156	1010125033	9586677599	E-19-S-V	67,299	43.5	YES
157	1010126669	4557236278	E-19-S-V	215,930	78.2	YES
158	1006767598	4552324686	E-19-S-V	71,455	20.9	YES
159	1006767501	4552324032	E-19-S-V	67,722	16.8	YES
160	1009848674	4552324168	E-19-S-V	62,866	18.4	YES
161	1010086814	4552324228	E-19-S-V	570,927	117.6	YES
			Total:	**6,565,466**		

APPENDIX C HISTORICAL RATE ANALYSIS

HISTORICAL RATE ANALYSIS

Meters highlighted in yellow would yield savings if switched to the identified ideal rates.

		CURRENT TOU RATES AND COSTS PER CURRENT BILLS					CURRENT TOU IDEAL RATES & COSTS					NEW TOU PROJECTED RATES AND COSTS					NEW TOU IDEAL RATES & COSTS				
SAID	Meter #	PG&E Rate	Bundled PG&E Costs	PG&E Solar Choice Costs	PG&E + CCA Default Rate Costs	PG&E + CCA Costs (100% clean)	PG&E Rate	Bundled PG&E Costs	PG&E Solar Choice Costs	PG&E + CCA Default Rate Costs	PG&E + CCA Costs (100% clean)	PG&E Rate	Bundled PG&E Costs	PG&E Solar Choice Costs	PG&E + CCA Default Rate Costs	PG&E + CCA Costs (100% clean)	PG&E Rate	Bundled PG&E Costs	PG&E Solar Choice Costs	PG&E + CCA Default Rate Costs	PG&E + CCA Costs (100% clean)
2070340127	1010580003	A-1	$930	$946	$923	$947	A-1-TOU	$922	$938	$915	$939	B-1	$930	$945	$923	$948	B-6	$901	$917	$895	$919
5751564849	1008993034	A-1	$790	$803	$784	$804	A-1-TOU	$783	$796	$777	$798	B-1	$789	$802	$784	$804	B-6	$766	$779	$760	$781
4552610271	1010280387	A-1	$8,554	$8,717	$8,477	$8,732	A-1-TOU	$8,250	$8,413	$8,184	$8,438	B-1	$8,457	$8,620	$8,390	$8,644	B-6	$8,110	$8,273	$8,045	$8,299
1293436265	1008999268	A-1	$3,237	$3,298	$3,209	$3,305	A-1-TOU	$3,210	$3,271	$3,183	$3,278	B-1	$3,240	$3,301	$3,214	$3,309	B-6	$3,131	$3,192	$3,106	$3,202
452437843	1008887095	A-1	$3,048	$3,107	$3,017	$3,114	A-1-TOU	$3,040	$3,099	$3,009	$3,107	B-1	$3,099	$3,157	$3,068	$3,165	B-6	$2,991	$3,049	$2,962	$3,059
1293436220	1010382692	A-1	$5,408	$5,510	$5,425	$5,637	A-1-TOU	$5,337	$5,438	$5,354	$5,566	B-1	$5,375	$5,477	$5,393	$5,605	B-6	$5,182	$5,284	$5,199	$5,411
4553578325	1010469462	A-1	$894	$909	$897	$928	A-1-TOU	$886	$901	$888	$920	B-1	$895	$910	$898	$929	B-6	$868	$883	$871	$902
776309766	1010356816	A-1	$440	$446	$436	$447	A-1-TOU	$439	$445	$436	$446	B-1	$442	$448	$439	$449	B-6	$432	$438	$428	$439
43122525	1008980534	A-1	$1,505	$1,532	$1,493	$1,535	A-1-TOU	$1,495	$1,522	$1,483	$1,525	B-1	$1,505	$1,532	$1,494	$1,536	B-6	$1,453	$1,480	$1,442	$1,484
5752628645	1008795927	A-1	$2,471	$2,517	$2,450	$2,522	A-1-TOU	$2,451	$2,497	$2,430	$2,502	B-1	$2,469	$2,515	$2,450	$2,521	B-6	$2,382	$2,427	$2,363	$2,435
9963923221	1010288399	A-1	$1,597	$1,626	$1,575	$1,636	A-1-TOU	$1,586	$1,615	$1,565	$1,625	B-1	$1,602	$1,631	$1,580	$1,641	B-6	$1,552	$1,581	$1,531	$1,591
1293436609	1009968203	A-1	$159	$160	$159	$160	A-1	$159	$160	$159	$160	B-1	$162	$162	$161	$162	B-6	$161	$161	$160	$162
8442870991	1010408601	A-1	$4,725	$4,815	$4,658	$4,845	A-1-TOU	$4,694	$4,784	$4,628	$4,816	B-1	$4,733	$4,823	$4,665	$4,853	B-6	$4,571	$4,661	$4,506	$4,693
4559881867	1010466960	A-1	$615	$625	$617	$637	A-1-TOU	$607	$617	$609	$629	B-1	$616	$626	$618	$638	B-6	$599	$609	$601	$621
4557297422	1010208627	A-1	$850	$864	$852	$882	A-1-TOU	$839	$853	$842	$871	B-1	$849	$863	$852	$881	B-6	$822	$837	$825	$855
1293436015	1010555567	A-1	$1,950	$1,986	$1,923	$1,998	A-1-TOU	$1,937	$1,973	$1,911	$1,986	B-1	$1,955	$1,991	$1,928	$2,003	B-6	$1,892	$1,928	$1,866	$1,941
2766823167	1010332398	A-1	$1,413	$1,438	$1,394	$1,447	A-1-TOU	$1,407	$1,432	$1,388	$1,441	B-1	$1,418	$1,443	$1,398	$1,451	B-6	$1,373	$1,398	$1,355	$1,407
1778944562	1010145407	A-1	$2,351	$2,395	$2,319	$2,411	A-6	$2,201	$2,245	$2,174	$2,266	B-1	$2,355	$2,399	$2,323	$2,415	B-6	$2,263	$2,307	$2,232	$2,324
7973267983	1008778282	A-1	$755	$767	$746	$772	A-1-TOU	$753	$765	$744	$770	B-1	$759	$772	$750	$776	B-6	$738	$750	$729	$755
9744092963	1010333736	A-1	$1,558	$1,586	$1,563	$1,621	A-1-TOU	$1,544	$1,572	$1,549	$1,607	B-1	$1,555	$1,583	$1,560	$1,618	B-6	$1,504	$1,532	$1,509	$1,567
1293436020	1009034817	A-1	$504	$512	$499	$514	A-1-TOU	$501	$509	$496	$511	B-1	$504	$512	$499	$514	B-6	$492	$499	$486	$502
1737291614	5000005192	A-1	$1,202	$1,223	$1,186	$1,228	A-1-TOU	$1,192	$1,213	$1,176	$1,219	B-1	$1,209	$1,229	$1,192	$1,235	B-6	$1,159	$1,179	$1,143	$1,185
9935462116	1010097662	A-1	$873	$888	$862	$892	A-1-TOU	$868	$882	$857	$887	B-1	$874	$889	$863	$894	B-6	$843	$857	$832	$862
6069076118	1006767464	A-1-TOU	$503	$510	$497	$513	A-1-TOU	$503	$510	$497	$513	B-1	$506	$514	$500	$516	B-6	$493	$500	$487	$503
1293436489	1006786565	A-1-TOU	$7,337	$7,483	$7,241	$7,544	A-6	$7,293	$7,438	$7,194	$7,497	B-1	$7,523	$7,669	$7,417	$7,720	B-6	$7,188	$7,334	$7,086	$7,389
4647695064	1006528016	A-1-TOU	$2,059	$2,097	$2,038	$2,102	A-1-TOU	$2,059	$2,097	$2,038	$2,102	B-1	$2,077	$2,115	$2,057	$2,121	B-6	$2,009	$2,047	$1,990	$2,053
1293436729	1005446887	A-1-TOU	$3,203	$3,265	$3,161	$3,290	A-1-TOU	$3,203	$3,265	$3,161	$3,290	B-1	$3,289	$3,351	$3,243	$3,372	B-6	$3,149	$3,211	$3,105	$3,234
1293436518	1009517896	A-1-TOU	$1,013	$1,030	$1,005	$1,032	A-1-TOU	$1,013	$1,030	$1,005	$1,032	B-1	$1,021	$1,038	$1,013	$1,041	B-6	$988	$1,006	$981	$1,009
7025364417	1005382266	A-1-TOU	$816	$830	$806	$834	A-1-TOU	$816	$830	$806	$834	B-1	$822	$836	$812	$840	B-6	$797	$810	$787	$815
9885130441	1005549790	A-1-TOU	$1,740	$1,772	$1,723	$1,776	A-1-TOU	$1,740	$1,772	$1,723	$1,776	B-1	$1,758	$1,790	$1,741	$1,794	B-6	$1,700	$1,731	$1,683	$1,736
3616579455	1006531868	A-1-TOU	$1,042	$1,060	$1,029	$1,067	A-1-TOU	$1,042	$1,060	$1,029	$1,067	B-1	$1,051	$1,069	$1,037	$1,075	B-6	$1,018	$1,036	$1,004	$1,042
1293436314	1006759362	A-1-TOU	$1,781	$1,814	$1,758	$1,827	A-1-TOU	$1,781	$1,814	$1,758	$1,827	B-1	$1,829	$1,862	$1,804	$1,873	B-6	$1,757	$1,790	$1,733	$1,802
1596555478	1006767179	A-1-TOU	$802	$815	$792	$820	A-1-TOU	$802	$815	$792	$820	B-1	$812	$826	$802	$830	B-6	$784	$798	$774	$802
1233772208	1006767547	A-1-TOU	$1,072	$1,091	$1,059	$1,098	A-1-TOU	$1,072	$1,091	$1,059	$1,098	B-1	$1,082	$1,101	$1,068	$1,107	B-6	$1,049	$1,067	$1,035	$1,074
1293436113	1009661621	A-1-TOU	$120	$120	$120	$120	A-1	$120	$120	$120	$120	B-1	$120	$120	$120	$120	B-1	$120	$120	$120	$120
1293436537	1005828848	A-1-TOU	$7,241	$7,382	$7,166	$7,401	A-1-TOU	$7,241	$7,382	$7,166	$7,401	B-1	$7,396	$7,537	$7,320	$7,555	B-6	$7,127	$7,268	$7,054	$7,289
1293436548	1005382893	A-1-TOU	$1,082	$1,101	$1,068	$1,107	A-1-TOU	$1,082	$1,101	$1,068	$1,107	B-1	$1,089	$1,108	$1,075	$1,114	B-6	$1,055	$1,074	$1,041	$1,080
9360756434	1009517072	A-1-TOU	$2,290	$2,333	$2,271	$2,338	A-1	$2,245	$2,289	$2,228	$2,295	B-1	$2,297	$2,341	$2,280	$2,348	B-6	$2,239	$2,283	$2,223	$2,291
9303994118	1007288286	A-1-TOU	$539	$547	$532	$550	A-1	$527	$536	$522	$539	B-1	$541	$550	$535	$553	B-6	$530	$539	$524	$542
1293436765	1005382536	A-1-TOU	$1,887	$1,922	$1,862	$1,935	A-1-TOU	$1,887	$1,922	$1,862	$1,935	B-1	$1,911	$1,946	$1,884	$1,958	B-6	$1,845	$1,880	$1,820	$1,893
2092604321	1005428275	A-1-TOU	$1,836	$1,870	$1,811	$1,882	A-1-TOU	$1,836	$1,870	$1,811	$1,882	B-1	$1,854	$1,888	$1,829	$1,899	B-6	$1,794	$1,828	$1,769	$1,840
41495856	1005529194	A-1-TOU	$701	$713	$693	$717	A-1-TOU	$701	$713	$693	$717	B-1	$708	$719	$699	$723	B-6	$687	$699	$679	$703
1293436760	1008724050	A-1-TOU	$1,436	$1,463	$1,426	$1,467	A-6	$1,387	$1,414	$1,378	$1,419	B-1	$1,483	$1,510	$1,472	$1,514	B-6	$1,427	$1,453	$1,416	$1,458
2319472137	1006758404	A-1-TOU	$2,568	$2,616	$2,542	$2,622	A-1-TOU	$2,568	$2,616	$2,542	$2,622	B-1	$2,591	$2,639	$2,565	$2,646	B-6	$2,504	$2,552	$2,479	$2,560
2352092220	1005828304	A-1-TOU	$717	$729	$709	$733	A-1-TOU	$717	$729	$709	$733	B-1	$723	$735	$714	$739	B-6	$703	$715	$695	$719
1293436809	1005427547	A-1-TOU	$346	$351	$343	$352	A-1	$344	$348	$341	$350	B-1	$334	$338	$331	$340	B-6	$328	$332	$325	$334
9349520251	1006707077	A-1-TOU	$5,122	$5,221	$5,139	$5,345	A-1	$5,104	$5,203	$5,122	$5,327	B-1	$5,135	$5,234	$5,153	$5,358	B-6	$4,943	$5,042	$4,961	$5,166
1293436159	1005372996	A-1-TOU	$717	$728	$708	$732	A-1-TOU	$717	$728	$708	$732	B-1	$722	$734	$713	$738	B-6	$701	$712	$692	$716
9136010298	1006727299	A-1-TOU	$206	$208	$205	$209	A-1	$200	$202	$199	$203	B-1	$206	$208	$205	$209	B-6	$205	$207	$204	$208
1293436521	1008775894	A-1-TOU	$1,831	$1,865	$1,816	$1,869	A-1-TOU	$1,831	$1,865	$1,816	$1,869	B-1	$1,851	$1,885	$1,837	$1,889	B-6	$1,792	$1,826	$1,778	$1,831
1293436049	1006729846	A-1-TOU	$3,270	$3,332	$3,243	$3,341	A-1-TOU	$3,270	$3,332	$3,243	$3,341	B-1	$3,310	$3,373	$3,284	$3,382	B-6	$3,196	$3,258	$3,171	$3,268
1293436323	1010381997	A-1-TOU	$120	$120	$120	$120	A-1	$120	$120	$120	$120	B-1	$120	$120	$120	$120	B-6	$120	$120	$120	$120
1293436819	1005382456	A-1-TOU	$710	$722	$702	$726	A-1-TOU	$710	$722	$702	$726	B-1	$716	$727	$707	$731	B-6	$694	$706	$685	$710
1293436517	1005382454	A-1-TOU	$2,098	$2,137	$2,070	$2,151	A-1-TOU	$2,098	$2,137	$2,070	$2,151	B-1	$2,117	$2,156	$2,088	$2,169	B-6	$2,048	$2,088	$2,020	$2,102
5718985787	1006758702	A-1-TOU	$1,733	$1,765	$1,716	$1,769	A-1-TOU	$1,733	$1,765	$1,716	$1,769	B-1	$1,750	$1,781	$1,733	$1,786	B-6	$1,693	$1,725	$1,677	$1,730
1293436023	1008817924	A-1-TOU	$2,545	$2,593	$2,524	$2,598	A-1-TOU	$2,545	$2,593	$2,524	$2,598	B-1	$2,570	$2,618	$2,550	$2,624	B-6	$2,484	$2,532	$2,465	$2,539
1293436976	1006767532	A-1-TOU	$924	$940	$913	$946	A-1-TOU	$924	$940	$913	$946	B-1	$935	$950	$923	$956	B-6	$905	$921	$893	$926
8869195870	1006758131	A-1-TOU	$696	$707	$690	$708	A-1-TOU	$696	$707	$690	$708	B-1	$704	$715	$698	$717	B-6	$683	$695	$677	$696
7980138350	1006528515	A-1-TOU	$1,827	$1,860	$1,808	$1,864	A-1-TOU	$1,827	$1,860	$1,808	$1,864	B-1	$1,849	$1,882	$1,831	$1,886	B-6	$1,786	$1,820	$1,769	$1,825
292016465	1006526718	A-1-TOU	$1,511	$1,539	$1,491	$1,548	A-1-TOU	$1,511	$1,539	$1,491	$1,548	B-1	$1,527	$1,554	$1,506	$1,563	B-6	$1,480	$1,507	$1,460	$1,517
423352474	1008698132	A-1-TOU	$849	$863	$838	$868	A-1-TOU	$849	$863	$838	$868	B-1	$854	$869	$843	$873	B-6	$829	$843	$818	$848
1293436298	1009130314	A-1-TOU	$1,480	$1,507	$1,485	$1,541	A-1-TOU	$1,480	$1,507	$1,485	$1,541	B-1	$1,493	$1,520	$1,498	$1,553	B-6	$1,443	$1,470	$1,448	$1,504
1293436206	1009077581	A-1-TOU	$224	$227	$225	$229	A-1-TOU	$224	$227	$225	$229	B-1	$225	$228	$226	$230	B-6	$222	$224	$222	$227

