SOLAR+ MICROGRID COSTS AT GAS STATION AND CONVENIENCE STORES IN THE STATE OF CALIFORNIA

By

Thalia Quinn

A Thesis Presented to

The Faculty of Humboldt State University

In Partial Fulfillment of the Requirements for the Degree

Master of Science in Environmental Systems: Environmental Resources Engineering

Committee Membership

Dr. Peter Alstone, Committee Chair

Dr. Charles Chamberlin, Committee Member

Dr. Margaret Lang, Program Graduate Coordinator

May 2019

ABSTRACT

SOLAR+ MICROGRID COSTS AT GAS STATION AND CONVENIENCE STORES IN THE STATE OF CALIFORNIA

Thalia Quinn

This project estimates the capital costs for Solar+ microgrids for the year 2018 and forecasted out to 2030. Solar+ systems include the use of battery energy storage, solar energy, electric vehicle chargers and control systems to manage energy consumption and generation for a single building and provide islanded "microgrid" features. The capital cost includes estimates for the components: DER technologies (battery, solar PV and EV charging stations), controls (programming and hardware), and integration costs (switchgear, engineering, permitting and site work). Methods used to estimate each cost included assessing historical and projected costs for each of the components.

Five Solar+ scenarios are evaluated to forecast the estimated total project cost, the separate component costs, and the variability of these estimates. The scenarios considered constructing Solar+ systems to fit gas station and convenience stores with varied sizes (small, medium, and large) and goals (resilient scenarios). The average capital cost projections for each scenario show that costs are expected to decrease by 50-60% by 2030, with today's unit cost at $4.8/W for a medium Solar+ microgrid. Changes in cost for each scenario show dependence on the system specification, including size of

the battery system and solar PV. EV charging infrastructure has the greatest impact on the total cost and is reported as the largest cost contributor for all scenarios in the future. Additional results from this project suggest that medium to large Solar+ systems have the lowest unit cost currently (in 2018), but smaller Solar+ systems will have comparable costs by 2030 at roughly $2.0/W.

ACKNOWLEDGEMENTS

First, I would like to thank the Schatz Energy Research Center for awarding me with the Schatz Energy Fellowship. Without the fellowship, I would not be the first in my family to receive a master's degree. The Schatz Center is filled with brilliant, caring people that work on crucial topics to better the world. I am proud to say I was able to work with these amazing people. Additionally, I thank the Schatz Center's Microgrid Group for sharing their knowledge, support, and skills to help complete this project.

Secondly, I would like to acknowledge my peers and co-workers that assisted with developing the model. A large portion of this project would not have been possible without the help of Ellen, Jo, and Rene. I am grateful for their contributions and enjoyed every minute of working with them to answer some difficult questions. Also, thanks go to Eli for showing me some tips and tricks for data management and sorting in R.

To my committee members, I extend many thanks to Dr. Peter Alstone and Dr. Charles Chamberlin. Thank you for the support, guidance, and time that you provided me throughout my academic career, especially throughout this project. Both of you helped me develop a mindset of critical thinking and statistical exploration. Thank you.

Lastly, I would like to thank my family and friends for encouraging me throughout my academic career and this project.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICIES

INTRODUCTION

Reliable electricity is a major need for human development. Without power we are unable to enjoy basic necessities of lighting our homes, keeping food fresh and connecting through technology. Access to electricity has proven to play an important role in improving human development through “productivity, health and safety, gender equality and education,” (Alstone et al. 2015). Also, the current bulk power system (BPS) in America is considered to be one of the most crucial and largest electrical infrastructures in the world (Albert et al. 2004). Two important features for the BPS are 1) be resilient, ready to respond to disasters or unexpected conditions, and 2) be reliable, able to meet demand consistently and with quality. Unfortunately, as time goes on there are stresses on the infrastructure that could reduce resiliency and reliability, including aging equipment, unpredictable natural disasters, and severe weather events that are expected to increase as climate change takes effect. One solution for this challenge the BPS faces is to prepare for these events and develop resilient and reliable infrastructure that can operate in any circumstance.

A current topic that addresses this need for resilient and reliable electrical infrastructures is the concept of “microgrids”. Microgrids are electrical systems which use localized power generation and storage to provide site-level reliability and resilience, while also being connected to the BPS. One particular design of a microgrid is a “Solar+” microgrid as shown in Figure 1. A Solar+ microgrid utilizes solar photovoltaics (PV), battery energy storage, electric vehicle (EV) charging stations and control systems to manage energy use, energy generation and energy efficiency all within a single building, or similar system (e.g.,. university campus, hospital, etc.).

As a part of a larger research group at the Schatz Energy Research Center, we are designing and building a Solar+ MG at a gas station and convenience store in Northern California. This thesis assists the project by focusing on the cost analysis of the installation of Solar+ systems built for the gas station and convenience store building type. Additionally, gas stations and convenience stores are the target building type due to 1) the ubiquitous characteristics that all gas stations have, 2) the potential to meet the growing technology of electrical vehicle charging infrastructure, and 3) the ability to provide food and other important resources in the event of a natural disaster. The state of California has close to 12,000 gas station convenience stores, making this building type an optimal design location for wide-scale deployment (National Association of Convenience Stores 2018).

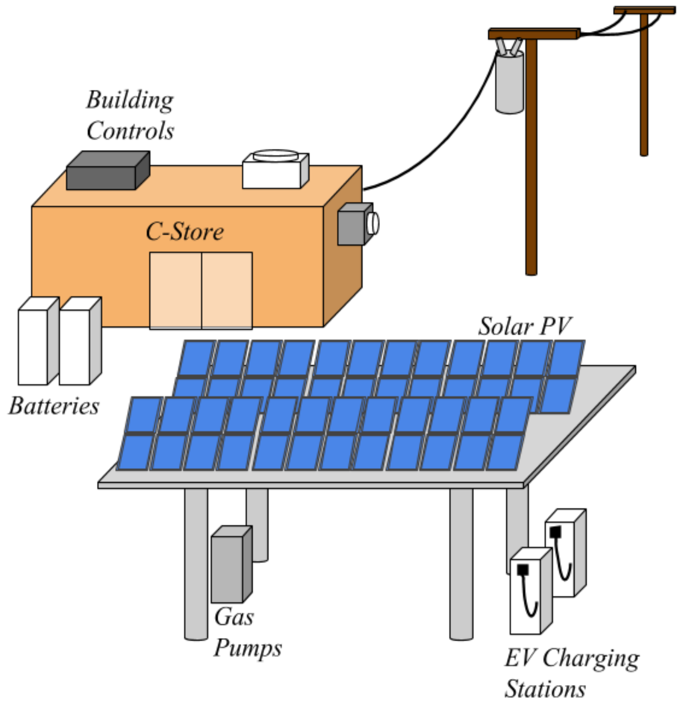


Figure 1. Solar+ microgrid applied to a gas station and convenience store. Adapted from the Schatz Energy Research Center Solar+ Project proposal (Alstone et al. 2016).

The hope for Solar+ and other microgrid systems is to create an easily repeatable design that can be quick to install and have multiple deployment opportunities. One major challenge with advancing microgrid technology through policy and R&D is understanding the costs that are required for installing such a system. This project reviews literature regarding the costs and benefits the systems provide to support development of a model that estimates current and future costs are for Solar+ systems from 2018 to 2030. Costs discussed throughout will be specifically targeted at system sizes applicable to gas station and convenience store building types.

The resulting model considers the costs for each of the categories: battery energy storage, solar PV, EV charging stations, controls (programming and hardware), and integration (switchgear, engineering, permitting and site work) costs. This model then assesses the costs for five particular systems or scenarios applicable to the range of building sizes for gas station and convenience stores. Further, the model estimates average total costs over time and with small variations to the types of systems installed (e.g., number of EV stations installed and capacity of battery system).

LITERATURE REVIEW

In this literature review, I will define what microgrids (MGs) are, describe the anticipated value streams, and the costs for previously installed MG systems. Then I will define a framework for the costs of construction and deployment of Solar+ MGs built to satisfy the convenience store gas station industry by reviewing costs associated with the separate components. These sections provide a detailed review of the reported costs for battery energy storage, solar PV, EV charging stations, MG controls and MG integration. Each cost category is researched independently for ease of developing independent cost functions for the final cost model in this thesis.

Microgrids by Definition

Recently MGs have become the topic for discussion amongst utility regulators, electric utility companies, research centers, the private sector, and communities concerned with reliable electricity. The definitions for MGs vary, but consistency is apparent among several sources regarding islanding (connecting and disconnecting from the BPS), and the collection of various components in a single electrical boundary. Appendix A lists four definitions by various experts in the field of MG research used to make the following conclusions regarding MG definitions. To summarize the common characteristics between current definitions, a MG includes:

- **Electricity Generation** – MGs include generation source(s) or distributed energy resources (DER) (e.g. generators, solar PV, wind turbines, etc.)

within the systems' electrical boundaries (Ton and Smith 2012). The generation is sized to serve the electrical loads for the MG system.

- **Energy Storage** – MGs include energy storage to serve loads and provide backup power to the system when power generation or grid connectivity is not available (Soshinskaya et al. 2014).
- **Consumer Loads** – Every MG is built specifically for serving a customer load, which can include a single customer, building or larger system (e.g. school campuses and neighborhoods) (North American Electrical Reliability Corporation 2017; Schwaegerl 2009). The customer loads and the desired operation are the determining factor for the size of the generation and storage.
- **Grid Connectivity** – MGs have the ability to connect and disconnect from the grid without decreasing operability of the system during a power outage, or similar event. This is an important aspect for defining these systems as a MG rather than a collection of distributed energy resources (North American Electrical Reliability Corporation 2017; Soshinskaya et al. 2014).

The collection of these four components help estimate whether a system is a MG or not. For clarification, the Solar+ MG is considered a MG focusing on the integration of specific components (solar PV, battery, EV chargers, and controls), while a MG is not limited to those components and can include additional features.

Figure 2, shows the expected flows of the energy to and from each of the components. The dashed and dotted line represents the electrical boundary of the MG. The MG controller, ensures the fluid operation of the system. This piece of equipment receives a range of information from each of the main components to provide the desired services, such as the delivery of electricity to the customer (Liu et al. 2016).

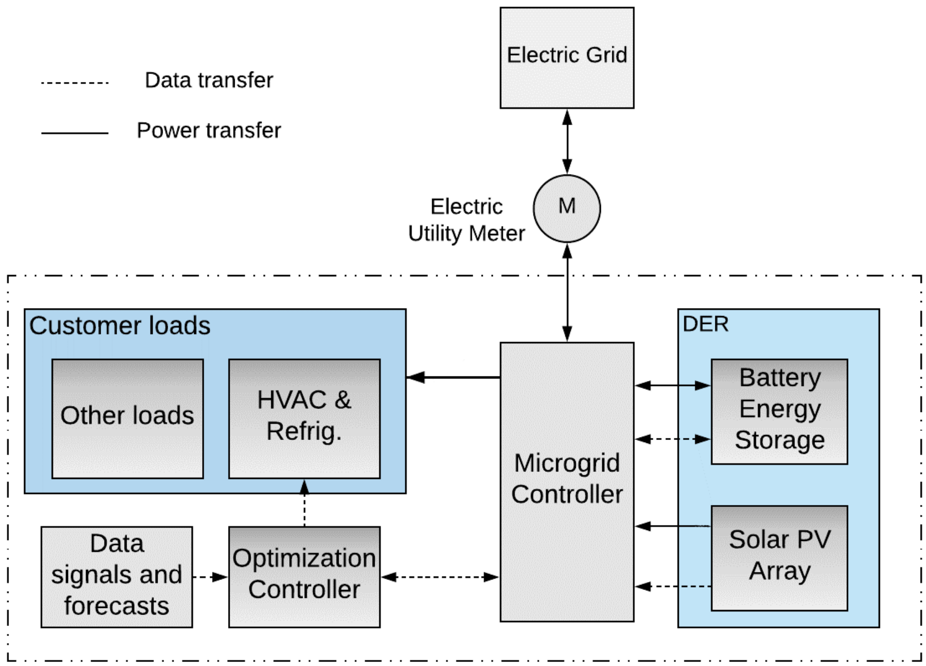


Figure 2. Example of basic MG with solar energy generation, and battery storage as the distributed energy resources, and a MG controller to manage all loads (grid, solar, battery, and customer).

One technical characteristic not defined specifically in available reports is the exact size for MGs systems. Various reports describe that MGs are usually low to medium voltage distribution networks, which range from < 1 kV to 100 kV (North American Electrical Reliability Corporation 2017; Schwaegerl 2009; Soshinskaya et al. 2014). MGs are not limited by size, but rather by the application of how power is supplied to local sources, (Soshinskaya et al. 2014). Although, additional reports and articles have classified MG systems by the size of the loads being served and the level of voltage of the network: picogrid serves a house, nanogrid serves a building, and microgrid serves a neighborhood, (Martin-Martinez, 2016, Mouton, 2017). Ultimately, the size of the MG depends on the customer loads due to matching the demand with on-site generation and/or dispatch of the battery for islanding capabilities, (Soshinskaya et al. 2014).

MG Value Propositions

MGs are growing in popularity for a list of reasons, some of which include: increased electricity resiliency, integration of renewable energy, potential for demand response, and decrease in electricity costs (Mouton 2017; Stadler et al. 2016; Ton and Smith 2012). I found that estimates of the value ($/kWh served) that MGs can provide to customers are uncertain and difficult to estimate, because this value depends highly on the customer and what services the MG is built to provide (Mouton 2017). Table 1 provides expected value streams estimated for MG technologies.

Table 1. Value streams for MG. Source: (Stadler et al. 2016).

Value stream	Description
Electricity export	Electricity generated within the MG can be exported to the electricity grid under a variety of agreements with utilities. The overall value of exports is highly situation dependent.
Demand response	The local control over load and DER output within a microgrid makes it well suited for demand response participation, wherein the MG responds to instructions or incentives from a utility (or other entity) to reduce net consumption and provide support to the broader electricity grid.
Outage resiliency	On-site generation and storage resources create redundancy and back-up power to mitigate economic losses due to unserved loads in the event of planned and unplanned outages in the electricity market.
Local energy market	Local energy markets can emerge when microgrids become sufficiently common to interact with one another. By trading between MGs, local markets may create more favorable conditions for distributed renewable generation. Thus, increasing the value for MG owners.

Export of electricity

MGs are not limited to serving electrical loads within the defined boundaries, which enable the possibility of selling electricity to the BPS (Stadler et al. 2016). This value stream exists when the electricity generated by the MG DER is greater than the MG demand. Especially if renewable energy generation sources produce more electricity than needed to support the MG, the excess electricity can be exported to the main grid, making profit for the MG operator/customer (Stadler et al. 2016). However, exporting energy must be done in collaboration with the local distribution utility to verify the cost of the electricity and other requirements.

Demand response

With load control systems inside the building and battery storage, MGs have the capability to shift and shed load. This makes it possible for MGs to participate in demand response (DR) programs (Stadler et al. 2016). The value associated with DR is the economic incentive to shift and shed load during periods of high costs on the wholesale market of electricity (Stadler et al. 2016) or based on other signals. DR capabilities also relate back to reliability. If the MG detects a blackout so that energy is not available from the grid, the MG can use demand response to shift loads to times when the DER will be producing electricity (Hyams et al. 2010). Also, a MG may shed load by reducing electricity to loads that are not essential to the operation of the MG, which is a form of efficiency (Mouton 2017).

<u>Outage resiliency</u>

MGs also provide resiliency and reliability. Resiliency is the ability to continue operation in the event of a natural disaster or blackout (Mouton 2017). Reliability is the system's ability to “deliver electricity in the quantity and with the quality demanded by users,” (Mouton 2017). The value stream associated with resiliency is important for critical infrastructure or buildings with sensitive loads. The Department of Homeland Security reports that there are 16 different types of critical infrastructure that are needed to be operational in the event of a disaster or emergency. This infrastructure includes the following sectors: chemical, commercial facilities, communications, critical manufacturing, dams, defense industrial base, emergency services, energy, financial services, food and agriculture, government facilities, healthcare and public health, information technology, nuclear facilities (reactors, materials, and water), transportation systems, and water and wastewater systems (Dept. of Homeland Security n.d.). These buildings are important for emergency response activities and human activities making them optimal use cases for MG systems.

Outage resiliency for critical infrastructure is not a new thing. Most hospitals are required to have backup generators on-site to ensure the operation of the hospital in the event of a power outage. What a MG can do differently from these generators is create a haven or operational network all within its electrical boundaries and efficiently operate with information signals for weather, electricity consumption, electricity cost, and more (North American Electrical Reliability Corporation 2017). Since a MG has all the components (generators, storage, and controls) on the customer side of the meter plus the

MG controller, the entire system can island and act as an independent unit (Schwaegerl 2009).

With respect to reliability, the value stream is based on the value that the customer holds when having reliable electricity for day to day operations. Reliability and resiliency are usually paired together because it is just as important for critical infrastructure to have reliable electricity as it is to have resilient electricity. The value stream provided is separate from outage resiliency, yet similar with respect to serving the customer's needs. Again, this value can change from customer to customer making it difficult to estimate and completely dependent on the specific MG.

Local energy market

Additional value streams for MGs may arise when there is the possibility of trading electricity from MG to MG on a local energy market. For these value streams to exist there must be a large amount of effort for the policy and regulatory aspects to create a new framework of a local energy market (Stadler et al. 2016). If a successful market were developed and a wide scale of MGs were installed, MGs may obtain more value producing opportunities in the future (Schwaegerl 2009). Various reports and articles suggest that MGs could provide services that include frequency, multi-site islanding, and balancing support (Mouton 2017; Schwaegerl 2009). Additionally, such a market would enable more renewable integration onto the grid due to the ability to trade locally amongst multiple MGs (Schwaegerl 2009; Ton and Smith 2012). It should be noted that these are not guaranteed value streams due to the current electricity market, but rather future value streams after research and development has been pursued.

MG case study

Other sources mention a number of additional value streams as reasons why electricity consumers are interested in developing MGs for their sites. A case study of 26 MG projects (9 in California, 10 elsewhere in the United States, and 7 outside of the U.S.) completed by Navigant Inc. for the California Energy Commission included a much longer list of value streams including: renewable energy integration, resiliency (mentioned before), bill savings/demand charge abatement, reduction in carbon footprint, reliability, provision of energy and capacity services, provision of ancillary services, linkage to virtual power plant, future revenue from energy transactions, and non-electricity services (Asmus et al. 2018). The study surveyed the value propositions for each MG to estimate the importance for each value proposition. The results for the rankings are shown in Figure 3 (Asmus et al. 2018).

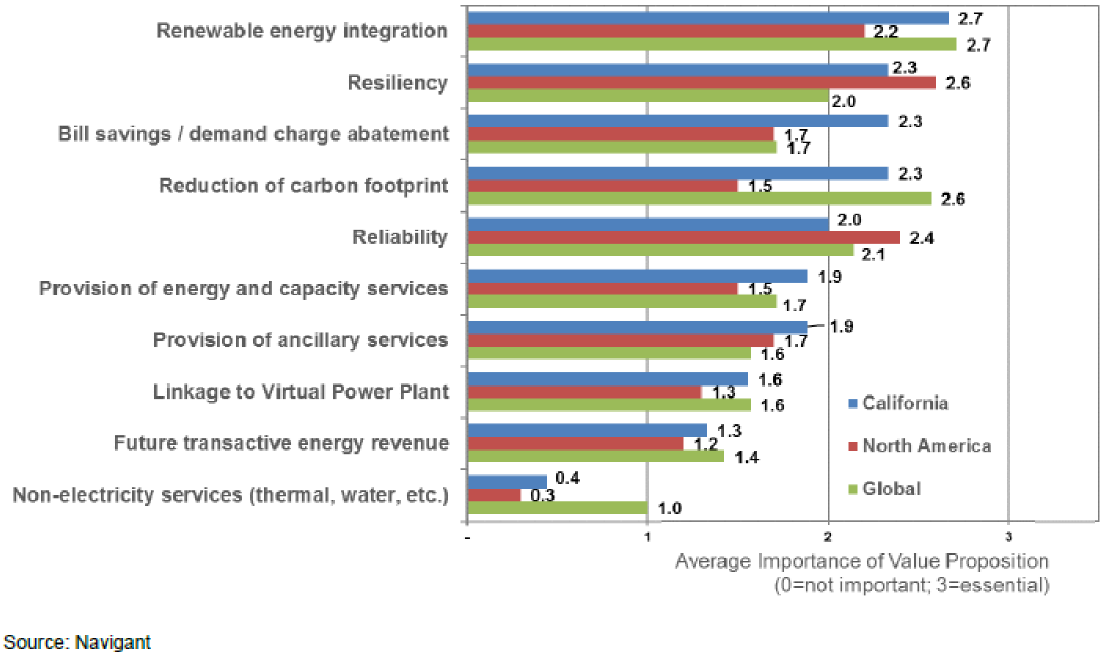


Figure 3. Value proposition rankings from survey of 26 MGs in California (9), elsewhere in North America (10) and outside of North America (7). Source: (Asmus et al. 2018).

