SAMTRANS

ENERGY PROCUREMENT STRATEGY

FINAL REPORT

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WSP USA

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GLOSSARY OF TERMS

AC	Alternating Current
AES	Advanced Energy Storage
APA	Attribute Purchase Agreement
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
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
ESP	Electric Service Provider
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GRC	General Rate Case
HFTZ	High Fire Threat Zone
IOU	Investor Owned Utility(ies)
IRR	Internal rate of return
IRS	Internal Revenue Service
ITC	Investment Tax Credit
kW	Kilowatt

kWh	Kilowatt-hour
LCFS	Low Carbon Fuel Standard
LSE	Load Serving Entity
MACRS	Modified Accelerated Cost- Recovery System
MOU	Municipal Owned Utility
MW	Megawatt
MWh	Megawatt-hour
NEM	Net energy metering
NGOM	Net generation output meter
NREL	National Renewable Energy Laboratory
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
SMR	Steam methane reforming
SOP	Super-Off-Peak
TELP	Tax-exempt lease purchase
TOU	Time of Use
TV	TerraVerde Energy, LLC
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)	CCE/CCA 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). SamTrans is currently served by a CCA provider.
Demand Reduction	Decreased demand for peak power.
Direct Access Power	Direct Access (DA) is an option available to non-residential customers that would allow SamTrans to purchase their electricity directly from a third-party supplier, including products that are exposed to wholesale market pricing. Under this option, SamTrans 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)	The LCFS is 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.

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 than ineligible sources. A Power Content Label (PCL) Identifies the percentage of eligible renewable energy resources used by an energy provider.
Renewable Energy Credit (REC)	RECs are 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)	The RPS is 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.
Retail Electricity	Retail providers (e.g., investor owned utilities 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.
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 – 7 PM year-round.
Wholesale Power	The wholesale electricity market is typically a market for generators and resellers (e.g., PG&E, CCAs and Electric Service Providers), but there are some instances where large energy users are granted access to the market (e.g., BART).

EXECUTIVE SUMMARY

As SamTrans transitions from diesel- to electric-powered buses, 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.

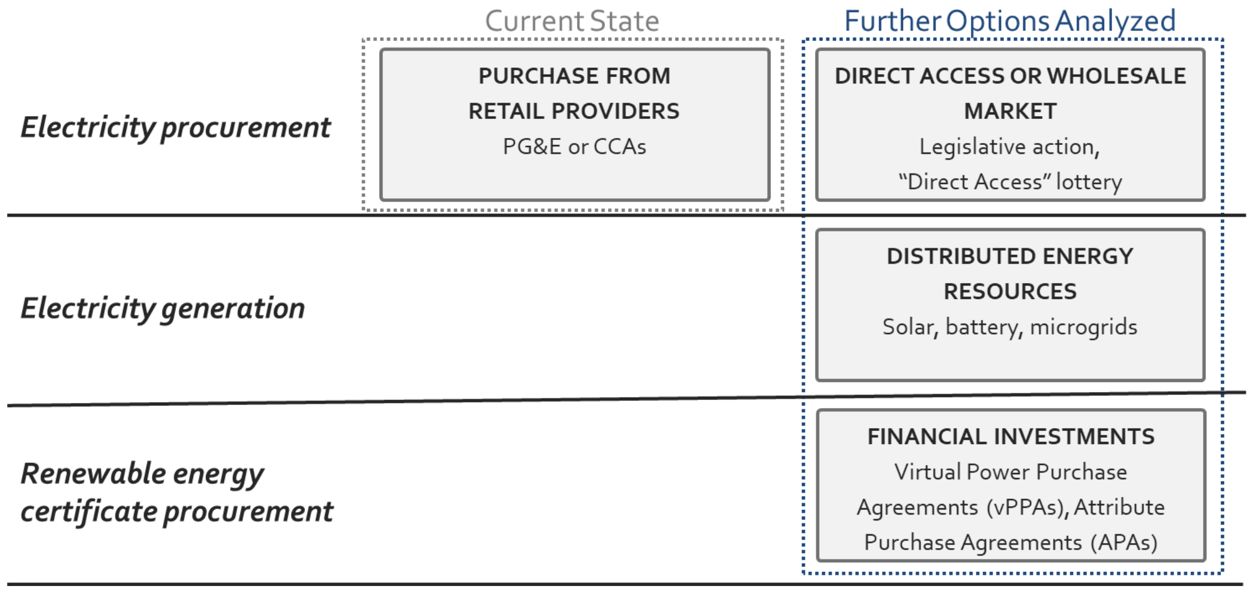
WSP and TerraVerde Energy (TerraVerde) (the "Project Team") were retained to conduct a comprehensive energy procurement study to evaluate SamTrans' short- and medium-term energy procurement options. This report provides an analysis of the electricity and technology procurement options available to SamTrans, 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 Caltrain.

The report analyzed SamTrans' total load when its bus fleet, currently comprised of diesel buses, is fully electrified and operating the same number of BEBs. While SamTrans is planning to rollout its electrification plan in phases, overall recommendations do not change.

SamTrans currently procures 100% greenhouse gas (GHG)-free and renewable electricity through Peninsula Clean Energy (PCE), a Community Choice Aggregation/Energy (CCA/CCE). This electricity is still delivered to SamTrans through Pacific Gas & Electric's (PG&E's) transmission and distribution network. Over the short-term (1 to 4 years), SamTrans 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) a CCA (in this case, PCE). SamTrans also has the option to install onsite distributed energy resource (DER) systems (a solar photovoltaic system and/or battery energy storage system) to reduce electricity procurement needs and costs.

Over the medium- to long-term (4+ years), SamTrans can continue to remain a retail electricity customer and choose between currently available providers, or it could pursue expanded retailer choice through the Direct Access (DA) or work to have access to the wholesale electricity market, provided DA capacity is available or SamTrans 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.

Figure ES-1. Energy Procurement and Technology Options



Key findings and suggestions from the study are presented in a condensed form below. For complete discussion please see the full report.

PHASE 1: SHORT-TERM ENERGY PROCUREMENT STRATEGY SUMMARY

Both PCE 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 PCE has more favorable standard rates compared to PG&E for SamTrans' existing and future electric load. The PG&E Solar Choice rate is less expensive compared to the CCA 100% renewable rate for SamTrans' existing load. However, the CCA 100% renewable rate is predicted to be less expensive compared to the PG&E Solar Choice rate for SamTrans' future battery electric bus (BEB) load. Table ES-1 summarizes the future annual costs associated with the new electrical services for full bus electrification at the North and South Operations and Maintenance (O&M) facilities.

SamTrans can also earn LCFS credits for switching from diesel buses to BEBs, which can offset a large portion of SamTrans' electricity costs[1]. The LCFS Program allows for the sale of Renewable Energy Credits (RECs) generated when low carbon fuel displaces fossil fuel use. SamTrans can sell the credits its BEB fleet generates for revenue in a statewide REC market. The potential financial benefits from the LCFS program are factored into the table, based on the use of

[1] SamTrans must register with the LCFS program and participate to receive revenues.

grid electricity and assuming full electrification. LCFS benefits scale in proportion to the amount of the fleet SamTrans has electrified and is operating.

As shown in Table ES-1, the CCA default option provides savings of approximately $137,780 over the PG&E standard rates. The PG&E Solar Choice battery electric vehicle (BEV) rates were not released at the time of this study. Therefore, the Project Team is unable to calculate the savings between the CCA 100% green option and the PG&E Solar Choice rates. However, based on a comparison of the non-BEV rates, it is expected that the CCA 100% green option will provide cost savings over the PG&E Solar Choice rate.

Table ES-1. Future Rate Analysis Summary[2]

Costs/Savings	Annual Electricity Cost (BEV Rate)	Total Electricity Costs with Grid Electricity LCFS Credit ($/YR)
PG&E Default Costs	$4,210,172	$344,508
PG&E Solar Choice Costs[3]	Unknown	Unknown
CCA Default Costs	$4,072,392	$206,728
CCA 100% Green Costs	$4,356,148	$490,484
CCA Savings (default)	**$137,780**	
CCA Savings (100% Green)	**Unknown**	

LCFS credits can increase in value if the fuel displacing fossil fuel is zero-carbon electricity. There are two pathways to achieving zero-carbon electricity for LCFS purposes: (1) through onsite renewable energy sources used to directly power the vehicles; or (2) by purchasing other qualifying 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. Pathway 2 is financially viable as long as revenue generated by the LCFS program from zero-carbon electricity exceeds the cost of the RECs. 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 $751,846 annually.

[2] Power demand reflects fully electrified fleet.
[3] The PG&E Solar Choice BEV rate was not available at the time of this study. The Solar Choice tariff has been updated with BEV rates as of March 5, 2021. A new analysis would need to be conducted to compare the cost of the Solar Choice rate and the CCA 100% Green rate.

Table ES-2. Low Carbon Fuel Standard Benefits Summary[4]

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)
North Base	15,624,203	$0.1362	$0.1627	$2,128,522	$2,542,505
South Base	12,751,320			$1,737,142	$2,075,005
TOTALS:	**28,375,523523**			**$3,865,664**	**$4,617,510**

The Project Team analyzed the feasibility of installing solar PV and/or battery energy storage (BESS) DER systems at North and South bases. Based on the analysis, a solar PV plus BESS system appears to be viable at both facilities and would yield greater economic benefits compared to solar-only. A cash purchase scenario, where SamTrans owns the solar PV and BESS infrastructure, is projected to yield greater savings compared to third-party ownership (see Table ES-3). A solar PV-only system would also be viable.

Table ES-3. Solar PV plus BESS Projected Utility Cost Impacts[5]

Site/ Scenario	Est. Capital Cost ($)/ PPA Rate ($/KWh)	SGIP[6] Incentive ($)	Cumulative Cash Position (Yr 25) ($)
North and South base 3rd Party Ownership	$0.1650 PPA + 70% shared savings BESS	TO PROVIDER	$2,231,833
North and South base Cash Purchase	$14,521,992	$2,130,800	$6,485,506

The projected solar PV production would only cover approximately 16 percent of SamTrans' estimated BEB electricity consumption. If the solar PV systems directly provide electricity to the BEB chargers, this would count as zero-carbon electricity under the LCFS program and increase SamTrans' LCFS revenue. Therefore, SamTrans would need to purchase RECs to achieve the

[4] 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.

[5] The pro formas are based on a 22 percent ITC rate. The 26 percent ITC rate was recently extended. Therefore, the third-party ownership structure would yield even greater savings if constructed were to commence in 2022.

[6] The SGIP incentive assumes the Large-Scale Storage budget based on Step 3 incentives adjusted as required by SGIP rules.

zero-carbon electricity LCFS value for its entire projected electricity consumption. As shown in Table ES-4, if SamTrans were to pursue zero-carbon LCFS credits, onsite solar PV production would reduce SamTrans' annual REC costs by approximately $89,512.

Table ES-4. Solar Production and REC Summary

Transformer	Consumption (kWh/YR)	Projected Solar PV Production (kWh/YR)	REC Cost[7] without Solar PV System ($)	REC Cost with Solar PV System ($)	Annual Reduction in REC Cost ($)
North Base	15,624,203	2,718,291	$312,484	$258,118	$54,366
South Base	12,751,320	1,757,286	$255,026	$219,881	$35,146
TOTALS:	**28,375,523**	**4,475,577**	**$567,510**	**$477,999**	**$89,512**

Short-term energy procurement findings and suggestions include:

- **The new BEB transformers should use the BEV rate Tariff.** PG&E introduced BEV rates, which can be used by SamTrans instead of the standard B-20-P rate. The BEV rate tariff provides cost savings over the B-20-P rate.
- **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 SamTrans 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 bus electrification.
- **Continue to procure electricity through regional CCA**. PCE, like most CCA providers, currently provide more cost effective rates compared to the PG&E equivalent rates. The PCE default rate is the most cost effective option available to SamTrans based on our analysis.
- **An onsite solar PV plus BESS at North and South bases will provide financial savings.** Based on current conditions and incentives, cash purchase of a solar PV and BESS system at North and South bases would provide approximately $6,485,506 savings over the lifespan of the systems. The financial benefit of a third-party ownership structure is heavily dependent on the status of the federal solar investment tax credit (ITC) at the time of

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

construction. At the time of this study, the ITC was 26 percent and set to reduce to 22 percent in 2021 and 10 percent in 2022. The Project Team prepared pro-formas based on the 22 percent and 10 percent ITC rates. Under the 22 percent rate, third-party ownership provides approximately $2,231,833 in financial savings over the lifespan of the systems. However, at 10 percent, the third-party ownership structure does not yield financial benefits. In December 2020, Congress extended the 26 percent ITC rate through the end of 2022. The rate will step down to 22 percent in 2023 and 10 percent in 2024. Therefore, if SamTrans were to contract with a third-party and start construction by the end of 2022, the total savings would be greater than identified in the financial analysis conducted as part of this study.

- **Cash purchase of the DER systems would likely not comport with SamTrans' balance sheet.** For both the solar plus DER and solar-only options, the initial project cost would corresponds to a considerable portion of unrestricted cash reserves and total operating revenues in FY 2019, even before the large financial impact of the COVID-19 pandemic. Loans, grants or specialized bonds or third-party ownership, are likely better options for SamTrans. See Section 3.36, 4.2.3, and Appendix E for more information.

- **SamTrans should consider leveraging a tax-exempt lease purchase (TELP) structure for onsite solar and/or battery systems.** This structure allows a municipality that wants to own a project, but needs to finance the purchase, to do so without the complication of issuing bonds. A TELP is essentially an installment sale of a project to a municipality. It is set up in form to look like the sponsor is leasing the project to the municipality, but the municipality has an option to purchase the project at the end of the lease term for a nominal price. The 'tax-exempt' qualification to this financing method is associated with the federal income tax exemption recognized by the lessor on the interest earnings they receive through the repayment schedule. Because the lessor does not pay federal income tax on the interest earned, the tax-exempt lease carries a much lower interest rate than other types of leases and installment loans. This significantly lowers the cost of financing to the borrower.

  While not offering direct ownership from "year 0," this option should be evaluated by SamTrans, as it allows to leverage certain incentives such as the Federal ITC described in Section 2.1.1. Under this scenario, a "tax-sponsor" (an entity other than the agency and subject to taxes) would own the project, or a portion of it, for a period of time before passing ownership to the agency, and would be able to leverage the ITC benefits which are realized in the year the solar project begins commercial operations. The duration of this initial time is normally at least five tax years, corresponding to six contract years, during which the asset vests to the owner, because, according to the "clawback" provision, the Internal Revenue Service (IRS) will recapture any unvested portion of the credit if the project owner sells it before the end of the fifth year of commercial operations. After six years the agency can buy out the unowned portion of the solar project at a depreciated fair market value. See Section 4.2.3 for more information.

- **SamTrans could also consider financing onsite solar and/or battery systems through other 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. SamTrans could also consider issuing a green bond to finance onsite DER systems. 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 battery energy storage system 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.
- **Consider purchasing RECs to increase the value of SamTrans' LCFS credits.** Achieving zero-carbon electricity provides a projected additional LCFS credit benefit of approximately $751,846, assuming a price of $20 per REC. SamTrans can reduce the amount of RECs needed if onsite solar is used to charge the BEBs. Based on the estimated value of the LCSF benefits and the costs for procuring energy, SamTrans has the potential to cover the majority of the costs of their utility bills once the fleet is fully electrified.
- **Consider implementing two energy efficiency recommendations.** SamTrans would realize minor energy and cost savings by implementing the two recommended energy efficiency improvements (upgrade belt-driven fan systems with synchronous belts and implement a chilled water supply temperature reset strategy) identified in Section 3.4.
- **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. However, a UEDM may only produce savings for SamTrans if pursued jointly with Caltrain.

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 SamTrans, but the agency can take steps now to position for future opportunities. Table ES-5 summarizes the estimated savings associated with DA or wholesale procurement.

Table ES-5. Estimated annual savings from DA or wholesale procurement versus retail

Estimated Electricity Consumption When Fully Electrified (MWh)	36,000
Percent Electrified at Plan	100%
Year Plan is Met	2032
Average Blended Rate from Task 3 Report ($/MWh)	$195
Estimated Annual Spend in Year Plan is Met (2020 dollars and rates)	$7,000,000
Estimated 10% Annual Savings Wholesale v. Retail Electricity[8]	$700,000

The emergency power review conducted as part of Phase 2 compared the various fuel sources, costs and availability of diesel, natural gas and hydrogen fuel cell emergency backup generators. Diesel emergency generators currently have the fewest barriers to entry from a capital and operational cost perspective and could be rented or shared between North and South bases. While cleaner burning, a natural gas-powered generator would require significant investment, particularly if there isn't a suitable natural gas line located adjacent to each base. Moreover, jurisdictions in the Bay Area have started to enact regulations prohibiting certain uses of natural gas. Hydrogen fuel cell emergency power generators have the lowest emissions. However, the technology is nascent, and therefore, expensive, particularly if SamTrans does not intend to purchase fuel cell vehicles. Based on SamTrans' 2020 Innovative Clean Technology (ICT) plan, SamTrans will not need significant backup power for the BEB fleet for several years. Therefore, SamTrans should monitor industry trends and reconsider hydrogen emergency power backup in the future as the technology matures.

Medium-term energy procurement findings and suggestions include:

- **SamTrans should engage the regional CCA relative to any products that would provide electricity and LCFS-compliant RECs.** PCE does not currently offer a product that meets

[8] Annual savings are <$0.5 million until 2029.

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.

- **SamTrans 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, they can choose a different electricity service provider 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 SamTrans, regardless of whether or not it pursues jointly with Caltrain. However, SamTrans' savings may be even higher if it does jointly procure with Caltrain. 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 SamTrans' anticipated load, it may be worth applying.
- **SamTrans 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. By pursuing legislation, SamTrans will have the option to switch to wholesale procurement in the future if desired.
- **SamTrans 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. SamTrans 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.
- **SamTrans 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 Electric Service Provider (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.

- **SamTrans would benefit from jointly procuring energy with Caltrain.** If SamTrans 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.
    - **If SamTrans does not procure jointly with Caltrain, it is likely not going to be financially beneficial to pursue wholesale electricity on its own, at least until full fleet electrification is reached.** SamTrans will have a much smaller load compared to Caltrain. In addition, the fleet will not be fully electrified until 2038.
- **Diesel-powered and battery electric system emergency power backup is more cost effective in the short-term.** SamTrans already has diesel infrastructure in-place and an onsite diesel-powered emergency generator. Based on the 2020 ICT Plan, the fleet will continue to need diesel fuel for another seventeen years. Therefore, it may be prudent to use traditional emergency generators initially until a larger portion of the fleet has been electrified. SamTrans could consider renting diesel generators to reduce cost and avoid investment in technology that may become obsolete in the future. In addition, if SamTrans installs a BESS at either base, the BESS system can provide backup power for a portion of the fleet.
- **SamTrans should monitor developments in hydrogen fuel cell emergency backup power technology.** The technology is currently nascent but is expected to become financially competitive in the future.
- **SamTrans should consider combining the solar PV and BESS system into a microgrid.** Installing a microgrid controller to enable the system to island from the grid would require minimal additional cost.