		CURRENT TOU RATES AND COSTS PER CURRENT BILLS					CURRENT TOU IDEAL RATES & COSTS					NEW TOU PROJECTED RATES AND COSTS					NEW TOU IDEAL RATES & COSTS				
SAID	Meter #	PG&E Rate	Bundled PG&E Costs	PG&E Solar Choice Costs	PG&E + CCA Default Rate Costs	PG&E + CCA Costs (100% clean)	PG&E Rate	Bundled PG&E Costs	PG&E Solar Choice Costs	PG&E + CCA Default Rate Costs	PG&E + CCA Costs (100% clean)	PG&E Rate	Bundled PG&E Costs	PG&E Solar Choice Costs	PG&E + CCA Default Rate Costs	PG&E + CCA Costs (100% clean)	PG&E Rate	Bundled PG&E Costs	PG&E Solar Choice Costs	PG&E + CCA Default Rate Costs	PG&E + CCA Costs (100% clean)
7616356837	1009169132	A-1-TOU	$1,079	$1,098	$1,069	$1,101	A-1-TOU	$1,079	$1,098	$1,069	$1,101	B-1	$1,092	$1,111	$1,082	$1,114	B-6	$1,057	$1,076	$1,047	$1,079
5751564634	1010579784	A-1-TOU	$1,384	$1,409	$1,366	$1,418	A-1-TOU	$1,384	$1,409	$1,366	$1,418	B-1	$1,410	$1,435	$1,391	$1,443	B-6	$1,367	$1,392	$1,348	$1,401
1293436634	1005447198	A-1-TOU	$549	$558	$543	$561	A-1-TOU	$549	$558	$543	$561	B-1	$553	$561	$547	$564	B-6	$539	$547	$532	$550
848285961	1006758567	A-1-TOU	$818	$832	$811	$834	A-1-TOU	$818	$832	$811	$834	B-1	$831	$845	$824	$847	B-6	$802	$815	$794	$817
209772704	1006767135	A-1-TOU	$203	$205	$202	$206	A-6	$200	$202	$199	$202	B-1	$205	$206	$203	$207	B-6	$203	$205	$202	$206
5168859377	1009856640	A-1-TOU	$9,170	$9,347	$9,201	$9,570	A-1-TOU	$9,170	$9,347	$9,201	$9,570	B-1	$9,286	$9,463	$9,316	$9,685	B-6	$8,923	$9,101	$8,954	$9,324
1293436484	1005383119	A-1-TOU	$1,454	$1,481	$1,435	$1,490	A-1	$1,428	$1,455	$1,411	$1,466	B-1	$1,459	$1,486	$1,440	$1,496	B-6	$1,428	$1,455	$1,410	$1,466
9267959434	1005428259	A-1-TOU	$8,019	$8,178	$7,914	$8,246	A-6	$7,926	$8,086	$7,820	$8,153	B-1	$8,234	$8,393	$8,117	$8,450	B-6	$7,835	$7,995	$7,723	$8,055
1293436965	1006767114	A-1-TOU	$1,375	$1,400	$1,357	$1,409	A-1-TOU	$1,375	$1,400	$1,357	$1,409	B-1	$1,389	$1,414	$1,370	$1,422	B-6	$1,345	$1,370	$1,327	$1,379
1961160076	1006767470	A-1-TOU	$1,604	$1,633	$1,582	$1,643	A-1-TOU	$1,604	$1,633	$1,582	$1,643	B-1	$1,615	$1,644	$1,593	$1,653	B-6	$1,564	$1,593	$1,542	$1,603
1293436672	1006767593	A-1-TOU	$566	$575	$559	$578	A-1-TOU	$566	$575	$559	$578	B-1	$571	$579	$564	$582	B-6	$556	$565	$550	$568
1293436036	1004472536	A-1-TOU	$120	$120	$120	$120	A-1	$120	$120	$120	$120	B-1	$120	$120	$120	$120	B-1	$120	$120	$120	$120
8581704782	1005428779	A-1-TOU	$782	$795	$772	$800	A-1-TOU	$782	$795	$772	$800	B-1	$788	$801	$778	$806	B-6	$765	$778	$755	$783
1293436189	1005428234	A-1-TOU	$846	$860	$836	$866	A-1-TOU	$846	$860	$836	$866	B-1	$856	$870	$845	$875	B-6	$831	$845	$821	$850
7616356592	1006767446	A-1-TOU	$120	$120	$120	$120	A-1	$120	$120	$120	$120	B-1	$120	$120	$120	$120	B-1	$120	$120	$120	$120
7616356293	1009275034	A-1-TOU	$120	$120	$120	$120	A-1	$120	$120	$120	$120	B-1	$120	$120	$120	$120	B-1	$120	$120	$120	$120
1293436689	1005446569	A-1-TOU	$822	$836	$812	$841	A-1-TOU	$822	$836	$812	$841	B-1	$826	$840	$816	$845	B-6	$802	$815	$792	$820
2178337696	1005447204	A-1-TOU	$614	$624	$607	$627	A-1-TOU	$614	$624	$607	$627	B-1	$619	$629	$612	$632	B-6	$602	$612	$595	$615
8479612659	1008922888	A-1-TOU	$978	$995	$966	$1,002	A-1-TOU	$978	$995	$966	$1,002	B-1	$996	$1,013	$983	$1,019	B-6	$961	$978	$949	$985
5756253498	1010348826	A-1-TOU	$2,220	$2,262	$2,190	$2,276	A-1-TOU	$2,220	$2,262	$2,190	$2,276	B-1	$2,243	$2,284	$2,212	$2,298	B-6	$2,164	$2,205	$2,134	$2,220
3305181364	1005529752	A-1-TOU	$1,093	$1,112	$1,079	$1,118	A-1-TOU	$1,093	$1,112	$1,079	$1,118	B-1	$1,104	$1,123	$1,089	$1,129	B-6	$1,069	$1,088	$1,055	$1,095
1297587432	1005382939	A-1-TOU	$1,586	$1,616	$1,567	$1,629	A-6	$1,530	$1,560	$1,512	$1,574	B-1	$1,636	$1,666	$1,614	$1,676	B-6	$1,572	$1,602	$1,551	$1,613
5039253980	1006768055	A-1-TOU	$1,515	$1,542	$1,495	$1,552	A-1-TOU	$1,515	$1,542	$1,495	$1,552	B-1	$1,530	$1,557	$1,509	$1,566	B-6	$1,478	$1,505	$1,458	$1,515
1293436194	1009285216	A-1-TOU	$1,875	$1,908	$1,849	$1,919	A-1-TOU	$1,875	$1,908	$1,849	$1,919	B-1	$1,891	$1,924	$1,864	$1,934	B-6	$1,814	$1,848	$1,788	$1,858
1293436178	1006483857	A-1-TOU	$122	$122	$122	$123	A-1	$122	$122	$122	$122	B-1	$122	$122	$122	$123	B-6	$122	$122	$122	$123
3578012254	1006527100	A-1-TOU	$737	$750	$731	$751	A-1-TOU	$737	$750	$731	$751	B-1	$745	$758	$739	$759	B-6	$722	$734	$716	$736
2847057957	1009190761	A-1-TOU	$393	$399	$394	$405	A-1-TOU	$393	$399	$394	$405	B-1	$396	$402	$397	$408	B-6	$386	$391	$387	$398
292016743	1005383168	A-1-TOU	$563	$572	$557	$575	A-1-TOU	$563	$572	$557	$575	B-1	$568	$577	$561	$579	B-6	$553	$562	$546	$565
1717382926	1006767530	A-1-TOU	$616	$626	$609	$630	A-1-TOU	$616	$626	$609	$630	B-1	$624	$633	$616	$636	B-6	$606	$616	$599	$619
1293436257	1006767627	A-1-TOU	$1,571	$1,600	$1,550	$1,610	A-1-TOU	$1,571	$1,600	$1,550	$1,610	B-1	$1,587	$1,615	$1,565	$1,624	B-6	$1,535	$1,564	$1,514	$1,574
1293436732	1006767028	A-1-TOU	$133	$134	$133	$134	A-1-TOU	$133	$134	$133	$134	B-1	$133	$134	$133	$134	B-6	$133	$133	$133	$133
6582523760	1006767026	A-1-TOU	$711	$722	$702	$727	A-1-TOU	$711	$722	$702	$727	B-1	$716	$728	$708	$732	B-6	$695	$707	$687	$711
1293436704	1006767165	A-1-TOU	$437	$443	$432	$445	A-1-TOU	$437	$443	$432	$445	B-1	$439	$446	$435	$448	B-6	$428	$435	$424	$437
7616356187	1008678733	A-1-TOU	$1,338	$1,362	$1,325	$1,365	A-1-TOU	$1,338	$1,362	$1,325	$1,365	B-1	$1,349	$1,373	$1,336	$1,377	B-6	$1,306	$1,330	$1,294	$1,334
1428067137	1009077720	A-1-TOU	$3,141	$3,200	$3,097	$3,221	A-1-TOU	$3,141	$3,200	$3,097	$3,221	B-1	$3,170	$3,229	$3,125	$3,249	B-6	$3,062	$3,122	$3,019	$3,143
1293436322	1005428260	A-1-TOU	$520	$528	$515	$531	A-1-TOU	$520	$528	$515	$531	B-1	$525	$533	$519	$536	B-6	$512	$520	$506	$522
1293436019	1006767709	A-1-TOU	$275	$278	$273	$279	A-1-TOU	$275	$278	$273	$279	B-1	$276	$279	$274	$280	B-6	$271	$274	$269	$275
7517379118	1006767546	A-1-TOU	$710	$722	$702	$726	A-1-TOU	$710	$722	$702	$726	B-1	$715	$727	$707	$731	B-6	$695	$707	$687	$711
3397012401	1005428254	A-1-TOU	$1,064	$1,083	$1,051	$1,090	A-1-TOU	$1,064	$1,083	$1,051	$1,090	B-1	$1,073	$1,092	$1,059	$1,098	B-6	$1,041	$1,060	$1,028	$1,066
1293436588	1010581927	A-1-TOU	$120	$120	$120	$120	A-1	$120	$120	$120	$120	B-1	$120	$120	$120	$120	B-6	$120	$120	$120	$120
1293436872	1006759328	A-1-TOU	$625	$635	$618	$638	A-1-TOU	$625	$635	$618	$638	B-1	$630	$640	$622	$643	B-6	$613	$623	$606	$626
1293436769	1006767697	A-1-TOU	$706	$718	$698	$722	A-1-TOU	$706	$718	$698	$722	B-1	$713	$724	$704	$728	B-6	$693	$705	$685	$709
5249520333	1009288395	A-1-TOU	$120	$120	$120	$120	A-1	$120	$120	$120	$120	B-1	$120	$120	$120	$120	B-1	$120	$120	$120	$120
1293436898	1007139008	A-1-TOU	$120	$120	$120	$120	A-1	$120	$120	$120	$120	B-1	$120	$120	$120	$120	B-1	$120	$120	$120	$120
4552324955	1005446164	A-1-TOU	$7,644	$7,795	$7,543	$7,859	A-6	$7,572	$7,723	$7,469	$7,785	B-1	$7,865	$8,017	$7,753	$8,069	B-6	$7,545	$7,697	$7,436	$7,752
1293436739	1005428525	A-1-TOU	$1,964	$2,001	$1,939	$2,018	A-6	$1,896	$1,934	$1,873	$1,952	B-1	$2,029	$2,067	$2,002	$2,080	B-6	$1,957	$1,995	$1,930	$2,009
650794714	1005529208	A-1-TOU	$2,119	$2,158	$2,090	$2,172	A-1-TOU	$2,119	$2,158	$2,090	$2,172	B-1	$2,142	$2,181	$2,112	$2,194	B-6	$2,070	$2,109	$2,041	$2,123
1293436568	1006767117	A-1-TOU	$1,836	$1,871	$1,813	$1,885	A-1-TOU	$1,836	$1,871	$1,813	$1,885	B-1	$1,879	$1,914	$1,853	$1,926	B-6	$1,810	$1,845	$1,785	$1,858
4383293771	1008695803	A-1-TOU	$894	$910	$884	$916	A-1-TOU	$894	$910	$884	$916	B-1	$896	$912	$885	$918	B-6	$877	$893	$867	$899
2538415392	1009661311	A-1-TOU	$120	$120	$120	$120	A-1	$120	$120	$120	$120	B-1	$120	$120	$120	$120	B-1	$120	$120	$120	$120
2473747687	1006767586	A-1-TOU	$1,376	$1,400	$1,358	$1,409	A-1-TOU	$1,376	$1,400	$1,358	$1,409	B-1	$1,389	$1,413	$1,370	$1,421	B-6	$1,344	$1,369	$1,326	$1,378
9744092683	1010576196	A-1-TOU	$3,523	$3,589	$3,534	$3,673	A-1-TOU	$3,523	$3,589	$3,534	$3,673	B-1	$3,564	$3,630	$3,575	$3,713	B-6	$3,434	$3,500	$3,445	$3,583
7681075064	1006766947	A-1-TOU	$307	$311	$308	$315	A-1-TOU	$307	$311	$308	$315	B-1	$309	$312	$309	$317	B-6	$301	$305	$302	$310
1293436983	1009314038	A-1-TOU	$3,043	$3,100	$3,053	$3,172	A-1-TOU	$3,043	$3,100	$3,053	$3,172	B-1	$3,079	$3,136	$3,089	$3,208	B-6	$2,961	$3,018	$2,971	$3,090
3865426092	1009606036	A-1-TOU	$7,454	$7,597	$7,479	$7,775	A-1-TOU	$7,454	$7,597	$7,479	$7,775	B-1	$7,514	$7,656	$7,538	$7,834	B-6	$7,209	$7,351	$7,233	$7,529
1293436790	1005529243	A-1-TOU	$1,637	$1,667	$1,615	$1,677	A-1-TOU	$1,637	$1,667	$1,615	$1,677	B-1	$1,654	$1,684	$1,632	$1,694	B-6	$1,603	$1,632	$1,581	$1,643
4550888824	1010127999	A-6	$11,369	$11,591	$11,267	$11,613	A-1-TOU	$11,184	$11,406	$11,091	$11,437	B-6	$11,121	$11,343	$11,031	$11,377	B-6	$11,121	$11,343	$11,031	$11,377
1832904139	1010283786	A-10-TOU-P	$111,158	$111,496	$111,675	$114,489	E-19-P-V	$101,100	$101,437	$101,468	$104,282	B-10-P	$115,984	$116,321	$116,468	$119,281	B-19-P-V	$103,399	$103,737	$103,768	$106,582
5347339954	1010239054	A-10-TOU-P	$38,066	$38,134	$38,152	$38,714	E-19-P-V	$33,811	$33,878	$33,913	$34,475	B-10-P	$35,372	$35,439	$35,480	$36,042	B-19-P-V	$35,204	$35,272	$35,297	$35,859
4552324646	1010124825	E-19-P-V	$66,068	$66,453	$65,884	$66,468	A-10-TOU-P	$65,324	$65,709	$64,949	$65,533	B-19-P-V	$67,289	$67,675	$67,100	$67,684	B-10-P	$59,477	$59,862	$59,265	$59,849
1837233652	1007074343	E-19-P-V	$324,238	$330,381	$325,482	$334,788	E-19-P-V	$324,238	$330,381	$325,482	$334,788	B-19-P-V	$327,029	$333,172	$328,313	$337,619	B-19-P-V	$327,029	$333,172	$328,313	$337,619
4552324771	1010058983	E-19-S-V	$21,018	$21,389	$20,804	$21,705	E-19-S-V	$21,018	$21,389	$20,804	$21,705	B-19-S-V	$22,247	$22,619	$21,997	$22,898	B-19-S-V	$22,247	$22,619	$21,997	$22,898
1293436638	1005428504	E-19-S-V	$17,897	$18,212	$17,650	$18,604	E-19-S-V	$17,897	$18,212	$17,650	$18,604	B-19-S-V	$19,031	$19,346	$18,725	$19,679	B-19-S-V	$19,031	$19,346	$18,725	$19,679
1293436182	1006727549	E-19-S-V	$124,134	$126,472	$122,721	$126,264	E-19-S-V	$124,134	$126,472	$122,721	$126,264	B-19-S-V	$128,512	$130,850	$127,081	$130,625	B-19-S-V	$128,512	$130,850	$127,081	$130,625
4552324421	1003873311	E-19-S-V	$18,360	$18,641	$18,094	$18,945	E-19-S-V	$18,360	$18,641	$18,094	$18,945	B-19-S-V	$19,038	$19,319	$18,739	$19,590	B-19-S-V	$19,038	$19,319	$18,739	$19,590