The top four value streams ranked by the 26 MG projects in this study included renewable energy integration, resilience, demand charge management, and reduction of carbon footprint (Asmus et al. 2018). This shows that the importance of exporting of electricity to the main grid and the potential to have value streams through a new local energy market (as presented in Table 2) are less sought value streams. Higher importance is placed on reduction in carbon footprint and renewable energy integration. Additional value streams discovered from the survey includes EV- charging infrastructure or secondary use for EV battery packs, cybersecurity, coordination with smart home devices, and benefits to the utility or community (Asmus et al. 2018).

MGs have potential to provide many services to its customers, and for these benefits to have value they need to outweigh the costs for the installation and operation of the system. It is important to note that while there is a large array of value streams mentioned, many are speculative or may be challenging to access simultaneously or with the same system. This brief assessment of possible value streams supports the remainder of the project by providing reasons that one would consider the installation of a Solar+ MG or other MGs. As a reminder, the scope of this thesis is only the cost analysis for Solar+ MGs over time which does not include any of the benefits mentioned above. These are included to provide context for the costs and provide reasoning for why a microgrid may be considered for installation.

Microgrid Costs

Costs for MGs, and Solar+ MGs, can be broken down into the following cost categories: DER technologies (battery energy storage, solar PV, and EV charging stations), controls, and integration costs. DER technologies can be broken down into each components, for example, this project assesses costs by battery, solar PV, and EV charging stations. The controls category includes costs of controls for the building plus the MG, and cost for programming those controls. The integration category includes costs for switchgear hardware, engineering, permitting, and additional site work. This categorization is not completely consistent with previous categorizations found in past reports but is relevant to the Solar+ system. The following section reiterates on past reports and articles addressing the costs for each of these categories.

MG cost breakdowns

In 2013, the DOE released the following relative cost (percentage) estimates per MG component: 30-40% DER (this includes generators, energy storage and controllable loads), 20% switchgear protection and transformers, 10-20% Smart grid communications and controls, 30% site engineering, and the remaining costs are for operations and markets (Ton and Smith 2012). More recent reports suggest higher cost percentages for generation/DER and lower cost percentages for engineering when considering previously installed utility distribution MG case studies in North America. Table 2 provides two cost breakdowns from various reports. The difference between the cost breakdown estimates could be dependent on their categorization of the separate components, the timeframe for when the cost breakdowns were estimated, and the type of technologies used for constructing the MG. Although, both reports agree that the highest contributor to cost is the generation/DER category.

Table 2. MG cost breakdowns by categories. Sources: Ton and Smith 2013; Asmus 2016.

Category	**DOE**	**Category**	**Navigant, Inc.**
DER (generators and storage)	30-40%	Conventional Generation, Energy Storage, and Renewable	38%, 6% and 5%
Switchgear and transformers	20%	Additional Electrical Infrastructure	19%
Smart grid and controls	10-20%	Controls	14%
Engineering	30%	Balance of systems	18%

Currently these cost breakdowns are changing and are expected to continue to change over time. One source suggests that the costs for DER technologies (energy storage and renewables) are decreasing drastically, while the soft costs including BOS, additional electrical infrastructure, and controls are increasing per unit since these costs are remaining the same (Asmus 2016). Future trends may show that the highest cost contributor is engineering, controls, or switchgear related costs.

Existing MG unit costs

According to the case study mentioned in previous section, the average unit cost for a MG in California was about 3.6 million dollars per megawatt (MW) capacity in 2018 (Asmus et al. 2018). This unit cost is based on the total cost of the system divided by the sum of the power capacities for the energy storage and the generation sources. Figure 4, compares the average unit costs for MG projects in California, North America and Global MG projects. Here the average unit cost for a MG in the U.S. is 3.8 million $/MW and outside of the U.S. is 2.1 million $/MW (Asmus et al. 2018). The total average for all MGs considered (which includes a total 26 MGs) resulted in a unit cost of 3.2 million $/MW.

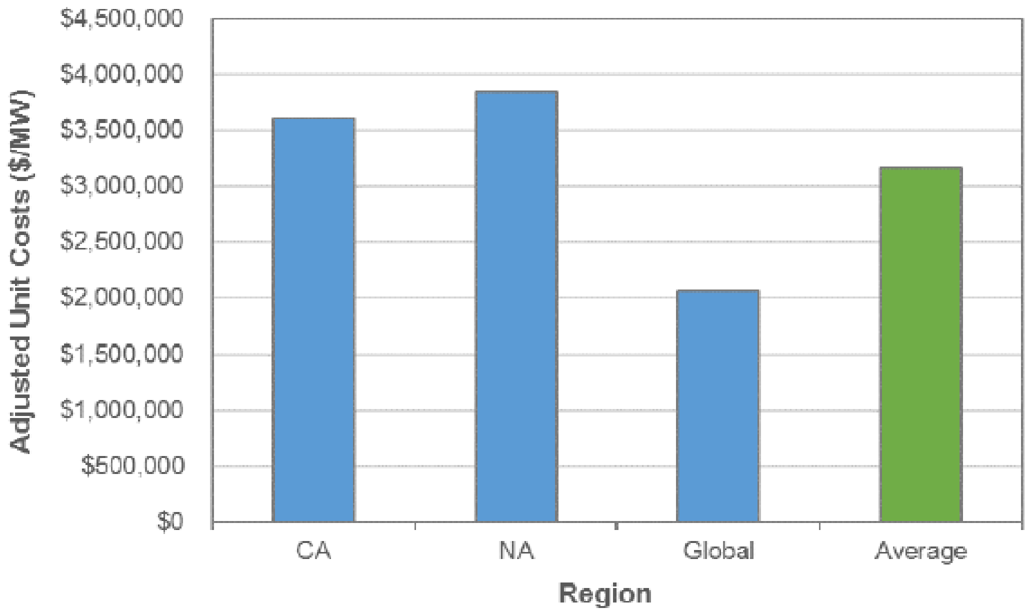


Figure 4. Regional average unit cost for MGs. Costs are based on the total cost over the sum of power capacity of all generation sources. Source: (Asmus et al. 2018).

It is important to note, the MG projects within each region and from region to region varied in DER mix. The DER included in the 9 California MGs included more solar PV and energy storage (57.2%) compared to the North American (24.3%) and Global (37.2%) MG projects (Asmus et al. 2018). Figure 5 below compares the DER mixes for each region. The U.S. MG projects outside of California have a large portion (36%) dedicated to biogas, when biogas is only representing 2% of California DER and none for the Global DER (Asmus et al. 2018). The differences in MG types may cause the differences found between the reported unit costs.

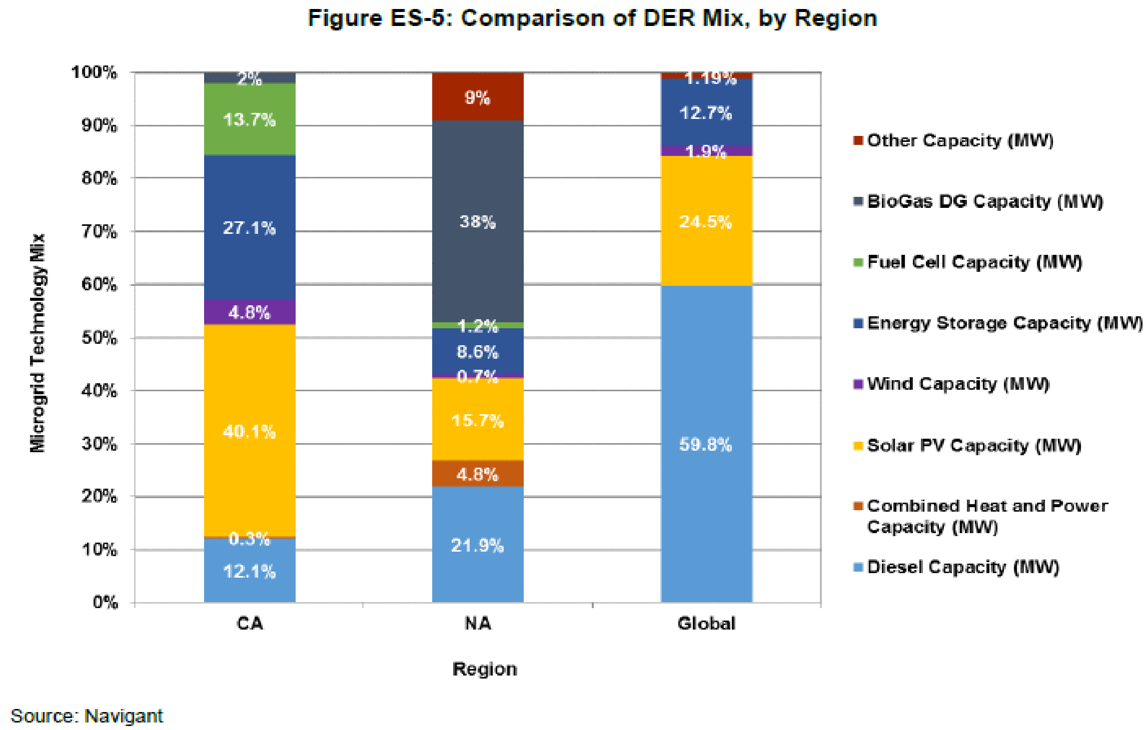


Figure 5. Comparison of DER mix by region. Breakdown DER type is provided for the various regions. Source: (Asmus et al. 2018).

When comparing the resulting unit costs to the DER mixes, it is easy to point out that using fossil fuel (diesel) generators can drive costs down, when using new technologies or non-conventional sources, like biogas, can drive costs up for a MG. Although, this report did not consider the external costs (such as the cost of greenhouse gas emissions) associated with using the conventional generation. If these external costs are included, the cost breakdowns are assumed to change to favor the renewable energy DER types. Also, each MG varied by value propositions as shown in Figure 3; this can also influence the unit cost due to the equipment needed to meet the needs of the customer. In conclusion, the cost of a MG varies greatly depending upon size, the DER and other generation sources installed, and the customers and contractors involved, (Asmus et al. 2018).

MGs with solar PV and battery energy storage

This section will evaluate the reported costs and sizes for 8 MGs only including solar PV and lithium-ion storage as the DER. The purpose for this brief analysis is to review the MG unit costs that are relevant to the work completed by this thesis. This MG architecture is significant for this study because it can provide insight to the cost relationship between MGs similar to a Solar+ MG. Table 3 provides the case study name, system size (regarding the solar PV and battery storage), total project cost in 2018 dollars and unit cost with respect to the total MW capacity for both the solar PV and battery systems. The unit costs for these 8 projects range from 3.2 – 7.1 million $/MW. This includes higher estimates than the previously reported unit cost of 3.8 million $/MW for MGs in the US. The following section provides a brief description of each of the listed projects.

Table 3. MG Case studies including solar PV and lithium-ion battery storage. Sources: (Asmus et al. 2018; Carter et al. 2018b).

Case Study	**PV (kW)**	**Storage (kW)**	**Storage (kWh)**	**Total Cost (2018 million $)**	**Unit Cost (million $/MW)**
2500 R Midtown Development	76.5	204	396	0.90	3.21
San Diego Zoo	90	100	100	1.09	5.75
US Marine Corps	152	50	400	1.10	5.42
Thousand Oaks	1,960	440	900	8.08	3.37
Thacher School	750	250	N/A	4.52	4.52
Pena Station Next	1,859	1,000	2,000	10.7	4.14
Palama Project	410	214	N/A	2.69	4.29
Blue Lake Rancheria Low-Carbon Community	420	500	950	6.58	7.16

The **2500 R Midtown Development** is a housing development project in Sacramento, CA, that installed solar PV plus energy storage systems inside 34 homes in 2014. The project is unique since each home can island individually or the entire development can island in the event of a power outage, (Asmus et al. 2018). Each system included a small solar array of 2.25 kW and a battery storage of 11.64 kWh (Asmus et al. 2018).

The **San Diego Zoo** installed a 100 kW lithium-ion polymer battery system paired with a 90 kW solar carport in 2012. The system works together to store energy from solar energy during the day, to then charging electric vehicles after sunset with the stored energy (Asmus et al. 2018). The entire system can island and also provides electricity to the MG at times of peak demand.

The **US Marine Corps Base Camp Pendleton** project is a solar PV plus battery storage system at a military facility in southern California (Asmus et al. 2018). The system was designed to provide "energy security and minimize risks for critical infrastructure by increasing resilience," (Asmus et al. 2018). The report noted that the largest cost was the installation ($800,000), followed by project development ($160,000), then commissioning and testing ($75,000) (Asmus et al. 2018).

The **Thousand Oaks Real Estate Portfolio** is a MG project within the Southern California Edison utility district which utilizes one existing solar PV array, and two new solar PV arrays with a hybrid battery storage system of lithium-ion and flow batteries. The report noted the following cost breakdown: installation ($7,680,000), project development ($120,000), and testing and commissioning ($100,000) (Asmus et al. 2018).

The **Thacher School** project is a MG project built to improve the school's resilience to power outages, which the school has previously suffered from because of wildfires. The MG included a 750-kW solar array with a 250-kW battery (the energy capacity of the system is not provided in the report) (Asmus et al. 2018). The report noted the cost breakdown of: solar PV system ($3,400,000), extra permitting and more for the PV array ($250,000), and the storage and MG controls ($580,000) with an additional cost for surveying ($100,000) (Asmus et al. 2018).

The **Pena Station Next** is a project near the Denver International Airport, with two solar PV arrays (1.6 MW and 259 kW) and one battery system (1 MW) (Asmus et al. 2018). It is important to note that the costs for the smaller array is not included in the $10.3 million overall cost and has not been included in the unit cost. The cost breakdown for this system included: battery storage ($2.3 million), and the solar array ($3.4 million), with and additional $2.5 million for structural equipment (Asmus et al. 2018). The remaining costs were spent on ancillary equipment, integration costs, warranties and O&M (Asmus et al. 2018).

The **Palama Project** is a MG project with a solar PV array of 410 kW and 2 battery systems with varied power capacity and energy capacity in Oahu, Hawaii. The MG was built in 2015 to provide resiliency to the Palama Holdings meat processing plant and H&W Food Services facilities (Asmus et al. 2018). The overall cost breakdown was not included in the report.

The **Blue Lake Rancheria Low-Carbon Community** project is a 420 kW solar array with a battery energy storage system of 950 kWh. The system was built in 2016 to provide resilience to critical infrastructure on-site and reduce the Rancherias carbon footprint. This project was also focused on research and development for a new MG controller, and including equipment that hadn’t yet been connected in a MG project before (Carter et al. 2018b). The effort towards utilizing the new controller and mechanisms was noted to increase the total cost of the project (as shown in the unit cost reported in Table 3) (Carter et al. 2018b).

With this broad range of projects, the variables noted that can affect the project's total cost are size of the solar PV, battery, and the duration (kWh/kW or hours) of the system. Figure 6 shows the linear regression of the solar PV size versus the total costs of the 8 MG systems. The intercept is not set to zero for this linear regression model and was found to have an R squared value of 0.72.

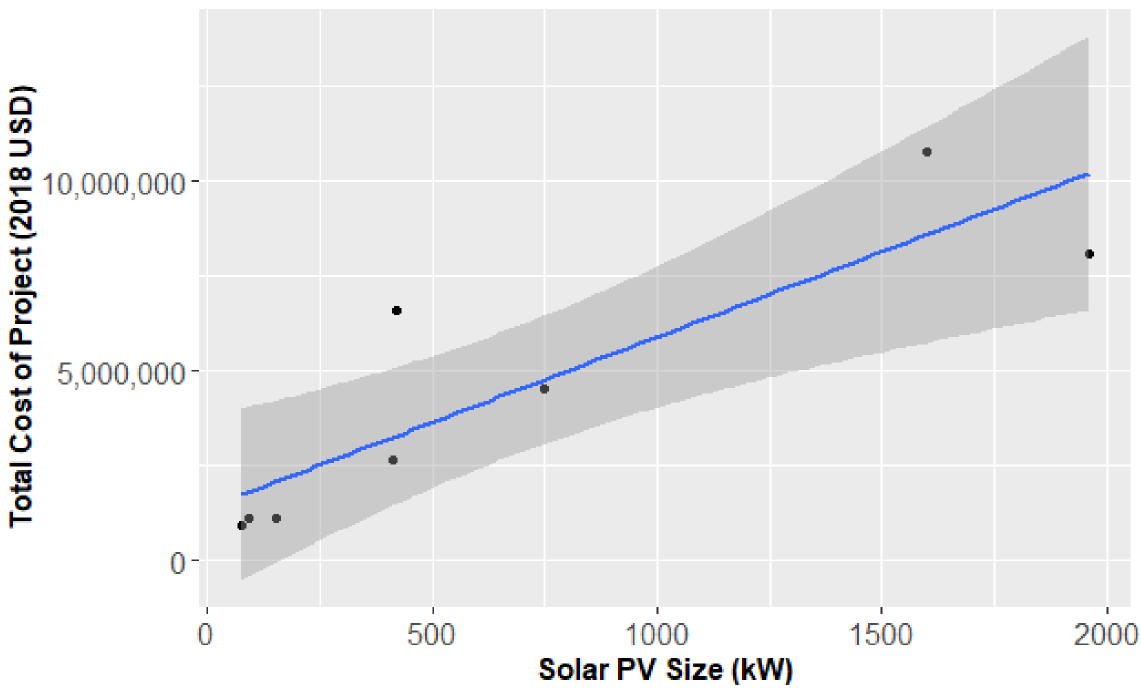


Figure 6. Total Costs of MGs According to Size of Solar PV Installed

Here most of the projects show a correlation except for the one project at the Blue Lake Rancheria (at 420 kW, 6.5 million $) and the Thousand Oaks Project (at 2000 kW, 8.08 million $). The Rancheria project is noted to be higher in costs due to innovations and extra costs incurred while working on one of a kind equipment, which may cause the variation shown in Figure 6. Additionally, the Thousand Oaks Project is the largest solar

PV project and the third largest battery project out of the selection, which may cause the lower total cost compared to the expected linear model. It should be noted that this trend will change when additional variables are considered.

Table 4 and Table 5 provide the regression values (R squared, model p-values, variable p-values, and the standard error) for each model tested with the available variables without assigning an intercept of zero. It is important to note that the models were generated from only 8 data points, which suggests that these models can change dramatically with additional data points. Assuming an intercept for the regression models may be a source of error; however, the model considering total cost, the solar PV power capacity, and the intercept of zero is provided at the end of Table 5. Five of the models (not including the two models with just the solar PV capacity as a variable) have standard errors greater than the estimates, making it possible to consider that the intercept could be zero. When comparing the model before and after setting the intercept the R squared value increases from 0.72 to 0.86, suggesting again that the intercept can be zero. All of the models suggest that the two variables with the largest significance on total project cost are solar PV size and storage size, both in kW.

Table 4. Regression values regarding of the total cost of the system and the variables including solar PV size in kW, and battery storage size (kW and kWh).

Model/Parameter	P-value	R^2	Parameter Est.	Standard Error
a + b * Solar PV (kW)	0.004567	0.724		
a ($)	0.203		1398769	979966
b ($/kW)	0.004		4500	1023
a + b * Storage (kW)	0.0009112	0.836		
a ($)	0.498		598642	829372
b ($/kW)	0.001		11227	1851
a + b * Storage (kWh)	0.008573	0.815		
a ($)	0.930		114641	1223811
b ($/kW)	0.009		5870	1220
a + b * Solar PV (kW) + c * Storage (kW)	0.000509	0.9325		
a ($)	0.52679		365717	537936
b ($/kW)	0.02716		2228	721
c ($/kW)	0.00689		7493	1695

Table 5. Continuation of regression values regarding of the total cost of the system and the variables including solar PV size in kW, and battery storage size (kW and kWh).