OPPORTUNITIES, RISKS AND TRADEOFFS

Each energy procurement decision is associated with different opportunities and risks and may have implications on other decisions. Tables ES-6 and ES-7 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-6. 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	$$$	🍃🍃🍃	✓	
Direct Access (DA)	Medium-term	High	$-$	🍃🍃🍃	✓	
Purchasing Wholesale Electricity						
Procuring Power on the Wholesale Market	Long-term	High	$-$	🍃🍃		
Wholesale Power Purchase Agreements (PPA)	Long-term	High	$-$	🍃🍃🍃		
On-Site Energy Resources						
Solar PV	Medium-term	Medium	$$$	🍃🍃🍃🍃	✓	✓
Battery Energy Storage	Medium-term	Medium	$$	🍃🍃🍃	✓	✓
Hydrogen	Long-term	High	$$$$	🍃🍃	✓	✓
Other Opportunities						
Renewable Energy Credits (REC)	Near-term	Medium	$	🍃		
Low Carbon Fuel Standard (LCFS) Credits	Near-term	Medium	$$$$	🍃🍃		
Grid Services Programs	Medium-term	Medium	$	🍃		

Table ES-7. 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 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

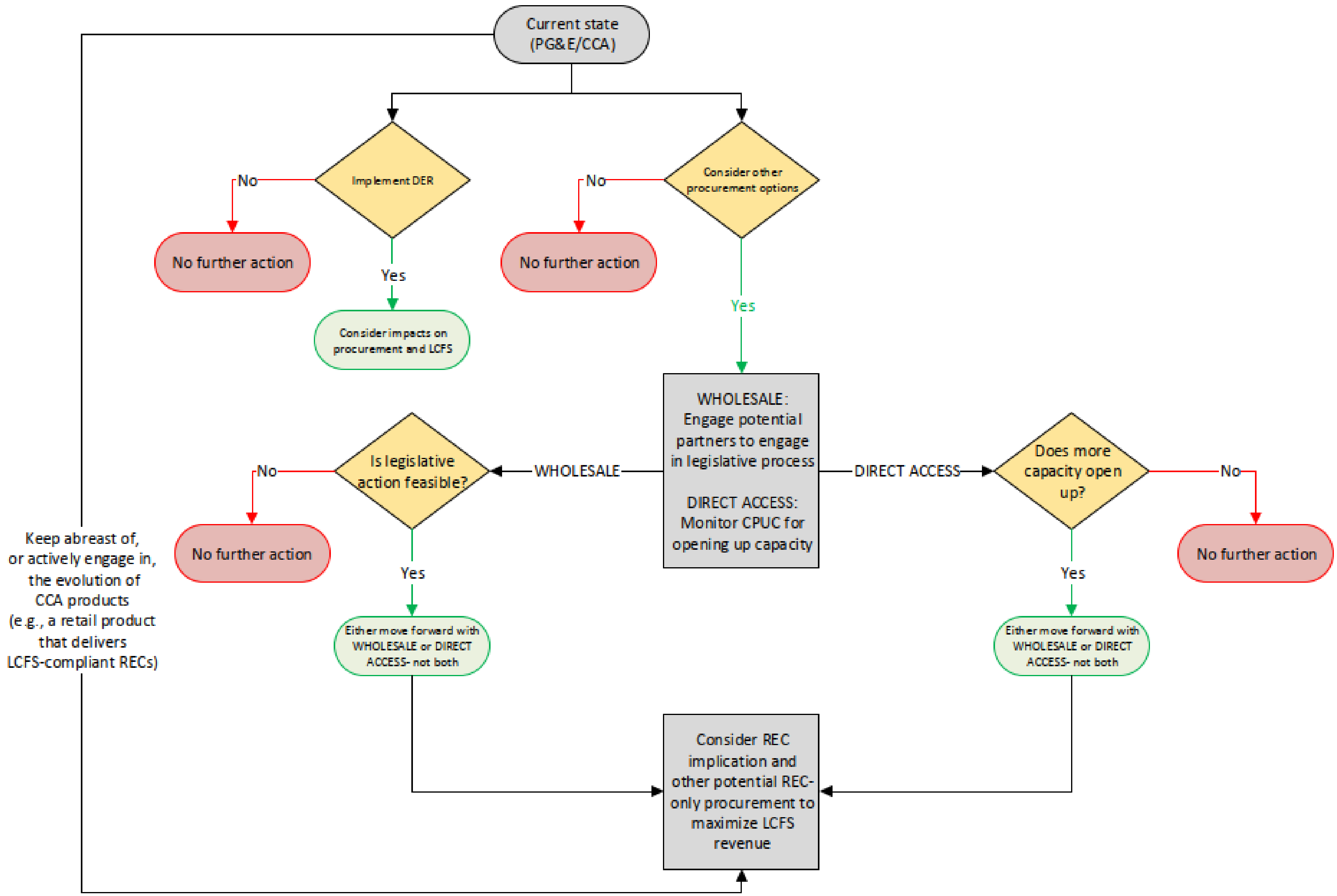
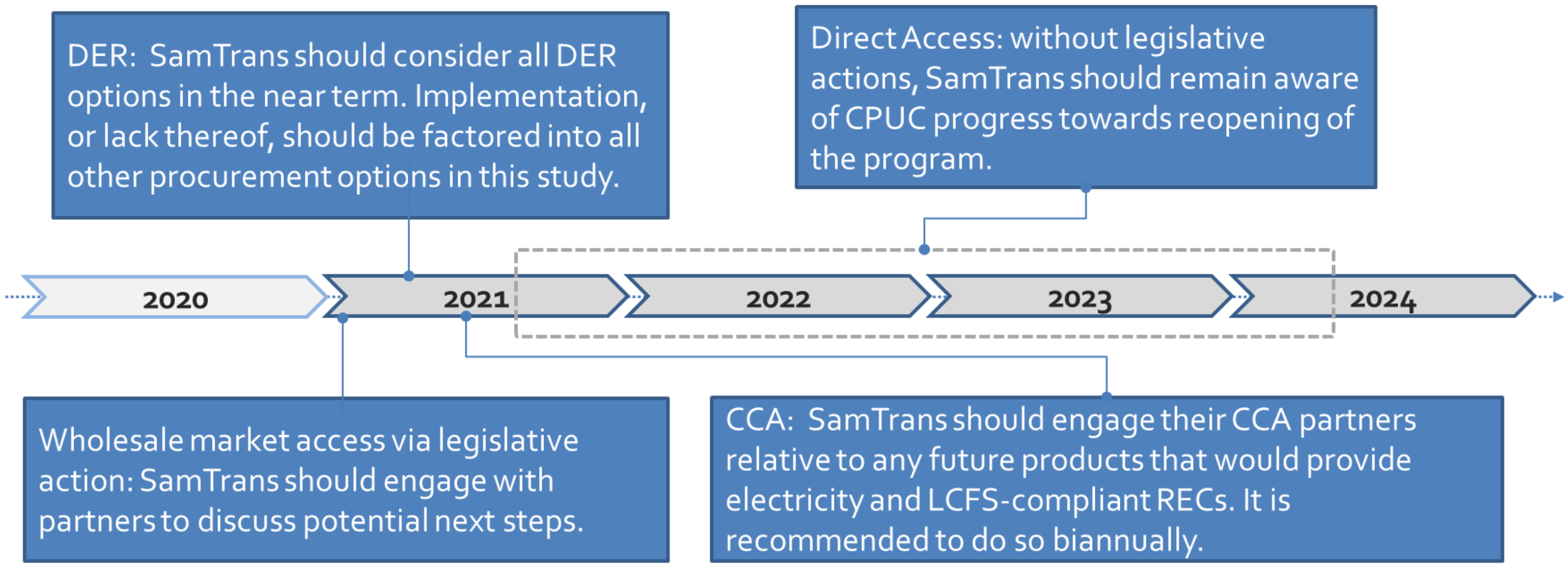


Figure ES-3. Time Horizon



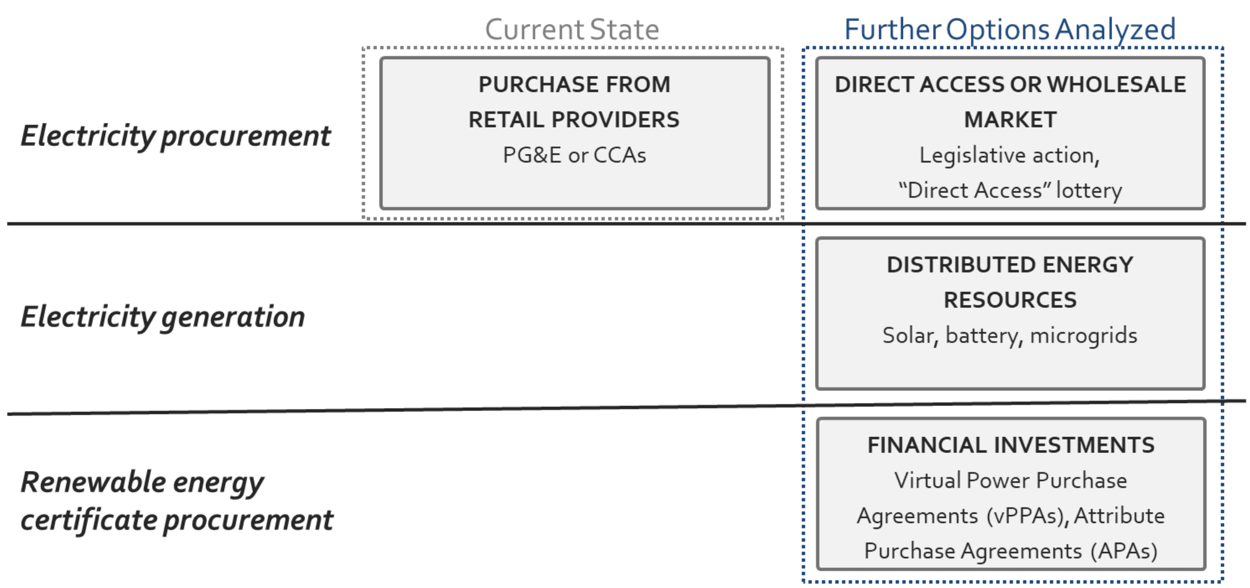
** Consideration of renewable energy certificate procurement should be considered throughout in relation to electricity procurement decisions*

1 INTRODUCTION

As SamTrans transitions from diesel to electric buses, 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 SamTrans' short and medium-term energy procurement options. This report provides an analysis of the electricity and technology procurement options available to SamTrans 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[9]



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

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

Figure 2. SamTrans Electricity Consumption Projection[10]

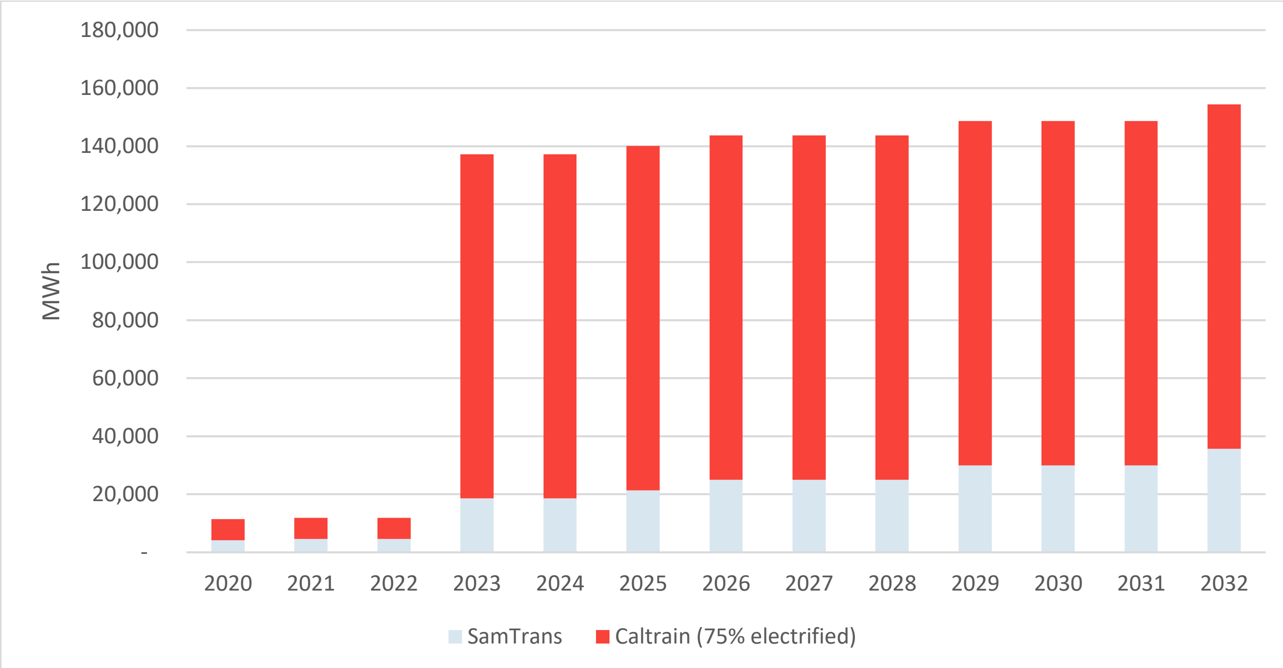
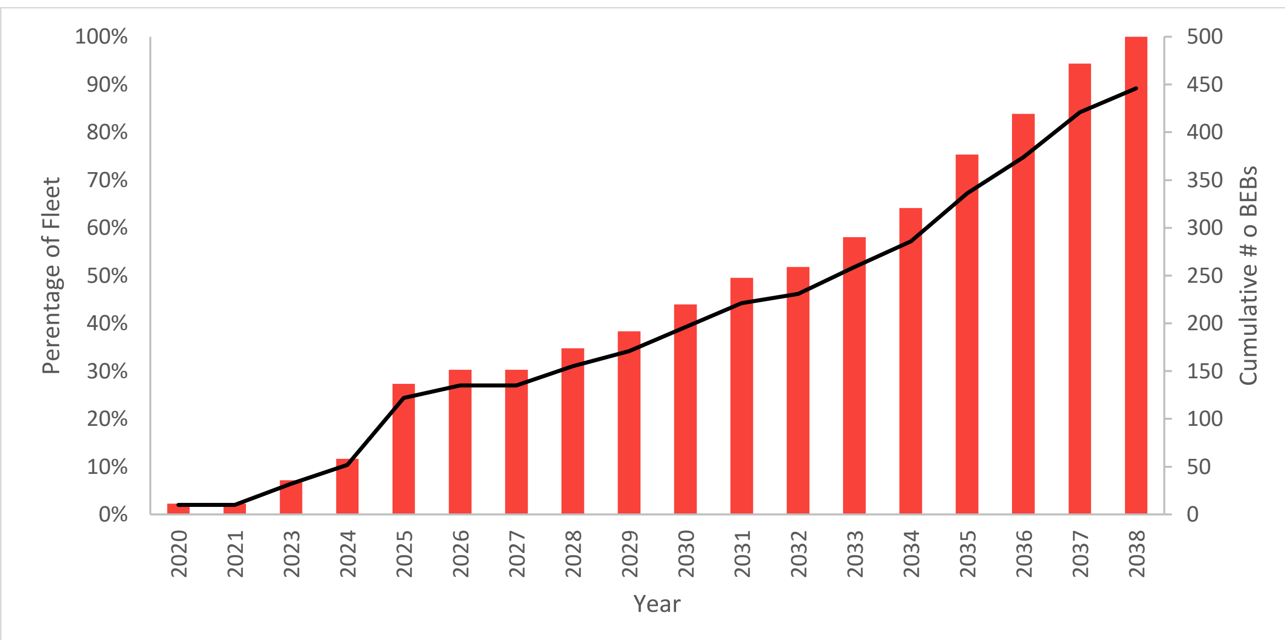


Figure 3. BEB Transition Timeframe[11]



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[10] This study is based on demand projections included in the HDR April 2020 demand study. Since this time, SamTrans has adopted an ICT that extends the BEB transition timeframe to 2038.

[11] SamTrans electricity consumption forecast based on bus conversion timeline from SamTrans Innovative Clean Transit (ICT) Rollout Plan December 2, 2020, available at:

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 SamTrans' 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 Caltrain and provides a timeline for SamTrans to reference as the agency considers the different options available to them currently and in the foreseeable future.
- Section 5 discusses emergency power options available to SamTrans' to provide resilience against electric grid outages.

https://www.samtrans.com/Assets/__Agendas+and+Minutes/SamTrans/Board+of+Directors/Agendas/2020/2020-12-02+ST+BOD+Meeting+Agenda.pdf#%5B%7B%22num%22%3A1425%2C%22gen%22%3A0%7D%2C%7B%22name%22%3A%22FitH%22%7D%2C792%5D.

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, SamTrans would not be eligible for these incentives. However, SamTrans 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%.[12]

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.

[12] 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

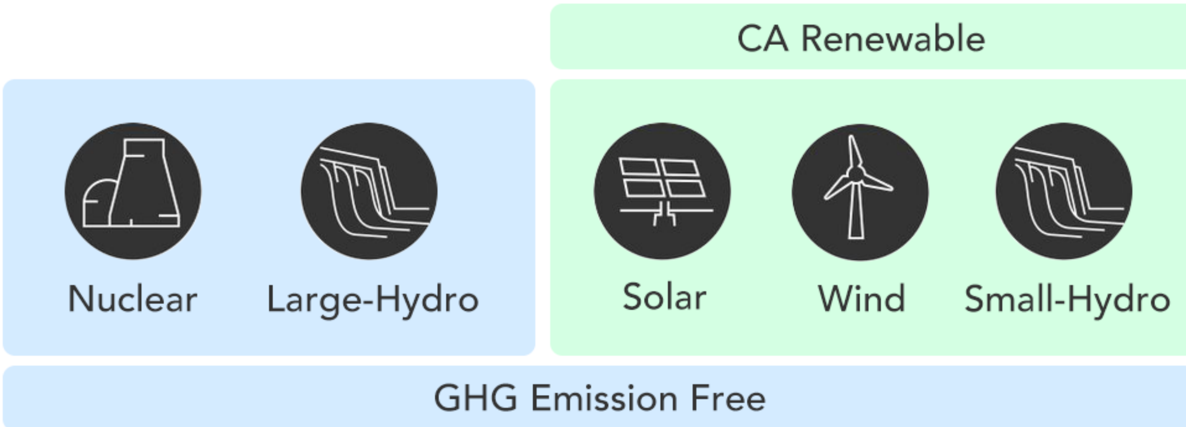
The New Markets Tax Credit (NMTC) Program was established in 2000 to incentivize community development, job creation, and economic growth by attracting investment to low-income and disadvantaged communities. The program allows taxpaying entities to receive federal income tax credits in exchange for making 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 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 4 illustrates the difference between GHG-free and renewable energy eligible for the RPS.

Figure 4. 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 SamTrans should be GHG-free regardless of provider. However, the carbon-free goal includes nuclear power and large hydroelectric power, which are not considered to be 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 1MW 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 expanded the NEM 2.0 tariff to allow battery energy storage systems to receive net energy metering credits for energy exported to the grid when the battery energy storage system is charged 100% from a renewable generation source, such as solar PV systems, and the battery energy storage system 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 time-of-use (TOU) peak periods. The decision allowed PG&E to expand the definition of the on-peak period from 12:00-6:00 pm during the summer to all year from 4:00-9:00 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 of the SamTrans 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 with and regularly report the GHG emissions reductions in order to recognize the financial benefit provided by the program. SamTrans will earn LCFS credits for switching from diesel buses to electric buses.

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 long term energy (generation) supply for customers prior to those 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 SamTrans 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 megawatt (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 electricity service provider 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, 2021), 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 high fire threat zone 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). SamTrans falls into this category. The SGIP program continues to evolve rapidly.

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, 4hr, etc.), overall battery capacity, cycling and GHG emission requirements, and site specific installation costs. Currently, PG&E’s SGIP allocation is in step 3 for the Large-Scale Storage budget, and there is approximately $16.2M in funding remaining in step 3 as of September 21, 2020. Step 3 incentive levels start at $0.35/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.