		CURRENT TOU RATES AND COSTS PER CURRENT BILLS					CURRENT TOU IDEAL RATES & COSTS					NEW TOU PROJECTED RATES AND COSTS					NEW TOU IDEAL RATES & COSTS				
SAID	Meter #	PG&E Rate	Bundled PG&E Costs	PG&E Solar Choice Costs	PG&E + CCA Default Rate Costs	PG&E + CCA Costs (100% clean)	PG&E Rate	Bundled PG&E Costs	PG&E Solar Choice Costs	PG&E + CCA Default Rate Costs	PG&E + CCA Costs (100% clean)	PG&E Rate	Bundled PG&E Costs	PG&E Solar Choice Costs	PG&E + CCA Default Rate Costs	PG&E + CCA Costs (100% clean)	PG&E Rate	Bundled PG&E Costs	PG&E Solar Choice Costs	PG&E + CCA Default Rate Costs	PG&E + CCA Costs (100% clean)
8356183296	5000118675	E-19-S-V	$55,896	$56,874	$54,861	$57,822	E-19-S-V	$55,896	$56,874	$54,861	$57,822	B-19-S-V	$57,465	$58,443	$56,372	$59,334	B-19-S-V	$57,465	$58,443	$56,372	$59,334
4552324506	1010057385	E-19-S-V	$9,249	$9,402	$9,114	$9,578	E-19-S-V	$9,249	$9,402	$9,114	$9,578	B-19-S-V	$9,659	$9,812	$9,503	$9,967	B-19-S-V	$9,659	$9,812	$9,503	$9,967
4552324834	1010124628	E-19-S-V	$20,556	$20,831	$20,248	$21,079	E-19-S-V	$20,556	$20,831	$20,248	$21,079	B-19-S-V	$20,840	$21,115	$20,527	$21,359	B-19-S-V	$20,840	$21,115	$20,527	$21,359
4552324757	1009776784	E-19-S-V	$13,359	$13,577	$13,210	$13,740	E-19-S-V	$13,359	$13,577	$13,210	$13,740	B-19-S-V	$13,946	$14,164	$13,786	$14,315	B-19-S-V	$13,946	$14,164	$13,786	$14,315
4552324481	1010018923	E-19-S-V	$137,264	$138,105	$136,658	$138,696	E-19-S-V	$137,264	$138,105	$136,658	$138,696	B-19-S-V	$139,868	$140,709	$139,280	$141,318	B-19-S-V	$139,868	$140,709	$139,280	$141,318
4552324080	1006910794	E-19-S-V	$35,465	$36,087	$34,884	$36,770	E-19-S-V	$35,465	$36,087	$34,884	$36,770	B-19-S-V	$36,676	$37,299	$36,035	$37,920	B-19-S-V	$36,676	$37,299	$36,035	$37,920
9586677599	1010125033	E-19-S-V	$17,533	$17,755	$17,377	$17,714	E-19-S-V	$17,533	$17,755	$17,377	$17,714	B-19-S-V	$17,817	$18,039	$17,669	$18,006	B-19-S-V	$17,817	$18,039	$17,669	$18,006
4557236278	1010126669	E-19-S-V	$43,553	$44,265	$43,720	$44,800	E-19-S-V	$43,553	$44,265	$43,720	$44,800	B-19-S-V	$46,330	$47,043	$46,470	$47,550	B-19-S-V	$46,330	$47,043	$46,470	$47,550
4552324686	1006767598	E-19-S-V	$14,917	$15,153	$14,717	$15,432	E-19-S-V	$14,917	$15,153	$14,717	$15,432	B-19-S-V	$15,693	$15,929	$15,455	$16,169	B-19-S-V	$15,693	$15,929	$15,455	$16,169
4552324032	1006767501	E-19-S-V	$13,676	$13,900	$13,483	$14,161	E-19-S-V	$13,676	$13,900	$13,483	$14,161	B-19-S-V	$14,417	$14,640	$14,188	$14,865	B-19-S-V	$14,417	$14,640	$14,188	$14,865
4552324168	1009848674	E-19-S-V	$13,548	$13,756	$13,363	$13,992	E-19-S-V	$13,548	$13,756	$13,363	$13,992	B-19-S-V	$14,152	$14,359	$13,937	$14,565	B-19-S-V	$14,152	$14,359	$13,937	$14,565
4552324228	1010086814	E-19-S-V	$102,600	$104,484	$102,990	$105,845	E-19-S-V	$102,600	$104,484	$102,990	$105,845	B-19-S-V	$106,782	$108,666	$107,128	$109,983	B-19-S-V	$106,782	$108,666	$107,128	$109,983
8363566360	1009661312	E-19-S-V	$3,706	$3,743	$3,677	$3,787	E-19-S-V	$3,706	$3,743	$3,677	$3,787	B-19-S-V	$3,820	$3,856	$3,785	$3,895	B-19-S-V	$3,820	$3,856	$3,785	$3,895
		TOTALS:	$1,412,310	$1,433,015	$1,407,014	$1,449,078		$1,395,845	$1,416,550	$1,390,260	$1,432,324		$1,443,859	$1,464,564	$1,438,091	$1,480,154		$1,416,224	$1,436,929	$1,410,371	$1,452,435
		CCA RATE SAVINGS:			$5,296	($16,062)				$5,584	($15,774)				$5,767	($15,591)				$5,852	($15,506)
		IDEAL RATE SAVINGS:					$16,466							$27,635							

[1]For the purposes of this analysis ***ideal rates*** are considered to be those that result in the lowest annual Utility bill.

APPENDIX D RATE ANALYSIS AND DER ANALYSIS ASSUMPTIONS

HISTORICAL RATE ANALYSIS ASSUMPTIONS

- PG&E meter 15-minute interval data was obtained from a third-party, Utility API, for all PG&E meters. Where a complete year of data could not be obtained directly from the meter data, data cleaning was completed to create a full twelve (12) months of energy usage. If intervals were missing in the first week of data, the missing intervals were inserted by using interval data from the subsequent week at the same time to fill in the gap. If intervals were missing in the any other of the 51 weeks of the year, the missing intervals were inserted by using interval data from the previous week at the same time to fill in the gap.
- The analyses shown in this report were calculated using the interval data and the PG&E tariffs made effective April 19, 2020.
- The analysis shown in this report used 2019 vintage rates for the PCIA charges.

FUTURE RATE ANALYSIS ASSUMPTIONS

- The analyses only considered Caltrain service (not CAHSR blended service).
- The analyses only evaluated the regenerative braking option.
- The analyses will be based on the 2015 LTK traction load study, which evaluated electric demand for when 75% of the fleet is converted to EMUs.
- The analyses are based on a generic EMU, not the Stadler EMU.
- A generic regenerative braking model was used in the analyses.
- Regenerative braking was assumed to provide energy savings of approximately 37.2%
- The schedule detailed in the LTK study for Caltrain is out of sync with the 15 minute interval data (e.g., the load in the interval data file starts at 4:35 AM); we will use the interval data as provided as the source of truth for the initial modeling.
- The 15-minute interval data provided only covers a typical weekday and does not adjust for seasonal or weekend/holiday variations. The analyses used the 15-minute interval data provided for every day of the year.
- GHG emissions were based on available information on the percentage of renewable energy associated with each produce evaluated. SB100 mandates that 100% of California's electricity will be GHG-free by 2045. Therefore, it is expected that the percentage of GHG-free energy associated with PG&E's base plan will gradually increase and ultimately become zero by 2045.