Model/Parameter	**P-value**	**R^2**	**Parameter Est.**	**Standard Error**
a + b * Solar PV (kW) + c * Storage (kWh)	0.01536	0.897		
a ($)	0.9124		109455	915249
b ($/kW)	0.1344		2172	1066
c ($/kWh)	0.0602		3909	1326
a + b * Storage (kW) + c * Storage (kWh)	0.0456	0.788		
a ($)	0.837		301148	1343753
b ($/kW)	0.545		8616	12674
c ($/kWh)	0.838		1470	6604
0 + b * Solar PV (kW)	0.0001	0.864		
b ($/kW)	0.0001		5539	769

When comparing the total cost for the 8 projects by the two variables solar PV capacity and battery capacity, it is apparent that costs vary depending on the type of project. As expected with new technology, innovative or ground-breaking projects may be more expensive than other projects using well understood concepts or designs. The higher cost may come in part from more time (labor) and engineering required for the specific project. For example, the high unit cost for the BLR MG system is a result of incorporating new technology not previously deployed. Figure 7 compares the total costs of each system to the capacities of the battery and solar PV units. The cost for the BLR system (orange marker at $6.5 million) should have been closer to $2-3 million dollars to compare to the other MG projects with respect to these two variables. This suggests the project included additional features not provided by the remaining projects making the cost much higher.

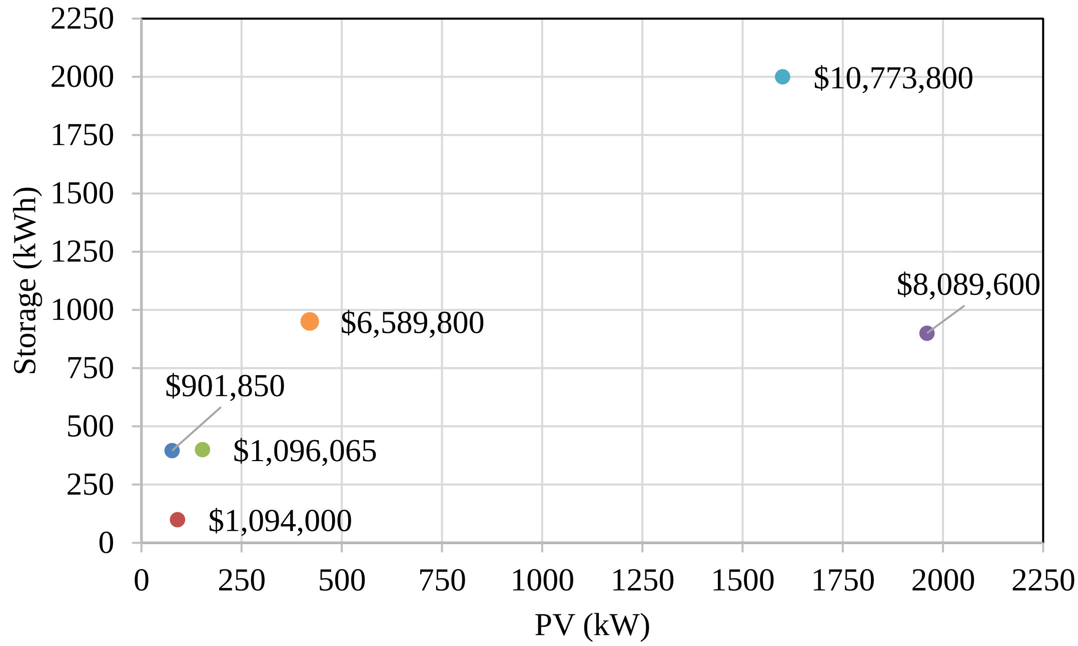


Figure 7. MG Case Study Capital costs depending on storage size (kWh) and solar PV size (kW).

Overall, the cost of a MG varies depending on the DER mix of the system, existing sources, size, capabilities, and technologies. The power capacity of the solar PV and the battery energy storage have the largest impact on the total cost of the system, but variability from project to project can change this relationship. In the future, costs for MGs are expected to change as policy initiatives develop in the coming years. Also, cost breakdowns for MGs are expected to change as specific components (e.g., batteries, and solar PV) decrease in cost, as suggested by researchers. Each components cost and their expected cost declines are discussed in the following sections

Battery Energy Storage Cost

Battery energy storage provides Solar+ MGs with the ability to store and effectively manage electricity generation and consumption within the system. The size of the system also enables the MG to island and continue operation in the event of unexpected conditions on the grid. Batteries types range from lead-acid, lithium-ion, and flywheels. This study only considers Lithium-ion (Li-ion) batteries as the optimal technology for battery energy storage because of the high energy density, high efficiency, and long lifecycle (Nitta et al., 2015).

I will discuss the current and predicted costs for Li-ion batteries, by reviewing research describing the current market and the expected cost decreases for this evolving technology. This research review touches on batteries of various sizes, (e.g. EV battery packs and small electronics batteries) because it is expected that the base technology and costs will be relevant to the technology used to develop the large scale battery systems used in Solar+ systems.

Battery hardware costs

Costs for Li-ion batteries have rapidly declined in recent years, due to the increased demand and mass production of electric vehicle (EV) technologies (Bronski et al. 2014; Curry 2017; Kittner et al. 2017). High global demand for EVs is a core driver for battery technology improvements, which has translated into lowering the costs for the technology (Curry 2017). Figure 6 shows how forecasts from various reports predict battery costs to decline over the next 40 years in 2014 (Bronski et al. 2014). A strong correlation exists between the increasing numbers of EV manufacturers and the decreasing cost of batteries. Due to this relationship, reports suggest that the cost for Li-ion batteries will decrease to less than $100/kWh by 2030, Figure 9 (Curry 2017).

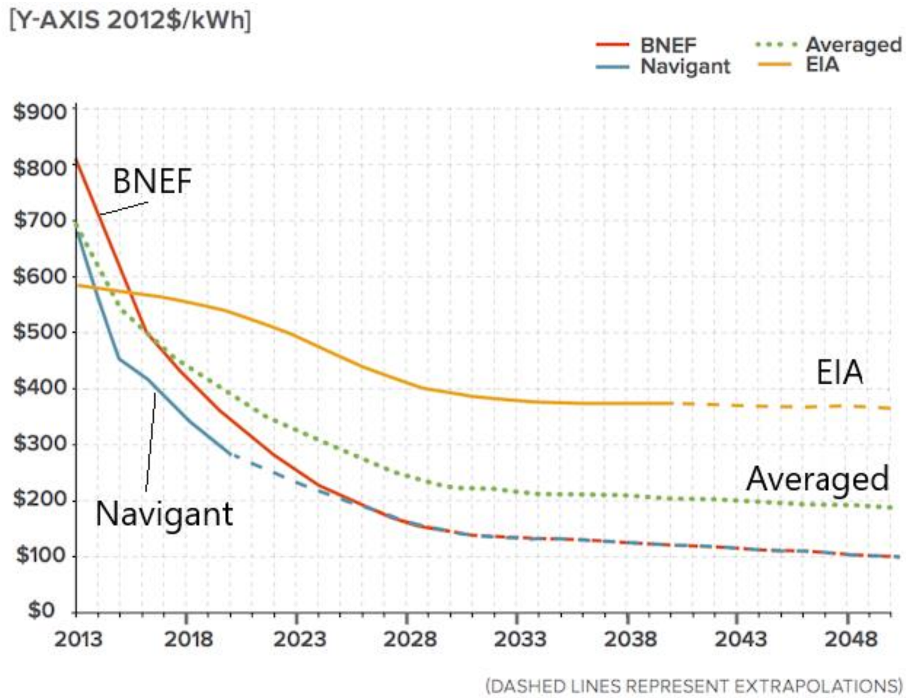


Figure 8. Li-ion battery cost forecasts from BNEF, Navigant, and the EIA. An average of the forecasts is provided as well for the year 2013 to 2050 Source: (Bronski et al. 2014).

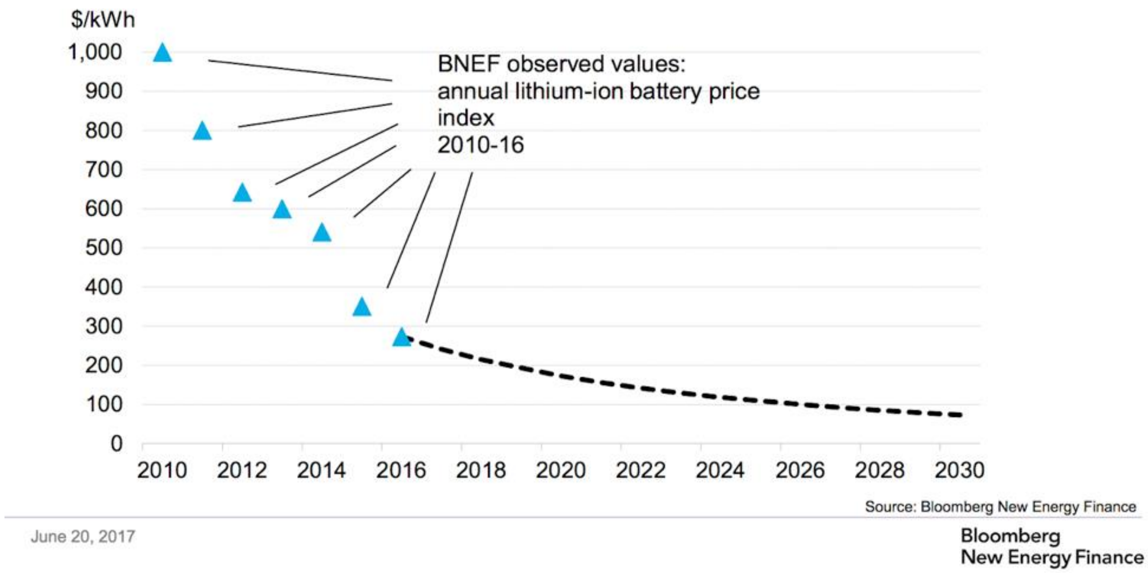


Figure 9. Cost forecast and historical costs for lithium-ion batteries by BNEF. Costs are reported for the years 2010 to 2030. Source: (Curry 2017).

Additional reports discuss the use of multivariable models to estimate the expected costs. One model included the use of a two-factor learning curve considering the patent activity and volume of production in EV battery packs. This model predicts that the cost for EV battery packs will drop below $100/kWh by 2018 (Kittner et al. 2017), based on the known production forecasts and assuming that the patent activity for this type of battery stays more active than the average level of patent activity from 2011 to 2015. The models historical and predicted trends out to 2020 are plotted in Figure 10, portraying the resulting learning curve from the historical cost trends of Li-ion batteries, and the normalized price reductions for solar PV modules, and wind turbines. The report goes further by recognizing the potential for EVs to become cheaper than conventional fossil-fueled vehicles. This phenomenon could further affect the costs of Li-ion batteries by increasing the demand and production volumes, accelerating cost reductions.

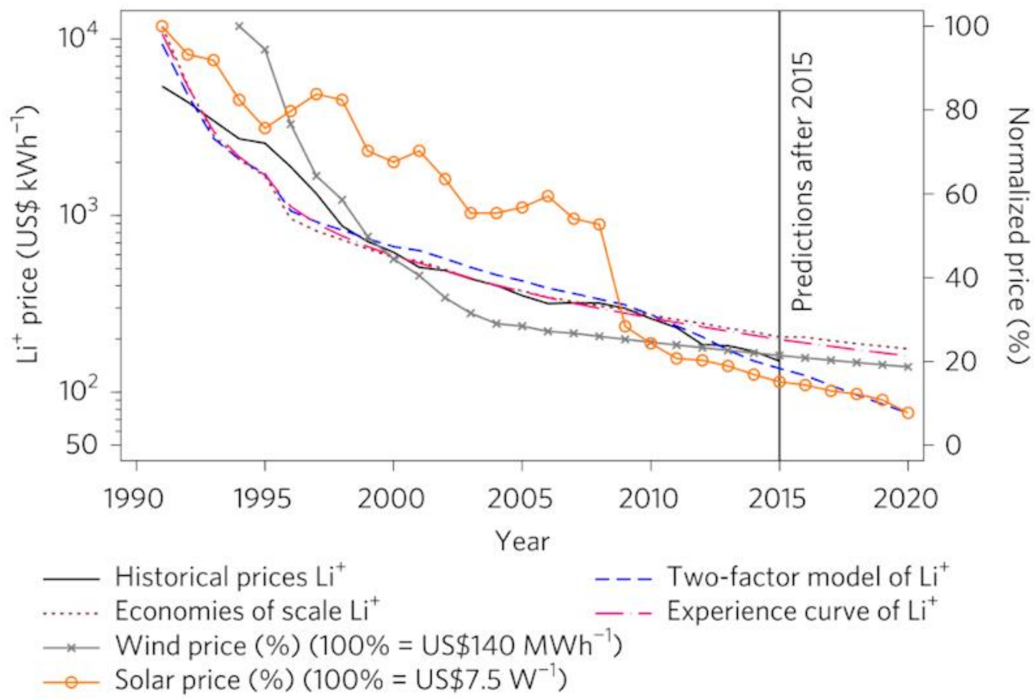


Figure 10. Comparison of traditional one-factor models for and the two-factor model to historical costs of lithium-ion. Wind and solar price reductions are normalized, see legend. Source: (Kittner et al. 2017).

When assessing the two geometries for Li-ion batteries, cylindrical and pouch batteries cost trends appear to be the slightly different. These types are known to be used in electronic devices as well as EV battery packs. The type of geometry chosen to construct a battery is dependent on the manufacturer (Korus 2017). A recent report predicts the two types of batteries will both drop below \$100/kWh by 2022, see Figure 11. The report suggests that the difference in the two curves is caused by the maturity of each type. The cylindrical batteries are considered as a more mature technology, as it has been the consumer choice for most rechargeable electronic devices, which results in the less dramatic cost decline (Korus 2017).

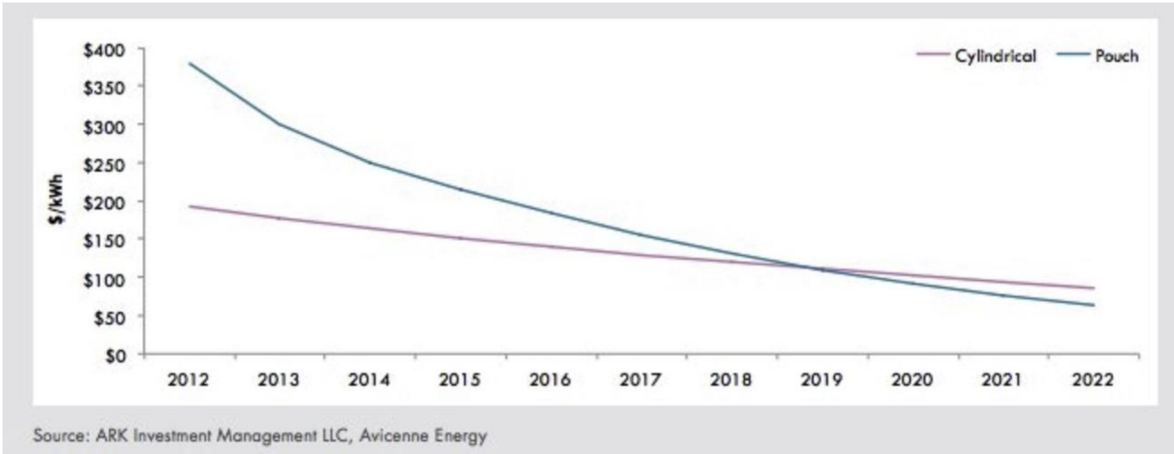


Figure 11. Expected cost decline for lithium-ion batteries by cell type (cylindrical and pouch). Projections begin in 2012 and end in 2022. Source: (Korus 2017).

Each source touches on how battery costs have declined in the past and are expected to continue to decline in the near future. Some sources are more enthusiastic than others, but it should be noted that the data and date of publishing for each source varies. The greatest factor for battery cost trends appears to be the condition of the EV market. Currently, the installed capacity for EV batteries is close to 75 GWh, and is forecasted to grow to 1,300 GWh by 2030 (Curry 2017). This growth justifies the cost trends predicting that battery unit costs will be dropping below or close to the $100/kWh mark before the year 2030.

<u>Battery system BOS costs</u>

This thesis project assumes that the balance of systems (BOS) for a battery energy storage system includes the installation labor, permitting, and supporting equipment such as inverters, conduit, and wires. This cost is for all of the supporting work and equipment needed to complete the installation of a battery energy storage system. Below, I discuss the expected trends for this supporting cost based on reported percent declines.

When reviewing available sources, cost for battery systems and BOS are expected to continue to decrease at a rapid pace (Maloney 2018). Figure 12 reports the percent decline from 2013 to 2022 for battery and BOS. Additionally, the figure categorizes four different technology phases to estimate how the costs will continue to decline as the market matures and the process of installation gets easier. The article suggests that after 2018, cost reductions remaining in the battery market will be driven by production increases, competition, and technology improvement (Maloney 2018). The BOS cost is expected to decrease by 50% from 2017 to 2022 (Maloney 2018). A similar source reviewing the change in cost for a 1 MW energy storage system predicts that BOS costs plus engineering, procurement, and construction (EPC), and soft costs, will decrease by 37% - 57% from 2017 to 2025 (Frankel et al. 2018).

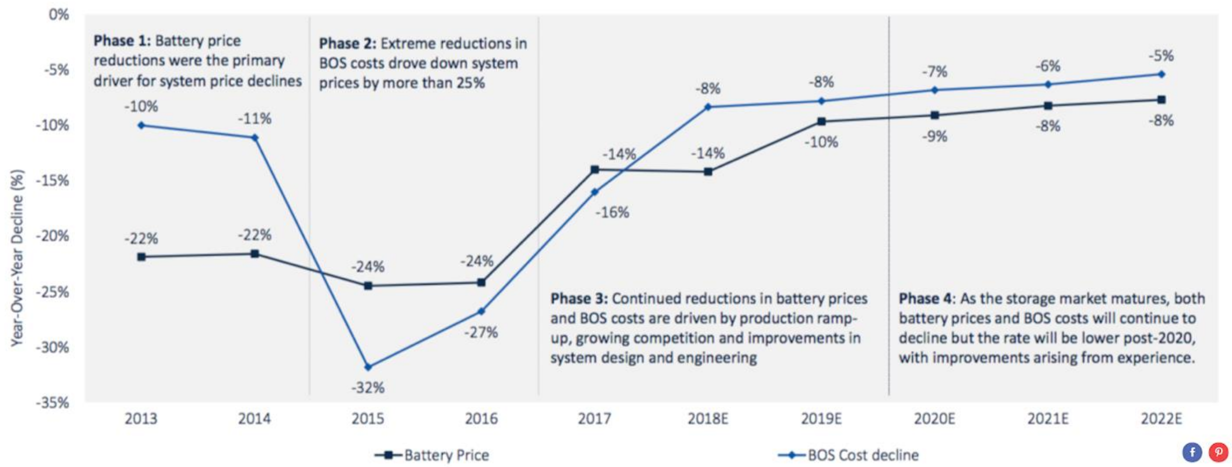


Figure 12. Green Tech Media research for energy storage cost decline from 2013 to 2022. Source: (Maloney 2018).

The cost for battery BOS is expected to decline along with the hardware unit cost. Reports suggest that there are still improvements (or lower costs) to reach within the market due to technology improvements and market demand. Costs for BOS are expected to decline by 30-50% within the next 10 years.

In conclusion, it is expected that for all applications for batteries (e.g., large battery energy storage systems to small scale batteries), the costs of installation should decrease within the next 10 years. Both the hardware (cell) and BOS are making cost improvements with increased demand and various technology innovations. These improvements in costs should support the growth of future energy storage and MG projects.