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 SamTrans' short-term (1 to 4 years) energy procurement options. Short-term options include whether to purchase electricity from PG&E or PCE and whether or not to install onsite DER systems. As part of Phase 1, the Project Team reviewed the HDR BEB Route Power Analysis V2 (HDR, 2020). Electric demand assumptions were developed based on this report.

3.1 EXISTING CONDITIONS ANALYSIS

The Project Team reviewed the route power analysis completed by HDR in April 2020 along with the 15-minute interval data in order to estimate future electric demand for the phase 1 and 2 analysis. HDR provided the 15-minute interval data in kW. The Project Team converted this to kWh for use in the future rate analysis study. Based on this review, the Project Team recommends reconsidering en-route charging as a potential solution to address longer routes and to avoid the need to procure 34 extra buses. Additional minor recommendations, points of clarification and assumptions are provided in Appendix A.

3.2 SHORT-TERM ELECTRICITY RATE ANALYSIS

The Project Team reviewed SamTrans' current energy usage and future energy usage following system electrification and conduct a rate analysis to determine the ideal (most cost effective) rates for SamTrans. The rate analysis for the existing seven SamTrans 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 (KWH)

PG&E provides energy distribution services to all SamTrans facilities. A total of seven electric utility meters served by PG&E were analyzed. One meter did not appear to be in active use. All of the PG&E accounts are enrolled with PCE 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, SamTrans consumed 4,179,478 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 TOU charges and (for certain tariffs) demand charges. The SamTrans accounts are enrolled on two different 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 below. 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 SamTrans 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	>1000 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.
BEV		BEV-1 BEV-2

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 SamTrans 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 bus electrification.

3.2.2 GHG Emissions and Renewable Energy

SamTrans currently purchases 100% GHG-free and renewable energy through PCE (ECO100). Therefore, SamTrans currently generates no market-based scope 2 GHG emissions. Table 3 compares estimated GHG emissions associated with SamTrans' 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. As shown in Table 3, SamTrans would only generate market-based scope 2 GHG emissions if the agency purchases the PG&E base plan, which is currently 86% GHG-free. The primary difference between the rates is the percentage of renewable energy. Note that in California, large hydroelectric and nuclear power generation sources are not considered to be renewable.

Table 3. GHG Emissions associated with SamTrans Electrification

Electricity Provider	Product	Current % GHG Emissions Free	Current % Renewable Energy	lb CO2e/ MWh	MWh/ year	Annual GHG Emissions (tCO2e)[1]
PG&E	Base Plan	86%	39%	206.5	28,376	2,658
	SolarChoice	100%	100%	0	28,376	0
PCE	ECOplus (default)	100%[2]	50%	0	28,376	0
	ECO100	100%	100%	0	28,376	0

1 GHG emissions were only calculated for SamTrans' new electric load.
2 As of 2021, PCE is procuring 100% GHG-free electricity across all products by 2021 and 100% RPS-eligible renewable energy by 2025.

3.2.3 Historical Rate Analysis

The historical rate analysis compares SamTrans' 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.

Table 4. Historical Rate Analysis Summary

	Current TOU Current Rates	Current TOU Ideal Rates	New TOU Similar Rates	New TOU Ideal Rates
PG&E Standard Costs	$787,089	$787,057	$796,697	$796,543
PG&E Solar Choice Costs	$800,909	$800,878	$810,517	$810,364
CCA Default Costs	$772,134	$772,104	$781,519	$781,368
CCA 100% Green Costs	$813,293	$813,263	$822,678	$822,527
CCA Savings (Default)	$14,955	$14,953	$15,177	$15,175
CCA Savings (100% Green)	($12,384)	($12,385)	($12,161)	($12,163)
Ideal Rate Savings	$31		$153	

3.2.4 Future Rate Analysis

The future rate analysis compares SamTrans' projected BEB power electricity costs under different PG&E and CCA rate structures, including the new PG&E BEV rate tariff. In order to create a cost projection for the two new electric services that are to be installed solely for the purposes of electric bus charging, the Project Team used 15-minute interval files created and provided by HDR as a result of the HDR SamTrans Route Power Analysis – V2 report (2020). In order to create a complete annual consumption profile for each of the North and South garages the Project Team combined the seasonal and daily 15-minute interval file variations that were provided by HDR. There is the potential for a variation in the total energy consumption (kWh) based on the HDR data provided, given that maximum power (kW) was provided for each 15-minute interval versus energy consumption (kWh) per 15-minute interval. The Project Team did their best to minimize the potential for large discrepancies by manipulating the data provided by HDR. Using the final annual consumption profile, the Project Team then analyzed the costs under two different rate tariffs (B-EV-2-P and B-20-P) that SamTrans is eligible for enrollment in based on the projected energy usage at both the North and South bases.

The analysis also factors in estimated value of the LCFS credits SamTrans 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.

Table 5. Future Rate Analysis

B-20 TOU RATE PROJECTED COSTS						BEV TOU RATE PROJECTED COSTS					LCFS PROJECTED BENEFITS	
SITE NAME	**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)**	**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 ELECTRICITY**
NORTH BASE	B-20	$2,537,807	$2,662,800	$2,498,256	$2,654,498	B-EV-2P	$2,384,902	Unknown	$2,302,071	$2,458,313	$2,388,358	$2,943,386
SOUTH BASE	B-20	$2,103,258	$2,205,269	$2,072,121	$2,199,635	B-EV-2P	$1,825,270	Unknown	$1,770,321	$1,897,835	$1,943,911	$2,395,654
	TOTALS:	$4,641,065	$4,868,069	$4,570,377	$4,854,133		$4,210,172		$4,072,392	$4,356,148	$4,332,269	$5,339,040
BEV RATE SAVINGS:							**$430,893**	**Unknown**	**$497,985**	**$497,985**		
CCA RATE SAVINGS:				**$70,688**	**$13,937**				**$137,780**	**Unknown**		

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 C for a summary of each account). The costs to purchase energy in the PG&E Solar Choice option varies between $0.0048/kWh for rate tariffs such as A-1 and A-6 to $0.0118/kWh for B-20-T using April 2020 rates. PCE charges an additional ($0.01/kWh) flat rate for enrollment in their 100% green energy procurement option regardless of the rate tariff. 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 seen in the future rate analysis results in Section 3.3.4, the BEV rate provides between $430,893 (PG&E standard) and $497,985 (CCA default) of annual bill savings over the B-20-P rate. The CCA default option also provides for savings of $137,780 over the PG&E standard rates.

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. Table 6 estimates the LCFS benefits associated with grid electricity.

Table 6. Future Rate Analysis Summary

Costs/Savings	Electricity Cost (New TOU BEV-2P)	Total Electricity Costs with Grid Electricity LCFS Credit ($/YR)
PG&E Default Costs	$4,210,172	$344,508
PG&E Solar Choice Costs	Unknown	Unknown
CCA Default Costs	$4,072,392	$206,728
CCA 100% Green Costs	$4,356,148	$490,484
CCA Savings (standard)	**$137,780**	

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 megawatt-hr of reported renewable energy generation. RECs can be transferred between parties and are regularly purchased by load serving entities (LSEs) as a means of complying with the California Renewable Portfolio Standard (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. The electricity generated by the proposed solar PV system would be used to generate RECs. The electricity generated by the proposed solar PV systems (see Section 3.3) would be used directly onsite to charge the electrified buses and to generate RECs. In each case, the production from the solar PV system would offset a portion of the RECs SamTrans needs to purchase to achieve zero-carbon electricity. Given that the available space for the installation of the proposed solar PV systems is limited, and the projected consumption from the electrified load is large, the solar PV system would allow SamTrans to avoid a projected cost of approximately $89,000/yr in REC market purchases as shown in Table 7.[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 System ($)[1]	REC Cost With Solar PV System ($)	Annual Reduction in REC Cost ($)
North Base	15,624,203	2,718,291	$312,484	$258,118	$54,366
South Base	12,751,320	1,757,286	$255,026	$219,881	$35,146
TOTALS:	**28,375,523**	**4,475,577**	**$567,510**	**$477,999**	**$89,512**

[13] Assumes the cost per REC is $20.

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

Site	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)
North Base	15,624,203	$0.1362	$0.1627	$2,128,522	$2,542,505
South Base	12,751,320			$1,737,142	$2,075,005
TOTALS:	**28,375,523**			**$3,865,664**	**$4,617,510**

Table 8 shows, achieving zero-carbon electricity provides a projected additional LCFS credit benefit of approximately $751,846 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 $184,335 without onsite solar (equivalent to approximately 4.5% of total electricity cost under the CCA default rate), and $273,847 with onsite solar (approximately 6.7% 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, SamTrans has the potential to cover the majority of the costs of their utility bills.

[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 DISTRIBUTED ENERGY RESOURCES

The Project Team analyzed the feasibility of installing solar and/or BESS systems at SamTrans' North and South base facilities. Based on the analysis, a solar plus BESS system would yield the greatest financial benefits for both bases.

3.3.1 Facility Information

SamTrans currently has operations at four main locations, North Base, South Base, Brewster Operations Facility and SamTrans (Central) headquarters. There are three other PG&E meters, one located at the SamTrans (Central) headquarters site and two other meters that provide lighting for parking lots.

The Project Team identified potential solar PV plus BESS layouts at North and South Bases as shown in Figure 5 and Figure 6.

Figure 5. Proposed Solar PV Layout at North Base

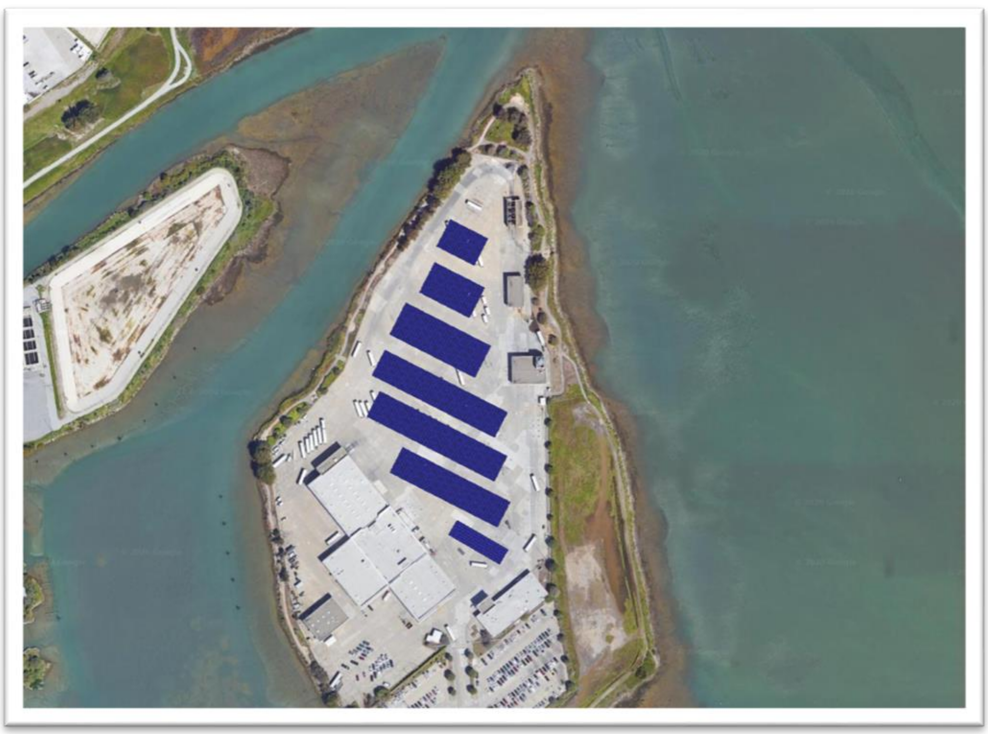
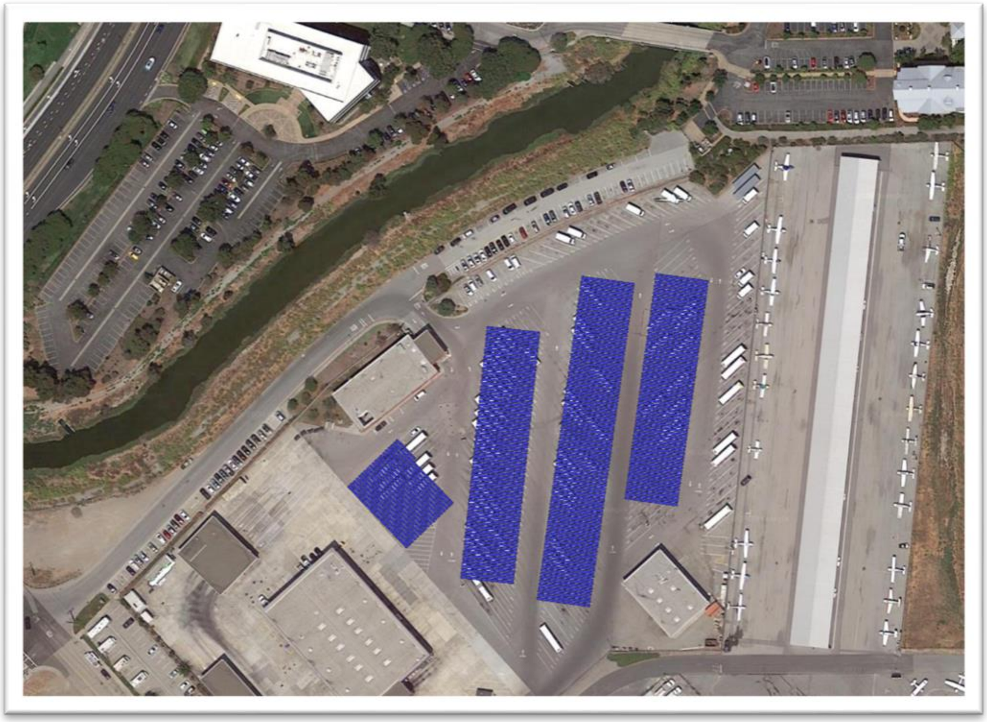


Figure 6. Proposed Solar PV Layout Of South Base



The Project Team used two main resources to evaluate SamTrans' operations for siting solar PV arrays: aerial reviews using Google Earth and a location-based production analysis tool known as Helioscope. The North and South bases were the locations investigated further for solar PV and battery energy storage installations given two factors[15]:

- These are the locations of the proposed new electrified load services;
- These locations have sufficient space to support the installation of the proposed solar PV systems.

There are existing PG&E meters at both the North and South base locations that are used to serve existing load, however, given that the energy consumption for the new electrified load PG&E services is large relative to the space availability for potential solar PV arrays, only the future meters were considered in the analysis.

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 parking spaces and are thus ideal for installation over existing parking lots. As discussed

[15] The Brewster facility was not evaluated because the consumption and demand are relatively small and SamTrans does not plan to charge future electric buses at the facility.

in the SamTrans Adaptation and Resilience Plan (2021), temperatures are projected to rise in the future and result in an increased in the number of high heat events. The solar canopies could provide relief for workers completing outdoor task during high heat events in the future. Given that bus parking involves extended length and width parking spaces in comparison to standard parking lots, a custom shade structure would be designed for each site. Engineering of the shade structures would be required to determine the location of the structure support posts but based on initial feedback from a leading contractor in the industry, there would be little to no impact to parking spaces. 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, rooftop solar could also be considered. Rooftop solar was not considered in this analysis but should SamTrans like to explore this option further, a small amount of additional solar PV capacity may be available.

The proposed battery energy storage system will be located as close as possible to the new PG&E service and will take up an electrical pad area of approximately 30 feet x 16 feet.

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.

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 7), including direct ownership and third-party ownership.

Figure 7. Example Solar Installation

Source: Images 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 EUL 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.

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.

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, the Project Team suggests that SamTrans 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.

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 SamTrans 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 effective useful life 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.

BESS INCENTIVES

- **Self-Generation Incentive Program (SGIP)** (CPUC, 2021a). 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 SamTrans 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 HDR. The projected electrical load interval data provided by HDR for each of the proposed new electrical services at North and South bases 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 is based on the calculated avoided cost which describes the cost of electricity provided by the Utility and that is replaced by the 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 prior to the installation of the solar PV systems, and the projected (or actual) billing after the PV systems are operating for a 12-month period.

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 battery energy storage system 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 battery energy storage system 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 battery energy storage system 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). Should SamTrans decide to pursue battery energy storage systems, the Project Team suggests 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

Based on the results of the review of the available space at each site for the installation of solar PV and battery energy storage systems and the anticipated consumption and billing profiles for the proposed North and South base electrified load services, a detailed financial analysis was completed. A solar PV only scenario was also completed and resulted in less savings than a combined solar PV and battery energy storage system.

Table 9 summarizes the solar and/or BESS system specifications for each site and the associated cost savings per kWh. Table 10 summarizes the estimated costs and savings for each site under a third-party ownership and cash purchase scenarios based on construction in 2022.[16] The full financial analysis can be found in Appendix E.

[16] The pro-formas for the San Jose solar PV project were completed prior to the December 2020 legislation extending the 26% ITC tax credit. Therefore, the pro-forma for the third-party ownership scenario were prepared using the 10% ITC tax credit.

Table 9. Solar PV + BESS System specification and Savings

Site	Rate Tariff	Est. Solar PV Annual Production (kWh)	Est. Solar PV Size (KW DC)	BESS Size (kW/kWh)	Solar PV Savings ($/kWh)	BESS Arbitrage Savings ($/kWh)
North Base	BEV-2P	2,718,291	1,900	1,044/4,176	$0.1251	$0.2320
South Base	BEV-2P	1,757,286	1,200	1,044/4,176	$0.1202	$0.2390

Table 10. Solar with BEV and Solar PV Projected Utility Cost Impacts

Site/Scenario	Est. Capital Cost ($)/PPA Rate ($/kWh)	SGIP[1] Incentive ($)	Est. Yr 1 Utility Gross Benefits ($)	Est. Yr 1 Expenses ($)	Est. Yr 1 Net Benefits ($)	Cumulative Cash Position (Yr 25) ($)
North and South Base – Third-Party Ownership Solar + BESS	$0.1890 PPA + 70% Shared Savings BESS	To Provider	$791,209	$1,057,803	$(266,594)	($298,403)
North and South Base – Cash Purchase Solar + BESS	$14,521,992	$2,130,800	$791,209	$130,099	$661,110	$6,485,506
North and South Base – Third-Party Ownership Solar PV Only	$0.1890 PPA	N/A	$551,460	$890.640	$(339.179)	$(2,757,261)
North and South Base – Cash Purchase Solar PV Only	$10,075,000	N/A	$551,460	$126,970	$424,491	$3,130,000

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).

Given that the solar PV and battery energy storage systems will be installed behind the PG&E meters dedicated to the electric bus charging, the Project Team reviewed the potential for the solar PV and battery energy storage to provide back-up power in terms of how many buses could be charged on a typical day during fire season, which aligns with the highest likelihood of a grid outage. Using the bus battery size assumed in the HDR study of 440kWh with a depth of discharge limit of 80%, the proposed solar PV + battery energy storage systems would be able to charge approximately thirty-three (33) buses at the North base and twenty-six (26) buses at the South base if the grid outage occurred during the day. If the grid outage occurred at night and the battery energy storage system was fully charged it would be able to charge approximately 12 buses at each base. Based on the HDR study, there are a total of one-hundred and thirty-two (132) buses anticipated to be charged at North base and a total of one-hundred and thirty-four (134) buses anticipated to be charged at the South base (not including spare buses at either base). Therefore, the proposed solar PV and battery energy storage systems would support charging approximately 25% of the bus fleet at North Base and 19% of the bus fleet at South base during a day-time grid power outage and approximately 9% of the total feet at each base during a night-time grid power outage if the systems are installed with microgrid capabilities.