SOLAR PV ASSUMPTIONS

- System sizes: per modeling to obtain optimal financial benefit or limited to site constraints

- Solar Technology: High efficiency PV modules and inverters
- Interconnection: Per PG&E Rule 21, NEM 2.0 tariff
- Project cost estimates: current market data (recent similar projects)
- Consumption & billing analysis using 15-minute interval data
- PG&E + CCA default B-19 rates
- PG&E and CCA annual cost escalation rate: 3%
- PV system annual production degradation rate: 0.5% (industry standard default)
- Solar energy generation profile: per PVWatts hourly production model
- Assumed no array shading, i.e., vegetation/trees/other obstacles removed where they would shade the arrays
- O&M costs, Insurance costs, and extended warranty costs per industry standards are the responsibility of the PPA provider and are incorporated into the PPA rate in the PPA scenarios and the responsibility of Caltrain in the case of the cash purchase scenarios
- REC ownership and value (revenue): RECs retained by Caltrain, with potential sale value excluded in the pro-forma. Caltrain can elect to sell the REC's for additional revenue, retire them for LCFS zero-carbon credits, or alternatively, green brand
- Installation date (2021)
- Project Development costs (i.e., consultants, permitting, environmental studies, legal, geotechnical, interconnection) are assumed to be the responsibility of the PPA provider and incorporated into the PPA rate in the PPA scenarios and the responsibility of Caltrain in the case of the cash purchase scenarios
- PPA rates assumptions:
    - Current market data for rates (recent similar projects)
    - Investor IRR requirements (internal Rate of Return) per market rates
    - PPA term length (25 years)
    - Performance Guarantee terms (95% of projected annual production on a weather adjusted basis)
    - Caltrain credit rating is assumed to be investment grade
    - PPA escalator of 0% (PPA escalators are typically used when/if the avoided cost is greater than the PPA rate in the 1st year)
    - Federal ITC of 10% + Accelerated Depreciation Schedule

    - Asset Management Services (AMS) cost: $0.01/kWh with a 3% annual escalation rate (oversight of PPA provider to ensure compliance with contract terms and performance guarantee agreement)

BESS ASSUMPTIONS

- Current market data for battery costs (recent similar projects)
- Investor IRR requirements (internal Rate of Return) per market rates (the percentage of the savings that the battery provider would earn is based on an assumed IRR for the battery provider with the remainder of the utility bill savings going to Caltrain
- Contract term length of 15 years (could be up to 25 years in some financing scenarios)
- Installation date (2021)
- Caltrain credit rating (assumed to be investment grade)
- O&M costs, Insurance costs, and warranty costs per industry standards (Responsibility of Battery provider and incorporated)

APPENDIX E DER PRO FORMAS

Pro Forma
Feasibility Study

Scenarios Included in this Pro Forma:

#1 - Battery Savings to Provider
#2 - Battery Cash Purchase

Summary of Results

Financing Scenario	Net Benefit Year 1	Net Benefit Years 1-10	Net Benefit Years 1-15	Years to Payback
#1 - Battery Savings to Provider	$ (50,116)	$ (550,271)	$ (870,002)	n/a
#2 - Battery Cash Purchase	$ (1,125,847)	$ (716,234)	$ (434,362)	n/a

Project Portfolio

Meter Name	Service Account ID	Meter Number	Connection Level	Rate (Current)	Rate (New TOU)	Rate (After Project)	Program	Customer Usage (kWh)	Max Demand (kW)
#1 - 341 TOWNSEND ST SAN FRANCISCO, CA 94107	4552324646	4552324646	P	E-19	B-19	B-19	AES	116,798	468
Portfolio Totals								116,798	468

Savings

Meter Name	Service Account ID	Cumulative Demand (kW)	Demand Reduction (kW)	Energy Discharged (kWh)	Battery Sizing	Battery Size (kWh)	Battery Size (kW)	Battery Savings From Demand Reduction (total)	Battery Savings From Demand Reduction ($/kW)	Battery Savings From Arbitrage (total)	Battery Savings From Arbitrage ($/kWh)
#1 - 341 TOWNSEND ST SAN FRANCISCO, CA 94107	4552324646	2,923	1,625	43,255	56%	1,856	464	$ 42,708	$ 26.28	$ 1,292	$ 0.0299
Totals		2,923	1,625	43,255	56%	1,856	464	$ 42,708	$ 26.28	$ 1,292	$ 0.030

Dashboard

Scenario: #1 - Battery Savings to Provider

Technical Assumptions		
Total Storage Project Size	1,856	kWh
Year-1 Demand Reduction	1,625	kW
Number of PG&E Accounts	1	

Avoided Cost & Revenue Sources		
Savings from Demand Reduction, yr-1	$26.28	/kW
Estimated Utility Energy Cost Escalator	3.00%	

Pricing	
Battery Savings to Provider	204%

Asset Management Services Assumptions		
Asset Management Services, Storage	$1,000	/battery
Asset Management Services Escalator	3.00%	

Resiliency		
Backup Duration on Worst Day - 4552324481	23.75	hours
Backup Duration on Worst Day - 4552324646	18.75	hours

Total Net Benefit (15 years)	
Gross Project Benefit	$818,351
Payments to 3rd Party Provider	($1,669,754)
Operating Expenses	($18,599)
Total Net Benefit	($870,002)

Cash Flow

TerraVerde ENERGY

	Electricity	Utility Savings				Expenses			Cash Position			
Year	Annual Demand Reduction (kW)	Savings from Storage due to Demand Reduction	Savings from Storage due to Arbitrage	Storage Savings (Total)	**Subtotal: Annual Gross Benefits**	Battery Payments to Provider	Asset Management Service (Storage)	**Subtotal: Annual Operating Expenses**	Net Benefits (Storage)	**Cumulative Cash Position**	**Conservative Cumulative Cash Position**	Term
2022	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0
2023	1,625	$ 42,708	$ 1,292	$ 44,000	$ 44,000	$ (93,116)	$ (1,000)	$ (94,116)	$ (50,116)	$ (50,116)	$ (54,516)	1
2024	1,625	$ 43,989	$ 1,331	$ 45,320	$ 45,320	$ (95,444)	$ (1,030)	$ (96,474)	$ (51,154)	$ (101,271)	$ (110,203)	2
2025	1,625	$ 45,309	$ 1,370	$ 46,680	$ 46,680	$ (97,830)	$ (1,061)	$ (98,891)	$ (52,212)	$ (153,482)	$ (167,082)	3
2026	1,625	$ 46,668	$ 1,412	$ 48,080	$ 48,080	$ (100,276)	$ (1,093)	$ (101,369)	$ (53,289)	$ (206,771)	$ (225,179)	4
2027	1,625	$ 48,068	$ 1,454	$ 49,522	$ 49,522	$ (102,783)	$ (1,126)	$ (103,908)	$ (54,386)	$ (261,157)	$ (284,517)	5
2028	1,625	$ 49,510	$ 1,498	$ 51,008	$ 51,008	$ (105,353)	$ (1,159)	$ (106,512)	$ (55,504)	$ (316,661)	$ (345,122)	6
2029	1,625	$ 50,996	$ 1,543	$ 52,538	$ 52,538	$ (107,986)	$ (1,194)	$ (109,180)	$ (56,642)	$ (373,303)	$ (407,018)	7
2030	1,625	$ 52,526	$ 1,589	$ 54,114	$ 54,114	$ (110,686)	$ (1,230)	$ (111,916)	$ (57,801)	$ (431,105)	$ (470,231)	8
2031	1,625	$ 54,101	$ 1,636	$ 55,738	$ 55,738	$ (113,453)	$ (1,267)	$ (114,720)	$ (58,982)	$ (490,087)	$ (534,787)	9
2032	1,625	$ 55,724	$ 1,686	$ 57,410	$ 57,410	$ (116,289)	$ (1,305)	$ (117,594)	$ (60,184)	$ (550,271)	$ (600,712)	10
2033	1,625	$ 57,396	$ 1,736	$ 59,132	$ 59,132	$ (119,197)	$ (1,344)	$ (120,541)	$ (61,408)	$ (611,679)	$ (668,034)	11
2034	1,625	$ 59,118	$ 1,788	$ 60,906	$ 60,906	$ (122,177)	$ (1,384)	$ (123,561)	$ (62,655)	$ (674,334)	$ (736,779)	12
2035	1,625	$ 60,892	$ 1,842	$ 62,733	$ 62,733	$ (125,231)	$ (1,426)	$ (126,657)	$ (63,923)	$ (738,257)	$ (806,976)	13
2036	1,625	$ 62,718	$ 1,897	$ 64,615	$ 64,615	$ (128,362)	$ (1,469)	$ (129,830)	$ (65,215)	$ (803,472)	$ (878,652)	14
2037	1,625	$ 64,600	$ 1,954	$ 66,554	$ 66,554	$ (131,571)	$ (1,513)	$ (133,083)	$ (66,530)	$ (870,002)	$ (951,837)	15
	24,375	$ 794,325	$ 24,027	$ 818,351	$ 818,351	$ (1,669,754)	$ (18,599)	$ (1,688,353)	$ (870,002)	$ (870,002)	$ (951,837)	

Dashboard

Scenario: #2 - Battery Cash Purchase

Technical Assumptions		
Total Storage Project Size	1,856	kWh
Year-1 Demand Reduction	1,625	kW
Storage System Cost	$628	/kWh
Number of PG&E Accounts	1	

Avoided Cost & Revenue Sources		
Savings from Demand Reduction, yr-1	$26.28	/kW
Estimated Utility Energy Cost Escalator	3.00%	

Asset Management Services Assumptions		
Asset Management Services, Storage (client-owned)	$1,000	/battery
Asset Management Services Escalator	3.00%	

Resiliency		
Backup Duration on Worst Day - 4552324481	23.75	hours
Backup Duration on Worst Day - 4552324646	18.75	hours

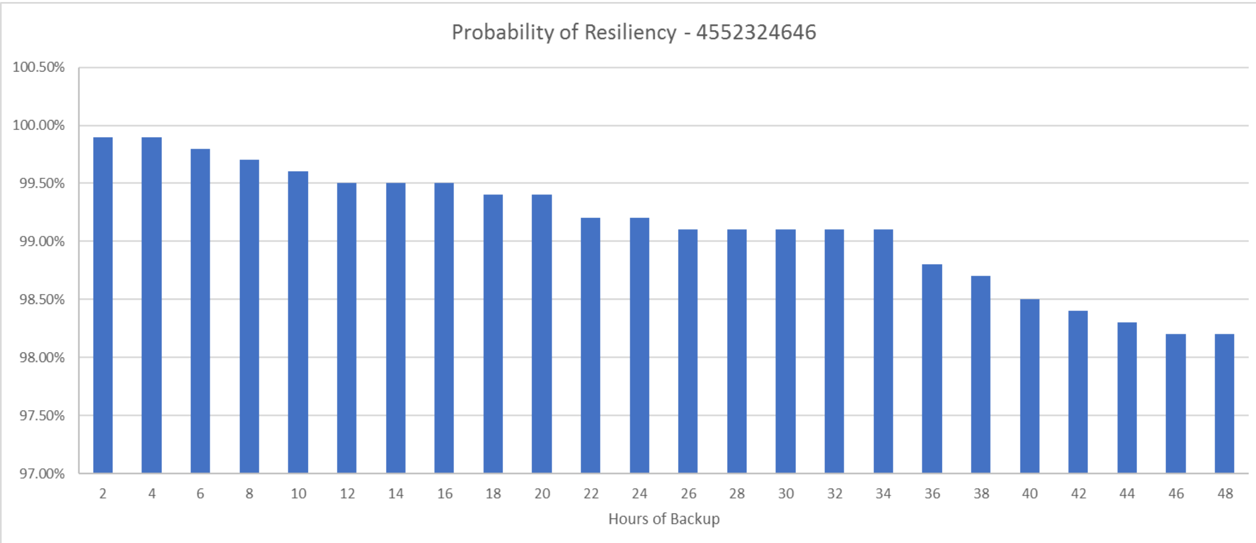
Total Net Benefit (15 years)	
Gross Project Benefit	$818,351
Total Initial Project Cost	($1,164,770)
Operating Expenses	($82,994)
Other Expenses	($4,950)
Total Net Benefit	($434,362)