Solar PV Cost

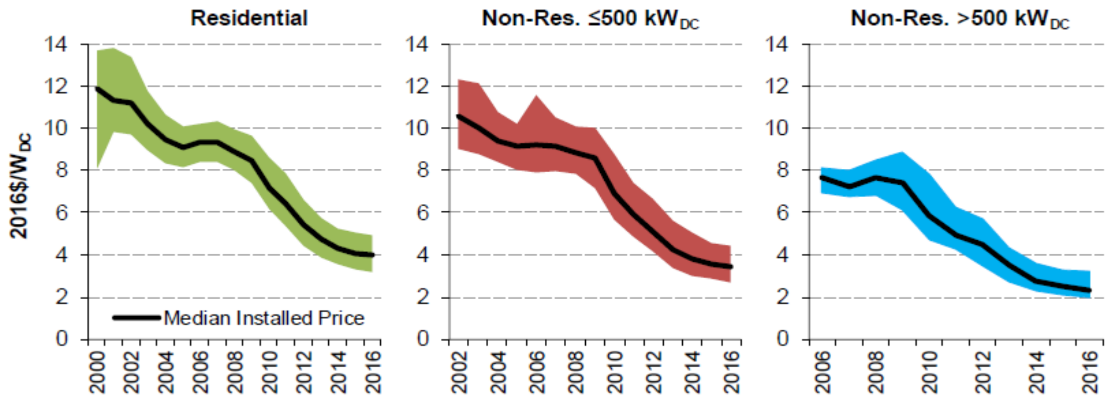
For Solar+ MGs, solar PV is the technology of choice for DER due to the ability to install various sizes of arrays in many locations (e.g. on rooftops and canopies) and has a much lower carbon footprint than a conventional generator. Additionally, the recent reported costs for solar PV are becoming comparable to other MG generation technologies (generators). For the construction of a Solar+ MG the solar PV is either constructed with mono or poly-crystalline modules and a fixed racking system.

I will discuss the recent and predicted trends solar PV projects, by reviewing research describing the current market and the expected cost declines for this technology. Data reviewed will include the reported costs for already installed solar PV projects and expected market trends.

Solar PV project costs

Most reports predict that costs will continue to decrease as technology efficiency improves, cell fabrication gets cheaper, and cell production increases in volume with economies of scale (Key and Peterson 2009). Production costs for solar PV modules experienced a small increase of roughly $0.75/W from 2004 to 2009, followed by a large reduction of roughly $2.75/W from 2009 to 2012 (Candelise et al. 2013). During this timeframe, the world's cumulative installed capacity for solar PV increased by 65.6 GW in just ten years and the efficiencies for the common silicon solar PV module increased from 12.5% in 2002 to 17.2% in 2016 (Barbose et al. 2017; Candelise et al. 2013). During this time, the demand and growth of the technology played an important role with the outcome of the cost. Additionally, cumulative installed capacity, the market size, patent activity, and R&D policy effort are reported to affect the cost of solar PV (Zheng and Kammen 2014).

The Track the Sun report, a report developed by Lawrence Berkeley National Laboratory, has recorded the various applications for existing solar PV projects including: residential, non-residential at a size less than 500 kW (DC) and non-residential larger than 500 kW (DC) over the past 10 years (Barbose et al. 2017). Data from this report shows how the cost for solar PV projects has change in the past ten or more year, shown in Figure 13. Costs are higher for smaller systems and for systems including premium modules (not shown in figure). It is noted that variability for solar PV installation costs from project to project are caused by varying project location, tax incentives in that location, from installer to installer (even within the same state), type of tracking or mounting system, and type of module (premium or standard) (Barbose et al. 2017).



Notes: Solid lines represent median prices, while shaded areas show 20th-to-80th percentile range. See Table 1 for annual sample sizes. Summary statistics shown only if at least 20 observations are available for a given year and customer segment.

Figure 13. Solar PV installed cost for projects at residential, non-residential (< or = 500kW (DC)), and non-residential (> 500kW (DC)). Cost trends were recorded through the Tracking the Sun report completed by LBNL. Source: (Barbose et al. 2017).

Using a bottom-up approach rather than reviewing reported project costs, one report shows solar PV costs declines from 60 - 80% (for residential to utility-scale PV systems) from 2010 - 2017 (Fu et al. 2017). This is considering the costs from the module, inverter, hardware balance of systems (including electrical and structural), soft costs (labor), and other soft costs (PII, net profit, sales tax, and land acquisition). Decreases in cost are not limited to the cost of the module, but also include inverter costs, soft cost and some hardware BOS costs (Fu et al. 2017). It was found that, small residential systems have more factors like BOS and marketing cost that can drive the total installed cost down when compared to the other categories which have much lower costs already. Figure 14 also shows the difference between costs from the various system sizes over the year span of 2010 - 2017.

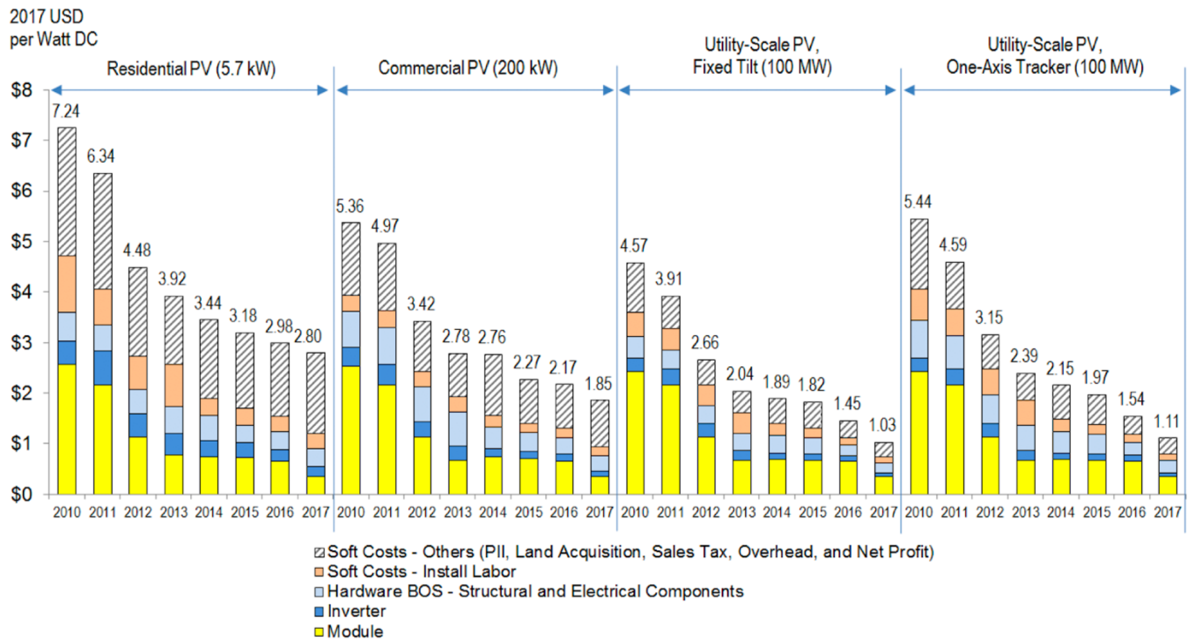
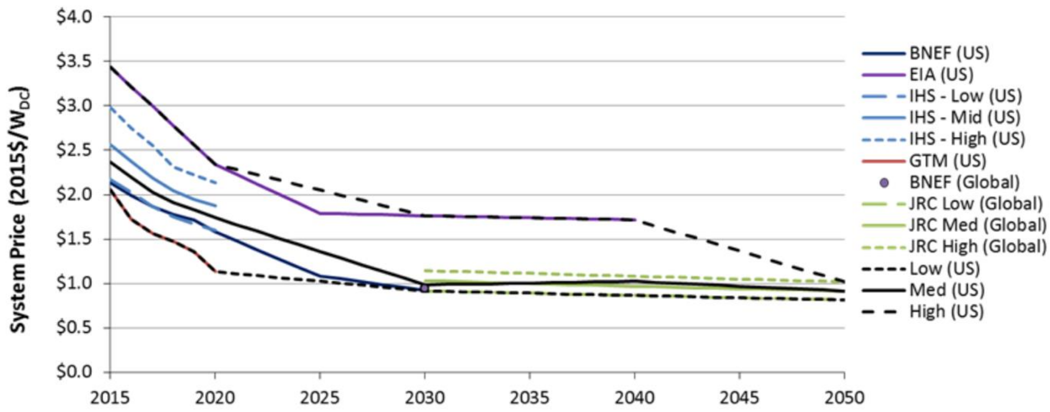
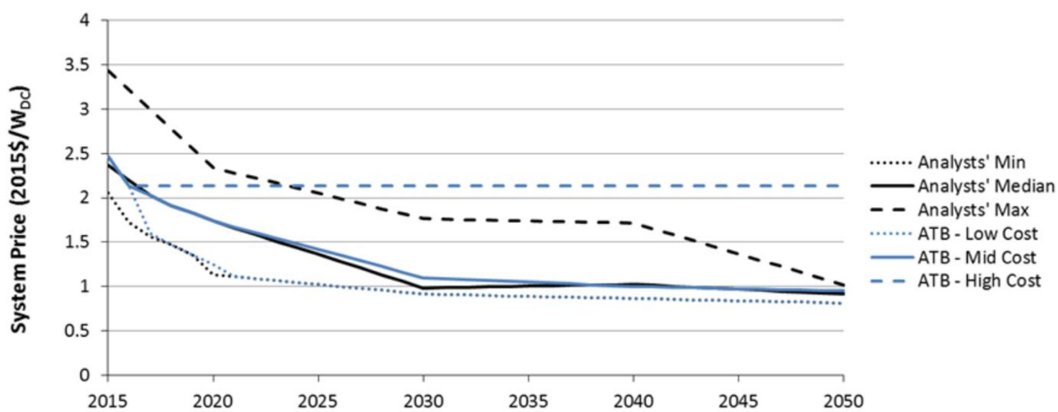


Figure 14. Benchmarked costs with cost breakdown noted for 2010 to 2017. Data is separated by system size and type. Source: (Fu et al. 2017).

When reviewing forecasted data from the NREL Annual Technology Baseline Report in 2017, costs are projected to decrease rapidly in the next 10 years and following those ten years, decreases will slow or become stagnant, see Figure 15 (Black & Veatch 2015; NREL 2017). Here the installed cost for commercial systems will be expected to drop to $1.11 per watt (DC) (2018 USD) in 2035 and decrease only slightly out to 2050 (NREL 2017).



Analyst forecast of commercial-scale PV pricing, 2015-2050
Source: National Renewable Energy Laboratory Annual Technology Baseline (2017), http://atb.nrel.gov



Commercial PV ATB cost projections compared with minimum, median, and maximum analyst forecast
Source: National Renewable Energy Laboratory Annual Technology Baseline (2017), http://atb.nrel.gov

Figure 15. a) Cost forecasts gathered by the NREL Annual Technology Baseline (2017). Costs are represented in 2015 USD. b) Cost forecasts results from the NREL ATB baseline in 2017. Source: (NREL 2017).

Solar PV cost trends are decreasing and are expected to continue to drop as technology and more projects are being developed. Various reports suggest that costs will continue to decline gradually while others predict slower cost declines. Technology improvements and innovations have shown their significance on the cost for solar PV modules and projects. Smaller PV systems tend to have higher costs, but are expected to see larger decreases in costs due to projected price decreases for BOS and other supporting costs. These trends should support the continued growth of installed solar PV capacity, and the installation of future Solar+ MGs.

Electric Vehicle Charging Station Costs

Electric vehicles will be a replacement for conventional vehicles in the future, and to prepare for this future adoption of electric vehicles there is a need to address and construct electric vehicle supply equipment (EVSE). With gas station and convenience stores being the main focus for this thesis, I assume these building types will incorporate charging infrastructure to service the automobile industry in the near future. The Solar+ MG for gas station and convenience stores incorporates EV charging stations to initiate the development of an EV friendly environment. The newest and the most expensive type of ESVE is direct current fast chargers (DCFC). DCFCs charge at a range of 20-400 amps and output roughly 24 - 90 kW (Smith & Castello, 2015). Differing from other ESVE, the DCFCs have direct current leaving the port which connects directly to the EV’s battery. These chargers can provide up to 75 miles of range per hour, (CCRPC 2014). For the purpose of this thesis it is assumed that the optimal charging infrastructure for gas station and convenience stores will be DCFCs with the ability to supply the necessary service to gas station customers in a reasonable amount of time (1 hour or less).

This section will introduce the costs for the various components for EVSE, including all work for purchasing and installing the hardware and equipment, and the previously reported costs for DCFC projects.

EVSE installation costs

Costs for DCFC units and installation vary widely depending on location, use, existing infrastructure and added features. Costs for a single DCFC unit connected directly to 480-volt, 3 phase electrical service ranged from $10,000 (low end) to $40,000 (high end) in 2015 (Castello & Smith, 2015). Costs depend on the power output (kW), the number of ports, and access equipment (e.g., customer card reader). The higher the power output the faster the charging speed, as well as, the ability to have multiple ports.

Installation costs for all EVSE can be broken down into: hardware unit, installation, additional capital, operation and maintenance, and miscellaneous costs. See Table 6 for the corresponding descriptions (Castello & Smith, 2015). Incentive credits like rebates, tax credits/exemptions, grants, and loans are also an option to reduce the total costs for EVSE investments/projects (Castello & Smith, 2015).

Table 6. EVSE associated costs list with descriptions. Table is recreated from list provided by Castello & Smith, 2015.

Cost	**Description**
Hardware Unit	• EVSE unit and optional equipment (e.g., card reader)
Installation	Contractor labor and equipment for: • Connect EVSE to electrical service (e.g., panel work, trenching, and repaving parking) and materials (e.g., wires) • New electrical service or upgrades (e.g., Transformers) • Meeting Americans with Disabilities Act (ADA) • Traffic protection, Signage, Lighting • Permitting and inspection • Engineering review and drawings
Additional Capital	• Hardware extended warranty • Repair labor warranty • Land/parking space purchase or lease
Operation and Maintenance	• Electricity consumption and demand charges • EVSE network subscription to enable additional features • billing transaction costs • preventative and corrective maintenance on EVSE unit • repairs (scheduled and unscheduled)
Miscellaneous	• Consultant fees • Site evaluations • Feasibility studies (e.g., electrical capacity, location utility lines)

Reported DCFC costs

Information regarding DCFCs and their installation cost is minimal at this time. Assuming that this is due to the newness of the technology, I expect that the project costs will change dramatically in the coming years. The information obtained on reported costs for previous DCFC is enough to inform this project.

Organized by the Idaho National Laboratory (INL), the EV Project deployed over 200 Level 2 and 100 DCFC chargers in metropolitan areas across the US. The project report, released in 2015, described the resulting installation costs for the projects that were deployed. Installation costs and capital costs for a DCFC averaged $23,662 (per charger / per site), with a maximum at $50,820 and minimum at $8,500 (INL, 2015). Figure 16 shows the resulting distribution for all DCFC projects. The projects were noted to cover a large range of difficulties, such as some projects required additional work than others due to the condition of the installation site. This is noted to cause the large range of costs in Figure 16.

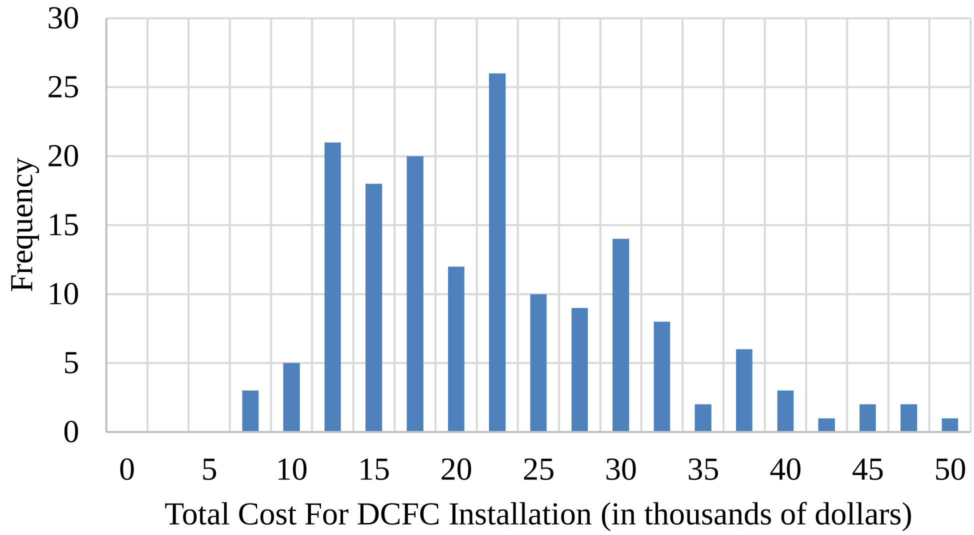


Figure 16. Distribution of installation costs in thousands of dollars for DCFC in 2015. Source (Idaho National Laboratory 2015).

INL reported that the results were largely dominated (50%) by DCFCs installed at restaurants. When removing these data points from the sample group, the distribution curve became more dispersed with two distributions as depicted in Figure 17, which shows the distribution of installation costs only for Arizona (result of the limited data collected). The average cost for the Arizona projects was similar to the full sample average at $23,302, but is bimodal (Idaho National Laboratory 2015). INL reports that the source of this bimodal cost difference is sites that had existing electrical service versus sites that needed new metered service to support the DCFC (Idaho National Laboratory 2015). This suggests that additional electrical service can be a large portion of the installation cost or a cost saver if the existing electrical service is at the necessary capacity. The curves show that having updated electrical service could decrease the total cost to close to 60%.

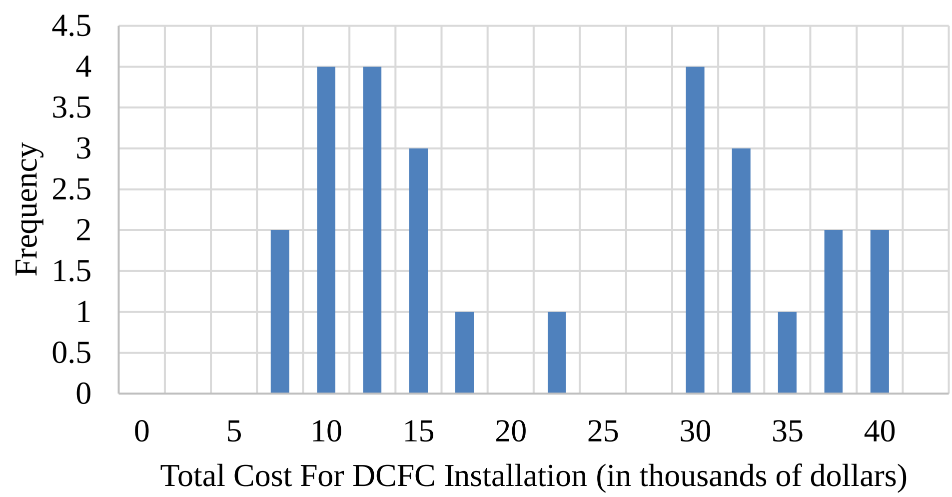


Figure 17. Distribution of DCFC Installation costs for Arizona projects in thousands of dollars. Source: (Idaho National Laboratory 2015).

Additional reports show similar installation costs for DCFC projects. In 2014, the Federal Highway Administration (FHWA) summarized several cost studies for the installation of multiple EVSE installation projects. Table 7 is reconstructed with all results including DCFC from this report. Cost values provided by each source do vary by a maximum of $20,000 year from source to source and the type of DCFC being discussed. The greatest range of costs for a single DCFC is from $15,000 to $83,000. These costs are from older reports than desired for this study.

Table 7: Summary of estimated cost ($) for DCFC projects by various sources. Source(s): FHWA, 2014.

	Charger Hardware		**Installation**		**Total**	
Source	**Low**	**High**	**Low**	**High**	**Low**	**High**
Plug-in America (2012)	$10,000	$30,000	$5,000	$30,000	$15,000	$60,000
US DOE (2012)	$15,000	$50,000	$23,000	$33,000	$28,000	$83,000
ETEC (2010)					$65,000	$70,000
Fuji Electric	$25,000	$60,000	$20,000	$20,000		
Inside EVs (2013)	$16,500					
RMI (2014)	$12,000	$35,000			$29,050	$80,400

The main cost factors for EVSE are the type, location, existing electrical infrastructure, and size of the EVSE installed. Cost components for EVSE include hardware, installation, additional capital including warranty fees and miscellaneous, and operation and maintenance. Areas that differ from the other remaining technologies are the increased cost of permitting and requirements involved with parking regulations. This will be considered for the remaining part of the thesis when assessing the costs for adding DCFC stations at gas station and convenience stores. The cost to install a DCFC can range anywhere from $7-40 thousand dollars, depending on the major factors. Since the technology is rather new, cost trends for the technology are not yet established which suggests that costs trends may be similar to past solar PV and battery cost trend when each market was beginning to mature. With expected increase in manufacturing and installation of all types of EVSE, costs (especially DCFC costs) are expected to decline similar to other technology learning trends.