The total cost for the additional equipment needed to establish the capability for the solar PV and BESS 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, but given that the services and facilities for the North and South base are currently being planned and will be newly installed, the costs should be nominal and could be coordinated with the overall site design.

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 Load Serving Entity (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 battery energy storage systems. 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.

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 battery energy storage system 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 battery energy storage system is through a competitive solicitation process that clearly outlines the revenue streams to be considered by participants.

For SamTrans, 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 SamTrans 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. However, as discussed in Section 2.1.1, the current 26% ITC was recently extended through 2022. Therefore, third-party ownership should yield financial savings if construction starts by 2023. SamTrans should update the financial analysis once detailed project specifications have been conducted.

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.

CASE PURCHASE (2021 OR 2022 START OF CONSTRUCTION)

- Year 1 Net Benefits for ***CASH PURCHASE*** - Solar PV + BESS project: **$661,110**
- 25yr Cumulative Cash Position for ***CASH PURCHASE*** - Solar PV + BESS project: **$6,485,506**

THIRD-PARTY OWNERSHIP (2021 START OF CONSTRUCTION – 22% ITC)

- Year 1 Net Benefits for ***THIRD-PARTY OWNERSHIP*** - Solar PV + BESS project: **$(159,180)**
- 25yr Cumulative Cash Position for ***THIRD-PARTY OWNERSHIP*** - Solar PV + BESS project: **$2,231,833**

THIRD-PARTY OWNERSHIP (2022 START OF CONSTRUCTION – 10% ITC)

- Year 1 Net Benefits for ***THIRD-PARTY OWNERSHIP*** - Solar PV + BESS project: **$(266,594)**
- 25yr Cumulative Cash Position for ***THIRD-PARTY OWNERSHIP*** - Solar PV + BESS project: **($298,403)**

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 assessment to evaluate potential energy efficiency opportunities at SamTrans North and South bases and the Central office. The assessment included reviews of design drawings, equipment inventory sheets, preventive maintenance protocols and a two-part interview with the Director of Facilities.

The Project Team found that the facilities are generally well-maintained and systems are operated as efficiently as could be expected given the age of certain equipment, control system limitations and the near-continuous operation of both base facilities. Central Office air handling systems are also currently running 24/7 as part of the facility's COVID-19 operations protocol. Ordinarily, Central Office systems would be enabled 1-2 hours prior to building occupancy in the mornings and disabled after 7 pm once the building is unoccupied. Other efficiency strategies and best practices noted during the assessment include:

- Completed or in-progress LED upgrades of North and South Base lighting
- Photocell exterior lighting controls
- Motion sensor interior lighting controls at North Base
- Routine completion of Preventive Maintenance Inspection Reports, which include thorough checklists for inspecting refrigeration compressor and condensing units, air handlers and packaged HVAC units, chillers and cooling towers, boilers, exhaust and ventilation fans, pumps, and controls components
- Monthly compressed air system inspections to mitigate system leaks
- Routine inspection of access points for proper weather-stripping and doorsweeps to reduce air infiltration
- North and South Base heating and ventilation unit interlocks with overhead doors, which lock out units whenever more than 3 doors are open at once
- Thermostatic control of exhaust fans
- Chiller lock-out when outside air temperature drops below 72°F
- Variable frequency control for AHU and cooling tower fans
- Zone thermostat setpoint adjustment by request only, to prevent occupant tampering

The Central Office is the oldest and most energy-intensive of the three facilities assessed and obvious deficiencies were noted from the documentation review and interview. The building was originally constructed nearly 50 years ago and some equipment and controls components remain in use today, operating well beyond their useful service life. Similarly, advanced lighting controls technologies have not been implemented and envelope leakage through single-pane windows and poorly insulated framing is reported to be significant. However, because SamTrans is planning to completely rebuild the Office facility soon, cap-ex projects to modernize HVAC systems and make the facility more energy efficient are not being considered.

The Project Team identified two efficiency measures for SamTrans to investigate and consider for implementation.

- **Upgrade belt-driven fan systems with synchronous belts.** Most belt drives in HVAC applications utilize v-belts to transfer power from the drive shaft to the fan. V-belts can achieve peak efficiency of up to 95% at time of installation. This can quickly deteriorate by 5% or more due to slippage if belt tension is not dutifully maintained on a 3 to 6-month basis. In contrast, synchronous belts, or timing belts, are 98% efficient, require minimal maintenance and retain that high efficiency throughout operation.

  While upgrading to synchronous belts is most cost-effective on systems with large motors that operate continuously, installing them on any belt-driven fan will generate appreciable energy savings. Using what was learned about the facilities' fan inventory and operational parameters, the Project Team estimates that upgrading to synchronous belts could generate up to 7,000 kWh of electrical savings. Assuming a commercial electrical rate of $0.16 per kWh, this translates to approximately $1,120 annual cost savings. Belt upgrades of this type typically result in paybacks of 3.5 – 4 years, depending on system operating conditions and prevailing materials and labor costs.

- **Implement a chilled water supply temperature reset strategy.** The Director of Facilities reported that the chilled water supply temperature for the chiller plant at the Central Office is kept constant throughout the year. The exact setpoint was not known at the time of the interview, but the Project Team recommends considering a chilled water supply temperature reset strategy to increase the setpoint incrementally when outside air conditions are mild, or when the load on the chiller is below a certain capacity. Currently, the chiller is enabled when outside air temperature exceeds 72°F. The Project Team assumes the chilled water set point to be a constant 44°F.

  - An outside air based reset strategy at the facility could function as follows: The system could potentially satisfy the building load with 46°F chilled water. In this case, a reset strategy could be implemented to have the chiller produce 46°F CHW when outside air is between 72-76°F, then reduce to 45°F CHW when outside air is between 76-80°F, and 44°F whenever outside air is greater than 80°F.

- Alternatively, a load-based reset strategy could function as follows: At 72°F, the building load could feasibly be at 60% of design and the chiller plant could potentially satisfy that load with 46°F chilled water. In this case, a reset strategy could be implemented to have the chiller produce 46°F CHW when the building load is at 60% of design, then reduce to 45°F CHW when the building load increases to 70% of design, and reduce further to 44°F whenever the building load reaches 80% of design.

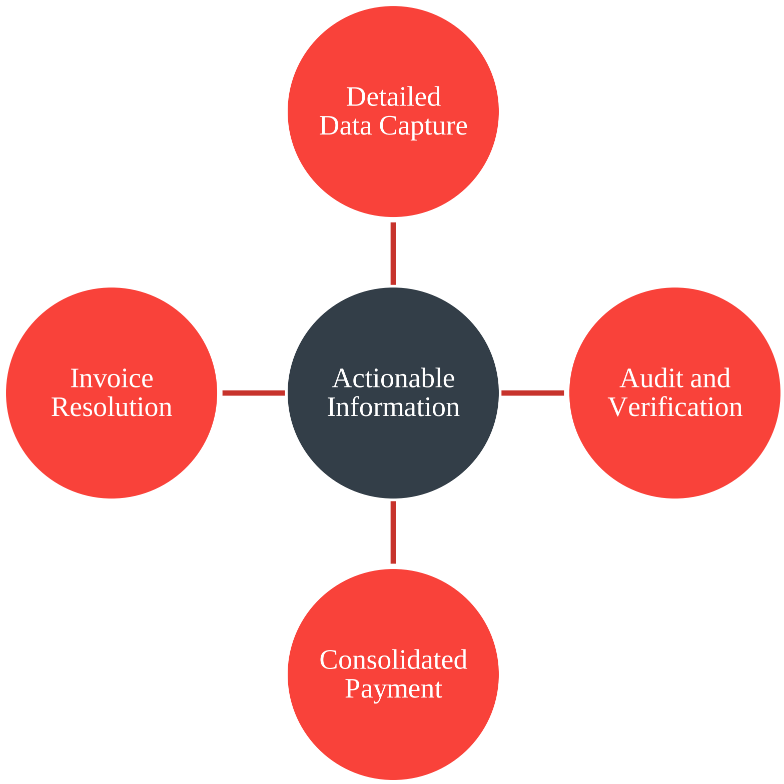
In general, a 1°F increase in chilled water supply temperature can lead to a 1-1.5% savings in chiller energy consumption. Implementing this measure would require some experimenting and fine-tuning on the part of the facility operations team to ensure that the chiller plant continues to satisfy the cooling load after the setpoint adjustments have been made. Depending on the onboard control system available at the chiller, chilled water supply temperature reset may already be a built-in function for the unit and need only be enabled and programmed with the correct parameters.

Based on our understanding of when the Central Office chiller plant is enabled, the Project Team estimates that a chilled water temperature reset measure could save over 2,000 kWh and $320 per year. Assuming that the required programming can be implemented by in-house engineers or under an existing service contract, the payback for this measure should be less than 1 year.

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 8). A UEDM can perform the following key functions:

Figure 8. 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 SamTrans' 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 11 summarizes the estimated costs to implement a UEDM for SamTrans based on the current number of meters (6). SamTrans would need to obtain a quote from a UEDM provider to confirm actual costs. Also, it is possible that the number of SamTrans meters could be too low to open a UEDM account without partnering with Caltrain.

Table 11. Estimated UEDM Costs

Implementation Fees			Costs
Implementation	**Account Setup Fee:** One-time fee for account setup	\$6.00 per account (one-time setup fee)	\$36
Historical Data Load Fee	Up to 12-months of electric and/or natural gas historical data	\$18.00 per account	\$108
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	\$252
	On-Going Account Setup Fee: One-time fee for new accounts setup	\$6.00 per account	\$36
	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	\$432
		Total Estimated Annual Costs	\$252

Estimated Savings

A UEDM system would result in the following savings:

- **Processing labor:** estimated around \$300 annually[17]

[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 (6 accounts x 12 months of bills x 5 minutes/meter)/60 minutes x \$50/hour).

- **Annual GHG inventory report cost savings:** approximately $600 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. However, due to the small number of SamTrans accounts, the savings may not be as significant.

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 BEV default rates provide the greatest financial benefit to SamTrans based on the projected electrified load. The CCA 100% GHG-free and 100% renewable rate is more costly, but could be lower than the equivalent PG&E rate (SolarChoice).

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, SamTrans could save a small amount (around $153) 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.

SamTrans will earn LCFS credits for transitioning from diesel buses to BEBs. Even using the lowest LCFS credit value (grid electricity), LCFS credits will enable SamTrans to offset a large portion of its electricity costs. SamTrans can increase the value of its LCFS credits by purchasing RECs. If SamTrans is able to install an onsite solar system at North and/or South base, this will offset a portion of the REC purchase necessary to attain the higher LCFS credit value.

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

- In March 2021 it would be advantageous to ask SamTrans' PG&E account manager to transition SAIDs 2887156370 and 2887156914 to B6. No change should be made to these accounts under the current TOU.
- The Project Team recommends that SamTrans stay with the regional CCA for its accounts at this time.
- LCFS can provide significant benefit in terms of offsetting the increased electricity costs for the new electrified loads.
- The PG&E Solar Choice kWh rate adder for the BEV rate tariff was not available at the time of the analysis, but the Project Team does not anticipate that this option would provide savings over the CCA 100% Green option given the results for the B-20-P analysis that showed the CCA 100% Green rate providing savings over the B-20-P Solar Choice rate.

- The BEV rate is preferable to the B-20-P rate for the North and South base new electrical service accounts.
- The installation of the proposed solar PV and battery energy storage systems are projected to provide financial savings for SamTrans based on utility bill savings alone and under a cash purchase scenario. Although the stand-alone solar PV system also provides financial savings under a cash purchase scenario, the projected savings are significantly higher with a combined solar PV and battery energy storage system.
- When further considering zero-carbon LCFS credits, the solar PV system has the ability to reduce the need to procure RECs through a combination of onsite solar PV consumption and retiring RECs associated with the solar PV generation.
- When considering the installation of DERs it is best to coordinate with PG&E as early as possible in the process. Given that the proposed locations of the solar PV + battery energy storage systems are behind the proposed new PG&E services at the North and South bases, informing PG&E of the plans to install solar PV + battery energy storage systems will allow for consideration during the PG&E engineering process for the new services.
- In order to maximize the ITC benefits for the proposed solar PV systems under a third-party financing option, it would be in SamTrans best interest to commence construction of the proposed solar PV projects (in compliance with IRS requirements for ITC eligibility) prior to the end of 2022, with consideration for having the new PG&E electrified load services installed and commencing operation of the electric bus services. Given the ITC extension, SamTrans should re-evaluate the financial performance of the solar PV + battery systems if it elects to consider third-party ownership.
- A RES-BCT solar PV project is an option that could be explored to provide renewable energy and utility bill savings for the existing SamTrans' electricity accounts. In order to determine if a RES-BCT solar PV project is an option, additional information regarding availability of land (approximately 40 acres of open land or a very large parking lot) that could serve as the installation location for a RES-BCT solar PV project would be required. At the time of writing, there is 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).
- SamTrans would realize a small amount of energy and cost savings by implementing the two recommended energy efficiency improvements identified in Section 3.4.
- 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.

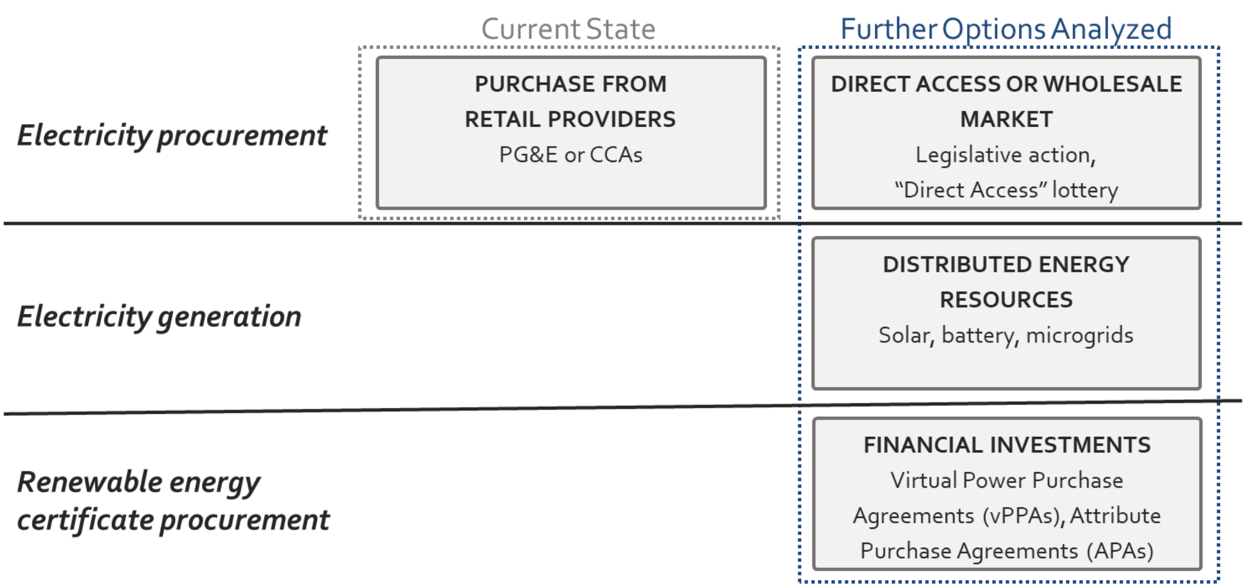
4 PHASE 2: MEDIUM-TERM ENERGY PROCUREMENT STRATEGY

The Project Team evaluated SamTrans' 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 SamTrans 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 Caltrain.

4.1 PROCUREMENT AND TECHNOLOGY OPTIONS

SamTrans currently procures electricity from Peninsula Clean Energy (PCE), which is delivered through PG&E. Over the medium to long-term (4+ years), SamTrans can continue to remain a retail electricity customer and choose between the available providers, or SamTrans 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 9.

Figure 9. Procurement and Technology Options



SamTrans 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 SamTrans 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 SamTrans' North and South bases. This section provides a description of the current technology, summary of implementation steps, discussion of potential impacts on operations and 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.

Battery energy storage systems 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, battery energy storage systems 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 Section 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 SamTrans elects to move forward with any of the identified DER projects, a more detailed onsite assessment would need to be conducted. In addition, given the recent ITC extension, SamTrans should re-evaluate the third-party financing scenario.

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. Battery energy storage systems 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 Public Safety Power Shutoff (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 Electric Service Providers), but there are some instances where large energy users are granted access to the market (e.g., BART).There are two primary mechanisms for SamTrans 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 12 provides an estimate of the potential savings for SamTrans in the year the 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 SamTrans 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 to better understand potential savings and costs to achieve those savings.

Table 12. Estimated annual savings from DA or wholesale procurement versus retail

Estimated Electricity Consumption When Fully Electrified (MWh)	36,000
Percent Electrified at Plan	100%
Year Plan is Met	2032
Average Blended Rate from Task 3 Report ($/MWh)	$195
Estimated Annual Spend in Year Plan is Met (2020 dollars and rates)	$7,000,000
Estimated 10% Annual Savings Wholesale v. Retail Electricity[18]	$700,000

DIRECT ACCESS LOTTERY

TECHNOLOGY DESCRIPTION

Direct Access is an option available to non-residential customers that would allow SamTrans to purchase their electricity directly from a competitive provider called an Electric Service Provider (ESP), including products that are exposed to wholesale market pricing. An ESP is a non-utility entity registered with the CPUC which provides electrical service to end customers within the service territory of an electric utility (CPUC, 2021b). Under this option, SamTrans would be granted the ability to contract directly with any ESP. If granted access to the DA market, SamTrans 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}[19] solar farm to serve their full load.

[18] SamTrans annual savings is < $0.5M until 2029.
[19] MW_{ac} is the output the solar array is designed to deliver to the grid.

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 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 SamTrans 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 12.

IMPACT ON OPERATIONS

The impact on electrical service to SamTrans' 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: SamTrans would need to expend resources on: monitoring the DA regulation; engage potential ESPs; and participating in the lottery (if the lottery persists in the new phase of opening up more capacity).
- Transaction: Once capacity is granted, SamTrans 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 SamTrans 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 SamTrans 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)
- SamTrans would become a "Fuel Reporting Entity"

RISK ANALYSIS

Capacity is very limited so access through this option is unlikely to meet 100% of SamTrans' 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[20]") and requires annual reporting of the electricity that is sourced. With similar access to the wholesale electricity market, SamTrans 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, the Federal Energy Regulatory Commission (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. 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.

[20] 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 SamTrans and 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 SamTrans 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 12). 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, referring to the estimates provided in Table 12 above. For example and based on our experience, it is unlikely that the benefits outweigh costs for SamTrans until SamTrans is nearly completely electrified should SamTrans and Caltrain choose to not achieve economies of scale by working to access the wholesale market as one procurement effort.

Finally, if a similar legislative exemption is granted for SamTrans, 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 SamTrans' 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. SamTrans 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 SamTrans 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 SamTrans' 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 Renewable Energy credits or RECs.

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. 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

SamTrans 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. SamTrans 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 SamTrans 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 SamTrans 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 SamTrans is expected to generate.