Cash Flow

TerraVerde ENERGY

	Electricity	Utility Savings				Expenses			Cash Position					
Year	Annual Demand Reduction (kW)	Savings from Storage due to Demand Reduction	Savings from Storage due to Arbitrage	Storage Savings (Total)	**Subtotal: Annual Gross Benefits**	Asset Management Service (Storage)	Other Expenses	**Subtotal: Annual Operating Expenses**	Net Benefits (Storage)	Cash Contribution	Total Cash	**Cumulative Cash Position**	**Conservative Cumulative Cash Position**	Term
2022	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,164,770)	$ (1,164,770)	$ (1,164,770)	$ (1,164,770)	0
2023	1,625	$ 42,708	$ 1,292	$ 44,000	$ 44,000	$ (1,000)	$ (4,077)	$ (5,077)	$ 38,923	$ -	$ 38,923	$ (1,125,847)	$ (1,130,247)	1
2024	1,625	$ 43,989	$ 1,331	$ 45,320	$ 45,320	$ (1,030)	$ (4,153)	$ (5,183)	$ 40,137	$ -	$ 40,137	$ (1,085,710)	$ (1,094,642)	2
2025	1,625	$ 45,309	$ 1,370	$ 46,680	$ 46,680	$ (1,061)	$ (4,232)	$ (5,293)	$ 41,387	$ -	$ 41,387	$ (1,044,323)	$ (1,057,923)	3
2026	1,625	$ 46,668	$ 1,412	$ 48,080	$ 48,080	$ (1,093)	$ (4,312)	$ (5,404)	$ 42,676	$ -	$ 42,676	$ (1,001,648)	$ (1,020,056)	4
2027	1,625	$ 48,068	$ 1,454	$ 49,522	$ 49,522	$ (1,126)	$ (4,393)	$ (5,519)	$ 44,004	$ -	$ 44,004	$ (957,644)	$ (981,004)	5
2028	1,625	$ 49,510	$ 1,498	$ 51,008	$ 51,008	$ (1,159)	$ (4,476)	$ (5,635)	$ 45,373	$ -	$ 45,373	$ (912,271)	$ (940,732)	6
2029	1,625	$ 50,996	$ 1,543	$ 52,538	$ 52,538	$ (1,194)	$ (4,561)	$ (5,755)	$ 46,783	$ -	$ 46,783	$ (865,488)	$ (899,202)	7
2030	1,625	$ 52,526	$ 1,589	$ 54,114	$ 54,114	$ (1,230)	$ (4,647)	$ (5,877)	$ 48,237	$ -	$ 48,237	$ (817,250)	$ (856,376)	8
2031	1,625	$ 54,101	$ 1,636	$ 55,738	$ 55,738	$ (1,267)	$ (4,735)	$ (6,002)	$ 49,736	$ -	$ 49,736	$ (767,514)	$ (812,214)	9
2032	1,625	$ 55,724	$ 1,686	$ 57,410	$ 57,410	$ (1,305)	$ (4,825)	$ (6,130)	$ 51,280	$ -	$ 51,280	$ (716,234)	$ (766,675)	10
2033	1,625	$ 57,396	$ 1,736	$ 59,132	$ 59,132	$ (1,344)	$ (4,796)	$ (6,140)	$ 52,992	$ -	$ 52,992	$ (663,242)	$ (719,596)	11
2034	1,625	$ 59,118	$ 1,788	$ 60,906	$ 60,906	$ (1,384)	$ (4,890)	$ (6,274)	$ 54,632	$ -	$ 54,632	$ (608,610)	$ (671,055)	12
2035	1,625	$ 60,892	$ 1,842	$ 62,733	$ 62,733	$ (1,426)	$ (4,985)	$ (6,411)	$ 56,323	$ -	$ 56,323	$ (552,287)	$ (621,006)	13
2036	1,625	$ 62,718	$ 1,897	$ 64,615	$ 64,615	$ (1,469)	$ (5,082)	$ (6,551)	$ 58,065	$ -	$ 58,065	$ (494,223)	$ (569,402)	14
2037	1,625	$ 64,600	$ 1,954	$ 66,554	$ 66,554	$ (1,513)	$ (5,181)	$ (6,694)	$ 59,860	$ -	$ 59,860	$ (434,362)	$ (516,198)	15
	24,375	$ 794,325	$ 24,027	$ 818,351	$ 818,351	$ (18,599)	$ (69,345)	$ (87,944)	$ 730,407	$ (1,164,770)	$ (434,362)	$ (434,362)	$ (516,198)	

Backup Power Duration



Disclaimers and Assumptions

1) Projections of future savings are calculated based on patterns of previous electricity usage with billing data from February 2020, and assume that historical usage patterns hold at the same level over the life of the project.

2) Projections based on stated assumptions. Final system size and costs will be based on the results of a procurement solicitation process.

3) Projections are subject to tariff eligibility over the life of the installation. This analysis uses PG&E rates published May 2020.

4) Net Operating Benefit does not include repayment of any client capital that may be invested.

5) This analysis assumes SGIP is unavailable due to project timing.

6) Other Expenses includes insurance, PDP and other O&M.

TerraVerde ENERGY

Caltrain

Pro Forma

Feasibility Study

Scenarios Included in this Pro Forma:

#1 - NEM 2.0: Solar Power Purchase Agreement and Battery Savings to Provider
#2 - NEM 2.0: Solar Cash Purchase and Battery Cash Purchase

Summary of Results

Financing Scenario	PPA Start Price	PPA Escalator	Net Benefit Year 1	Net Benefit Years 1-10	Net Benefit Years 1-25	Years to Payback
#1 - NEM 2.0: Solar Power Purchase Agreement and Battery Savings to Provider	$ 0.1240	0.00%	$ (72,112)	$ (507,277)	$ (220,552)	n/a
#2 - NEM 2.0: Solar Cash Purchase and Battery Cash Purchase			$ (3,518,299)	$ (2,130,107)	$ 151,417	24

Project Portfolio

TerraVerde ENERGY

Meter Name	Service Account ID	Meter Number	Connection Level	Rate (Current)	Rate (New TOU)	Rate (After Project)	Program	Customer Usage (kWh)	Max Demand (kW)
#1 - San Jose Station	4552324228	1010086814	S	E-19	B-19	B-19	NEM-A + AES	570,931	118
#2 - CEMOF (NEM-A with #1)	1837233652	1007074343	P	E-19	B-19	B-19	NEM-A	1,861,265	413
Portfolio Totals								**2,432,196**	**530**

Savings

Meter Name	Service Account ID	Customer Usage (kWh)	Solar Production (kWh)	Solar Sizing	Solar Array Size (kW)	Solar Savings	Solar Savings ($/kWh)	Cumulative Demand (kW)	Demand Reduction (kW)	Energy Discharged (kWh)	Battery Sizing	Battery Size (kWh)	Battery Savings From Demand Reduction (total)	Battery Savings From Demand Reduction ($/kW)	Battery Savings From Arbitrage (total)	Battery Savings From Arbitrage ($/kWh)
#1 - San Jose Station	4552324228	570,931	1,736,056	71%	1,150	$ 46,015	$ 0.0929	1,260	424	121,819	34%	464	$ 21,836	$ 51.46	$ 909	$ 0.030
#2 - CEMOF (NEM-A with #1)	1837233652	1,861,265		-		$ 115,256		4,541	-	-	-	-	$ -	$ -	$ 2,703	$ -
Totals		**2,432,196**	**1,736,056**	**71%**	**1,150**	**$ 161,271**	**$ 0.0929**	**5,801**	**424**	**121,819**	**7%**	**464**	**$ 21,836**	**$ 51.46**	**$ 3,612**	**$ 0.030**

Dashboard

Scenario: #1 - NEM 2.0: Solar Power Purchase Agreement and Battery Savings to Provider

Technical Assumptions		
Total Solar Project Size	1.15	MW, DC
Annual Solar Yield	1,510	kWh/kW
Year-1 Solar Production	1,736,056	kWh
Annual Solar Degradation Factor	0.50%	
Total Storage Project Size	464	kWh
Year-1 Demand Reduction	424	kW
Number of PG&E Accounts	2	

Avoided Cost & Revenue Sources		
Savings from Solar Production, yr-1	$0.0929	/kWh
Savings from Demand Reduction, yr-1	$51.46	/kW
Savings from Arbitrage, yr-1	$0.030	/kWh
Estimated Utility Energy Cost Escalator	3.00%	
Average 25-year REC Price	$0.0040	/kWh

Pricing	
PPA Rate	$0.1240
PPA Annual Escalator	0.00%
Battery Savings to Provider	99%

Asset Management Services Assumptions		
Asset Management Services, Solar (PPA)	$0.0100	/kWh
Asset Management Services, Storage	$1,000	/battery
Asset Management Services Escalator	3.00%	

Resiliency		
Backup Duration on Worst Day - San Jose Station	6.75	hours

Total Net Benefit (25 years)	
Gross Project Benefit	$5,953,793
Power Purchase Agreement (PPA) Payments	($5,070,911)
Payments to 3rd Party Provider	($451,881)
Operating Expenses	($651,552)
Total Net Benefit	($220,552)

Cash Flow

	Electricity						Utility Savings				
Year	Annual Solar Production (kWh)	Annual Storage kWh Discharged	Solar Savings per kWh Produced	Annual Demand Reduction (kW)	Demand Savings per kW Reduced	Storage Savings per kWh Discharged	Savings from Solar	Savings from Storage due to Demand Reduction	Savings from Storage due to Arbitrage	Storage Savings (Total)	**Subtotal: Annual Gross Benefits**
2022	-	-	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2023	1,736,056	121,819	$ 0.0929	424	$ 51.46	$ 0.030	$ 161,271	$ 21,836	$ 3,612	$ 25,448	$ 186,719
2024	1,727,376	121,819	$ 0.0957	424	$ 52.74	$ 0.030	$ 165,278	$ 22,379	$ 3,702	$ 26,081	$ 191,359
2025	1,718,739	121,819	$ 0.0986	424	$ 54.05	$ 0.031	$ 169,385	$ 22,935	$ 3,794	$ 26,729	$ 196,114
2026	1,710,145	121,819	$ 0.1015	424	$ 55.39	$ 0.032	$ 173,595	$ 23,505	$ 3,888	$ 27,393	$ 200,988
2027	1,701,594	121,819	$ 0.1046	424	$ 56.77	$ 0.033	$ 177,908	$ 24,089	$ 3,985	$ 28,074	$ 205,982
2028	1,693,086	121,819	$ 0.1077	424	$ 58.18	$ 0.034	$ 182,330	$ 24,687	$ 4,084	$ 28,771	$ 211,101
2029	1,684,621	121,819	$ 0.1109	424	$ 59.63	$ 0.034	$ 186,860	$ 25,301	$ 4,185	$ 29,486	$ 216,347
2030	1,676,198	121,819	$ 0.1142	424	$ 61.11	$ 0.035	$ 191,504	$ 25,929	$ 4,289	$ 30,219	$ 221,723
2031	1,667,817	121,819	$ 0.1177	424	$ 62.63	$ 0.036	$ 196,263	$ 26,574	$ 4,396	$ 30,970	$ 227,233
2032	1,659,478	121,819	$ 0.1212	424	$ 64.18	$ 0.037	$ 201,140	$ 27,234	$ 4,505	$ 31,739	$ 232,879
2033	1,651,180	121,819	$ 0.1248	424	$ 65.78	$ 0.038	$ 206,138	$ 27,911	$ 4,617	$ 32,528	$ 238,666
2034	1,642,924	121,819	$ 0.1286	424	$ 67.41	$ 0.039	$ 211,261	$ 28,605	$ 4,732	$ 33,336	$ 244,597
2035	1,634,710	121,819	$ 0.1324	424	$ 69.09	$ 0.040	$ 216,511	$ 29,315	$ 4,850	$ 34,165	$ 250,675
2036	1,626,536	121,819	$ 0.1364	424	$ 70.80	$ 0.041	$ 221,891	$ 30,044	$ 4,970	$ 35,014	$ 256,905
2037	1,618,404	121,819	$ 0.1405	424	$ 72.56	$ 0.042	$ 227,405	$ 30,790	$ 5,094	$ 35,884	$ 263,289
2038	1,610,312	-	$ 0.1447	-	$ -	$ -	$ 233,056	$ -	$ -	$ -	$ 233,056
2039	1,602,260	-	$ 0.1491	-	$ -	$ -	$ 238,847	$ -	$ -	$ -	$ 238,847
2040	1,594,249	-	$ 0.1535	-	$ -	$ -	$ 244,783	$ -	$ -	$ -	$ 244,783
2041	1,586,277	-	$ 0.1581	-	$ -	$ -	$ 250,866	$ -	$ -	$ -	$ 250,866
2042	1,578,346	-	$ 0.1629	-	$ -	$ -	$ 257,100	$ -	$ -	$ -	$ 257,100
2043	1,570,454	-	$ 0.1678	-	$ -	$ -	$ 263,488	$ -	$ -	$ -	$ 263,488
2044	1,562,602	-	$ 0.1728	-	$ -	$ -	$ 270,036	$ -	$ -	$ -	$ 270,036
2045	1,554,789	-	$ 0.1780	-	$ -	$ -	$ 276,747	$ -	$ -	$ -	$ 276,747
2046	1,547,015	-	$ 0.1833	-	$ -	$ -	$ 283,624	$ -	$ -	$ -	$ 283,624
2047	1,539,280	-	$ 0.1888	-	$ -	$ -	$ 290,672	$ -	$ -	$ -	$ 290,672
	40,894,447	**1,827,285**	**$ 0.1344**	**6,365**	**$ 71.62**	**$ 0.035**	**$ 5,497,957**	**$ 391,133**	**$ 64,704**	**$ 455,837**	**$ 5,953,793**