Controls Cost

Energy efficiency

MGs must serve the overall and peak electrical demand of the customers within its boundaries during an islanding event. A Solar+ MG includes energy efficiency measures that reduce the loads for devices. These measures can include the thermostats used for managing heating, ventilation, and air conditioning (HVAC) equipment, the controllers for the refrigeration equipment, and lighting. These are an important part of the Solar+ MG system, because they can decrease energy usage, potentially extend the life of the battery (if in the islanding mode), and increase the amount of electricity being sold back to the grid (if in the grid connected mode). With energy efficient measures in place there can be a decrease in the overall demand which can improve the performance of the MG system.

Costs for these components are assumed to be negligible due to the expected improvements for all basic building control devices. For the Solar+ Design is it expected that the addition of this system will require upgrades that will include energy efficient components.

MG controller

In addition to the building device efficiency the MG must have a MG controller which manages the various loads (solar, battery and customer demand). This controller is a unique and critical for the overall system and the performance of the MG.

Collaboration with the Schatz Center was important due to the Centers involvement with multiple MG projects and experience in the field of developing and programing MG supervisory controllers; I did not identify other organizations that published detailed estimates of the cost of controls for MGs. The costs being considered here are the cost for the controller hardware and the work required to program the controller to manage these loads.

The supervisory controller hardware and software can measure and complete tasks regarding the generation and consumption of electricity at each site. The controller also considers cost of electricity, weather, and many more inputs to make decisions about when to charge and discharge the battery system. The cost for one of these systems includes the computer hardware and the logic programing behind it. It should be noted this technology is specific to the work that the Schatz Center is developing, and for future projects the type of technology may vary depending on who is developing it and the purpose for these types of controllers. Experts at the Schatz Center estimate that cost for the hardware of the controller and the associated control hardware is roughly $25,000(Carter et al. 2018a).

Additional costs are dedicated to developing the software (programming the logic) that makes the decisions and are estimated to total about $45,000. The Schatz

Center suggests that replication and development of the controller will decrease the hardware cost by 80% ($5,000) and the software program development cost will be removed. It is assumed that future projects will have similar supervisory controllers, which will utilize the same logic to manage MGs, therefore the technology will already be developed. The future cost should only be dependent on the amount of hardware required to run the software.

The overall total cost for controls is estimated to be $70,000 for a typical Solar+ MG, today (circa 2018) (Carter et al. 2018a). With development in the programming of software as well as improvements in the hardware components, costs should drop to 5,000 dollars in the next 10-13 years. With declines in the future, this cost could go down based on the removed programming costs and improvement in software code.

Integration Cost

Integration components are the engineering, site work, permitting (interconnection), and switchgear for the Solar+ MG that are required to actually integrate and build a system. Because of a dearth of published estimates for these "soft costs," this section along with the previous section relies heavily on discussions from industry experts at the Schatz Center and their experience with costs for Solar+ MG components.

Engineering for MG projects includes the civil, electrical, protective relay programming, administrative, integration engineering, and IT networking for the project.

Experts at the Schatz Center gave their insight for the fixed costs for engineering and where they see these costs going. Estimates discussed came from current and past projects completed by the Schatz Center. In the next ten years, decreases in costs are expected with improvements and increased experience for each area. The typical Solar+ MG is expected to have an engineering cost of $105,000 (Carter et al. 2018a). The Center believes that costs will decrease with improvements in speed and learning and expect that costs will drop to $35,000 by 2030 (Carter et al. 2018a).

Site work includes contractors (electrical and civil) and laborers, equipment (or equipment rentals), testing to prepare the site for the installation, the installation of the switchgear. Cost of site work was estimated by a bottom up approach provided by a member of the Schatz Center. Estimates included the following: testing ($16,000-17,000), switchgear installation ($8,000), and any additional civil work ($5,000-6,000), (Marshall et al. 2019). Each future site will need equipment for installation and trenching for the installation of conduit and wires, plus the switchgear unit itself. Although, costs are expected to decline due to assumed improvements in the design of Solar+ MGs. With these improvements in the required testing and installation costs, costs may decrease by 10% by 2030 (Marshall et al. 2019).

Permitting of the MG is mostly focused on the interconnection process and site permitting for the construction at the site. The interconnection permitting process ensures the reliability of the grid will not be diminished and is completed with the local utility. Typically the process includes a local utility review of the design of the system (often with a fee charged for this service) and complete a compliance test before the actual connection. The utility we are working with on permitting is Pacific Gas & Electric (PG&E), and currently their fees for the interconnection process total $3,300 for the application plus an additional review fee (Marshall et al. 2019). The site permitting is estimated at $2,000 making the total permitting fees add up to $5,300 per MG. This fee is not site dependent but can increase if there are issues regarding the relay testing and need for additional review if problems arise. Experts at the Schatz Center expect that the cost for review and relay testing will decrease if research and development were focused on easing the process of meeting compliance with the larger electric grid. The Schatz Center estimates that the costs could decrease to less than 1,000 dollars by 2030 (Carter et al. 2018a).

Switchgear is a critical equipment element of MGs, which enables disconnection and reconnection from the area's electric power system. It is controlled with a dedicated real-time controller that communicates with the supervisory controller. Like an automatic transfer switch (ATS), this equipment is the connection of the solar PV, battery storage, the electric grid and the customers demand. Schatz Center experts recommended that switchgear is dependent on the power rating of the system and that costs could mimic the same costs as an ATS in the future. Table 8, provides the current cost estimates for switchgear and developed ATS equipment. Currently, switchgear costs are high due to the uniqueness of the component, but the design should become more standardized in the future. With this assumed trend the cost for switchgear will decrease by at least 20% for future projects.

Table 8. Cost Estimates for Switchgear and Automatic Transfer Switches (ATS) with provided power ratings.

Power Rating (kVA)	**Cost of Switchgear ($)**	**Cost of ATS ($)**	**Cost ($/kVA)**	**Source**
215	72,000		334.80	(Carter et al. 2018a)
2,250	250,000		111.10	(Carter et al. 2018a)
499		6,901	13.80	(Home Depot n.d.)
665		5,449	8.20	(Norwall Power Systems n.d.)
333		9,750	29.28	(SPW Industrial n.d.)
2,494		50,801	20.36	(PSI Control Solutions n.d.)
1,330		29,508	22.19	(PSI Control Solutions n.d.)

The integration costs for MGs include both fixed costs (engineering, permitting, and site work) and variable cost for the switchgear that depends on the scale of the MG. All of these costs expected to decrease in the coming years with research and development and deployment experience. This thesis will assume the estimates provided by the Schatz Center for modeling the costs for all integration components.

METHODS

The purpose of this study is to assess the associated initial costs for constructing a Solar+ MG at gas station and convenience stores in the state of California. A cost model is developed based on previously reported information regarding the cost for the multiple components involved with the construction of a Solar+ MG. This final cost model includes the use of inputs dependent on the size of the Solar+ MG and when the installation will occur. Assumptions are made based on the type of data used for the development of this model, and the inputs necessary to estimate the total cost of the system.

To construct the framework for the overall model, five functions were developed to support estimation of costs for Solar+ MGs, with each function focusing on a particular element of the cost: battery, solar PV, EV charging stations, controls, and integration. Since the goal of this model is to estimate the total initial or capital cost of a Solar+ system based on size and the year installed from 2018 to 2030, the model does not include assessment of the on-going expenses and benefits (including energy bill savings) that are obtained after the installation. Figure 18 provides a schematic view of the overall model and the five functions used to estimate the total capital cost for a specific Solar+ MG system.

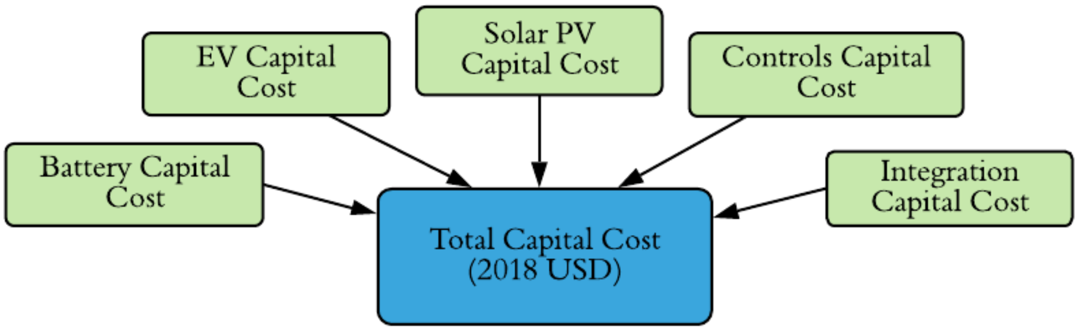


Figure 18: Framework for Total Capital Cost of Solar+ Microgrid Systems.

Inputs and outputs

The model assumes that one can estimate the total cost of a system based on multiple inputs related to size, installation date and type of technology. The outputs are only related to cost of the specific cost component. Table 9 lists the inputs and outputs for each cost function and the constraints for those inputs. The functions were limited based on the expected size of installations relevant to gas station convenience stores, see Table 9. Battery types were limited to Li-ion batteries, because of the performance and estimated size needed to match roughly three times the maximum size of a solar PV array or the maximum customer demand for convenience stores. The battery durations were limited to 1-4 hours in duration due to the typical batteries found in today's market. The solar PV cost function considered the common types of modules, and the size of the maximum solar PV array was assumed to be 200 kW. This PV array could be placed on top of either the roof of the convenience store, the gas pump canopy or both. The type of EV chargers installed are limited to only 50kW DCFC and the number installed were limited to 1-10. This assumes that all Solar+ MGs will be built with at least one EV charging station.

Table 9. Inputs and Outputs for the Model Functions.

Function	Inputs	Constraints	Cost Outputs
Battery Cost	• Battery capacity (kW) • Batt. duration (hours) • Type of battery • Year of install	10 – 600 kW 1 – 4 hours Li-ion 2018 - 2030	• Total battery cost • Hardware cost • BOS cost
EVSE Cost	• Number of EVSE installed • Year of install	1 – 10 chargers 2018 - 2030	• Total EVSE cost • Hardware cost • BOS cost
Solar PV Array Cost	• Solar PV capacity (W) • Type of PV (Mono or Poly) • Year of install	10 – 200 kW Mono- or Poly-crystalline 2018 - 2030	• Total solar PV array cost
Controls Cost	• Year of install	2018 - 2030	• Controller hardware cost • Programming cost
Integration or Fixed Cost	• Solar PV capacity (kW) • Year of install	10 - 200 kW 2018 - 2030	• Engineering cost • Site work cost • Permitting cost • Switchgear cost

When modeling the system costs, the size of the system regarding the battery capacity and duration, solar PV capacity and type, number of EV chargers, and the year of the install are inputs. This model is limited to these constraints due to the data used for developing the functions. The following section describes the equations used for each of the functions listed in Table 9. As a reminder, this model is strictly used for developing a final cost estimate for Solar+ MGs.

Descriptions of Cost Functions

Battery energy storage

The initial cost for a battery energy system is divided into two components: the cost for the battery storage unit and for the balance of system (including labor). The total capital cost is the summation of these two values. Each calculation is dependent on the maximum power output capacity (kW), or the energy duration (hours) of the given system and the year of installation, see Figure 19. Additionally, the battery type will have an effect on cost, this model is limited to only Li-ion batteries.

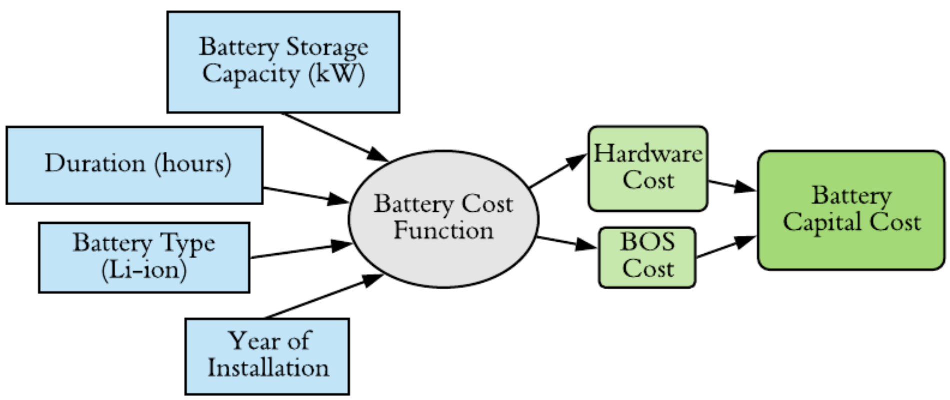


Figure 19. Battery Storage System Cost Function.

Equation 1 defines how the unit cost ($/kWh) of the battery storage unit is estimated for specific years. The function developed for this model estimated the factors A and B to estimate battery costs for the years 2018 to 2030.

$$X_{batt}(t) = A * exp(B * t) \quad \text{Eq. 1}$$

where:

- *X_{batt} is the unit cost for battery systems ($/kWh) for given installation year*
- *A is regression estimated constant, in $/kWh*
- *B is regression estimated constant, in $year^{-1}$*
- *t is the year the battery system (and entire system) is installed (e.g., 2018, 2019, …2030)*

The battery storage cost model coefficients were estimated from building a semi-log regression model of the available lithium-ion battery costs from historical data and future cost projections provided by BNEF, ARK Invest, and McKinsey & Co., (Curry 2017; Frankel et al. 2018; Korus 2017). Three trend lines are made to estimate a smooth curve to follow the expected cost changes for Li-ion batteries. The trend lines developed estimated a low, middle and high estimate for the costs over time. The three separate costs estimates were based on fitting these semi-log regression models to separate sets of data. The middle estimate included every set of data found which reported the costs over time. Table 10, provides the final equations with factors A and B listed for the corresponding cost estimate.

Table 10. Summary of cost models used to develop battery cost function.

Estimate Type	**Equation ($/kWh)**	**R^2**
Low	$1.044E91 * e^{-0.1009*t}$	0.86
Middle	$2.635E58 * e^{-0.0876*t}$	0.74
High	$1.045E73 * e^{-0.0803*t}$	0.77

Error associated with this method for regression modeling is expected to be an underestimate for the costs. The unit cost trend lines could be improved by using a non-linear regression model, but for the ease of modeling unit costs this methods is used for this and the remaining cost functions.

The cost of the BOS and labor is dependent on the maximum power capacity of the battery system. Due to the available information regarding the battery system BOS costs, the equation for forecasting future BOS is dependent on the expected future percent decrease trends for specific year. In Equation 2 the unit cost for BOS and labor is estimated by multiplying the previous year's cost by the expected cost decline.

$$X_{batt\_BOS}(t) = (1 - D_{batt\_BOS}(t)) * X_{batt\_BOS}(t-1) \qquad \text{Eq. 2}$$

where:

- *X_{batt_BOS} is the unit cost of the BOS and labor given the install year ($/kW)*
- *D_{batt_BOS} is the percent decrease in costs from the previous year (%/year)*

For estimating the unit cost for battery BOS and labor, data regarding the expected percent decline per year was taken from reports by GTM and McKinsey & Co. and advise from experts at the Schatz Center (Carter et al. 2018a; Frankel et al. 2018; Maloney 2018). An exponential trend line fit to this data estimates the expected cost of BOS and labor, this represents D_{batt_BOS} in Equation 2. The resulting exponential trend line, Equation 3, is used to inform the estimation of the BOS cost ($/kW) function.

$$D_{batt\_BOS} = 2.625E49 * e^{-0.055*t} \qquad \text{Eq. 3}$$

These unit cost declines are based on an estimated unit cost of 555 $/kW for BOS and labor in year 2015 only for battery storage systems provided by consultation with Schatz Center (Carter et al. 2018a).

Overall capital cost of the battery storage system is then shown in Equation 4. Here the capital cost of the battery storage unit is estimated by the overall size of the system and the estimated cost for the battery and BOS.

$$C_{batt}\,(t) = X_{batt}(t) * (h_{batt} * F_{batt}) + X_{batt\_BOS}(t) * F_{batt} \qquad \text{Eq. 4}$$

where:

- *h_{batt} is the duration of the battery system (kWh)*
- *F_{batt} is the maximum power capacity of the battery system (kW)*
- *C_{batt} is the total cost of the battery system ($)*

To account for economies of scale, a scaling factor was implemented to represent the assumed decrease in unit cost ($/kWh) as the capacity of the system (kWh) increased, see Equation 5. The exponent used in Equation 5 is estimated from confidential information provided the Schatz Center (Carter et al. 2018a).

$$C_{batt,\ adj} = C_{batt} * [h_{batt} * F_{batt}]^{-0.2} \qquad \text{Eq. 5}$$

where:

- *$C_{batt,\,adj}$ is the total capital cost of the battery system in 2018 dollars*

This completes the cost function for the battery storage system. It should be noted that the resulting function is limited to Li-ion batteries systems ranging from 10 - 600 kW batteries with durations ranging from 1- 4 hours. Error associated with this cost function is assumed to be ~30%, this is found from the R squared values for each fitted semi-log regression line.

Solar PV

Developed by René DeWees, a student research assistant at the Schatz Center, and others at the Schatz Center, the solar PV array cost function includes multiple log-log linearized functions built for specific solar PV system sizes, and types of modules as shown in Figure 20. Solar PV Array Cost Function.Figure 20. The output of the function provides the solar PV array cost estimates for the years 2018 out to 2030. The model considers the size of the solar PV array (kW), the type of solar modules used, and the year of installation, see Figure 20.

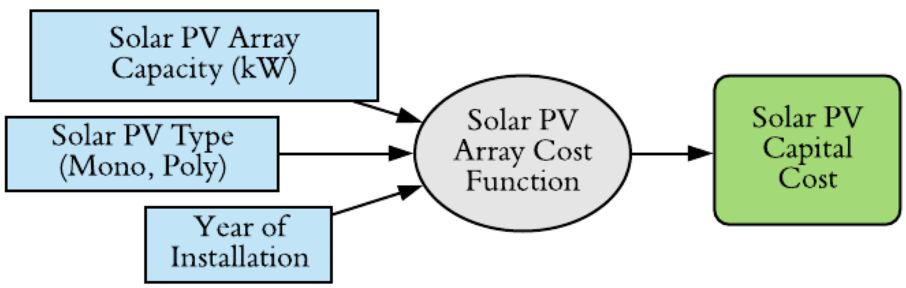


Figure 20. Solar PV Array Cost Function.

Four cost models were developed for four separate power ranges and each module type (mono and poly-crystalline) to estimate the unit cost of installation in dollars per watt ($/W) with respect to the installation year. The eight total models assessed the average cost per fiscal quarter from 2007 to 2016. The resulting models are log-log linearized functions estimated by the cost data in relation to the year in terms of the Julian date (with the origin data being January 1, 1970). Equations 6 and 7, details the general form of the cost functions:

$$Log_{10}X_{PV} = G * Log_{10}(t_J) + H \quad \text{Eq. 6}$$

which simplifies to:

$$X_{PV}(t) = 10^H * {t_J}^G \quad \text{Eq. 7}$$

where:

- *X_{PV} is the installation unit cost for a specific year ($/W)*
- *t_J is the Julian date in days (based on the origin: 01/01/1970)*
- *G and H are regression estimated constants dependent on size of the system (*Table 11*)*

The total capital cost is then estimated by the following equation, Equation 8:

$$C_{PV}(t) = X_{PV}(t) * F_{PV} \quad \text{Eq. 8}$$

where:

- *C_{PV} is the final capital cost for the solar PV array ($)*
- *F_{PV} is the maximum power rating of the solar PV array (W)*

The solar PV array cost function utilized data from the NREL Open PV Project database (NREL n.d.). The Open PV Project provides public data on installation costs for solar PV projects within various industry sectors from the entire nation. This dataset was chosen due to the large number (over one million recorded projects) of data points available. A total of 1485 poly-crystalline and 814 mono-crystalline project costs from this large dataset are used relate total project cost to system installation size, tracking capability (fixed) and type of module (mono and polycrystalline). These projects were selected by only choosing projects completed in California, with fixed racking systems (no tracking capability), and either mono- or poly- crystalline modules. All other projects noted in the large dataset were not included.