4.2.3 Financing Opportunities

The following section discusses some of the financing options for the purchase of the solar and BESS DER systems at North and South bases, as described in Section 3.3. 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 DER systems provides the best long-term financial return for SamTrans, as well as other benefits such as direct control over the asset, retention of RECs and environmental attributes. However, with direct ownership the agency cannot leverage some of the federal incentives discussed in this report, such as the ITC, which may not be claimed if the project is owned by tax-exempt entities such as municipal utilities and government agencies, and it must face the initial capital cost which can be significant. As shown in Appendix E, the analysis shows a total initial project cost of $10,075,000 for the solar-only option and $14,521,002 for the solar plus battery option. These are considerable investments for the agency, and a financing strategy 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

SamTrans 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. For reference, the initial projects costs for the two options are presented in Table 13 for comparison with some key financial indicators for the agency, as reported in the 2019 Annual Financial Report for SamTrans.

Table 13. Cash Purchase as a Percentage of Cash Reserves and Revenues

Option	Solar Only	Solar + Battery
Initial Project Cost	$ 10,075,000	$ 14,521,992
As percentage of Agency’s unrestricted cash reserves (FY 2019)	11.76%	16.95%
As percentage of Agency’s total operating revenues (FY 2019)	64.72%	93.29%

For both options, the initial project cost would correspond to a considerable portion of unrestricted cash reserves and total operating revenues in FY 2019, even before the large financial impact of the COVID-19 pandemic, so a cash purchase will not be the primary option unless the agency has strong strategic reasons for it.

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 solar PV and energy storage projects is evolving, with new options still developing in terms of either structures, sizes, or partnerships. SamTrans can directly approach traditionally preferred lenders and compare the conditions they offer for solar PV and BESS financing. Alternatively, some new-to-market lending agencies, such as SunPower and Murphy International, have been developing their expertise specifically on financing new technology for alternative energy sources. Most major vendors of solar PV technology and BESS also developed agreements with lending partners that are familiar with this new technology and the risks that come with it. Table 14 shows how the estimated initial project cost for both options compare to the agency’s total long-term debt in FY 2019, for reference.

Table 14. Cash Purchase as a Percentage of Long-Term Debt

Option	Solar Only	Solar + Battery
Initial Project Cost	$ 10,075,000	$ 14,521,992
Percentage of Agency’s Total Long-Term Debt (FY 2019)	4.96%	7.14%

For both options, issuing new debt to finance the initial project capital cost would represent a small but significant increase in total debt for the agency. SamTrans must consider this option in the context of its long-term strategy and its approval processes for issuing new loans, as it will impact future payments of capital debt, interests, and the agency’s debt capacity.

FEDERAL, STATE AND LOCAL FINANCIAL INCENTIVES AND SPECIAL LOANS

SamTrans, 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. SamTrans 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, SamTrans 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. SamTrans 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.

TAX-EXEMPT LEASE PURCHASES (TELPS)

This structure allows a municipality that wants to own a project, but needs to finance the purchase, to do so without the complication of issuing bonds. A TELP is essentially an installment sale of a project to a municipality. It is set up in form to look like the sponsor is leasing the project to the municipality, but the municipality has an option to purchase the project at the end of the lease term for a nominal price. The 'tax-exempt' qualification to this financing method is associated with the federal income tax exemption recognized by the lessor on the interest earnings they receive through the repayment schedule. Because the lessor does not pay federal income tax on the interest earned, the tax-exempt lease carries a much lower interest rate than other types of leases and installment loans. This significantly lowers the cost of financing to the borrower.

While not offering direct ownership from “year 0,” this option should be evaluated by the agency, as it allows to leverage certain incentives such as the Federal ITC described in Section 2.1.1. Under this scenario, a “tax-sponsor” (an entity other than the agency and subject to taxes) would own the project, or a portion of it, for a period of time before passing ownership to the agency, and would be able to leverage the ITC benefits which are realized in the year the solar project begins commercial operations. The duration of this initial time is normally at least five tax years, corresponding to six contract years, during which the asset vests to the owner, because, according to the “clawback” provision, the Internal Revenue Service (IRS) will recapture any unvested portion of the credit if the project owner sells it before the end of the fifth year of commercial operations. After six years the agency can buy out the unowned portion of the solar project at a depreciated fair market value.

This represents an attractive option for SamTrans, which would have to issue an RFP and select a vendor among private companies like ForeFront Power or CollectiveSun to partner with for this option. If the construction of the project starts prior to the end of 2023 for example, the tax-sponsor could benefit of a 22% tax credit based on the capital value of the installed solar PV investment and the project costs that are eligible for ITC consideration. This incentive can be combined with the IRS’ MACRS, which allows for the asset to be fully depreciated in only five years, and lead to up to a 31% decrease for the system’s capital cost. Table 16 summarizes the potential savings under a TELP arrangement, assuming start of construction in 2023.

Table 15. Potential TELP Savings

Option	Solar Only	Solar + Battery
Initial Project Cost	$ 10,075,000	$ 14,521,992
Potential savings under lease + buyout option (31%)	$3,123,250	$4,501,818
Approximate Capital Cost including Potential Savings under lease + buyout option	$6,951,750	$10,020,174

4.3 ECONOMIES OF SCALE/DISTRICT LEVEL PROCUREMENT

4.3.1 DER Procurement

As discussed in Section 3.3, SamTrans 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 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' smaller 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 Conditional Use Permit (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 support SamTrans 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 SamTrans 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 California Environmental Quality Act (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 North and South bases 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 10 and Figure 11 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 10. Photo of the 200 MW PCE Write Solar PPA in Mercer County, CA

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 (NREL), 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.

Figure 11. PCE Buena Vista 38 MW Wind Power Facility

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 MW (SF Water, n.d.).[21] Damming a river to create a reservoir for a large hydropower project results in significant land use, habitat impacts and emit methane over time. 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 blooms (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 changed.

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

[21] 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 SamTrans 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 SamTrans 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, SamTrans 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 16 identifies the estimated lifecycle GHG emissions associated with renewable energy compared to non-renewable energy (Union of Concerned Scientists, 2013c).

Table 16. 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 SamTrans' new electric load.

As shown in Table 3, SamTrans would generate approximately 2,658 tCO2e market-based scope 2 GHG emissions if it were to purchase the PG&E base plan and 0 GHG emissions under the default of 100% renewable CCA rates. 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 GHG-free 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 17 and Table 18 present the primary risks, trade-offs and other considerations for each of the options in this study. Figure 12 illustrates the energy procurement options in a decision tree format.

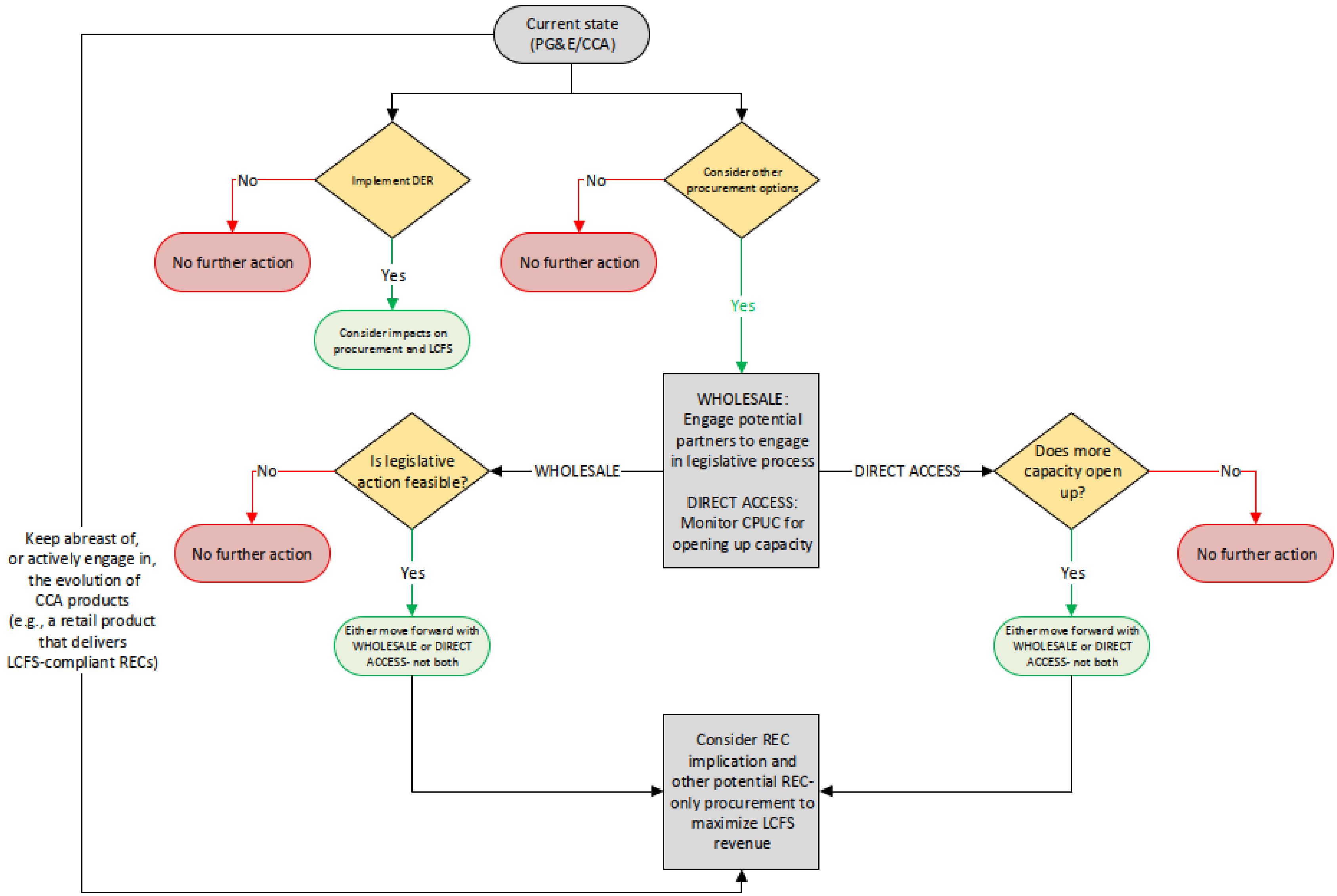
Table 17. Energy Procurement Opportunity Matrix

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 18. 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 12. Energy Procurement Decision Tree



4.6 TIME AND INVESTMENT HORIZON ANALYSIS

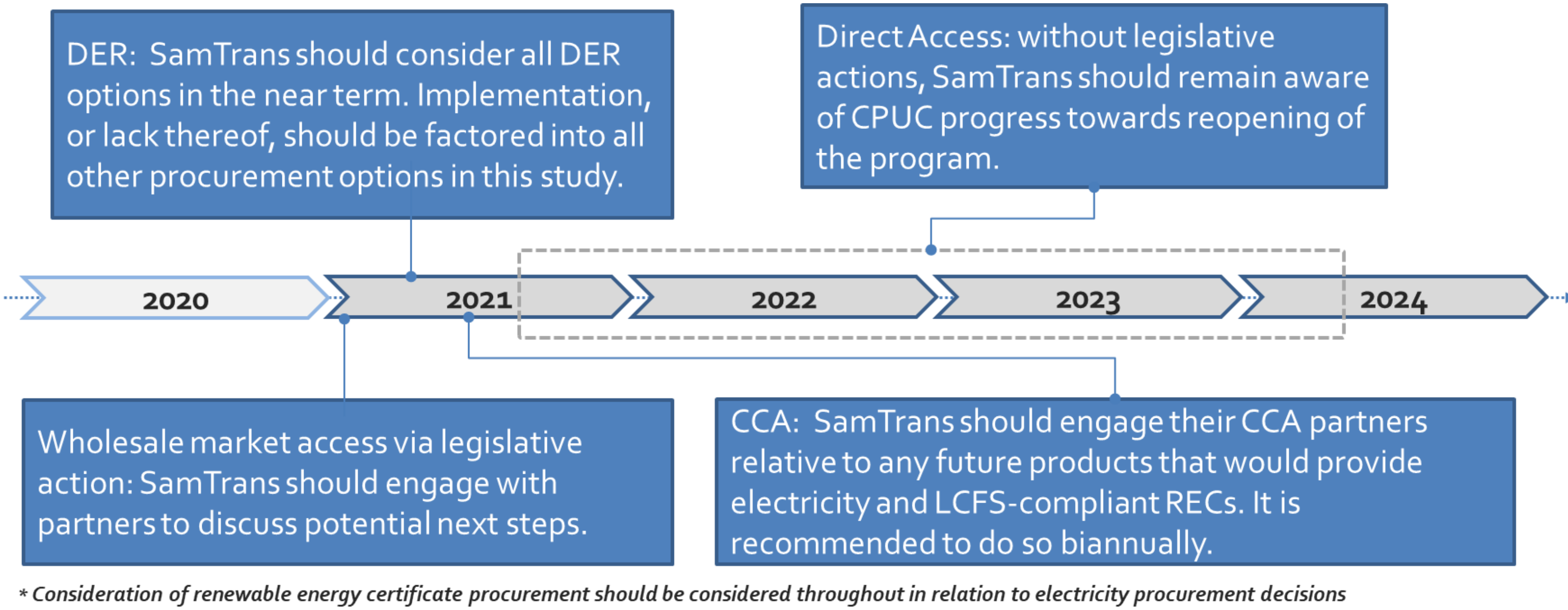
This study evaluates options for SamTrans' energy strategy based on viable options including currently available technologies for electricity generation and potential near-term supply and REC procurement options. Therefore, this study is valid for as long as those options exist. Per the time horizon 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 SamTrans 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 SamTrans 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 SamTrans' LCFS market participation, it is recommended to revisit current contracting with CCAs on a biannual basis, provided that SamTrans hasn't 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 SamTrans 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, SamTrans 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 SamTrans 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 13.

Figure 13. Energy Procurement Time Horizon



4.7 CONCLUSION

As stated in the introduction, electricity procurement is becoming an ever more important component of SamTrans' 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 SamTrans 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:

- **SamTrans should engage the regional CCA 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.
- **SamTrans 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 electricity service provider 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 SamTrans, regardless of whether or not they pursue jointly with Caltrain. 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 SamTrans' anticipated load, it may be worth applying.
- **SamTrans 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, SamTrans will have the option to switch to wholesale procurement in the future if desired.

- **SamTrans 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. SamTrans 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.
- **SamTrans and Caltrain would benefit from jointly procuring energy.** If SamTrans elects to pursue onsite DER, unique CCA products or DA, wholesale market, it would benefit from procuring energy with Caltrain to reduce costs and streamline management.

5 EMERGENCY/BACKUP POWER OPTIONS

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

5.1 RATIONALE FOR BACKUP POWER

When transitioning to electric bus 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. Ensuring dependable delivery of service from an operational standpoint or evacuations of vulnerable populations are of critical concern to a transit agency. By documenting the risks associated with electric operations, SamTrans will be able to make informed decisions on vital infrastructure and plan holistically for new and emergent technologies.

NATURAL DISASTERS AND EMERGENCY PREPAREDNESS

SamTrans' 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 SamTrans (SamTrans, 2010), the most significant hazards to SamTrans 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.

Both the North and South bus facilities are located on Bay mud. Particularly, in the Loma Prieta earthquake, there was a back-fill failure due to liquefaction under one column at the South Base facility. In the same earthquake, the pea gravel back-fill around the underground tanks dropped and caused the concrete slabs on the surface to subsequently fall and be damaged. This problem was fixed at South Base, but it is not clear if it was also done at North Base.

5.2 POWER RELIABILITY

Power reliability is a vital factor when considering the transition to BEBs. Without an understanding of existing reliability, SamTrans 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 19). The Project Team gathered information from CPUC as it relates to PG&E, the local distribution utility.

Table 19. 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

5.2.1 PG&E Reliability

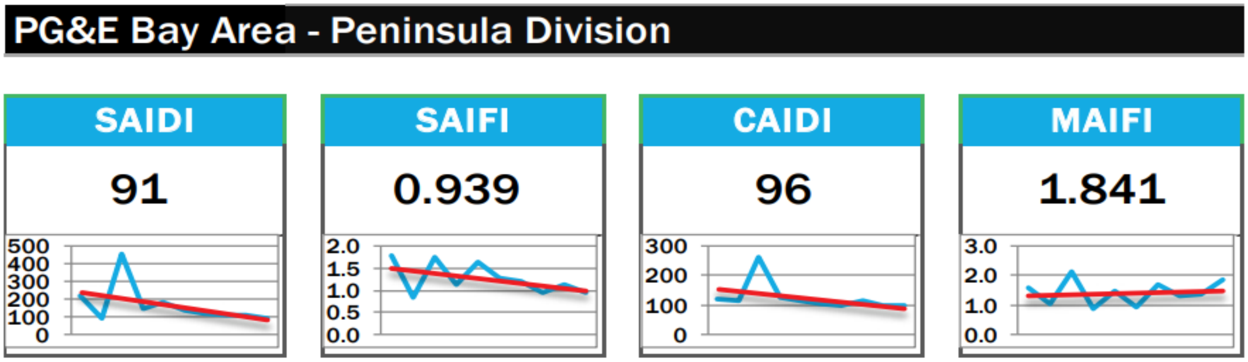
Because reliability metrics oscillate from year to year based on large power outage events, such as the Camp Fire in Paradise, California, in 2018 or the Southwest Blackout of 2011, CPUC generally uses 10-year rolling averages to show improvements over time. After PG&E's transmission lines caused the deadliest fire in California history (the Camp Fire), CPUC and regulated utilities began to implement PSPS events 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 19), 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 14 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.