	Expenses				Cash Position					
Year	PPA Payments	Battery Payments to Provider	Asset Management Service (Solar & Storage)	**Subtotal: Annual Operating Expenses**	Net Benefits (Solar)	Net Benefits (Storage)	Net Benefits (Total)	**Cumulative Cash Position**	**Conservative Cumulative Cash Position**	Term
2022	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0
2023	$ (215,271)	$ (25,200)	$ (18,361)	$ (258,831)	$ (71,361)	$ (752)	$ (72,112)	$ (72,112)	$ (90,784)	1
2024	$ (214,195)	$ (25,830)	$ (18,911)	$ (258,936)	$ (66,798)	$ (779)	$ (67,577)	$ (139,689)	$ (177,497)	2
2025	$ (213,124)	$ (26,476)	$ (19,479)	$ (259,078)	$ (62,156)	$ (808)	$ (62,964)	$ (202,653)	$ (260,072)	3
2026	$ (212,058)	$ (27,137)	$ (20,063)	$ (259,259)	$ (57,434)	$ (837)	$ (58,271)	$ (260,924)	$ (338,442)	4
2027	$ (210,998)	$ (27,816)	$ (20,665)	$ (259,479)	$ (52,629)	$ (868)	$ (53,497)	$ (314,421)	$ (412,537)	5
2028	$ (209,943)	$ (28,511)	$ (21,285)	$ (259,739)	$ (47,739)	$ (899)	$ (48,638)	$ (363,059)	$ (482,285)	6
2029	$ (208,893)	$ (29,224)	$ (21,923)	$ (260,041)	$ (42,762)	$ (932)	$ (43,694)	$ (406,753)	$ (547,614)	7
2030	$ (207,849)	$ (29,955)	$ (22,581)	$ (260,384)	$ (37,696)	$ (966)	$ (38,662)	$ (445,414)	$ (608,448)	8
2031	$ (206,809)	$ (30,704)	$ (23,259)	$ (260,771)	$ (32,538)	$ (1,000)	$ (33,539)	$ (478,953)	$ (664,710)	9
2032	$ (205,775)	$ (31,471)	$ (23,956)	$ (261,203)	$ (27,287)	$ (1,036)	$ (28,323)	$ (507,277)	$ (716,321)	10
2033	$ (204,746)	$ (32,258)	$ (24,675)	$ (261,679)	$ (21,939)	$ (1,074)	$ (23,013)	$ (530,290)	$ (763,201)	11
2034	$ (203,723)	$ (33,064)	$ (25,415)	$ (262,202)	$ (16,493)	$ (1,112)	$ (17,605)	$ (547,895)	$ (805,265)	12
2035	$ (202,704)	$ (33,891)	$ (26,178)	$ (262,773)	$ (10,945)	$ (1,152)	$ (12,097)	$ (559,992)	$ (842,430)	13
2036	$ (201,690)	$ (34,738)	$ (26,963)	$ (263,392)	$ (5,294)	$ (1,193)	$ (6,487)	$ (566,479)	$ (874,608)	14
2037	$ (200,682)	$ (35,607)	$ (27,772)	$ (264,061)	$ 463	$ (1,235)	$ (772)	$ (567,251)	$ (901,709)	15
2038	$ (199,679)	$ -	$ (27,047)	$ (226,726)	$ 6,330	$ -	$ 6,330	$ (560,921)	$ (918,684)	16
2039	$ (198,680)	$ -	$ (27,859)	$ (226,539)	$ 12,308	$ -	$ 12,308	$ (548,613)	$ (930,260)	17
2040	$ (197,687)	$ -	$ (28,694)	$ (226,381)	$ 18,401	$ -	$ 18,401	$ (530,211)	$ (936,337)	18
2041	$ (196,698)	$ -	$ (29,555)	$ (226,254)	$ 24,612	$ -	$ 24,612	$ (505,599)	$ (936,812)	19
2042	$ (195,715)	$ -	$ (30,442)	$ (226,157)	$ 30,943	$ -	$ 30,943	$ (474,656)	$ (931,579)	20
2043	$ (194,736)	$ -	$ (31,355)	$ (226,091)	$ 37,397	$ -	$ 37,397	$ (437,259)	$ (920,531)	21
2044	$ (193,763)	$ -	$ (32,296)	$ (226,058)	$ 43,978	$ -	$ 43,978	$ (393,282)	$ (903,557)	22
2045	$ (192,794)	$ -	$ (33,265)	$ (226,058)	$ 50,688	$ -	$ 50,688	$ (342,594)	$ (880,543)	23
2046	$ (191,830)	$ -	$ (34,263)	$ (226,092)	$ 57,531	$ -	$ 57,531	$ (285,062)	$ (851,374)	24
2047	$ (190,871)	$ -	$ (35,290)	$ (226,161)	$ 64,511	$ -	$ 64,511	$ (220,552)	$ (815,931)	25
	$ (5,070,911)	**$ (451,881)**	**$ (651,552)**	**$ (6,174,345)**	**$ (205,908)**	**$ (14,644)**	**$ (220,552)**	**$ (220,552)**	**$ (815,931)**	

Dashboard

Scenario: #2 - NEM 2.0: Solar Cash Purchase and Battery Cash Purchase

Technical Assumptions		
Total Solar Project Size	1.15	MW, DC
Annual Solar Yield	1,510	kWh/kW
Year-1 Solar Production	1,736,056	kWh
Solar System Cost	$2.86	/Wp
Annual Solar Degradation Factor	0.50%	
Total Storage Project Size	464	kWh
Year-1 Demand Reduction	424	kW
Storage System Cost	$795	/kWh
Number of PG&E Accounts	2	

Avoided Cost & Revenue Sources		
Savings from Solar Production, yr-1	$0.0929	/kWh
Savings from Demand Reduction, yr-1	$51.46	/kW
Savings from Arbitrage, yr-1	$0.030	/kWh
Estimated Utility Energy Cost Escalator	3.00%	
Average 25-year REC Price	$0.0040	/kWh

Asset Management Services Assumptions		
Asset Management Services, Solar (client-owned)	$0.0200	/kWh
Asset Management Services, Storage (client-owned)	$1,000	/battery
Asset Management Services Escalator	3.00%	

Resiliency		
Backup Duration on Worst Day - San Jose Station	6.75	hours

Total Net Benefit (25 years)	
Gross Project Benefit	$5,953,793
Total Initial Project Cost	($3,655,357)
Operating Expenses	($1,716,601)
Other Expenses	($430,418)
Total Net Benefit	$151,417

Cash Flow

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Electricity

Year	Annual Solar Production (kWh)	Annual Storage kWh Discharged	Solar Savings per kWh Produced	Annual Demand Reduction (kW)	Demand Savings per kW Reduced	Storage Savings per kWh Discharged
2022	-	-	$ -	-	$ -	$ -
2023	1,736,056	121,819	$ 0.0929	424	$ 51.46	$ 0.030
2024	1,727,376	121,819	$ 0.0957	424	$ 52.74	$ 0.030
2025	1,718,739	121,819	$ 0.0986	424	$ 54.05	$ 0.031
2026	1,710,145	121,819	$ 0.1015	424	$ 55.39	$ 0.032
2027	1,701,594	121,819	$ 0.1046	424	$ 56.77	$ 0.033
2028	1,693,086	121,819	$ 0.1077	424	$ 58.18	$ 0.034
2029	1,684,621	121,819	$ 0.1109	424	$ 59.63	$ 0.034
2030	1,676,198	121,819	$ 0.1142	424	$ 61.11	$ 0.035
2031	1,667,817	121,819	$ 0.1177	424	$ 62.63	$ 0.036
2032	1,659,478	121,819	$ 0.1212	424	$ 64.18	$ 0.037
2033	1,651,180	121,819	$ 0.1248	424	$ 65.78	$ 0.038
2034	1,642,924	121,819	$ 0.1286	424	$ 67.41	$ 0.039
2035	1,634,710	121,819	$ 0.1324	424	$ 69.09	$ 0.040
2036	1,626,536	121,819	$ 0.1364	424	$ 70.80	$ 0.041
2037	1,618,404	121,819	$ 0.1405	424	$ 72.56	$ 0.042
2038	1,610,312	-	$ 0.1447	-	$ -	$ -
2039	1,602,260	-	$ 0.1491	-	$ -	$ -
2040	1,594,249	-	$ 0.1535	-	$ -	$ -
2041	1,586,277	-	$ 0.1581	-	$ -	$ -
2042	1,578,346	-	$ 0.1629	-	$ -	$ -
2043	1,570,454	-	$ 0.1678	-	$ -	$ -
2044	1,562,602	-	$ 0.1728	-	$ -	$ -
2045	1,554,789	-	$ 0.1780	-	$ -	$ -
2046	1,547,015	-	$ 0.1833	-	$ -	$ -
2047	1,539,280	-	$ 0.1888	-	$ -	$ -
	40,894,447	**1,827,285**	**$ 0.1344**	**6,365**	**$ 71.62**	**$ 0.035**

Utility Savings

Year	Savings from Solar	Savings from Storage due to Demand Reduction	Savings from Storage due to Arbitrage	Storage Savings (Total)	**Subtotal: Annual Gross Benefits**
2022	$ -	$ -	$ -	$ -	$ -
2023	$ 161,271	$ 21,836	$ 3,612	$ 25,448	$ 186,719
2024	$ 165,278	$ 22,379	$ 3,702	$ 26,081	$ 191,359
2025	$ 169,385	$ 22,935	$ 3,794	$ 26,729	$ 196,114
2026	$ 173,595	$ 23,505	$ 3,888	$ 27,393	$ 200,988
2027	$ 177,908	$ 24,089	$ 3,985	$ 28,074	$ 205,982
2028	$ 182,330	$ 24,687	$ 4,084	$ 28,771	$ 211,101
2029	$ 186,860	$ 25,301	$ 4,185	$ 29,486	$ 216,347
2030	$ 191,504	$ 25,929	$ 4,289	$ 30,219	$ 221,723
2031	$ 196,263	$ 26,574	$ 4,396	$ 30,970	$ 227,233
2032	$ 201,140	$ 27,234	$ 4,505	$ 31,739	$ 232,879
2033	$ 206,138	$ 27,911	$ 4,617	$ 32,528	$ 238,666
2034	$ 211,261	$ 28,605	$ 4,732	$ 33,336	$ 244,597
2035	$ 216,511	$ 29,315	$ 4,850	$ 34,165	$ 250,675
2036	$ 221,891	$ 30,044	$ 4,970	$ 35,014	$ 256,905
2037	$ 227,405	$ 30,790	$ 5,094	$ 35,884	$ 263,289
2038	$ 233,056	$ -	$ -	$ -	$ 233,056
2039	$ 238,847	$ -	$ -	$ -	$ 238,847
2040	$ 244,783	$ -	$ -	$ -	$ 244,783
2041	$ 250,866	$ -	$ -	$ -	$ 250,866
2042	$ 257,100	$ -	$ -	$ -	$ 257,100
2043	$ 263,488	$ -	$ -	$ -	$ 263,488
2044	$ 270,036	$ -	$ -	$ -	$ 270,036
2045	$ 276,747	$ -	$ -	$ -	$ 276,747
2046	$ 283,624	$ -	$ -	$ -	$ 283,624
2047	$ 290,672	$ -	$ -	$ -	$ 290,672
	$ 5,497,957	**$ 391,133**	**$ 64,704**	**$ 455,837**	**$ 5,953,793**

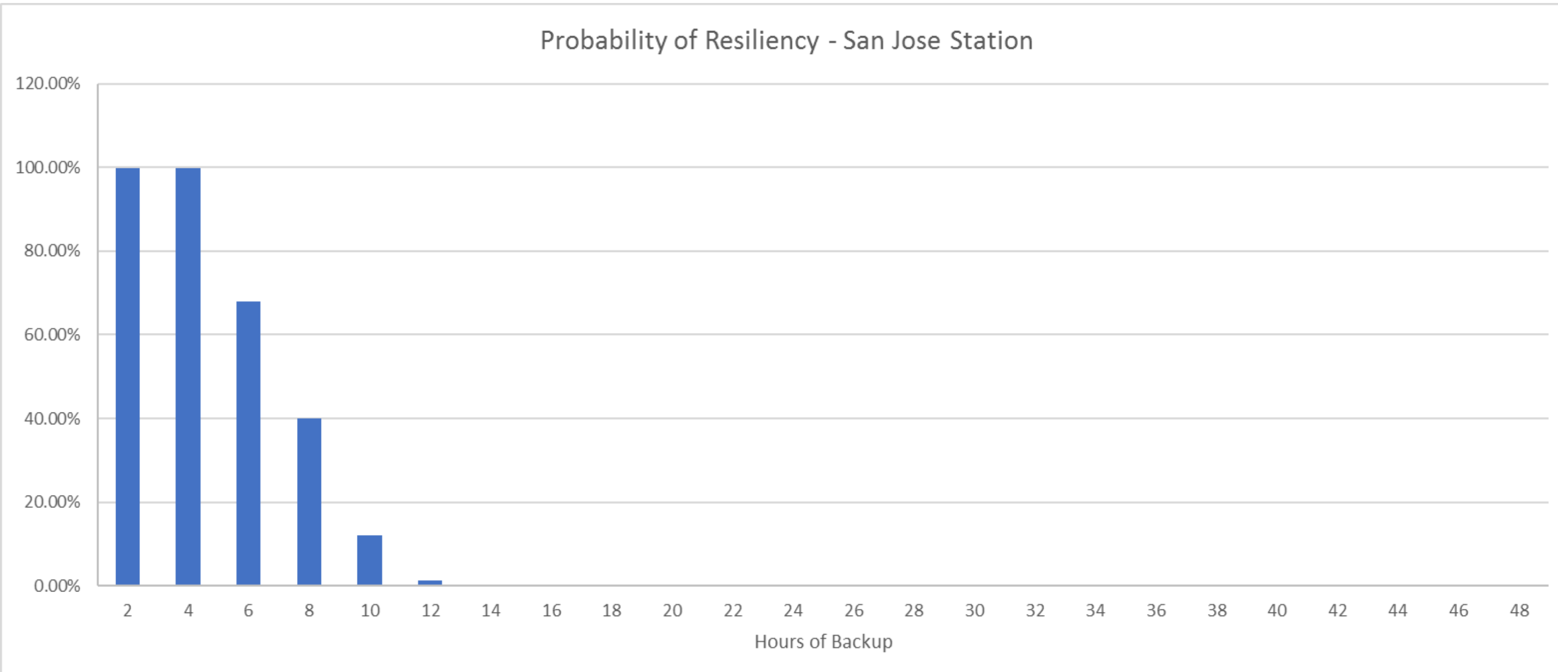
Expenses

Year	Asset Management Service (Solar & Storage)	Other Expenses	**Subtotal: Annual Operating Expenses**
2022	$ -	$ -	$ -
2023	$ (35,721)	$ (13,939)	$ (49,660)
2024	$ (36,793)	$ (14,278)	$ (51,071)
2025	$ (37,897)	$ (14,625)	$ (52,522)
2026	$ (39,033)	$ (14,981)	$ (54,015)
2027	$ (40,204)	$ (15,346)	$ (55,550)
2028	$ (41,411)	$ (15,719)	$ (57,130)
2029	$ (42,653)	$ (16,102)	$ (58,755)
2030	$ (43,932)	$ (16,494)	$ (60,427)
2031	$ (45,250)	$ (16,896)	$ (62,147)
2032	$ (46,608)	$ (17,308)	$ (63,916)
2033	$ (48,006)	$ (17,610)	$ (65,616)
2034	$ (49,446)	$ (18,042)	$ (67,489)
2035	$ (50,930)	$ (18,485)	$ (69,415)
2036	$ (52,458)	$ (18,939)	$ (71,397)
2037	$ (54,031)	$ (19,404)	$ (73,436)
2038	$ (54,094)	$ (19,795)	$ (73,890)
2039	$ (55,717)	$ (20,283)	$ (76,000)
2040	$ (57,389)	$ (20,782)	$ (78,171)
2041	$ (59,110)	$ (21,294)	$ (80,405)
2042	$ (60,884)	$ (21,819)	$ (82,703)
2043	$ (62,710)	$ (100,945)	$ (163,655)
2044	$ (64,592)	$ (101,495)	$ (166,087)
2045	$ (66,529)	$ (102,060)	$ (168,589)
2046	$ (68,525)	$ (102,638)	$ (171,163)
2047	$ (70,581)	$ (103,231)	$ (173,811)
	$ (1,284,505)	**$ (862,514)**	**$ (2,147,019)**