To develop the cost functions a total of four array size ranges were analyzed. The timeframes chosen to use for modeling the cost function included recent data from 2007 to 2016. With respect to size, the four chosen datasets included size capacities ranging from 10-20 kW, 20-80 kW, 80-120 kW, and 120-200 kW, respectively. It should also be noted, gas station and convenience stores are expected to install panels that will be roof mounted and fixed; therefore, the datasets only included projects with fixed axis panels.

The fitted coefficients for each of the models are shown in Table 11. Here the resulting eight cost functions are listed by the specified system size and type. The functions are limited to forecasting future cost trend for the years 2018 to 2030.

Table 11. Summary of the cost models used to develop the PV installation cost function and estimate X_{pv}.

System Size	**Polycrystalline**	**Monocrystalline**
10-20 kW	$10^{18.7} * t_J{}^{-4.31}$	$10^{18.1} * t_J{}^{-4.15}$
20-80 kW	$10^{19.7} * t_J{}^{-4.55}$	$10^{18.4} * t_J{}^{-4.24}$
80-120 kW	$10^{20.2} * t_J{}^{-4.66}$	$10^{18.1} * t_J{}^{-4.17}$
120-200 kW	$10^{20.2} * t_J{}^{-4.67}$	$10^{21.2} * t_J{}^{-4.90}$

With the cost functions listed in Table 11 the cost of solar PV array installation projects can be estimated with a known year of installation (in Julian data) and capacity (kW). Unlike the previous battery cost function where there are two cost functions (i.e., for the unit itself and the BOS), the total cost estimate for solar PV will include all costs for solar PV: modules, BOS and labor cost. Data used in this model reported only the total project costs making it impossible to separately estimate the unit costs for the hardware and BOS. Although the cost function were built to represent system sizes ranging from 10 kW to 200 kW, DeWees notes that this cost function can also be used to estimate the cost for systems ranging from 200 kW to 2.5 MW. Additional analysis of larger system costs from the Open PV Project shows similar trends to that of the 120 - 200 kW cost function.

It should be noted that these resulting functions were interpolated between each transition to avoid discontinuous artifacts in estimated solar PV system costs. The unit costs for the midpoints of each size category were estimated with the reported equation, but end points were interpolated from the equation from that size bin and the neighboring equation. For example, a 15 kW system could be estimated by the 10 – 20 kW equations listed, but a system slightly larger than 20 kW would have its unit cost estimated from the interpolation of the results from the 10 – 20 kW and 20 – 80 kW equation.

The resulting costs functions provide estimated values dependent upon the data used to fit the equations. It is noted that the slope of the equations differ causing the unit costs function to overlap in some situations. This method for determining the solar PV unit costs is noted to be an area that may be improved with using non-linear regressions, but for ease of using linear regression the equations listed will represent the solar PV unit cost function.

Electric vehicle supply equipment

The EVSE cost function was developed by Ellen Thompson, a student research assistant at the Schatz Center, with support from Rene DeWees and others at the Schatz Center. Thompson developed a model that considered current costs for DCFCs and assumed that future cost trends for EVSE technologies would be similar to solar PV inverter technologies. The final function inputs the type of charger (which is only DCFCs for this model), the number of chargers installed and the expected installation year; see Figure 21. Similar to the previous cost functions, projections are limited to forecasting for the years 2018 to 2030.

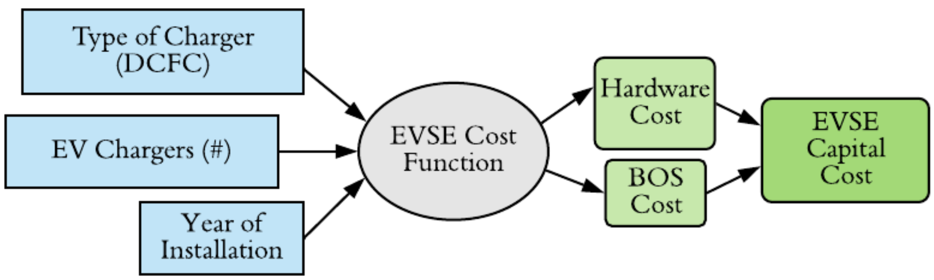


Figure 21. EVSE Cost Function.

EVSE is a new technology with very little development compared to solar PV and battery technologies. Here Thompson was able to assess data points regarding the installation of DCFC stations (ranging from 25 kW to 150 kW) and make estimates dependent on expected demand of the technology and similar technology cost declines (e.g., solar PV).

The outputs for the function include estimated unit costs for the charger hardware (charger unit) and for the BOS and labor cost. BOS cost includes permitting, engineering, contractor’s installation and administration labor, subcontracted construction labor or equipment (e.g., concrete, asphalt, trenching, boring, etc.), and cost for any remaining materials. This BOS includes labor that is specific to this component and should not be considered labor required for the remaining parts of the Solar+ system. The capital cost for the EVSE is then the sum of these two components. First, Equation 9 provides the method for obtaining the unit cost for the EVSE hardware:

$$X_{EVSE}(t) = (1 - D_{EVSE}(t)) * X_{EVSE}\,(t-1) \qquad \text{Eq. 9}$$

where:

- X_{EVSE} *is the unit cost for chargers given the install year ($/charger)*
- D_{EVSE} *is the percent decline in costs from the previous year (%)*
- $X_{EVSE(t-1)}$ *is the previous year's unit cost of charger($/charger)*

This is a summation dependent on the previous year's costs and expected percent decline. Data used to model the hardware costs for EVSE over time included previous costs trends recorded for solar PV inverters (D_{EVSE}) and present-day costs reported by manufacturers ($X_{EVSE(2018)}$). Here we assume that an EV charger technology is similar to a solar PV inverter, because both pieces of hardware complete similar tasks, making the technology comparable.

For the cost decline in chargers, an exponential model considered installed capacity of solar PV and the reported solar PV inverter cost trends reported by NREL and the California Solar Statistics website. This model was then fit to future EVSE charger demand reported by the CEC (high and low estimates listed in Table 12) to then estimate the change in costs for EVSE.

Table 12. Estimated Annual Demand and Installed Capacity for DCFC for California. Estimates for years 2017 to 2025 were provided by the CEC (Bedir et al. 2017).

Year	Low Estimate from CEC (#/yr)	High Estimate from CEC (#/yr)	Average Installation (#/yr)	Average Installed Capacity (MW/yr)
2017	2,005	5,877	3,941	305
2020	4,881	13,752	9,316	722
2025	9,064	24,967	17,015	1,318
2030 extra-polated				1,957

High and low demand estimates for 2020 and 2025 are provided by the CEC (Bedir et al. 2017). From these values an average was taken to convert into an assumed installed capacity. With this average kW demand over time for DCFC, a linear regression model was used to estimate the expected installation for the year 2030. The capacity of each charger was assumed to by 77.5 kW since the current range for DCFC can range from 50kW to 105kW. In Table 12, the data for year 2030 is extrapolated from the linear trend line obtained from the average install and average installed capacity for the previous years. This process then made it possible to relate historical costs for solar PV inverters with respect to installed capacity of solar PV to the expected costs for EVSE with respect to expected installed capacity. The final model considered a decrease in unit cost as the total number of EV chargers increased. This was assumed to be 10% after an interview with a manufacturer (Thompson 2018).

For EVSE BOS and labor costs, the reported BOS and labor costs trends for solar PV were again assessed for comparison. Equation 10 represents the method used to estimate the cost for EVSE BOS and labor. Similar to the cost for the hardware unit, the function is dependent on the number of chargers and the installation year:

$$X_{EV_{BOS}}(t) = (1 - D_{EV\_BOS}(t)) * X_{EV\_BOS}(t-1) \qquad \text{Eq. 10}$$

where:

- *X_{EV_BOS} is the cost for BOS and labor ($/charger) given the installed year*
- *D_{EV_BOS} is the percent decrease in costs from the previous year (%/yr)*

The cost for installation and supporting equipment (BOS) for this technology is expected to show trends that mimic the past solar PV trends (D_{EV_BOS}). The costs are taken from estimates obtained from the PV Project previously discussed in the literature review (NREL n.d.). The final capital cost of the systems is based on Equation 11:

$$C_{EVSE}(t) = J * X_{EVSE}(t) + J * X_{EV_{BOS}}(t) \qquad \text{Eq. 11}$$

where:

- *C_{EVSE} is the total capital cost for EVSE installed in a given year*
- *J is the number of chargers installed*

<u>Controls</u>

The controls cost function includes the cost for the programming, the hardware to run the software, and additional equipment to keep the system powered and fully operating, as shown in Figure 22. The cost for controls is only dependent upon the installation year, because it is assumed that the cost for controlling MG systems will stay the same regardless of the size of the system.

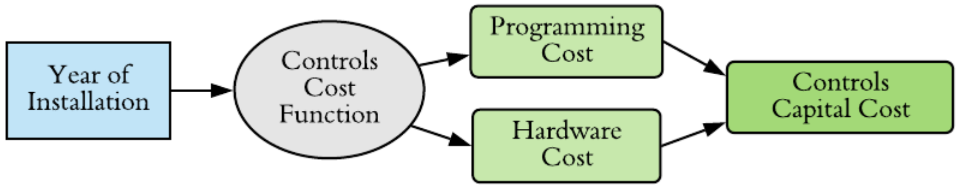


Figure 22. Controls Cost Function.

The final function was developed from estimates for recent control systems designed and implemented by the Schatz Center. As mentioned in the controls section in the literature review, a supervisory controller is roughly $25,000 to purchase in 2018. The Schatz Center estimates this cost to decrease due to increased knowledge and manufacturing. An exponential function was created to model the costs for supervisory controllers projected into the future with an assumed decrease to 5,000 dollars by 2030. A second linear model was used to project the costs for programming the controllers from 25,000 dollars for 2018 projects to zero dollars for 2030 projects.

<u>Integration components</u>

The integration cost function includes all remaining costs, including engineering, site work, permitting, and switchgear costs, that are specific the integration of the Solar+ MG, as shown in Figure 23. Here the costs are dependent the installation year, size solar PV array output, and the size of electrical service for the specific building. Individual costs are grouped together to represent the total integration capital cost.

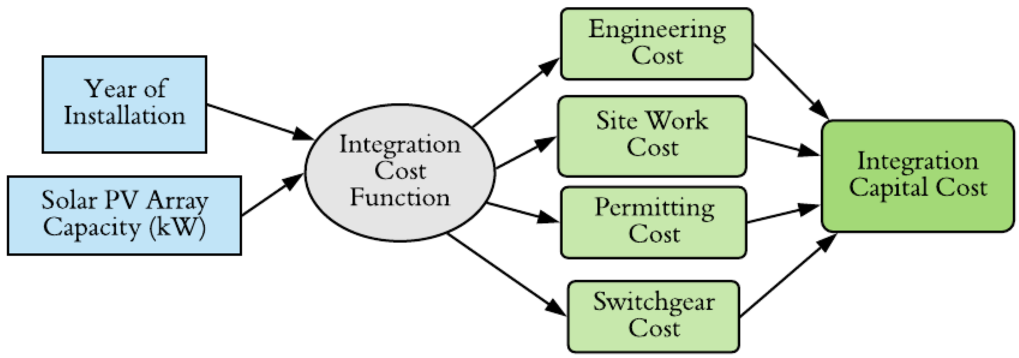


Figure 23. Integration Components Cost Function.

The integration cost is separated further into cost functions for fixed costs, switchgear costs, and site work costs. Not all outputs are dependent on all inputs, see Figure 24. For the fixed costs, the engineering and permitting costs, the year of installation is the only input required for engineering and permitting the cost are not size dependent, but they are expected to decrease in the future. For the switchgear, the year of installation and the size of the buildings electric utility service is required to estimate the final costs. Finally, for site work, the year of installation and the size of the electrical service (in kilo-volt amps) is required to estimate the cost. For simplicity and ease of understanding, these costs are all placed into this one function to output the final integration cost.

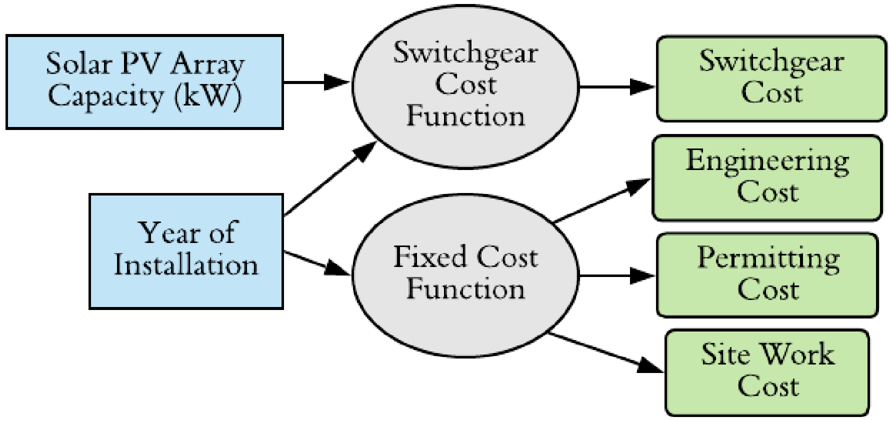


Figure 24. Separated Integration Cost Components.

To model the cost of switchgear, the data provided in Table 8 was utilized to develop two linear models to estimate 1) the cost of switchgear depending on size (kW) of the system and 2) the cost of automatic transfer switches (ATS) depending on size (kW) of the ATS. To estimate the change in cost for switchgear over time first a linear models was developed to mimic the cost of switchgear as a function of size. This model was assumed to the cost of switch gear today (2018). Then with the assumption that switchgear costs will eventually cost the same as automatic transfer switches, a second linear model was used to estimate the cost of switchgear in 2030 by using the ATS costs listed in Table 8. The remaining costs in between the years 2018 to 2030 were estimated through linear interpolation between the two models. This data was then used to develop a size dependent function that would estimate the cost for the switchgear. The technology for an automatic transfer switch is like switchgear required for Solar+ MGs; therefore, the linear model of today's costs for automatic transfer switches were treated as the future costs for switchgear in 2030.

To model the cost of site work, previous project estimates were provided by the Schatz Center (Marshall et al. 2019). The total estimate for site work for 2018 was roughly $30,000. Schatz members believed that this cost would only decrease by 10% by 2030: therefore estimates used to inform the final cost of integration include a linear model mimic this percent decrease.

Final Cost Assessment

Each of these five cost functions (i.e., battery, solar PV, EVSE, controls, and integration costs) are then summed together to complete the total cost model. The model is used to estimate the total cost for the following scenarios listed in Table 13. These scenarios represent possible Solar+ MGs which could be installed at various gas station and convenience stores (C-stores). The goal for each scenario are different with varied component sizes. The first three scenarios mimic the traditional sizing for various stores. In scenario one (Small) the size of the solar PV array is fit to the assumed size of the gas pump canopy (~60 kW or 2,800 square feet). In scenario two (Medium) the battery is sized based on a generic peak consumption data assuming a gas station will need a 100 kW peak demand during a black out situation. In scenario three (Large) the number of EV charging stations is assumed to be proportional to the available number of gas pumps.

The fourth and fifth (Resilient and Large Resilient) scenarios are sized to reach specific goals at one small location and at one large location. The Resilient scenario, is a small site sized with excess battery capacity. This is to understand the change in cost that may target those that have low electrical demand but expect longer outages, hence the longer duration time of 4 hours. The Resilient Large scenario, is sized with excess battery capacity and power (260 kW), with slightly fewer EV charging stations. Although the duration is the same as the Resilient scenario the power capacity is increased by 200 kW making the system have a total of 1040 kWh of energy capacity. Note that these factors were defined only to support the work of this thesis and can change depending on the specific site location, space availability and goals for the installer.

Table 13. Solar+ MG Convenience Store Scenarios. Solar modules are assumed to be monocrystalline.

Scenarios	**Battery (kW, kWh)**	**Solar PV (kW)**	**EV (#)**	**Description**
Small C-Store	60, 60	40	2	Small store, one attendant in a room with solar PV on gas pump canopy. Available gas pumps onsite: 2 - 4.
Medium C-Store	100, 200	60	4	Typical store with multiple attendants, a refrigeration unit and food products. Solar PV on canopy and roof. Available gas pumps onsite: 4 – 6.
Large C-Store	100, 400	140	8	Large store with multiple personnel refrigeration units and a restaurant area. Solar PV array on gas pump canopy, store roof, and elsewhere on the property. Available gas pumps onsite: 6 – 10.
Resilient	60, 240	40	2	Small store with the goal to island with higher energy capacity.
Resilient Large	260, 1040	140	6	Large site with goal to island and still meet majority of the sites loads.

This analysis will assess the change in costs from the various applications that Solar+ MGs can be use or constructed for. Also this will show the range of costs for the range of building sizes that exist in the gas station and convenience store industry.

The total costs of the scenario systems are estimated through the use of a Monte Carlo approach using R software. This Monte Carlo simulation used a random triangle distribution (package "triangle") to output a unit cost within defined variabilities for each component. This package uses a minimum, maximum, and mode estimates to randomly estimate a unit cost within the provided distributions. The mode estimate for each component corresponded to the estimates from each of the models presented in the methods section. The maximum and minimum estimates were assumed to be within 30% of the mode estimate, similar to the 0.72 R squared value found from the linear regression analysis of the original MG case studies. This excluded the battery unit cost function estimates. The battery cost estimates were estimated through the three exponential functions developed to provide minimum, average, and maximum estimates. Once an estimate from the random triangle distribution was estimated, a total of 1000 iterations for each scenario was simulated. The resulting dataset was then mined to obtain the results discussed below.

RESULTS

For the results section I first present the cost projections and breakdown the Medium C-Store scenario (as defined previously in the methods section) for the years 2018, 2022, 2026, and 2030. Secondly, I discuss how the separate cost components affect the total costs of the systems by presenting each component unit cost trends. Third, I compare the results from each of the five scenarios and investigate the uncertainty in the cost model. And finally, I discuss comparisons of cost trends between a wide range of various systems sizes.

Total System Costs Breakdown

For the Medium C-Store scenario (i.e., 100 kWh battery storage, 2 hour duration, 60 kW PV array, and 4 EVSEs) the final cost projections and cost breakdowns are shown in Figure 25. The figure also provides the 95th and 5th percentiles as the error bars of system cost for each year. Cost projections show that the costs of all components are projected to decrease as expected. More specifically, the cost of the MG decreases by 25% in 2022, then by 44% in 2026, and finally by 59% in 2030. Visually, none of the components seem to dominate the percent declines seen the coming years, although this could change for a different system specification.

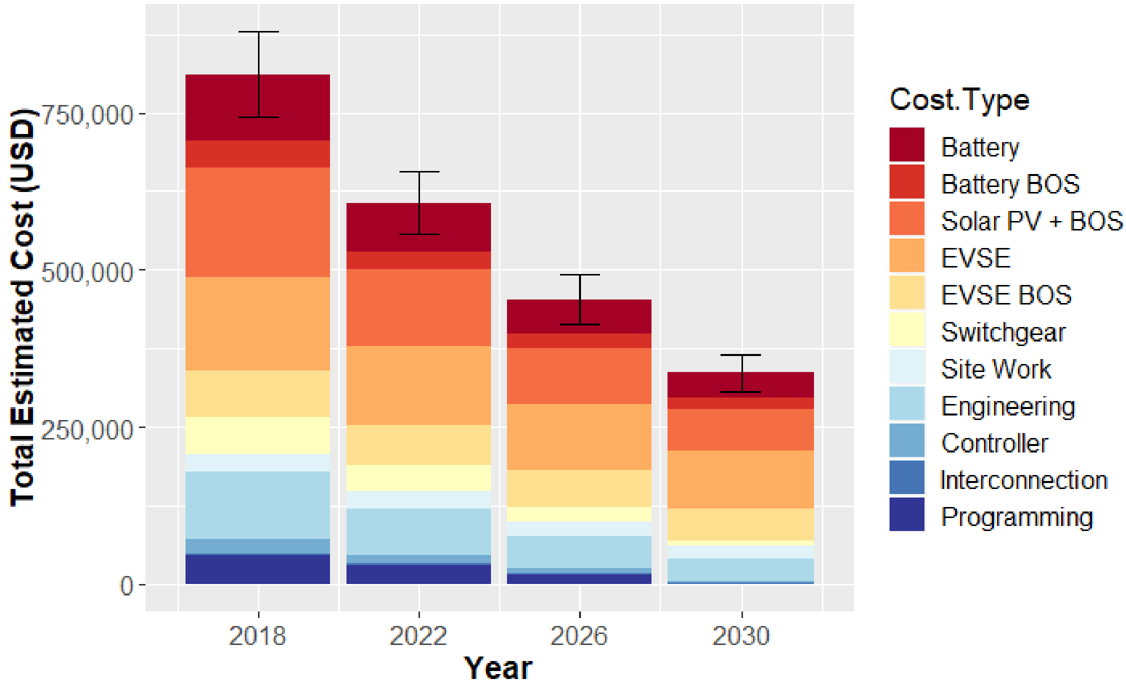


Figure 25. Expected cost breakdowns for a Solar+ MG constructed to serve a Medium C-Store. Error bars represent the 95th and 5th percentiles interval from all simulations from the Monte Carlo simulation.