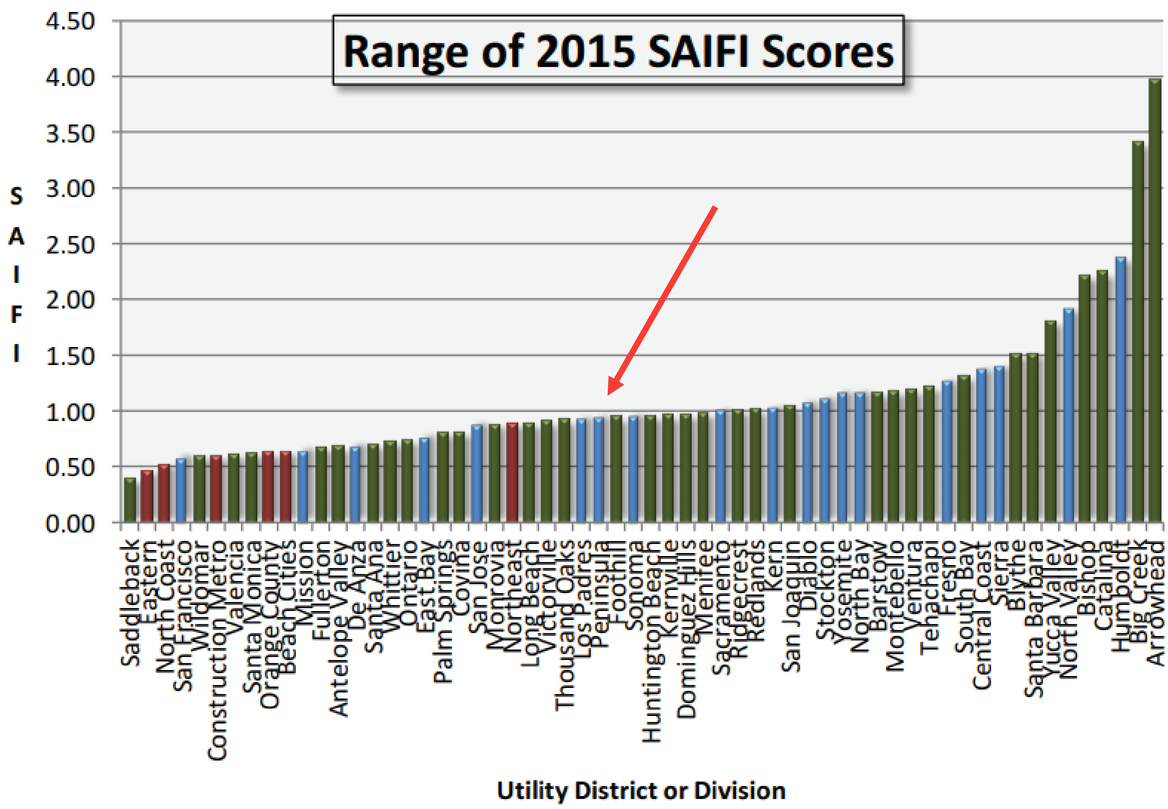
Figure 14. Peninsula Division Metrics (2006-2015)



Source: CPUC

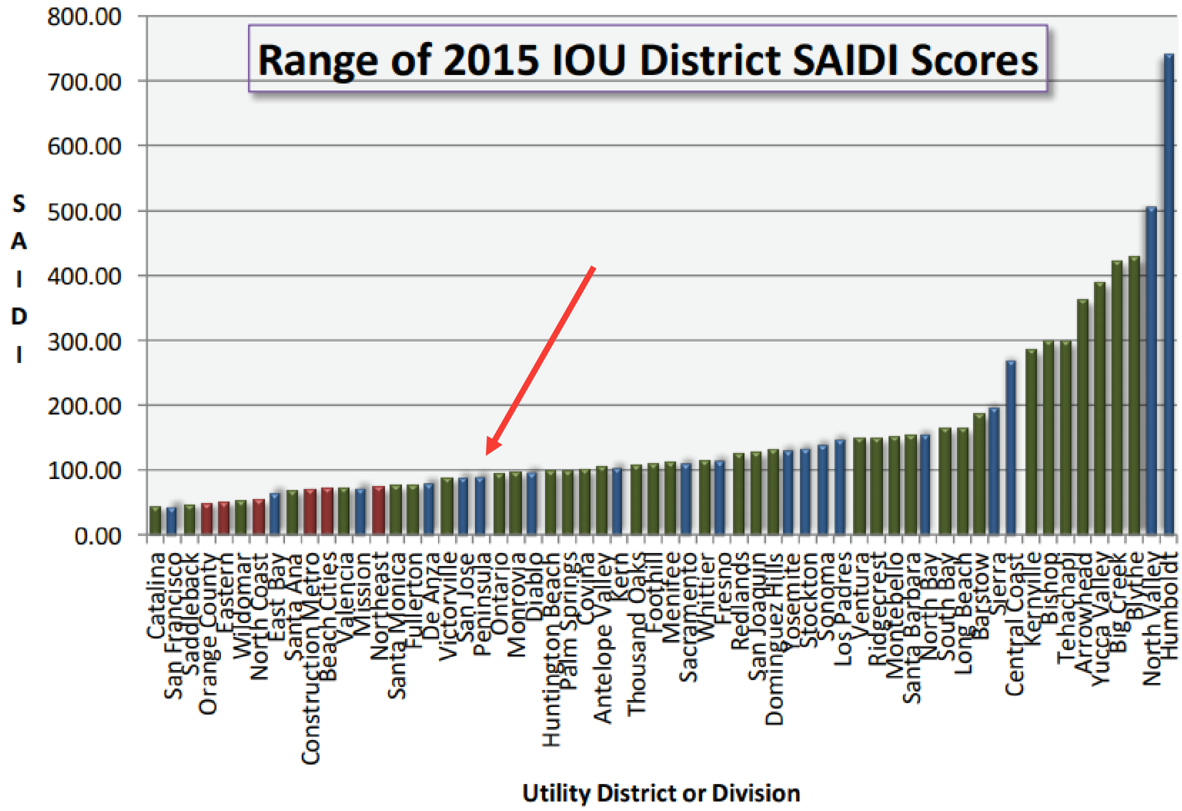
As indicated above, these statistics place PG&E's Peninsula Division squarely in the middle of performance across California, as shown in Figure 15 and Figure 16. As SamTrans plans for additional electric buses, actual charging time will need to be compared with the risks of an outage.

Figure 15. California SAIFI Scores by Utility Division (2006-2015)



Source: CPUC

Figure 16. California SAIDI Score by Utility Division (2006-2015)



Source: CPUC

5.2.2 PG&E Rotating Outages

During times of great stress on the grid, PG&E can enact rolling blackouts to conserve energy. This is a rare occurrence, but is happening during the current heat wave in August 2020. PG&E divides its circuits up into Blocks and shuts them off for an hour at a time. North Base is part of Block 11 and is subjected to these outages. South Base is on a circuit that serves essential loads, such as hospitals, police, or fire stations. These essential uses are labeled “Block 50” and are unlikely to be affected by rotating block outages.

As SamTrans begins to electrify, the Project Team recommends that SamTrans petition PG&E/CPUC to be listed as an essential use. This will allow the North Base to also qualify as a Block 50 load and secure South Base as critical as well (PG&E, 2020). Although the Project Team was not able to independently verify this at the current time, 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,” while the SamTrans bus infrastructure has not historically been listed.

5.3 BACKUP POWER OPTIONS

The following section outlines potential emergency backup power technologies that could provide SamTrans with adequate supply in the event of an extended disruption or disaster.

5.3.1 Diesel Fuel Generator

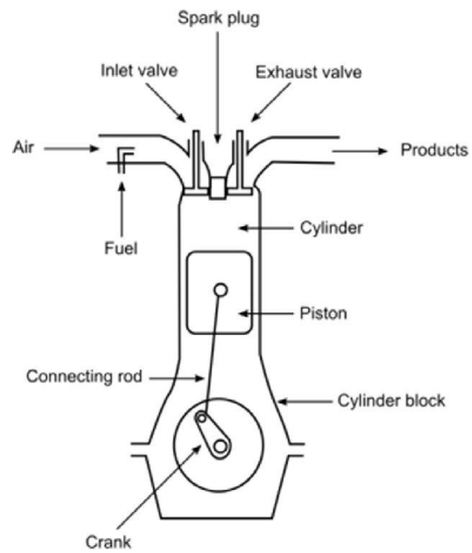
Diesel generators convert fuel energy (diesel or biodiesel) into mechanical energy by utilizing an internal combustion engine, and then into electric power by using an electric generator. Diesel generators are the most common electricity generator used in building-integrated microgrids because of their size, initial cost, simplicity, and the ease of buying the fuel. A diesel generator is composed mainly of an internal combustion engine, an electric generator, mechanical coupling, an automatic voltage regulator, a speed regulator, a support chassis, a battery for starting the motor that permits the diesel generator start-up, a fuel tank, and a command panel (Sechilariu and Locment, 2016).

Diesel generators are classified as compression ignition (CI) engine because the air that flows into the compressor is compressed to a temperature sufficiently high for auto-ignition. The combustion chamber then mixes the heated air with fuel and burns it. Diesel generators convert some of the chemical energy contained by the diesel fuel to mechanical energy through combustion. This mechanical energy then rotates a crank to produce electricity. Electric charges are induced in the wire by moving it through a magnetic field. In an electric generator application, two polarized magnets usually produce the magnetic field. A wire is wound around the crankshaft of the diesel generator that is placed between the magnets in the magnetic field. When the diesel engine rotates the crankshaft, the wires are then moved throughout the magnetic field, which can induce electric charges in the circuit (Office of Energy Efficiency & Renewable Energy, 2013).

5.3.2 Natural Gas Generator

Unlike diesel engines that only use the heat from compression and the injection of fuel to start the combustion process, natural gas engines will need an external spark to begin the process and therefore classified as a spark-ignition engine (SI engine). In a spark-ignition engine, the fuel is mixed with air and then inducted into the cylinder during the intake process. Whereas in diesel engine, only air is admitted at this stage. In the simplest case, this spark plug is located at the top of the cylinder and directly ignites the mixture within the cylinder (Figure 17). After the piston compresses the fuel-air mixture, the spark ignites it, causing combustion. The expansion of the combustion gases pushes the piston during the power stroke (Office of Energy Efficiency & Renewable Energy, 2013).

Figure 17. Spark-Ignition Engine



Source: Martinez et al., 2017

5.3.3 Stationary Battery Storage

Stationary batteries are not an alternative energy source, they are merely a mechanism system to store electrical energy. They can store power when loads are low and power is cheap, such as nighttime, and release that energy when power is expensive. Unlike generators, batteries have a limited time duration and get more expensive the longer duration is required. As discussed in Section 3.3, batteries can be integrated with a solar PV system and used as a source of emergency backup power.

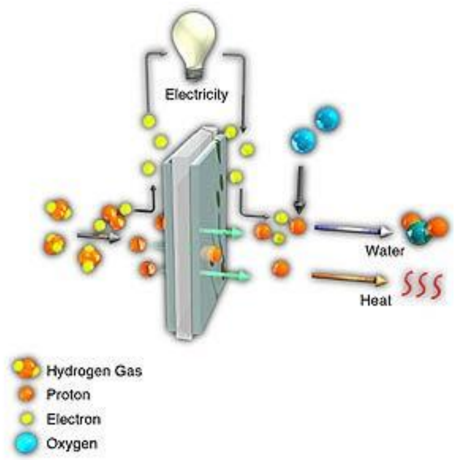
5.3.4 Hydrogen Fuel Cell Generator

There is increasing interest and research into utilizing hydrogen (H_2) for power generation to achieve a completely carbon-free energy ecosystem. H_2 is a clean-burning fuel that does not produce any carbon emissions as it does not include any carbon. In a complete and balanced reaction, hydrogen would mix with oxygen in the air to produce only water and thus does not emit hazardous air pollutants or greenhouse gases (GHGs).

When used in a generator, hydrogen produces power by using fuel cell technology which is a chemical reaction and does not contain any combustion. A fuel cell is constructed much like a typical battery with an anode, a cathode, and an electrolyte membrane. A fuel cell works by passing hydrogen through the anode (-) of a fuel cell and oxygen through the cathode (+). At the anode side, the hydrogen molecules have the electron separated, leaving the hydrogen molecule with a positive charge. The positively charged hydrogen ion passes through the electrolyte membrane, while the electrons are forced through an electrical circuit, generating an electric current and excess heat. At the cathode, the hydrogen ions, electrons, and oxygen combine to produce water (Figure 18). Fuel cells are more efficient than combustion technology.

Note that most fuel cells in use today use natural gas (CH_4) instead of hydrogen in the fuel cell. The process is the same, but the additional carbon molecules end up producing CO_2 as a byproduct as well. However, unlike a natural gas combustion generator, a natural gas fuel cell generator avoids the production of nitrogen oxide (NOx) and particulate matter (PM) air pollutants. The major fuel cell manufacturers are moving toward offering hydrogen and this report describes the options for a full hydrogen fuel cell system. Note that some hydrogen fuel cell technologies are designed to accommodate either natural gas or hydrogen.

Figure 18. Electricity Generation in Fuel Cell

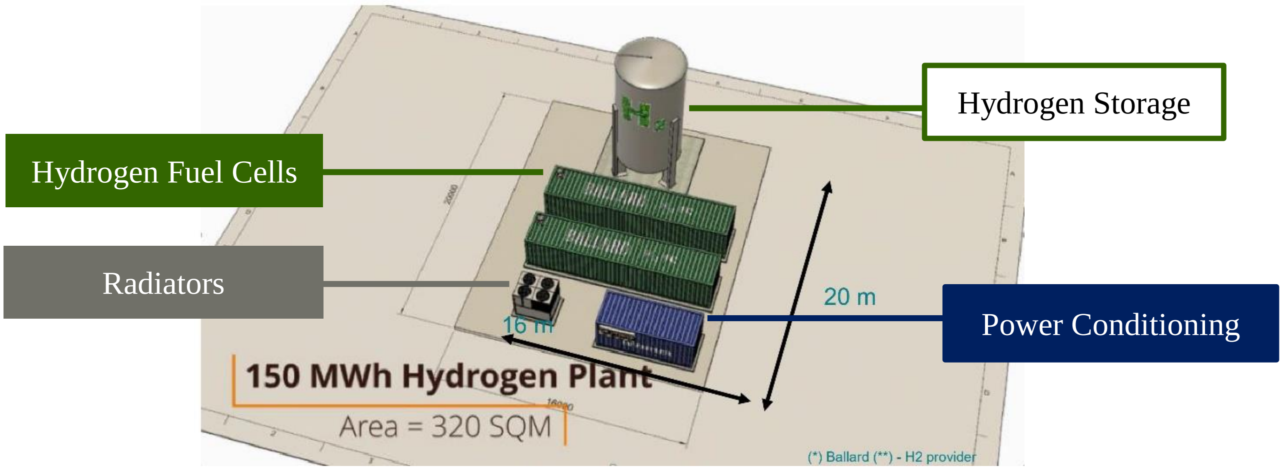


Source: Sciencescene, n.d.

Fuel cell generators also offers some drawbacks. The immediate concerns are the fuel source and the space required to store the fuel and fuel cells. There are four general choices for how hydrogen can be sourced: 1) hydrogen gas delivery via a high-pressure tube trailer or mobile refueler; 2) liquified hydrogen delivery via a tanker; 3) pipeline delivery of hydrogen gas; and 4) on-site production via steam methane reforming (SMR) or electrolysis. Access to inexpensive hydrogen fuel remains a significant challenge, though many companies are trying to crack this challenge across the globe. Therefore, careful consideration of long-term costs for hydrogen sourcing should be considered. In addition, considerations for contingency and redundancy should be considered for all technologies in case of equipment failure.

Despite the source, all hydrogen, whether gaseous or cryogenically liquified, must have adequate and safe on-site storage. Hydrogen has a lower energy content per volume compared to CNG, requiring larger storage containers to deliver the same energy. Figure 19 depicts the layout example for fuel cells that can give 3 MW power for 48 hours by using 10,000 kg of liquid H_2. A more detailed space analysis for hydrogen generators will be discussed in Section 5.4.5.

Figure 19. Hydrogen Generator Layout Example



Source: Ballard

An additional concern that must be taken into consideration when using H_2 fuel is the overall safety of the facility. Hydrogen flame has high heat and low luminosity and is, therefore, hard to see visually. A flame detection system specifically configured for hydrogen flames has to be installed on the maintenance facility. Adjustments to the maintenance facility's safety code and safety zones might also be needed in the case of a hydrogen leak, especially because hydrogen is more flammable and more prone to seepage compared to natural gas.

5.3.5 Rental Units

It is possible to rent the backup power generators needed for supplying power to the battery electric buses, instead of purchasing them. Renting generator units from a third party has pros, cons, and additional impacts to SamTrans operations that should be considered are outlined in the technical analysis.

5.4 TECHNICAL ANALYSIS

This evaluation considers the following three technological options for providing backup power at the SamTrans North Base and South Base: natural gas generators, diesel generators and stationary hydrogen fuel cells. Using daily energy and peak load requirements at each site, a comparison of the technologies is made based on cost, spatial footprint and emissions. The following section outlines the methodologies and results of this comparative study.

5.4.1 Primary Assumptions

The majority of the assumptions used to establish a baseline of backup power needs at the North and South Base were derived from the *SamTrans BEB Route-Power Analysis Report* provided by HDR (2020). This analysis assumes the entire fleet at each site will operate using a 440 kWh battery (though various battery sizes are currently available on the market, 440 kWh is a common selection and allows for a reasonable estimation among various bus sizes). To provide conservative estimations aimed at supporting unforeseen events or emergency service, energy requirements were calculated independently from the HDR study, to assume the entire fleet would charge to 80% of the battery capacity within a six-hour charging window; in practice, it is unlikely that the entire fleet would be in operation and fully deplete the available state-of-charge (SOC) within a single day of service, but this assumption allows for simple calculations as SamTrans defines their resiliency policy and fleet needs.[22] These calculations are also within 2% of the HDR calculations, which used a different methodology. The charger power (150 kW) and bus-to-charging ratio (2:1) used in this analysis represent options that are often recommended for reducing peak demand costs and utility infrastructure on-site.

Based on these assumptions, the estimated peak power required for BEB operations at each garage is approximately 12 MW and the estimated daily energy requirements at each garage is approximately 56,000 kWh (Table 20). This relatively intensive energy requirement presents significant challenges for providing multiple days of backup power, for this reason, this analysis only assumed energy storage adequate to power the fleet during a single day of operation. Under these assumptions, extended power service for the full fleet may be constrained by the availability of daily fuel delivery for the options requiring on-site fuel storage. It should be noted that these assumptions provide a conservative baseline from which SamTrans may develop an emergency response policy; in practice, SamTrans may consider typical outage durations and assign a small subset of the fleet to provide emergency service to refine backup power needs, which would likely dramatically reduce costs and footprint.

Table 20. Baseline Assumption for Determining Backup Power Needs at SamTrans North and South Garage

Factor	North Garage	South Garage
Number of Buses	159	161
Bus Battery Capacity (kWh)	440	440
SOC Safety Buffer	20%	20%
Charger Power (kW)	150	150
Charger to Bus Ratio	2:1	2:1
Peak Power (MW)	12	12.2
Daily Energy (kWh)	55,968	56,672

[22] The remaining 20% SOC is reserved as a safety buffer to prevent full battery depletion and long-term battery degradation.

5.4.2 Size and Footprint

A foundational consideration for determining the viability of the various backup power options is the surface area necessary for hosting the generator and supporting equipment, referred to in this analysis as the footprint. The site footprint is established by identifying the size and quantity of the backup power units, fuel storage and supporting infrastructure. In addition to the spatial requirements of physical components, safety codes often require minimum offsets from hazardous and vulnerable areas in case of combustion. The determination of safety offsets requires an in-depth review of site layouts, for this reason this consideration was omitted from this analysis. Once SamTrans selects their preferred backup power solution, it is recommended that it consult applicable National Fire Protection Association guidelines and coordinate with the local fire marshal to ensure all safety requirements are met.

To identify the number of backup power units required at each site, this analysis established baseline unit sizes for consideration. Typical sizes of commercial diesel and natural gas generators range between 600 kW and 2,000 kW. Commercial-sized stationary hydrogen fuel cells are still emerging in the market, thus provide few options, however, a 1,500 kW system produced by Ballard was identified. Beyond size availability, this analysis selected units that could be stored in containerized systems which provide several benefits such as, ease of transport (in the case of diesel), better cooling performance, lower operational noise, higher maintenance performance, and reductions in safety offset distances.

In consideration to the large energy requirements at each site, this analysis selected 2,000 kW systems for diesel and natural gas analysis and the 1,500 kW system for hydrogen fuel cell. Based on these assumptions and the total energy needs at the site, the total number of generators required to provide emergency backup power to charge all 320 buses and resulting footprint was established.

A summary of the size and footprint of the backup power options is presented in Table 21 and Table 22 below.

Table 21. Size and Total Footprint of Power Units for One Site

Fuel Type	Length (ft)	Width (ft)	Number of Units	Total Footprint (ft^2)
Diesel	40	8.5	5	1,700
Natural Gas	50	13.5	5	3,375
Hydrogen (fuel cell)	40	8.5	7	2,380
Hydrogen Storage	8.3	8.3	1	69

Table 22. Total Footprint of Power Units Including On-Site Fuel Storage for One Site

Fuel Type	Diesel	Natural Gas	Hydrogen
Total Footprint (ft^2)	1,700	3,375	2,449

Some auxiliary items such as electrical interconnections and diesel hoses are not included in the footprint at this time, but these should be similar for all options and potentially moveable during non-emergencies.