Cash Position

Year	Net Benefits (Solar)	Net Benefits (Storage)	Net Benefits (Total)	Cash Contribution	Total Cash	**Cumulative Cash Position**	**Conservative Cumulative Cash Position**	Term
2022	$ -	$ -	$ -	$ (3,655,357)	$ (3,655,357)	$ (3,655,357)	$ (3,655,357)	0
2023	$ 112,804	$ 24,254	$ 137,058	$ -	$ 137,058	$ (3,518,299)	$ (3,536,971)	1
2024	$ 115,432	$ 24,856	$ 140,288	$ -	$ 140,288	$ (3,378,011)	$ (3,415,819)	2
2025	$ 118,120	$ 25,473	$ 143,592	$ -	$ 143,592	$ (3,234,419)	$ (3,291,838)	3
2026	$ 120,869	$ 26,104	$ 146,973	$ -	$ 146,973	$ (3,087,446)	$ (3,164,964)	4
2027	$ 123,680	$ 26,751	$ 150,432	$ -	$ 150,432	$ (2,937,014)	$ (3,035,130)	5
2028	$ 126,556	$ 27,414	$ 153,971	$ -	$ 153,971	$ (2,783,044)	$ (2,902,270)	6
2029	$ 129,498	$ 28,094	$ 157,592	$ -	$ 157,592	$ (2,625,452)	$ (2,766,313)	7
2030	$ 132,506	$ 28,790	$ 161,296	$ -	$ 161,296	$ (2,464,156)	$ (2,627,189)	8
2031	$ 135,583	$ 29,503	$ 165,086	$ -	$ 165,086	$ (2,299,070)	$ (2,484,827)	9
2032	$ 138,729	$ 30,234	$ 168,963	$ -	$ 168,963	$ (2,130,107)	$ (2,339,151)	10
2033	$ 141,947	$ 31,103	$ 173,050	$ -	$ 173,050	$ (1,957,057)	$ (2,189,968)	11
2034	$ 145,239	$ 31,870	$ 177,109	$ -	$ 177,109	$ (1,779,948)	$ (2,037,319)	12
2035	$ 148,604	$ 32,656	$ 181,260	$ -	$ 181,260	$ (1,598,688)	$ (1,881,126)	13
2036	$ 152,046	$ 33,461	$ 185,508	$ -	$ 185,508	$ (1,413,180)	$ (1,721,309)	14
2037	$ 155,566	$ 34,287	$ 189,853	$ -	$ 189,853	$ (1,223,327)	$ (1,557,785)	15
2038	$ 159,166	$ -	$ 159,166	$ -	$ 159,166	$ (1,064,161)	$ (1,421,924)	16
2039	$ 162,847	$ -	$ 162,847	$ -	$ 162,847	$ (901,314)	$ (1,282,962)	17
2040	$ 166,611	$ -	$ 166,611	$ -	$ 166,611	$ (734,702)	$ (1,140,828)	18
2041	$ 170,461	$ -	$ 170,461	$ -	$ 170,461	$ (564,242)	$ (995,454)	19
2042	$ 174,397	$ -	$ 174,397	$ -	$ 174,397	$ (389,845)	$ (846,767)	20
2043	$ 99,834	$ -	$ 99,834	$ -	$ 99,834	$ (290,011)	$ (773,282)	21
2044	$ 103,949	$ -	$ 103,949	$ -	$ 103,949	$ (186,062)	$ (696,337)	22
2045	$ 108,158	$ -	$ 108,158	$ -	$ 108,158	$ (77,904)	$ (615,854)	23
2046	$ 112,461	$ -	$ 112,461	$ -	$ 112,461	$ 34,557	$ (531,756)	24
2047	$ 116,860	$ -	$ 116,860	$ -	$ 116,860	$ 151,417	$ (443,962)	25
	$ 3,371,924	**$ 434,850**	**$ 3,806,774**	**$ (3,655,357)**	**$ 151,417**	**$ 151,417**	**$ (443,962)**	

TerraVerde ENERGY



Disclaimers and Assumptions

1) Projections of future savings are calculated based on patterns of previous electricity usage with billing data from January 2020, and assume that historical usage patterns hold at the same level over the life of the project.

2) Projections based on stated assumptions. Final solar project size and costs will be based on the results of a procurement solicitation process.

3) Projections are subject to tariff eligibility over the life of the installation. This analysis uses PG&E rates published May 2020.

4) Projections are based on interconnection of all sites under NEM 2.0 tariff. Remaining capacity under NEM 2.0 is subject to availability. NEM 3.0 proceedings are underway and NEM 2.0 may be replaced with NEM 3.0 as soon as December 2021.

5) Net Operating Benefit does not include repayment of any client capital that may be invested.

6) NEM-A analysis assumes the client solely owns contiguous parcels where the aggregated meters exist.

7) NEM projects are grandfathered for 20 years. Savings shown beyond year 20 are subject to change based on future NEM structure.

8) This analysis assumes SGIP is unavailable due to project timing.

9) Other Expenses includes insurance, contingency, array washing and other O&M.

10) This analysis assumes a 26.0% Investment Tax Credit based on starting construction prior to 2022. This does not constitute tax advice and should seek professional tax advice from their tax advisors to confirm all potential tax savings and the assumptions made in this analysis

Pro Forma

Feasibility Study

Scenarios Included in this Pro Forma:

#1 - Battery Savings to Provider
#2 - Battery Cash Purchase

Summary of Results

Financing Scenario	Net Benefit Year 1	Net Benefit Years 1-10	Net Benefit Years 1-15	Years to Payback
#1 - Battery Savings to Provider	$ (22,801)	$ (232,018)	$ (348,879)	n/a
#2 - Battery Cash Purchase	$ (1,332,165)	$ (433,885)	$ 181,320	14

Project Portfolio

Meter Name	Service Account ID	Meter Number	Connection Level	Rate (Current)	Rate (New TOU)	Rate (After Project)	Program	Customer Usage (kWh)	Max Demand (kW)
#1 - 7150 MONTEREY ST GILROY, CA 95020	4552324481	4552324481	S	E-19	B-19	B-19	AES	254,741	618
Portfolio Totals								254,741	618

Savings

Meter Name	Service Account ID	Cumulative Demand (kW)	Demand Reduction (kW)	Energy Discharged (kWh)	Battery Sizing	Battery Size (kWh)	Battery Size (kW)	Battery Savings From Demand Reduction (total)	Battery Savings From Demand Reduction ($/kW)	Battery Savings From Arbitrage (total)	Battery Savings From Arbitrage ($/kWh)
#1 - 7150 MONTEREY ST GILROY, CA 95020	4552324481	4,893	2,950	86,787	60%	2,320	580	$ 89,352	$ 30.29	$ 1,573	$ 0.0181
Totals		4,893	2,950	86,787	60%	2,320	580	$ 89,352	$ 30.29	$ 1,573	$ 0.018

Dashboard

Scenario: #1 - Battery Savings to Provider

Technical Assumptions		
Total Storage Project Size	2,320	kWh
Year-1 Demand Reduction	2,950	kW
Number of PG&E Accounts	1	

Avoided Cost & Revenue Sources		
Savings from Demand Reduction, yr-1	$30.29	/kW
Estimated Utility Energy Cost Escalator	3.00%	

Pricing	
Battery Savings to Provider	120%

Asset Management Services Assumptions		
Asset Management Services, Storage	$1,000	/battery
Asset Management Services Escalator	3.00%	

Resiliency		
Backup Duration on Worst Day - 4552324481	23.75	hours
Backup Duration on Worst Day - 4552324646	18.75	hours

Total Net Benefit (15 years)	
Gross Project Benefit	$1,691,093
Payments to 3rd Party Provider	($2,021,373)
Operating Expenses	($18,599)
Total Net Benefit	($348,879)

Cash Flow

	Electricity	Utility Savings				Expenses			Cash Position			
Year	Annual Demand Reduction (kW)	Savings from Storage due to Demand Reduction	Savings from Storage due to Arbitrage	Storage Savings (Total)	**Subtotal: Annual Gross Benefits**	Battery Payments to Provider	Asset Management Service (Storage)	**Subtotal: Annual Operating Expenses**	Net Benefits (Storage)	**Cumulative Cash Position**	**Conservative Cumulative Cash Position**	Term
2022	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0
2023	2,950	$ 89,352	$ 1,573	$ 90,924	$ 90,924	$ (112,725)	$ (1,000)	$ (113,725)	$ (22,801)	$ (22,801)	$ (31,893)	1
2024	2,950	$ 92,032	$ 1,620	$ 93,652	$ 93,652	$ (115,543)	$ (1,030)	$ (116,573)	$ (22,921)	$ (45,721)	$ (64,179)	2
2025	2,950	$ 94,793	$ 1,668	$ 96,462	$ 96,462	$ (118,432)	$ (1,061)	$ (119,492)	$ (23,031)	$ (68,752)	$ (96,856)	3
2026	2,950	$ 97,637	$ 1,719	$ 99,355	$ 99,355	$ (121,392)	$ (1,093)	$ (122,485)	$ (23,130)	$ (91,882)	$ (129,921)	4
2027	2,950	$ 100,566	$ 1,770	$ 102,336	$ 102,336	$ (124,427)	$ (1,126)	$ (125,553)	$ (23,217)	$ (115,098)	$ (163,371)	5
2028	2,950	$ 103,583	$ 1,823	$ 105,406	$ 105,406	$ (127,538)	$ (1,159)	$ (128,697)	$ (23,291)	$ (138,389)	$ (197,203)	6
2029	2,950	$ 106,690	$ 1,878	$ 108,568	$ 108,568	$ (130,726)	$ (1,194)	$ (131,920)	$ (23,352)	$ (161,741)	$ (231,411)	7
2030	2,950	$ 109,891	$ 1,934	$ 111,825	$ 111,825	$ (133,994)	$ (1,230)	$ (135,224)	$ (23,399)	$ (185,140)	$ (265,993)	8
2031	2,950	$ 113,188	$ 1,992	$ 115,180	$ 115,180	$ (137,344)	$ (1,267)	$ (138,611)	$ (23,431)	$ (208,571)	$ (300,942)	9
2032	2,950	$ 116,584	$ 2,052	$ 118,636	$ 118,636	$ (140,778)	$ (1,305)	$ (142,083)	$ (23,447)	$ (232,018)	$ (336,252)	10
2033	2,950	$ 120,081	$ 2,114	$ 122,195	$ 122,195	$ (144,297)	$ (1,344)	$ (145,641)	$ (23,447)	$ (255,464)	$ (371,918)	11
2034	2,950	$ 123,684	$ 2,177	$ 125,861	$ 125,861	$ (147,905)	$ (1,384)	$ (149,289)	$ (23,428)	$ (278,893)	$ (407,933)	12
2035	2,950	$ 127,394	$ 2,242	$ 129,636	$ 129,636	$ (151,602)	$ (1,426)	$ (153,028)	$ (23,392)	$ (302,285)	$ (444,288)	13
2036	2,950	$ 131,216	$ 2,310	$ 133,525	$ 133,525	$ (155,392)	$ (1,469)	$ (156,861)	$ (23,336)	$ (325,620)	$ (480,976)	14
2037	2,950	$ 135,152	$ 2,379	$ 137,531	$ 137,531	$ (159,277)	$ (1,513)	$ (160,790)	$ (23,259)	$ (348,879)	$ (517,988)	15
	44,246	$ 1,661,843	$ 29,251	$ 1,691,093	$ 1,691,093	$ (2,021,373)	$ (18,599)	$ (2,039,972)	$ (348,879)	$ (348,879)	$ (517,988)	