When reviewing each cost projection the variable that appears to have the greatest change in cost is the engineering cost, which is based on the expected decrease of $60,000 over the 13 year period. Percent reductions relative to 2018 projections show that programming, switchgear, and the controller are the three components to experience the greatest reduction of component cost, see Table 14. It should be noted Table 14 reports the results specifically from the Medium C-store scenario. These percentages are expected to be similar for other scenarios since the total cost of the components is independent of the total cost of the system. Further analysis of the unit cost trends are in the following sectioin.

Table 14. Reduction in total component cost reductions relative to 2018 costs estimates for the Medium C-store scenario.

Component	**2022**	**2026**	**2030**
Battery	27%	47%	62%
Battery BOS	30%	48%	58%
Solar PV + BOS	28%	47%	60%
EVSE	17%	28%	39%
EVSE BOS	12%	20%	28%
Switchgear	30%	59%	89%
Site Work	10%	22%	33%
Engineering	30%	51%	66%
Controller	41%	65%	79%
Interconnection	23%	45%	68%
Programming	33%	67%	100%
Total	25%	43%	58%

To compare the percentage of total contribution to the cost, Table 15 provides the percentage of contribution to the total cost by component. The greatest contributor to total cost is found to be the solar PV plus BOS cost at 21% in 2018, but by 2030 the major contributor is the hardware for EV charging stations at 27%. Both the EVSE and EVSE BOS costs become the largest contributors for future installations of the Medium C-Store scenario. This is expected due to the reported cost reductions of 39% and 28%, which are roughly half of the estimated cost reductions for the remaining components. This observation of the EVSE being the largest contributor in the future is similar for all scenarios, see Appendix C - Appendix F.

.

Table 15. Percent Contribution to total cost by year for Medium C-store Scenario.

Component	**2018**	**2022**	**2026**	**2030**
Battery	12%	12%	12%	11%
Battery BOS	5.1%	4.8%	4.7%	5.1%
Solar PV + BOS	21%	20%	19%	20%
EVSE	18%	20%	23%	27%
EVSE BOS	9.1%	10%	12%	15%
Switchgear	7.2%	6.7%	5.2%	1.8%
Site Work	3.7%	4.4%	5.1%	5.9%
Engineering	12%	12%	11%	10%
Controller	3.0%	2.4%	1.8%	1.5%
Interconnection	0.31%	0.32%	0.30%	0.24%
Programming	5.6%	4.9%	3.2%	0.0%

Component Cost Trends

Here the resulting unit cost trends are reported for each of the five cost functions discussed in the methods section. Each unit component is plotted by unit cost (or similar) over time to understand the trends and patterns expected for 2018 to 2030.

Battery energy storage

The projected trends of average unit cost for a battery energy storage (in $/Wh) and battery BOS (in $/W) are shown in Figure 26. This shows the average unit cost trends from the exponential functions developed in the methods section. It is expected that storage costs will drop by 62% from 2018 to 2030 and the balance of systems and labor costs decrease by 59% from 2018 to 2030.

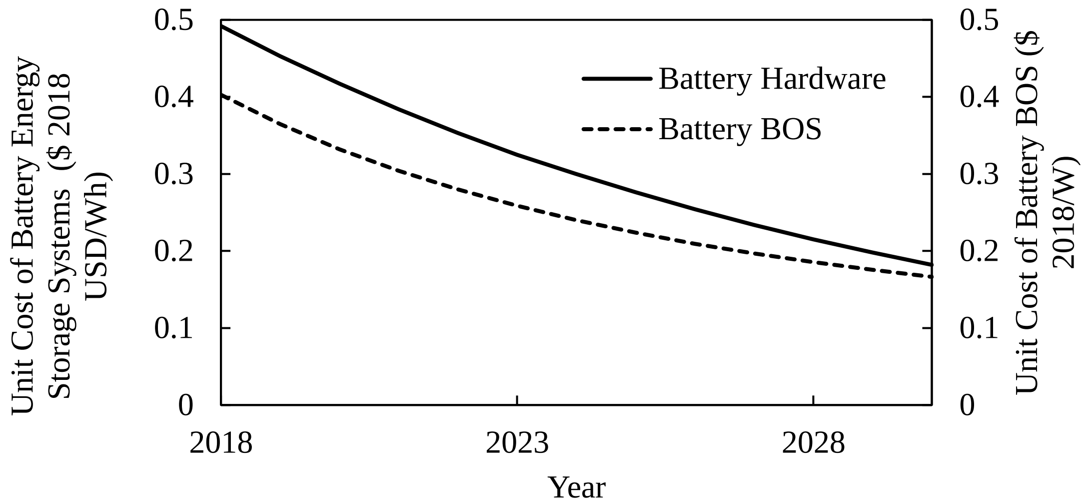


Figure 26. Average Cost Projections for Battery Hardware ($/Wh) and BOS ($/W). Note secondary axis reports the cost of BOS).

Solar PV

The projected time trends for unit cost in $/W for solar PV modules of both common types (monocrystalline, and polycrystalline) are shown in Figure 27. As expected both types have continued downward trends in cost. Monocrystalline PV arrays are more expensive and experience slower decay rates than polycrystalline, but this is expected due to the higher performance for monocrystalline modules. Unit costs for both types of modules are expected to drop between 60-63% from 2018 to 2030.

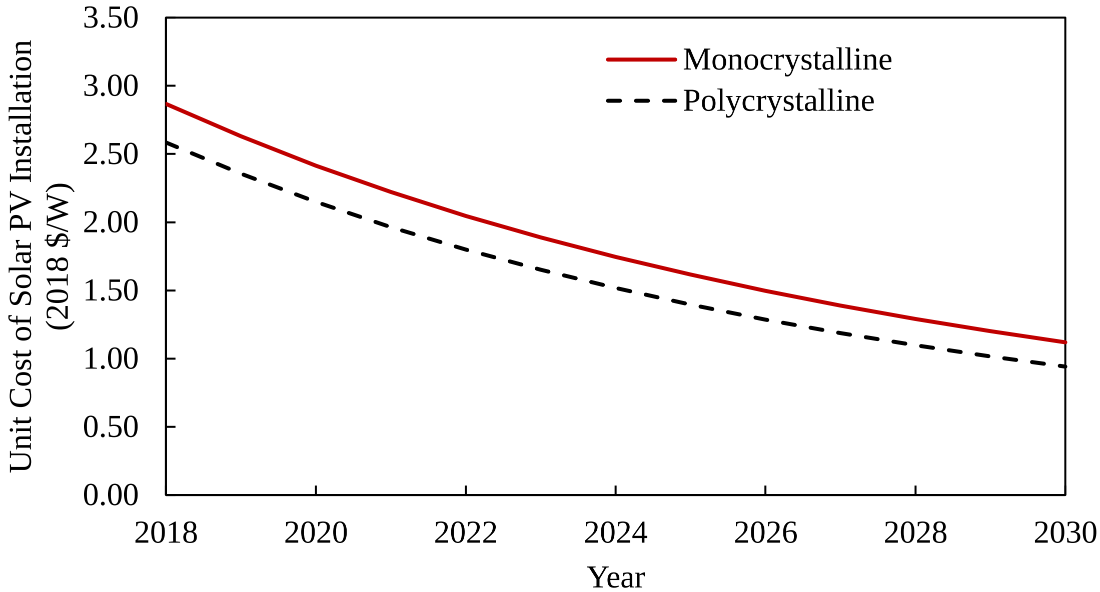


Figure 27. Cost projections for monocrystalline and polycrystalline PV array projects at 60 kW.

<u>DCFC</u>

The unit cost projections for DCFCs including the unit and BOS in $/W are included in Figure 28. These unit cost projections are for a single charging unit installation and do not represent the cost projections for the various sizes of systems with different numbers of chargers. The method to estimate the cost for DCFC included using previous learning curves from solar PV inverters. It should be noted that the trends do not directly mimic the solar PV inverter cost trends. This is due to the method of converting the relationship between cost and installed capacity of solar PV inverters over time to the cost of EVSE and the expected installed capacity of EVSE which creates a much smaller percent decrease than expected. The downwards trends are less apparent than the previous results for the battery and solar PV costs. Here the unit costs are expected to decrease by 39% for the charger unit and 28% for the BOS cost from 2018 to 2030.

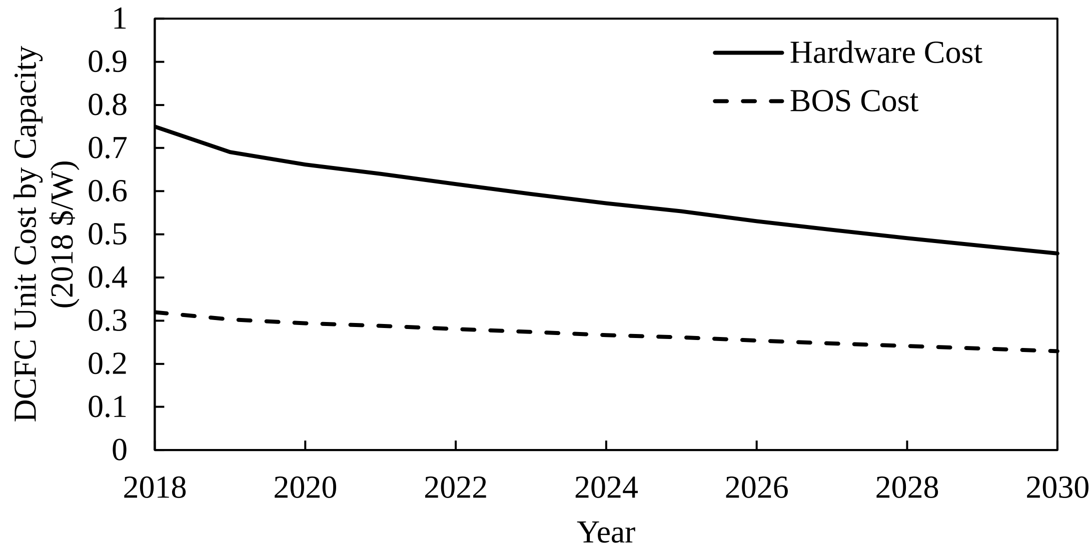


Figure 28. Cost projections for Direct Current Fast Charger Hardware and BOS cost from 2018 to 2030. Costs represent the installation of a single unit.

<u>Controls</u>

The cost trends for the controls portion of the Solar+ system are represented in Figure 29. As explained in the methods section the cost for Solar+ controls systems includes the supervisory controller and the programming for that controller. Here it is assumed that in ten years the cost for programming will be omitted because the development of the software should be final or very minimal at that stage in the technology. The cost of the controller hardware unit is expected to decrease by 80% assuming that these controllers will also be developed and deployed over the next ten years. The trend shown here includes an exponential curve to mimic a technology learning curve for costs related to the hardware components for the controller.

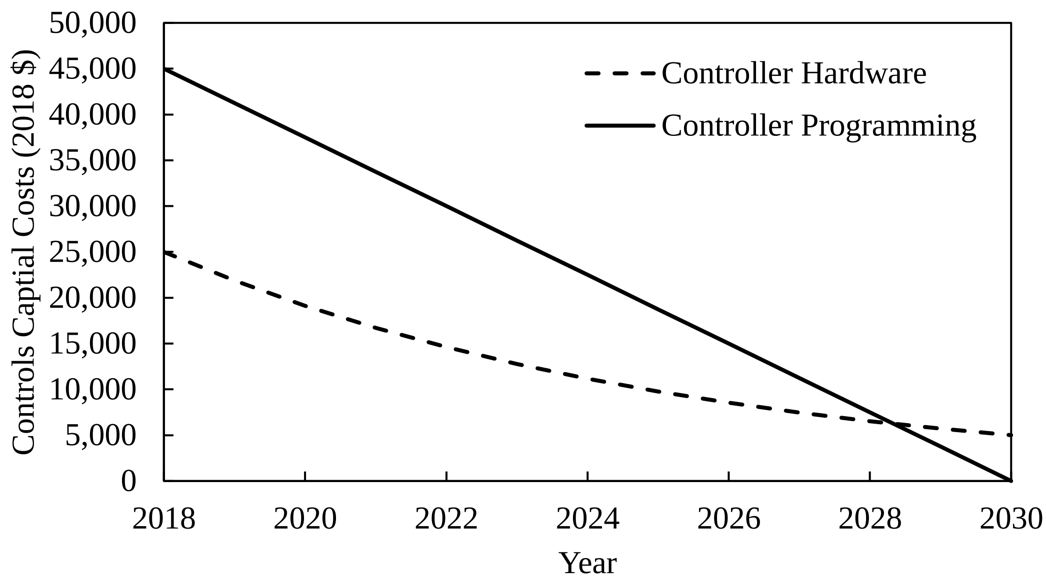


Figure 29. Cost Projections for Controller Hardware and Programming.

<u>Integration components</u>

Integration costs are expected to gradually decrease over time. The resulting cost projections for engineering, interconnection, site work, and switchgear costs are displayed in Figure 30. Here the engineering and interconnection costs are assumed to be fixed costs for any type or size of Solar+ system to be installed. In practice this assumption may not be true which would result in error in the estimated costs. For the purposes of this project, the limited range of system sizes suited to a specific building type support this assumption. The projections are that engineering, site work, and interconnection costs will decrease by 66%, 10%, and 90%, respectively. For switchgear the costs are dependent on the size of the solar PV array. Switchgear unit costs represented in the figure include the estimated costs ($/W) for switchgear for a solar PV array of 50 kW. These costs are expected to decrease by 89% from 2018 to 2030.

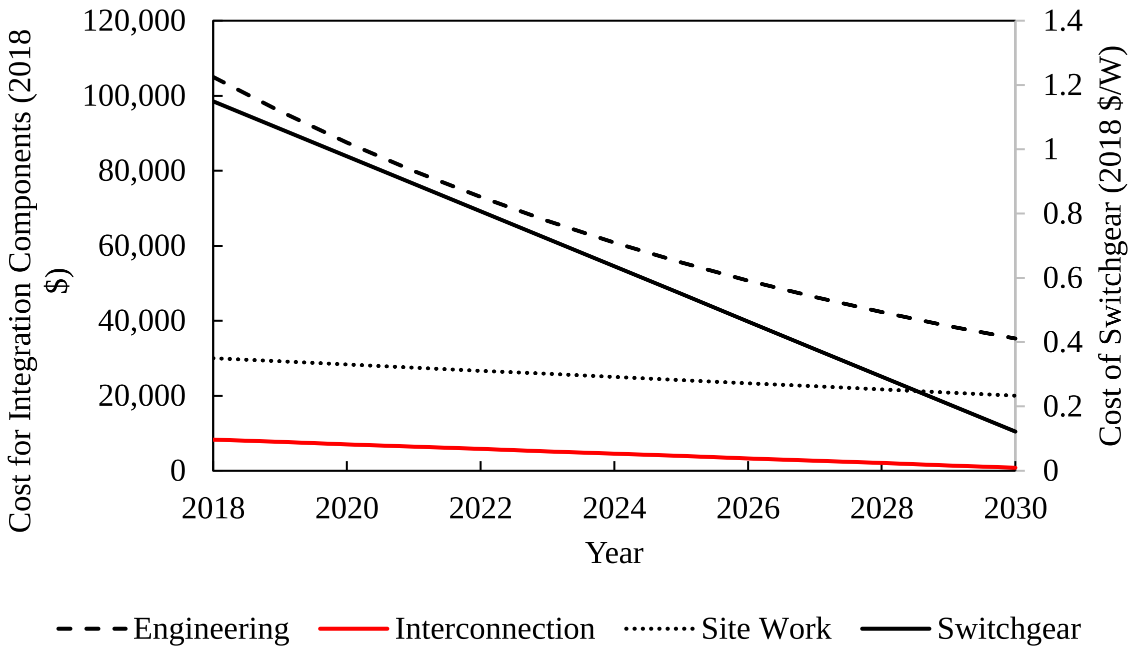


Figure 30. Cost Projections for Integration Components. Switchgear projections are for a 50 kW solar PV array.

Each of the cost projections listed above, represent the method for estimating the mode used in the random triangle distribution used in the Monte Carlos simulations. The following section decribes the results and statistics from all five of the scenarios assuming the reported trends.

All Scenario Comparision

Comparing the first three C-store scenarios (small, medium, and large) the costs follow the expected trends over the time period of 2018 to 2030, see Figure 31. When comparing the breakdowns in costs the integration and controls costs were the smallest contributer to overall cost for each scenario. Although, the smaller C-store scenario each of the cost categories contribute to the total cost more evenly. This is expected since the model assumed that the integration costs would stay the same.

The error bars (or the 95th and 5th percentiles) suggest that the larger the system gets, the greater the variabilty in the estimated total cost. The percent of the reported standard deviation over the estimated mean cost (or the coefficient of variation) is reported for the year 2030 and for each scenario in Table 16. Additional values for each scenario and year are provided in

Appendix B. Here, the variability increases as the size of the system increases. For example, the coefficient of variance increases by 1.6% for the large scenario to the large resilient scenario (a 160 kW size difference in the battery size). Also, reported in the Table 16 is the ratio of the interquartile range (IQR) to the median, which expresses similar increases with size.

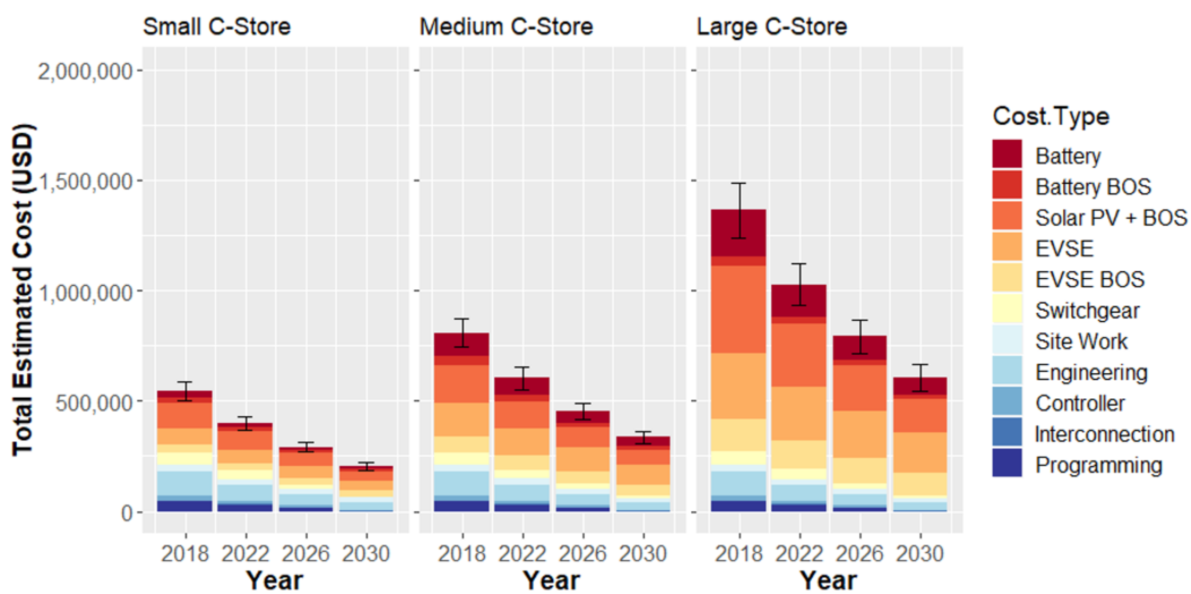


Figure 31. Total Capital Cost Estimates for Small, Medium, and Large C-Stores.