DIESEL GENERATORS

A significant benefit of containerized diesel generators is the opportunity to substantially reduce costs and space requirements through the use of roll-up/portable generators, which allows SamTrans the option of sharing a set of generators between North and South Bases. Diesel generators shared between the bases can be an effective strategy for providing power during localized power outages; however, in the event of a large-scale regional disaster, such as earthquakes, this strategy reduces redundancy and the resulting degree of resiliency. Considerations to the amount of time required to transport multiple generators between sites should also be considered when developing SamTrans' internal ZEV resiliency policies. To provide the most economic strategy, however, this analysis calculates both the shared use of five 2,000 kW diesel roll-up generators with independent installation costs at each site and a full build out of stationary generators at both sites.

The fuel consumption required to operate of all five 2,000 kW diesel generators at full load is approximately 4,200 gallons per service day. A 4,000 gallon, above ground diesel tank would have a footprint of approximately 128 ft^2 and cost approximately $10,000; however, since SamTrans has existing on-site diesel storage tanks capable of supplying more than a day's fuel needs, no additional footprint or cost was calculated for diesel storage. Quick connections would need to be prepared to extract fuel from existing underground fuel tanks to the new mobile generators.

NATURAL GAS GENERATORS

Though not as common as roll-up diesel generators, mobile natural gas generators are technically feasible if the sites are designed with rapid connectivity interfaces to new natural gas lines. In this situation, maintaining a full day's operational service using natural gas would require five 2,000 kW generators shared between both sites with independent installation costs at each site. A typical footprint for a natural gas generator of this size is 50'x13.5', resulting in a total footprint of 3,375 ft^2 to house all five units. Storage is generally not an option for natural gas since it is typically supplied via local pipelines. The pipelines used to supply heating to North and South Base would likely require significant upgrades which would result in higher installation costs, coordination with the local natural gas utility (PG&E), would be required for an accurate estimation of these upgrades. Though the pipeline distribution of natural gas eliminates the need for fuel storage infrastructure, it presents a new vulnerability in the situation that an event disrupts the natural gas supply.

STATIONARY HYDROGEN FUEL CELL

Stationary hydrogen fuel cells are typically not built to the scale required to provide backup power for North and South Base, however, this technology is beginning to emerge as a clean and reliable energy strategy. As a nascent technology, the number of units necessary to support energy needs at each site is slightly higher than the alternative options, requiring a total of 7 units if shared between both sites. Again, sharing fuel cells between sites is uncommon, but technically viable and would require both sites to have power conditioning and cooling fan sets on site with rapid connectivity interfaces between the fuel cell, hydrogen, and power conditioning; SamTrans would need to work with the product supplier to determine an accurate estimation of these costs. As a containerized solution, the fuel cell system alone is relatively compact (especially compared to battery storage solutions), presenting a total footprint of 2,380 ft^2 at each site.

To support the daily energy needs at each site, approximately 4,000 kg of hydrogen stored on-site at each base would be required. At this scale, cryogenically liquified hydrogen is the preferred storage method. In a liquid form, the equivalent volume for this amount of hydrogen is approximately 15,000 gallons. 15,000-gallon liquid hydrogen tanks are available both horizontally and vertically positioned. To conserve space, the vertical position is often recommended, requiring a footprint of 69 ft^2. In total, seven 1,500 kW on-site hydrogen fuel cells and the supporting fuel storage requires a total surface area of 2,449 ft^2.

As discussed previously, current fuel cell designs usually use natural gas the main fuel. All suppliers, including Ballard and Bloom Energy, have a roadmap to full use of clean hydrogen. It would not be advantageous to build natural gas delivery infrastructure and then replace it with hydrogen delivery/storage infrastructure. It is possible for hydrogen to be delivered by pipeline in the future, but it is not currently a viable option.

5.4.3 Costs

Among the considerations for determining the best-fit backup power strategy to support BEV operations are the life-cycle costs. This analysis focuses on the primary costs associated with each backup power strategy to support SamTrans in evaluating the cost-benefit of each option, these include: 1) power unit costs, 2) fuel storage costs, 3) installation costs, 4) maintenance costs and 5) energy costs. A summary of the anticipated costs for each backup power option is presented in Table 23.

Table 23. Summary of Total Estimated Costs of Backup Power Options

	Diesel	Natural Gas	Hydrogen
1 Year Maintenance Costs (10MW)	$350,000	$350,000	$367,500
Fuel Costs (1 Day Operation; 56,000 kWh)	$13,200	$6,529	$11,100
Mobile Gen-sets Capital Costs	**$8,800,000**	**$10,450,000**	**$22,827,000**
Stationary Generators Capital Costs	**$14,600,000**	**$17,700,000**	**$38,577,000**

CAPTIAL COSTS

Included in the considerations for determining the capital cost of each backup power strategy are the costs associated with procurement of the unit itself, fuel storage costs, and installation costs. In this analysis, each item cost is broken down by cost per kilowatt to provide a standard metric of evaluation. Costs used in this analysis were sourced from several references including, direct manufacturer quotes, past purchase agreements, and scholarly reports.

As the most mature technology option, the diesel component costs are lower than the natural gas and hydrogen fuel cell at $580 per kilowatt. This cost assumes the diesel generator includes any additional equipment required to meet the Environmental Protection Agency's (EPA's) most stringent air quality standards, classified as Tier 4. The installation costs associated with diesel generators is also the lowest at approximately $150 per kilowatt. Component costs and installation costs for natural gas generators are comparable to diesel at $725 and $160 per kilowatt, respectively. The most expensive option (albeit cleanest), with the highest component and installation costs as well as an additional consideration for fuel storage is the hydrogen fuel cell option, requiring an investment of $1,500 per kilowatt for the components and an additional $337 per kW for installation and on-site fuel storage (Table 24). It should be noted that the on-site hydrogen fuel storage costs assume a direct procurement of the liquid hydrogen tank; alternatively, SamTrans may elect to lease out a tank at approximately $8,000 per month which would also alleviate responsibility to maintain the equipment.

The capital costs for natural gas exclude the cost of upgrading pipeline infrastructure at each site, which could be substantial and would need to be discussed with PG&E.

Table 24. Estimated Capital Costs per kW of Power

Fuel Type	Diesel (2 MW)	Natural Gas (2 MW)	Hydrogen (1.5 MW)
Generator	$580	$725	$1,500
On-site fuel Storage			$4

Fuel Type	Diesel (2 MW)	Natural Gas (2 MW)	Hydrogen (1.5 MW)
Installation	$150	$160	$333
Mobile Gen-sets Total Capital Costs	**$8,800,000**	**$10,450,000**	**$22,827,000**
Stationary Gen-sets Total Capital Costs	**$14,600,000**	**$17,700,000**	**$38,577,000**

OPERATIONAL COSTS

The costs associated with operating backup power units include fuel costs for a full day of service and ongoing maintenance costs. Fuel costs were estimated per kilowatt hour by multiplying current regional fuel costs by the fuel consumption per hour of the associated technology. A 2,000 kW diesel generator operating at full load, has an approximate fuel consumption of 141 gallons per hour. At the current regional price of diesel ($3.40 as reported by the U.S. Energy Administration), the anticipated diesel fuel cost per kWh is $0.24. The estimated fuel consumption per hour of a 2,000 kW natural gas generator is 203 therms per hour. The regional Small Commercial Gas Rate is approximately $1.17 per therm, resulting in an estimated cost of $0.12 per kWh[23]. The fuel consumption per hour for the hydrogen fuel cell was based the ratio of DC output energy to the lower heating value of hydrogen (33.3 kWh/kg); resulting in an hourly consumption of 45 kg. The cost of delivered hydrogen fuel can vary depending on supplier location and local supply, however, current rates in California average around $9 per kg, resulting in an estimated cost of $0.20 per kWh. In total, the cost to fuel backup power using natural gas is exponentially lower than the alternative options at $6,500 per day. Following natural gas in cost competitiveness is hydrogen at $11,000 per day with diesel trailing behind at $13,200 per day (Table 25).

Beyond the cost of fuel, the ongoing operational costs for maintaining backup power includes periodic tests and repairs to the unit. If the unit primarily serves emergency situations with low operational hours, it can be assumed that the majority of the maintenance performed will be scheduled maintenance and testing. The maintenance costs used in this analysis were sourced from the NREL and are applied equally to all backup power options (NREL, 2019). Under these assumptions SamTrans may expect to pay approximately $35 per kilowatt for maintenance. If extended over a one-year period, the total cost to maintain five 2,000 kW diesel and natural gas generators is $350,000 and the cost to maintain seven 1,500 kW stationary fuel cells is $367,500 (Table 26).[24] It should be noted that the operational costs included in this analysis do not explicitly

[23] Rate based on PG&E August 2020 Small Commercial Gas rate, Schedule G-NR1 during winter months. Sourced from https://www.pge.com/tariffs/GRF0820.pdf

[24] The total expected life of backup generators can vary widely depending on manufacturer, operational cycles, and storage, 12-years was selected as a lifecycle metric to align with the typical expected life of a transit bus.

account for permitting costs required to operate diesel generators larger than 50 horsepower in California.

Table 25. Estimated Fuel Costs for Three Backup Power Options at a Single Site

Fuel Type	Fuel Consumption /Hour	Fuel Cost	Fuel Cost/kWh	Total Fuel Cost for One Service Day
Diesel	141 gallons	$3.40/gallon	$0.24	**$13,200**
Natural Gas	203.3 therm	$1.17/therm	$0.12	**$6,500**
Hydrogen	45 kg	$9.00/kg	$0.20	**$11,000**

Table 26. Estimated Yearly Maintenance Costs and Fuel Costs for a One-Day Outage

Item	Diesel	Natural Gas	Hydrogen
Fuel Cost (1 Day Operation)	$13,200	$6,500	$11,100
1 Year Maintenance Costs	$350,000	$350,000	$367,500
Total	**$363,200**	**$356,500**	**$378,600**

5.4.4 Rental Considerations

Renting generator units from a third party comes with additional considerations that should be taken into account. If SamTrans chooses this route, it should get a rental agreement in place far ahead of the next crisis situation. The main advantage of rental equipment is the avoided upfront capital costs. All rental options have the same weakness as the mobile units; units need to be set up after a power outage occurs. Therefore, if a 90 minute outage occurs, the rental company might mobilize, but the power will come back on before the rental generators are ready to produce power.

Diesel rental companies are quite common and diesel infrastructure rentals is a mature market. There are both local and national options available. The main advantage of a diesel rental is speed of installation and ease of operations. The fastest contracts are usually for generators to be set up and operating within 6 hours. The diesel generators have a higher cost to produce energy, so actual usage and run time are a significant driver of total cost of ownership.

Natural gas rentals are becoming more common and have quite significant operating cost savings. However, it takes longer to get them set up, so they should only be used for long duration outages. If prepared ahead of time, they can be set up in around 48 hours, which may not be acceptable to SamTrans, depending on operating profile.

Hydrogen fuel cell rentals are very rare, but have potential in the future. This should be considered in the future when the battery electric fleet is more built out.

The Project Team contacted Aggreko, a national company, to get budgetary cost quotes for rentals in the SamTrans area. The operating costs were calculated based on 56,000 kWh per weekday and 28,000 kWh per weekend day, an average month is 22 weekdays and 8 weekend days. Table 27 summarizes the estimated monthly rental and operating costs for a rental unit. Figure 20 is a photo of an example rental unit.

Table 27. Estimated Monthly Rental and Operating Costs

Item	Diesel (7 X 1,500 kW)	Natural Gas (8 X 1,300 kW)	Hydrogen
Monthly Rental Cost	$119,000	$360,000	Not Available
Monthly Fuel Costs	$350,000	$175,000	$291,000
Total	**$469,000**	**$535,000**	**N/A**

Figure 20. Photo of Rental Unit Set Up

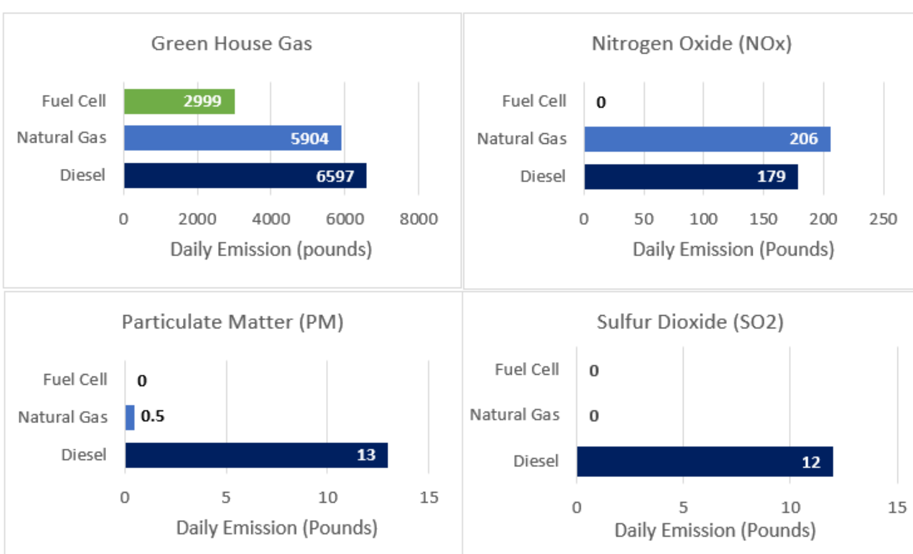
5.4.5 Emissions

Emergency and non-emergency generators using common combustion sources can have a significant impact on air quality and public health. If located in a metropolitan or urban area, generators increase the risk of exposing communities to dangerous air pollutants and GHG emissions. Particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxide (NOx) are the major air pollutants that can cause serious health risks. PM is a complex mixture of microscopic particles and liquid droplets that get into the air. Once inhaled, these particles can affect the heart and lungs and cause serious health effects. SO_2 and NOx contribute to acid rain, and if inhaled, can harm the heart, irritate airways, and aggravate respiratory diseases. PM and NOx are the leading causes of reduced visibility (haze) in parts of the United States.

GHGs are gases that retain heat in the atmosphere, thus increasing global temperature, alter the climate, and change weather patterns at the global and regional levels. The main greenhouse gases are water vapor, carbon dioxide (CO_2), methane (CH_4), ozone (O_3), nitrous oxide (N_2O), and chlorofluorocarbons (CFCs).

Emissions levels vary dramatically by generator configuration and fuel type. Figure 21 illustrates the different levels of significant air pollutant emissions released on-site based on natural gas fuel cell, natural gas generator, and diesel generator. The emission calculations for Figure 21 do not take into account the extraction of natural gas and diesel. Based on the figure, fuel cell-powered generators emit the least pollutants in total. In contrast, the operation of diesel generators has the highest daily total emission for GHGs, SO_2, and PM, while natural gas generators emit the most NOx daily.

Figure 21. Air Pollutants and GHGs Daily Emission Based on Generator Fuel Type



* The daily emission calculation was assumed for a 150 kW-rated generator and 24 hours operation time.

Source: Minnesota Pollution Control Agency et al., 2017

While current diesel generators pollute significantly less than older models, they still present potential health risks. To anticipate these risks, the EPA implements a tier system for diesel generators based on the engine's power and year. Based on this regulation, all new diesel generators have to comply to the strictest standard of allowed emissions (Tier-4) (Ericson and Olis, 2019. For backup generators that are used only during grid outages, Tier 3 and Tier 2-compliant engines are permitted. However, California law mandated all diesel generators to use the Ultra-Low Sulfur Diesel Fuel with a 0.05% by weight sulfur.

In addition, to comply with the Bay Area Air Quality Management District (BAAQMD) and California Air Resource Board (CARB) regulations, all diesel generators with power over 50 HP will require a permit (BAAQMD, 2006). Diesel generator typically trigger additional scrutiny because diesel particulate generated from running a diesel generator is a state listed Toxic Air Contaminant. It has to comply with CARB Airborne Toxic Control Measure (ATCM) (CARB, 2021) and requires a health risk assessment (HRA). Even though there is no limitation for emergency generators' operational hours for public transit-related emergency use, permit evaluator cannot approve engine-operating hours in excess of what would fail a risk screening analysis or ATCM standard. The engine PM emission rate will also affect the allowed operating hours for reliability related activities, such as hours used for testing and maintenance. Per ATCM standard, diesel engines with less than 0.15 g/bhp-hr PM emission rate can operate for a maximum of 50 hours for reliability related activities. Meanwhile, engines with less than 0.01 g/bhp-hr PM emission rate can operate for a maximum of 100 hours for reliability-related activities.

Emissions from natural gas engines are less than those from Tier 2 diesel generators and mostly on par with those of the Tier 4 diesel system. Based on EPA Stationary Combustion Emission Factors (EPA, 2020), natural gas engines emit approximately 28% less CO_2, 67% less CH_4, and 83% less N_2O compared to diesel-fueled engines. Because natural gas engines emit significantly fewer emissions than comparable diesel engines, it can meet air quality requirements easier that results in a more straightforward permitting process. Natural gas and LPG generators do not have an ATCM or trigger HRA requirements.

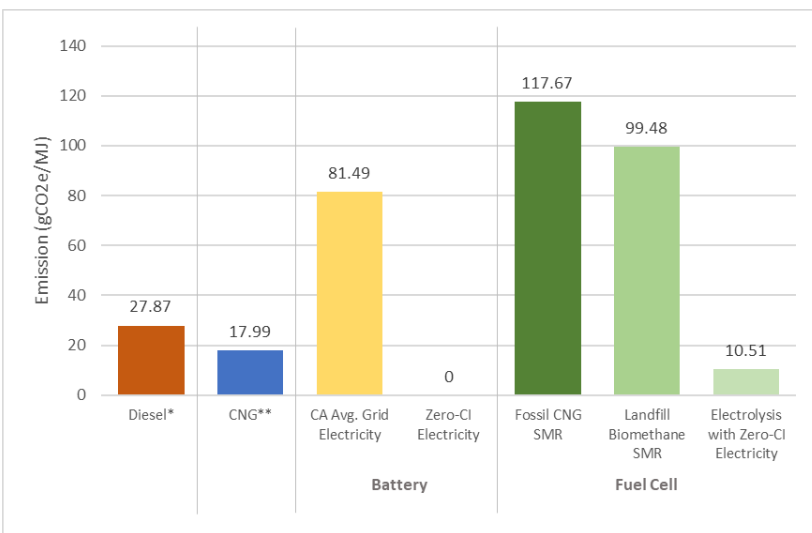
However, it should be noted that some jurisdictions in California, including several in the Bay Area, are implementing or evaluating natural gas bans. San Mateo, San Jose, Berkley, Menlo Park, and Marin County have recently enacted regulations that either ban natural gas in new homes or require energy efficiency measures if gas is used (Andersen, 2019). In January 2020, the California Public Utilities Commission indicated that it would start evaluating how to manage the state's transition away from natural gas (Moench, 2020). It is unknown if and when these restrictions could apply to commercial users, and more specifically, natural gas used for emergency power. It is possible that some of the current natural gas supply could be replaced with renewable natural gas, which is considered to be a GHG-free energy resource under the California Renewable Portfolio Standard (RPS). However, there is not currently a large supply of renewable natural gas and it is more expensive compared to traditional natural gas.

Due to the nascency of fuel cell-powered engines, there are not any significant regulations that directly pertain to hydrogen generators. However, considering that it emits even fewer pollutants than natural gas-powered generators, it will be easier to meet the permitting requirements related to air quality standards.

Though hydrogen-powered generators produce the least emissions on-site, there are still concerns with the emissions resulting from the production of hydrogen and hydrogen leakage. Figure 22 illustrates the amount of emissions produced during the production, processing, and delivery of each fuel (well-to-tank emissions). Hydrogen generation from fossil CNG SMR produces the most CO_2 equivalent emissions compared to other fuel production. Currently, fossil CNG SMR is the main production method for most of the hydrogen that is generated in California. Hydrogen production through the electrolysis of water, on the other hand, only produces hydrogen (H_2) and water as a by-product. However, it requires a large amount of energy and water and is still not commonly used by commercial hydrogen suppliers due to the nascency of the technology.