Dashboard

Scenario: #2 - Battery Cash Purchase

Technical Assumptions		
Total Storage Project Size	2,320	kWh
Year-1 Demand Reduction	2,950	kW
Storage System Cost	$611	/kWh
Number of PG&E Accounts	1	

Avoided Cost & Revenue Sources		
Savings from Demand Reduction, yr-1	$30.29	/kW
Estimated Utility Energy Cost Escalator	3.00%	

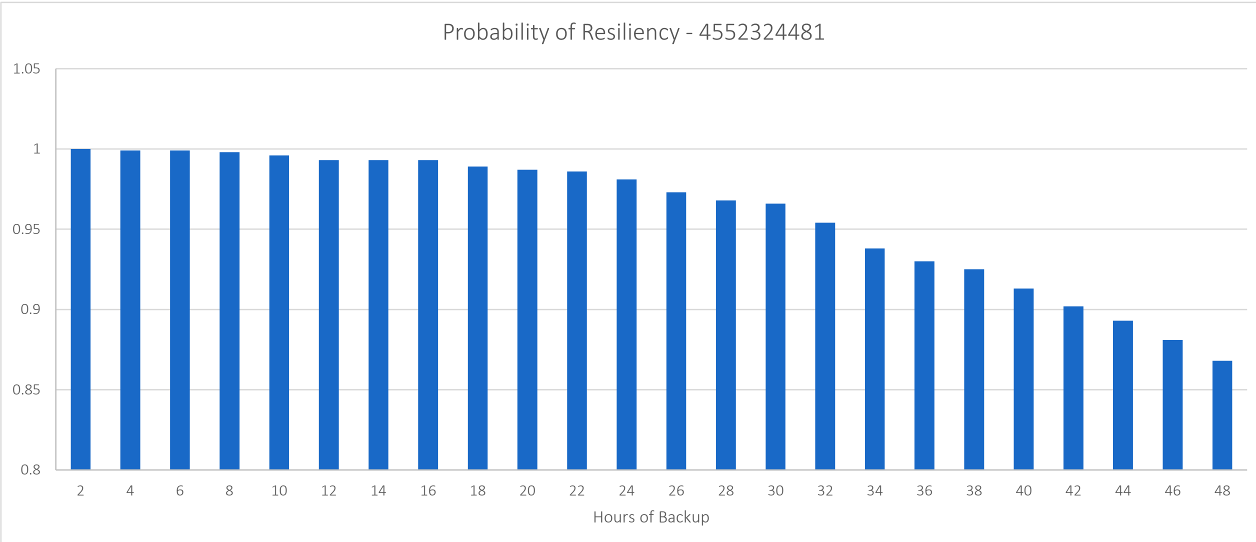
Asset Management Services Assumptions		
Asset Management Services, Storage (client-owned)	$1,000	/battery
Asset Management Services Escalator	3.00%	

Resiliency		
Backup Duration on Worst Day - 4552324481	23.75	hours
Backup Duration on Worst Day - 4552324646	18.75	hours

Total Net Benefit (15 years)	
Gross Project Benefit	$1,691,093
Total Initial Project Cost	($1,417,775)
Operating Expenses	($86,234)
Other Expenses	($5,764)
Total Net Benefit	$181,320

Cash Flow

	Electricity	Utility Savings				Expenses			Cash Position					
Year	Annual Demand Reduction (kW)	Savings from Storage due to Demand Reduction	Savings from Storage due to Arbitrage	Storage Savings (Total)	**Subtotal: Annual Gross Benefits**	Asset Management Service (Storage)	Other Expenses	**Subtotal: Annual Operating Expenses**	Net Benefits (Storage)	Cash Contribution	Total Cash	**Cumulative Cash Position**	**Conservative Cumulative Cash Position**	Term
2022	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,417,775)	$ (1,417,775)	$ (1,417,775)	$ (1,417,775)	0
2023	2,950	$ 89,352	$ 1,573	$ 90,924	$ 90,924	$ (1,000)	$ (4,315)	$ (5,315)	$ 85,610	$ -	$ 85,610	$ (1,332,165)	$ (1,341,258)	1
2024	2,950	$ 92,032	$ 1,620	$ 93,652	$ 93,652	$ (1,030)	$ (4,396)	$ (5,426)	$ 88,226	$ -	$ 88,226	$ (1,243,939)	$ (1,262,397)	2
2025	2,950	$ 94,793	$ 1,668	$ 96,462	$ 96,462	$ (1,061)	$ (4,478)	$ (5,539)	$ 90,922	$ -	$ 90,922	$ (1,153,017)	$ (1,181,120)	3
2026	2,950	$ 97,637	$ 1,719	$ 99,355	$ 99,355	$ (1,093)	$ (4,563)	$ (5,655)	$ 93,700	$ -	$ 93,700	$ (1,059,316)	$ (1,097,356)	4
2027	2,950	$ 100,566	$ 1,770	$ 102,336	$ 102,336	$ (1,126)	$ (4,648)	$ (5,774)	$ 96,562	$ -	$ 96,562	$ (962,754)	$ (1,011,027)	5
2028	2,950	$ 103,583	$ 1,823	$ 105,406	$ 105,406	$ (1,159)	$ (4,736)	$ (5,895)	$ 99,511	$ -	$ 99,511	$ (863,244)	$ (922,057)	6
2029	2,950	$ 106,690	$ 1,878	$ 108,568	$ 108,568	$ (1,194)	$ (4,825)	$ (6,020)	$ 102,549	$ -	$ 102,549	$ (760,695)	$ (830,365)	7
2030	2,950	$ 109,891	$ 1,934	$ 111,825	$ 111,825	$ (1,230)	$ (4,917)	$ (6,146)	$ 105,679	$ -	$ 105,679	$ (655,016)	$ (735,869)	8
2031	2,950	$ 113,188	$ 1,992	$ 115,180	$ 115,180	$ (1,267)	$ (5,009)	$ (6,276)	$ 108,904	$ -	$ 108,904	$ (546,112)	$ (638,483)	9
2032	2,950	$ 116,584	$ 2,052	$ 118,636	$ 118,636	$ (1,305)	$ (5,104)	$ (6,409)	$ 112,227	$ -	$ 112,227	$ (433,885)	$ (538,120)	10
2033	2,950	$ 120,081	$ 2,114	$ 122,195	$ 122,195	$ (1,344)	$ (5,081)	$ (6,425)	$ 115,770	$ -	$ 115,770	$ (318,115)	$ (434,569)	11
2034	2,950	$ 123,684	$ 2,177	$ 125,861	$ 125,861	$ (1,384)	$ (5,179)	$ (6,563)	$ 119,297	$ -	$ 119,297	$ (198,818)	$ (327,858)	12
2035	2,950	$ 127,394	$ 2,242	$ 129,636	$ 129,636	$ (1,426)	$ (5,280)	$ (6,705)	$ 122,931	$ -	$ 122,931	$ (75,887)	$ (217,891)	13
2036	2,950	$ 131,216	$ 2,310	$ 133,525	$ 133,525	$ (1,469)	$ (5,382)	$ (6,851)	$ 126,675	$ -	$ 126,675	$ 50,788	$ (104,568)	14
2037	2,950	$ 135,152	$ 2,379	$ 137,531	$ 137,531	$ (1,513)	$ (5,486)	$ (6,999)	$ 130,532	$ -	$ 130,532	$ 181,320	$ 12,211	15
	44,246	**$ 1,661,843**	**$ 29,251**	**$ 1,691,093**	**$ 1,691,093**	**$ (18,599)**	**$ (73,399)**	**$ (91,998)**	**$ 1,599,095**	**$ (1,417,775)**	**$ 181,320**	**$ 181,320**	**$ 12,211**	


Probability of Resiliency - 4552324481
1.05
1
0.95
0.9
0.85
0.8
2 4 6 8 10 12 14 16 18 20 22 24 26 28 30 32 34 36 38 40 42 44 46 48
Hours of Backup

Disclaimers and Assumptions

1) Projections of future savings are calculated based on patterns of previous electricity usage with billing data from February 2020, and assume that historical usage patterns hold at the same level over the life of the project.

2) Projections based on stated assumptions. Final system size and costs will be based on the results of a procurement solicitation process.

3) Projections are subject to tariff eligibility over the life of the installation. This analysis uses PG&E rates published May 2020.

4) Net Operating Benefit does not include repayment of any client capital that may be invested.

5) This analysis assumes SGIP is unavailable due to project timing.

6) Other Expenses includes insurance, PDP and other O&M.

APPENDIX F CA HSR TRAIN CONTROL POWER SUPPLY ALTERNATIVES MATRIX

CA HSR Train Control Power Supply Alternatives Matrix

	APPLICATION								
	Track Circuits	**Wayside Signal Locations**	**Universal Interlockings**	**Interlockings at or near stations and yards**	**Stations**	**Radio Tower**	**Wayside Intrusion Devices**	**Wayside Defect Detectors**	**Notes**
Estimated Power Load Per Location	200W	400W	5KW	10KW	5KW	3KW	200W	200W	
Supply Alternatives									
Power Cable from adjacent location	Possible, if distant then other options must be compared	Possible, if distant then other options must be compared	Possible, if distant then other options must be compared	Recommended; power from utility feed, assumption is that utility power will be available at stations and yards.	The assumption is that utility power will be available at stations and fed directly to all equipment facilities within the station.	Possible, if distant then other options must be compared	Possible, if distant then other options must be compared	Possible, if distant then other options must be compared	1
Power Cable from nearest traction power facility	Possible, if distant then other options must be compared	Possible, if distant then other options must be compared	Possible, if distant then other options must be compared	Not recommended; power from utility feed, assumption is that utility power will be available at stations and yards.	Not Recommended, assumption is that utility power will be available at stations.	Possible, if distant then other options must be compared	Possible, if distant then other options must be compared	Possible, if distant then other options must be compared	1
Local Power cable feed from utility	Recommended where local power is close	Recommended where local power is close	Recommended where local power is close	Not recommended; power from utility feed, assumption is that utility power will be available at stations and yards.	Recommended, assumption is that utility power will be available at all stations.	Possible, if distant then other options must be compared	Not Recommended	Not Recommended	2
Drop from OCS or Negative Feeder	Possible, recommended where local power is distant, consider solar as a back-up.	Possible, recommended where local power is distant, consider solar as a back-up.	Not recommended; maintenance train moves will require reliable interlocking operation when OCS is isolated.	Not recommended; power from utility feed, assumption is that utility power will be available at stations and yards.	Not Recommended; assumption is that utility power will be available at yards.	Not recommended; maintenance train moves will require reliable radio operation when OCS is isolated.	Possible, recommended where local power is distant, consider solar as a back-up.	Possible, recommended where local power is distant, consider solar as a back-up.	3
Solar Power	Possible for very remote locations as a back up to distant feeds from remote facilities. Maintenance of solar panels must be taken into consideration.	Possible for very remote locations as a back up to distant feeds from remote facilities. Maintenance of solar panels must be taken into consideration.	Not recommended due to power load from a high number of switch machines; larger load than wayside signal locations	Not recommended; power from utility feed, assumption is that utility power will be available at stations and yards.	Not Recommended, assumption is that utility power will be available at stations.	Possible for very remote locations as a back up to distant feeds from remote facilities. Maintenance of solar panels must be taken into consideration.	Possible for very remote locations as a back up to distant feeds from remote facilities. Maintenance of solar panels must be taken into consideration.	Possible for very remote locations as a back up to distant feeds from remote facilities. Maintenance of solar panels must be taken into consideration.	4
Wind Turbine (could be used in combination with solar)	Possible but not recommended due to maintenance liability of turbine	Possible but not recommended due to maintenance liability of turbine	Possible but not recommended due to maintenance liability of turbine	Not recommended; power from utility feed, assumption is that utility power will be available at stations and yards.	Not Recommended, assumption is that utility power will be available at stations.	Possible but not recommended due to maintenance liability of turbine	Possible but not recommended due to maintenance liability of turbine	Possible but not recommended due to maintenance liability of turbine	5
Type of UPS	Float charged dc batteries	Float charged dc batteries	Float charged dc batteries	Float charged dc batteries	Vital circuits using float charged dc batteries plus diesel generator for longer term outages	Float charged dc batteries	Float charged dc batteries	Float charged dc batteries	6

Source: California High Speed Rail, 2010

Notes:

1. The running of a power supply cable from a nearby location at which utility power is available must be evaluated on a case by case situation, voltage drop, cable costs, and maintenance have to be taken into account.

2. Local power from a utility is preferable from a stability and reliability standpoint in most cases, however obtaining convenient local utility drops for a reasonable cost at all locations where power is required is unlikely. Certain locations will be prohibitively expensive, and in some cases not practicable. ATC equipment at or near stations will be able to be fed from the station utility supply. ATC at or near substations and other traction power facilities will be able to be fed from the utility supply to those locations.

3. Although convenient, problems will arise when the OCS is isolated for emergencies and maintenance purposes. Although electric trains will not be moving with the OCS isolated, the ATC system will drain batteries and at some point, the signaling system will cease to function until power is restored.

4. Solar power panels are becoming highly efficient and relatively cheap, still most practicable where loads are small such as track circuits and intermediate signal locations.

5. Probably only useful in small load situations, not as efficient as solar as sufficient wind speed is less probable than sunlight in CA. Some concerns that turbines might be damaged in high speed train slipstreams.

6. To back up the primary power feed to each location, a bank of batteries shall be provided. The number of batteries in the field must be kept to a minimum, or multiple location UPSs consolidated as much as possible to ease maintenance demands. The battery type shall meet the environmental requirements and also minimize maintenance over the lifecycle of the ATC equipment.