Solutions have been considered to achieve greener hydrogen production, such as using renewable natural gas (RNG) or carbon capture and sequestration (CCS) technologies for SMR, and the use of renewable energy sources for electrolysis (Goldmeer, 2019). As can be seen from Figure 22, using Landfill Biomethane SMR can reduce CO_2e emissions. Moreover, using a zero carbon intensity (Zero-CI) electricity sources, such as solar, wind, or wave panels, to produce hydrogen through electrolysis will reduce the emissions even further.

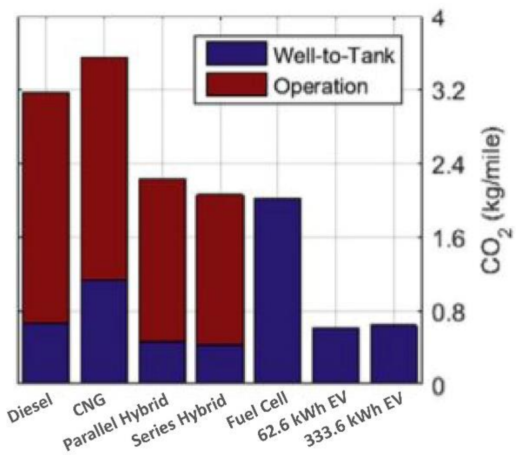
Figure 22. Maximum Potential Well-to-Tank Emission for Different Types of Fuel



Source: *NREL, 2015, ** Lajunen and Lipman, 2016, and Ballard

It is important to note that even though the hydrogen generation through SMR produces more emissions compared to the production of other fuels, the operation of the fuel cell engine itself will generate zero emissions. Hydrogen is a clean-burning fuel that does not include any carbon (C) in its balanced combustion reaction and only produced water as a by-product. From Figure 23, it can be concluded that fuel cell vehicles produce the most emissions from well-to-tank hydrogen production, but ends up with a lower total emission compared to diesel, CNG, or diesel-CNG hybrid vehicles. The Project Team assumes that generators will have comparable emission proportions with the internal combustion engines used in vehicles.

Figure 23. CO_2 Emissions for Vehicles with Different Fuel Types



Source: Lajunen and Lipman, 2016

Research also shows that significant hydrogen leakage could have negative effects on the atmosphere, such as increasing the lifetime of methane, increasing climate effects, and causing some depletion of the ozone layer. The research found that overall air quality in the lower atmosphere will still improve if hydrogen is introduced to the future mix of energy sources due to the reduction of fossil fuel use. However, hydrogen could also potentially act as a GHG itself under high levels of leakage. Therefore, safety measures to prevent leakage have to be put in place and are essential to achieve a green hydrogen use (Van Ruijven et al., 2011).

Another sustainable option for backup power is by using battery energy storage systems. Much like fuel cell generators, the emissions from using battery energy storage systems are only emitted during electricity production (Figure 23). Therefore, the level of emissions will vary based on the source of electricity. When using the average electricity grid source in California, the level of emissions from electricity production is lower than the emissions from hydrogen production from SMR. Such emissions can be reduced to zero if using Zero-CI electricity sources, such as solar PV.

5.4.6 Microgrids and Other Options

SamTrans could consider installing a microgrid, which would consist of an on-site power generation service that can run during blue-sky operations, but also run in full island mode during power outages. Microgrids often feature more than one type of power generation source, with one of the most common configurations as solar, battery, and a natural gas generator. This provides some flexibility in operations. Usually the natural gas generator is clean enough to run regularly. This combination of assets can have a good return on investment and there are companies that specialize in financing and operating these assets to improve returns.

Traditional back up power options are not able to be used for revenue or energy bill management. However, cleaner sources of power can potentially be run to reduce costs or provide revenues to SamTrans. For example, due to their clean nature, fuel cells (both hydrogen and natural gas) can be run 24/7 and may produce a strong payback. AC Transit, based in Oakland, has a few fuel cell installations for this reason. There are also ways to build natural gas generators that are able to help California meet fast ramping markets in the evening hours when power prices are highest. Potential revenue generating opportunities will be discussed in a separate report.

Battery energy storage systems can participate in wholesale markets as well, earning revenues from California ISO, the operator of the transmission system. One additional benefit from batteries could be reduced interconnection costs from PG&E.

5.5 CONCLUSIONS

By comparing the various fuel sources, costs, and availability (in 2020 dollars), diesel-fueled power generation has the fewest barriers to entry from a capital and operational costs perspective. For instance, diesel-fueled power generation can be comprised of a single mobile unit that may be moved between the two bases, thereby reducing overall expenditures. However, diesel has significant negative externalities. It has the highest emissions due to fossil fuel combustion and is already the target of increased government regulation, potentially with regard to which fuels are permitted to power a zero-emission fleet.

SamTrans already has diesel infrastructure in-place and an onsite diesel-powered emergency generator. Based on the 2020 ICT Plan, the fleet will continue to need diesel fuel for another seventeen years. Therefore, it may be prudent to use traditional emergency generators initially until a larger portion of the fleet has been electrified. SamTrans could consider renting diesel generators to reduce cost and avoid investment in technology that may become obsolete in the future. In addition, if SamTrans installs a BESS at either base, the BESS system can provide backup power for a portion of the fleet.

Natural gas generators are seen as more reliable than diesel generators, though these conclusions are based on estimates from small data sets and significant assumptions. Thus, natural gas provides the largest reliability premium compared to diesel for regions that face high risks of long outages. Natural gas is a viable solution in the medium term when located adjacent to a pipeline and has significantly lower emissions than diesel.

With regard to the feasibility of hydrogen fuel-cell backup power generation, it is significantly more expensive than established technologies. However, making an informed decision based on SamTrans' strategic goals will behoove the agency in the overall transition to zero-emission bus technology. It is therefore recommended to continue researching technological possibilities in term of backup power generation. For example, fuel cells can run on natural gas today easily, and be converted to hydrogen when it makes sense to do so[25]. Due to the nascency of emergent technologies, such as hydrogen fuel-cell technology, the Project Team suggests observing industry trends, disruptions, and advancements that appear on the horizon over the next decade. Vested interests, existing infrastructure, and geopolitical support continue to enable fossil fuel technologies' costs to remain artificially low. However, what is feasible in the years ahead will be drastically different than the solutions presented in this 2020 study.

Specifically, in the realm of zero-emission vehicles, a "tipping point" is forecasted to occur in the coming five to seven years, when technological advances in terms of batteries and alternative and renewable fuel sources will be financially competitive in the transportation marketplace. Systemic disruption allows for economies of scale to emerge for these new systems and technological opportunity to emerge. Finally, given its local access, SamTrans may wish to partner with an existing Silicon Valley firm or startup to engage in further research and development in order to support alternative technologies.

Table 28 summarizes the benefits and trade-offs between the major emergency power options considered in this study.

[25] https://www.bloomenergy.com/newsroom/press-releases/bloom-energy-announces-hydrogen-powered-energy-servers-make-always-renewable

Table 28. Comparison of Emergency Generator Technology

Type	Costs	Footprint	Emissions	Setup and Response Time	Technology Maturity
Generator Type					
Stationary Units	1.6x more expensive	Need permanent space at both bases	Marginally higher O&M emissions	Immediate Fastest; full coverage at both sites No setup required Could be integrated into a microgrid	Mature technology for diesel and natural gas Hydrogen fuel cell is still nascent
Mobile Unit	Only need 1 unit	Only need space at one base Can be moved offsite	Marginally fewer O&M emissions	Slower; requires external vendor to transport Setup time could be as long as standard power outage	Diesel mobile generators are well-established Limited options for natural gas and hydrogen fuel cell
Rental Units	Very limited upfront costs, high costs for usage	Same as other technologies, no long term storage space required	Same emissions as other tech options	Slowest set up times	Diesel mobile generators are well-established Limited options for natural gas and hydrogen fuel cell
Fuel Type					
Diesel	Lowest costs Could be higher regulatory costs in the future	Smallest footprint Can potentially use existing diesel storage tanks	Worst GHG and CAP emissions Subject to regulatory restrictions on usage	Immediate	Well-established Technology used by most currently Many different options
Natural Gas	1.2x more expensive than diesel	2x more space needed compared to diesel (not counting diesel storage tanks)	Slightly fewer GHG emissions compared to diesel Significantly fewer CAP emissions compared to diesel Fewer regulatory restrictions on usage, but could change	Immediate Risk of disruption to natural gas pipeline during an incident	Well-established, but requires access to natural gas pipeline
Hydrogen Fuel Cell	2.6x more expensive than diesel	1.4x more space needed compared to diesel	No GHG emissions during usage No CAPs	Immediate	Nascent – limited options and most still use natural gas currently Modular design allows for future expansion

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APPENDIX A SAMTRANS BEB ROUTE POWER ANALYSIS

SAMTRANS BEB ROUTE POWER ANALYSIS

The Project Team has the following recommendations and comments based on the Project Team's review of the BEB route power analysis prepared by HDR in April 2020:

- p. 5: Which data were used for the bus efficiency assumption(s)? Figure 1 indicates a key input as "Bus data from OEM or performance logs," however these reported numbers are often quite problematic and misrepresentative of actual road conditions. Which performance logs were used—Altoona or self-reported numbers?
- p. 6: Table 2, Route 286 is an outlier with nearly 9,887 kWh, has this been vetted as a challenging route? What are its route characteristics?
- p. 9: "Blocks from other garages (San Francisco Yard, RWC Brewster Yard, and Half Moon Bay Garage) were assigned to either North/ South garage." Half Moon Bay is 16.6 miles away from the South Base, how is this deadhead distance being factored into the "other bases" and the accompanying analysis? How were these buses assigned and was this accounted for in the Zero+ model?
- p. 9: What are charging inefficiencies? 1st main body paragraph: please elaborate on which routes are too long for a 440 kWh battery, based on the Zero+ model.
- p. 13, the "Total Energy Estimate" of 4kW at 60° F does not match the value listed in the table (p. 14) as 6kW. Please verify which is correct?
- p. 20, suggest defining "nameplate energy rating of 10MW-hours" for reader clarity.
- p. 25, under "Prelim Infrastructure Design," third bullet: suggest defining loops and providing more explanation of how they can be used to provide redundancy. It is unclear if this is actual feasible.
- p. 26, under "Operational Aspects," suggest defining availability ratio (The number of days the buses are actually available compared to the days that the buses are planned for operation, expressed as percent availability).
- p. 26, Second paragraph: Why is a continuous training bus needed as a spare? Can this not be sourced from the OEM to provide appropriate training instead of devoting a bus full-time solely to the purpose of driver training?
- Adding 34 buses to an overall fleet is an extremely capital-intensive ask, despite the increased spare ratio. The Project Team recommends further analyzing en-route charging, as 34 additional buses results in roughly $30,000,000 in additional capital. These added costs are not discussed in the report.
- Even when operating the additional fleet, there are still three blocks that cannot be completed (Table 9). However, there is no further discussion about how said blocks will be incorporated from an operational standpoint.

- Based on the modeling results, SamTrans will need 265 buses, which is 21 buses less than their current fleet. However, the modeling team decided to add 8% adjustment (due to variables not incorporated in the model) to bring back the number to the current fleet. Perhaps it is possible to optimize the size of the fleet to be smaller than is in current operations by including en-route charging.
- Where was gradeability discussed after initial modeling assumptions for Zero+? SamTrans in likely to incur issues surrounding topography versus extreme temperatures, what were the impacts of grade on the overall findings of the analysis?
- HDR used a 440 kWh bus capacity for the modeling while the Project Team typically uses 660 kWh as a barometer for future BEB purchases, given the nascency of the technology.
    - Regarding en-route charging: both 350 and 150 kW chargers were considered while typical en-route chargers use 500 kW. What are the considerations? i.e., 4x 350 kW chargers are being considered at the DC BART station, why not 2x 500 kW? Why a single 350 kW charger at Palmetto Ave?
    - Why are costs not considered for charging infrastructure (depot and en-route)?
    - How were the minutes determined for the on-route charging locations?

15-MINUTE DEMAND INTERVAL DATA

HDR provided the following 15-minute interval data:

- 15-minute interval data for the South Garage for each season and for the anticipated energy use on each of a weekday, a Saturday, and a Sunday.
- 15-minute interval data for the North Garage for each season and for the anticipated energy use on each of a weekday, a Saturday, and a Sunday.

The Project Team created complete annual energy use profile for each garage using the HDR provided files and will assume a Saturday schedule for holidays. HDR used historical average daily weather data to build a 15-minute energy profile for the North and South Base for the following time periods: February 1-7, May 1-7, August 1-7 and November 1-7. Each time period noted the average daily temperatures the day of the week. A total of eight energy profiles, four for North Base and four for South Base were delivered in excel spreadsheets.

As discussed in Section 3.1, the Project Team adjusted the HDR 15-minute interval data from kW to kWh.

APPENDIX B ELECTRIC ACCOUNT OVERVIEW

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	1005389455	2887156370	A-1-TOU	18,332	8.3	NO
2	1005383132	2887156914	A-1-TOU	0	0.0	NO
3	1009470015	2887156638	A-1-TOU	504	0.1	NO
4	5010R0	2887156060	E-19-S-V	2,634,515	530.4	YES
5	1010238116	2888979600	E-19-S-V	929,785	186.0	YES
6	1010410600	2887156879	E-19-S-V	469,136	129.1	YES
7	1004497449	2887156609	E-19-S-V	127,206	38.1	YES
			Total:	**4,179,478**		

APPENDIX C HISTORICAL RATE ANALYSIS

HISTORICAL RATE ANALYSIS

			CURRENT TOU RATES AND COSTS PER CURRENT BILLS				CURRENT TOU IDEAL RATES[1] & 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)	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)	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)	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)
2887156370	1005389455	A-1	$4,599	$4,687	$4,533	$4,717	A-1	$4,571	$4,659	$4,507	$4,690	B-1	$4,595	$4,683	$4,530	$4,713	B-6	$4,447	$4,535	$4,384	$4,567
2887156914	1005383132	A-1	$120	$120	$120	$120	A-1	$120	$120	$120	$120	B-1	$120	$120	$120	$120	B-6	$120	$120	$120	$120
2887156638	1009470015	A-1	$239	$241	$237	$242	A-6	$235	$238	$234	$239	B-1	$242	$245	$240	$245	B-6	$237	$239	$235	$240
2887156060	5010R0	E-19-S-V	$486,745	$495,439	$477,202	$503,547	E-19-S-V	$486,745	$495,439	$477,202	$503,547	B-19-S-V	$491,387	$500,080	$481,757	$508,102	B-19-S-V	$491,387	$500,080	$481,757	$508,102
2888979600	1010238116	E-19-S-V	$169,406	$172,474	$166,177	$175,475	E-19-S-V	$169,406	$172,474	$166,177	$175,475	B-19-S-V	$172,779	$175,847	$169,420	$178,718	B-19-S-V	$172,779	$175,847	$169,420	$178,718
2887156879	1010410600	E-19-S-V	$98,502	$100,050	$96,683	$101,374	E-19-S-V	$98,502	$100,050	$96,683	$101,374	B-19-S-V	$99,690	$101,238	$97,848	$102,539	B-19-S-V	$99,690	$101,238	$97,848	$102,539
2887156609	1004497449	E-19-S-V	$27,478	$27,897	$27,182	$27,818	E-19-S-V	$27,478	$27,897	$27,182	$27,818	B-19-S-V	$27,884	$28,304	$27,605	$28,241	B-19-S-V	$27,884	$28,304	$27,605	$28,241
		TOTALS:	$787,089	$800,909	$772,134	$813,293		$787,057	$800,878	$772,104	$813,263		$796,697	$810,517	$781,519	$822,678		$796,543	$810,364	$781,368	$822,527
		CCA RATE SAVINGS:			$14,955	($12,384)				$14,953	($12,385)				$15,177	($12,161)				$15,175	($12,163)
		IDEAL RATE SAVINGS:					$31									$153					

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

APPENDIX D FUTURE RATE AND DER ANALYSIS ASSUMPTIONS

FUTURE RATE ANALYSIS ASSUMPTIONS

- The analysis completed was based on the April 27, 2020 HDR study, which includes year-round service, including the assumptions stated below as well as all additional assumptions in the study, in order to complete a high level analysis of the anticipated energy procurement costs.
- The HDR data was provided in kW per 15-minute interval and was converted to kWh per 15-minute interval by the Project Team. Discrepancies in the total kWh consumption may occur as a result.
- No en-route charging was considered in the 15-minute interval data provided by HDR, only depot charging. All charging will occur at either North or South Base.
- Contracted fleet service (CUB) routes were included in the analysis. The energy for the routes will be accounted for and assumed to be charged at either North or South Base. The 37 managed lanes BEB's are not included in the analysis.
- The existing PG&E services at the South and North garages are anticipated (and will be assumed) to remain with the existing load they serve remaining behind those meters (secondary service).
- New PG&E primary voltage services are being installed for the purposes of bus charging only (this is a requirement of the BEV rate).
- SamTrans will train drivers to drive in a fashion that will maximize the range of the buses and minimize the drain on the battery (limits consumption and this is assumed in HDR study).
- The quantity of EV chargers and electric buses (and the resulting electricity consumption profile) used in the HDR study closely represent quantity of EV chargers and electric buses that SamTrans will purchase.
- The data from the HDR study reflecting the number of buses, the time of day and the number of times the buses charge per base and per day is a good approximation of how SamTrans will operate.
- SamTrans will purchase real-time software control or use a predetermined charging scheme to control peak demand due to bus charging (limits demand and is assumed in the HDR study).
- The analysis completed does not consider route adjustments that will be made as part of the comprehensive operational analysis (COA) process.
- The analysis assumes that 100% of the fleet will be converted to BEVs. Hydrogen Fuel Cell Electric Buses (FCEBs) are not being factored into this analysis or study.

- This analysis assumes that 100% of the fleet is electrified, in line with the HDR study.
- The study cannot be updated later with new demand information at a later date without modifying the project scope.
- 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.
- In order to create a cost projection for the two new electric services that are to be installed solely for the purposes of electric bus charging, the Project Team used 15-minute interval files created and provided by HDR as a result of the HDR SamTrans Route Power Analysis – V2 report. In order to create a complete annual consumption profile for each of the North and South garages the Project Team combined the seasonal and daily 15-minute interval file variations that were provided by HDR. There is the potential for a variation in the total energy consumption (kWh) based on the HDR data provided, given that maximum power (kW) was provided for each 15-minute interval versus energy consumption (kWh) per 15-minute interval. The Project Team made best efforts to minimize the potential for large discrepancies by manipulating the data provided by HDR. Using the final annual consumption profile, the Project Team then analyzed the costs under two different rate tariffs (BEV-2-P and B-20-P) that SamTrans is eligible for enrollment in based on the projected energy usage at both the North and South bases.

DER ASSUMPTIONS

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 + PCE default B-EV-2P rates
- PG&E and PCE 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 SamTrans in the case of the cash purchase scenarios
- REC ownership and value (revenue): RECs retained by SamTrans, with potential sale value excluded in the pro-forma. SamTrans can elect to sell the REC's for additional revenue, retire them for LCFS zero-carbon credits, or alternatively, green brand
- Installation date (2022)
- 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 SamTrans 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)
    - SamTrans' 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 (based on start of construction before EOY 2022)
    - 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 SamTrans
- Contract term length of 15 years (could be up to 25yrs in some financing scenarios)
- Installation date (2022)
- SamTrans' 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