Table 16. Coefficient of Variation and Ratio of IQR to Median for the year 2030.

Variable	Small	Medium	Large	Resilient	Large Resilient
Battery (kW)	60	100	100	60	260
Solar PV (kW)	40	60	140	40	140
Combined (MW)	0.1	0.16	0.24	0.1	0.4
COV (%)	5.0%	5.3%	6.1%	5.9%	7.7%
IQR/Median ($/$)	0.068	0.074	0.084	0.083	0.106

The change in the coefficient of variation and the ratio of the IQR to the median also exhibits greater expected variability for each size range over time, see Table 17. For the Medium C-store scenario the coefficient of variation increases by 0.41%, and the IQR/median increases by 0.05 from 2018 to 2030. These observations are consistent throughout each scenario and year reported, see Appendix B for all values regarding the results from each scenario.

Table 17. Statistics from Medium C-Store scenario for each reported year.

Year	Mean ($)	Median ($)	Standard Deviation ($)	IQR ($)	COV (%)	IQR/Median ($/$)
2018	809,000	808,000	40,000	55,000	4.9%	0.068
2022	604,000	603,000	30,000	45,000	5.0%	0.074
2026	453,000	453,000	23,000	31,000	5.1%	0.0702
2030	335,000	335,000	17,900	24,000	5.3%	0.074

When comparing the Resilient C-store scenario to the original Small C-store scenario, the total cost of the system in 2018 is $94,000 more and in 2030 is $35,000 more than the small system, see Figure 32. The percent change from the small to resilient system consistently stays at 17% for each year reported. The capacity of the battery system is 60 kWh in the Small C-store scenario to 240 kWh in the Resilient C-store scenario, providing at least an additional 3 hours of power (assuming a 60 kW peak demand at the site and no PV power generation). The extra investment could prepare the site for unpredicted grid conditions. These results suggest that for a small location willing to install a Solar+ MG, they may want to consider adding the larger capacity systems due to the substantial improvement in performance of 4 times the energy capacity at only 17% cost increase.

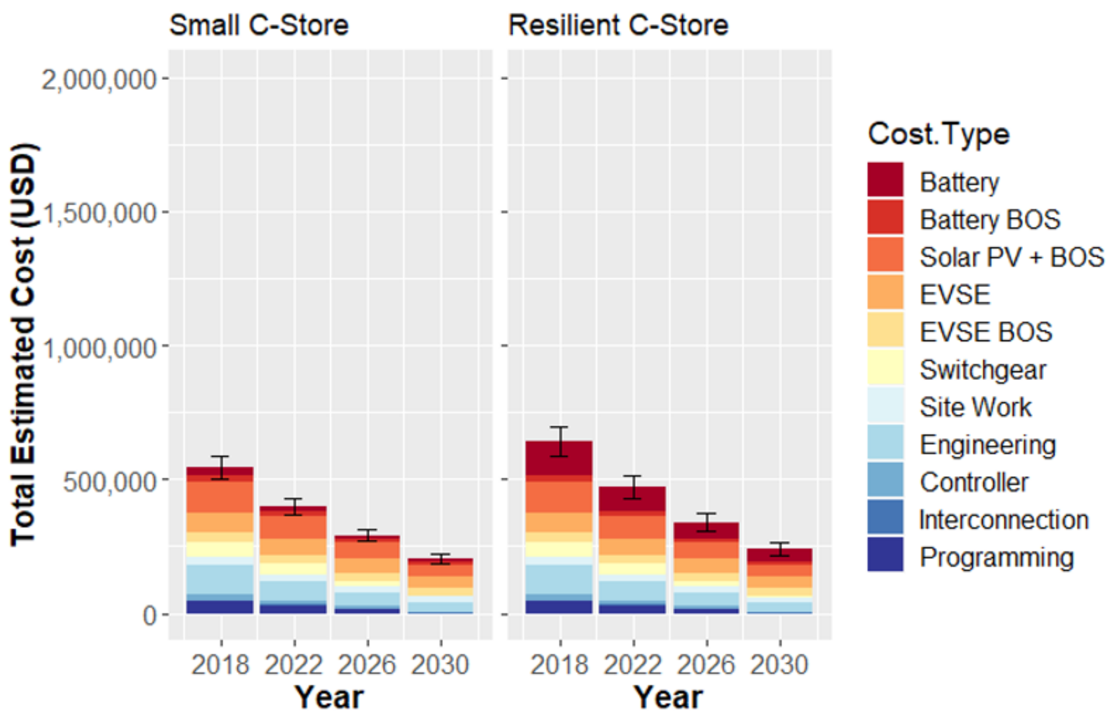


Figure 32. Estimated Capital Costs for Small and Resilient C-Store Scenarios.

Figure 33 compares the costs of the Large C-store scenario to the Large Resilient scenario. The cost for the Large Resilient scenario is about 21% more in cost than for the Large C-store scenario in 2018. Interestingly, the change in cost drops to 13% by 2030, this can be explained by the expected cost decrease for battery systems. The number of EV charging stations was decreased from eight for the Large C-store scenario to six for the Large Resilient scenario, assuming that the site would not prioritize having EV charging services, when there is a high electrical load for refrigeration and other plug loads. If the EV charging stations were to stay at eight chargers, the cost decrease is expected to decay at a slower rate for the Large Resilient scenario.

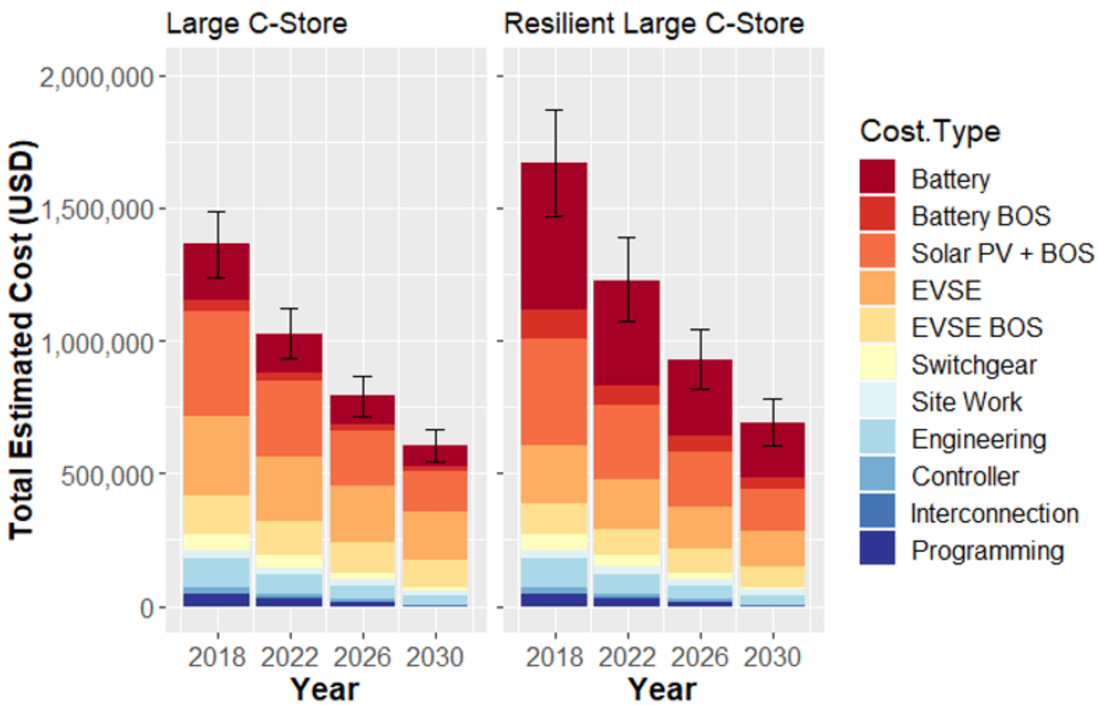


Figure 33. Estimated Capital Cost for Large and Resilient C-Store Scenarios.

Although the two resilient scenarios estimated 17 – 21% cost increases compared to the original scenarios, these systems provide four times more operation periods during grid outages providing resiliency when reliable electricity from the grid is a concern. In 2016, the frequency of outages in the U.S. for each utility type (municipal, co-op, and investor-owned) was at least one outage, and these outages averaged to be roughly 2 hours without major events and up to 4 hours with major events (Energy Information Administration 2018). Having a larger power output is expected to prepare a building for such events by being able to serve in-store electrical loads (such as refrigeration, lighting, cash registers, etc.), and possible EV charging stations during outages. These options would save the site additional lost opportunity cost by ensuring operations which makes these higher cost scenarios a feasible option.

The total cost estimates for each scenario and the reported years are provided in Table 18. These estimates show that a small Solar+ MG can cost up to 550 thousand dollars today (circa 2018) and are expected to cost less than half of that (205 thousand dollars) by 2030. Each scenario mimics these same trends, which all scenarios are expected to decrease in cost by 55-62% by the year 2030. The least amount of cost decrease is estimated for the two large systems, and the greatest decrease is found from the two small systems (Small and Resilient).

Table 18. Mean System Costs ($) for each scenario and year reported.

Scenario	**2018**	**2022**	**2026**	**2030**
Small	545,000	400,000	292,000	205,000
Medium	809,000	604,000	453,000	335,000
Large	1,360,000	1,030,000	791,000	608,000
Resilient	641,000	469,000	341,000	241,000
Resilient Large	1,650,000	1,230,000	925,000	690,000

The distributions for estimated total costs for the Medium C-store scenario is shown in Figure 34 for 2020-2030. All standard deviations, medians, and IQRs for the scenarios are reported in Appendix B. The figure shows that the distribution of estimated costs decrease for future projects. Although, as the costs distributions (or IQR) decrease over time the variability still increases, because the quantity of the total cost decreases. This aligns with the projected coefficients of variations and the ratio of the IQR to the median cost estimate.

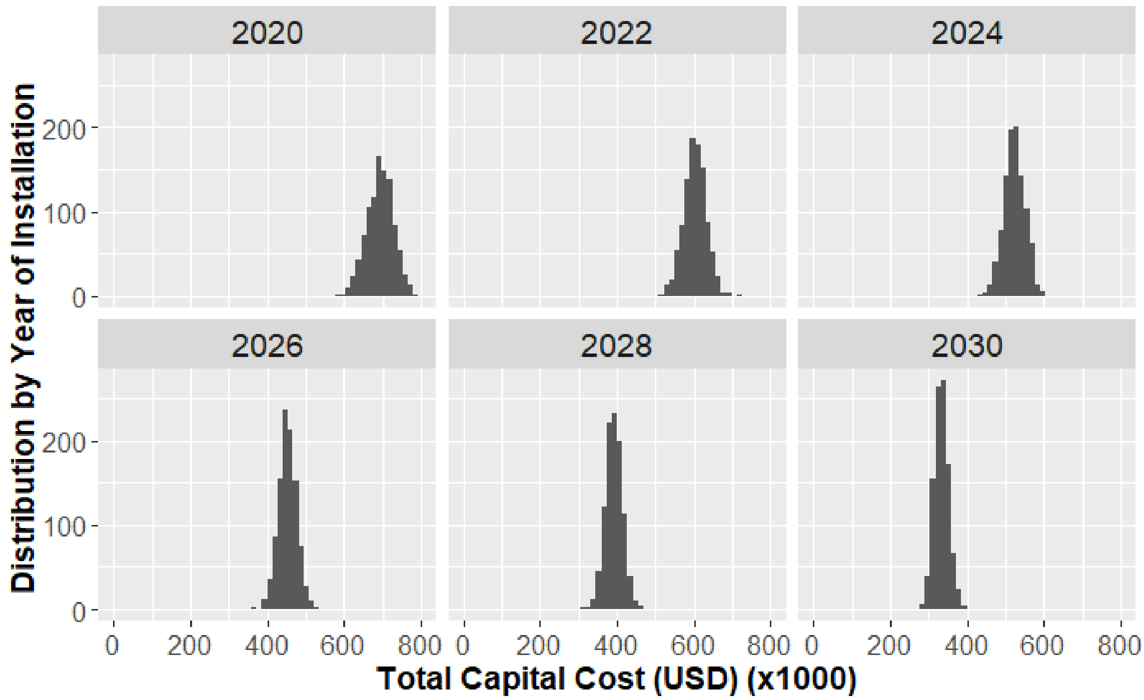


Figure 34. Distribution of Estimated Total Cost for Medium Solar+ MG. Cost is reported in thousands of dollars.

Additional Sensitivity Analysis

By using a range of inputs the sensitivity of the total capital cost was assessed by each input. The inputs included in this analysis are shown in Table 19 to investigate the sensitivity of the model to the battery capacity (kW and hours), the PV array capacity (kW) and the number of EVSEs.

Table 19. Parameters tested in Monte Carlo Simulations

Parameter	**Range**
Battery Capacity (kW)	20, 140, 260
Battery Duration (hours)	1, 2, 3, 4
Solar PV Capacity (kW)	20, 40, 60, 80, 140
EV Charging Stations	2, 4, 6, 8, 10

Here, I explored cost variation among a range of system sizes utilizing only monocrystalline modules. Figure 35 represents the average total cost for specific battery (columns) and solar PV (rows) sizes, and various numbers of EV chargers with a set battery duration of 4 hours. The lines represent the average total cost with various number of EV chargers. It is apparent here that the larger the system the greater decrease in cost will occur. For example, when comparing a 20 kW battery and a 20 kW solar PV capacity system and a 140kW battery and a 140 kW solar PV capacity system, the slope of the trends is ~1.7 times steeper for the larger system than the smaller system. An even steeper trend is shown for the 260 kW battery and 140 kW solar PV system which suggests the idea that larger battery systems will have the greatest change in cost over time. Also, the number of chargers proportionally increases the total cost over time.

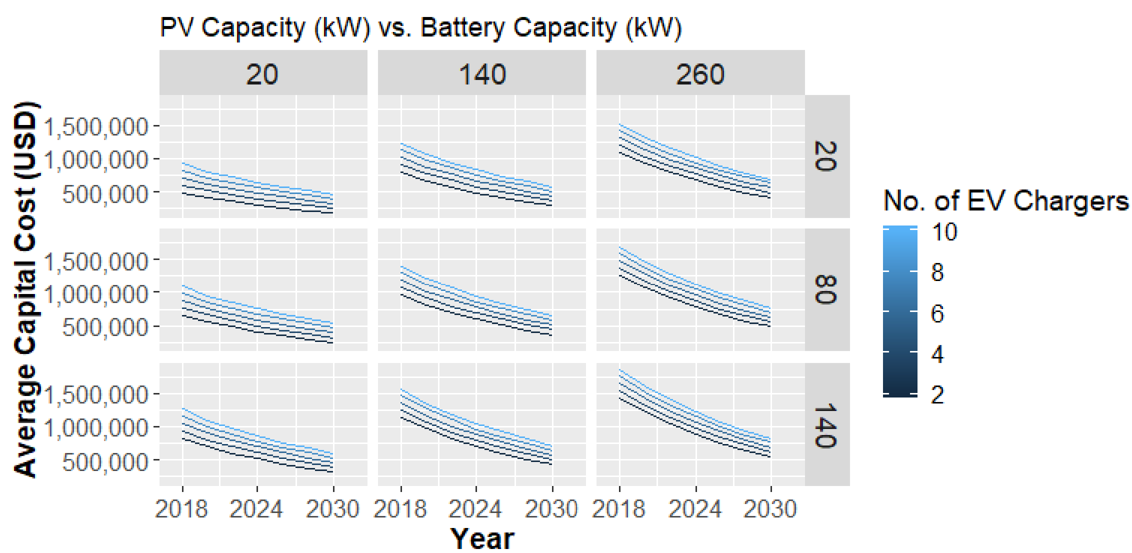


Figure 35. Estimated Total Cost for specified Solar+ Systems with Varied Component Sizes. This output is for a site with monocrystalline solar PV modules, and a battery system with a duration of 4 hours. Rows represent solar PV capacity and columns represent battery capacity.

In Figure 36, the average capital cost for specific battery (columns) and solar PV (rows) sizes, and various battery durations. Differing from the previous figure, the number of EV chargers is set to six chargers and the battery duration is varied. Interestingly, the difference in capital cost for a system with a 60 kW battery having a one hour duration to a system with a 60 kW battery having a four hour duration is almost negligible in these plots. This may be caused by the smaller impact of the battery unit cost which depends on the battery energy capacity. Although, when looking at the larger battery systems with 260 kW and the difference in capital cost is greater. This suggests that the larger energy capacity (or battery duration) the greater the cost of the overall system. This validates the earlier note that the battery cost will have a larger impact on the total cost of the system if the battery is a larger system.

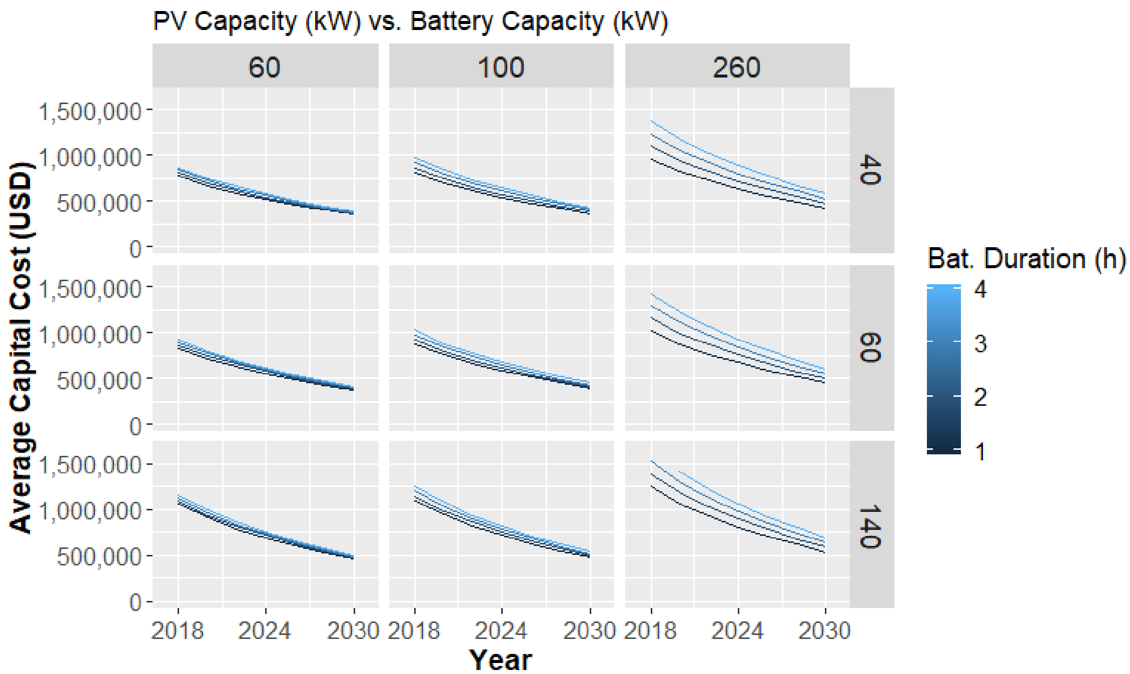


Figure 36. Estimated average cost for Solar+ systems with various battery and solar PV sizes. Plot is specific to a site with monocrystalline modules, and six EV chargers onsite. Rows represent solar PV capacity and columns represent battery capacity.

When comparing the total cost per MW of installed battery plus solar PV capacity for the system, the medium scenario is optimal due to the lower unit cost for the system without considering the resilient scenarios, see Table 20. The Large Resilient scenario shows the least cost per MW throughout the all years. In today's estimates the Large Resilient scenario and the Medium are the two lowest unit costs, making them optimal for constructing today. Although, by 2030 the Small scenario becomes cheaper in the future than the Medium scenario.

Table 20. Averaged Unit Costs (million $/MW) for Five Solar+ MG Scenarios. This unit cost it the total system cost divided by the combined capacities of the battery storage system plus the solar PV system.

Scenario	**2018**	**2022**	**2026**	**2030**
Small	5.45	4.01	2.93	2.05
Medium	5.06	3.78	2.84	2.10
Large	5.68	4.30	3.30	2.54
Resilient	6.42	4.70	3.41	2.41
Resilient Large	4.14	3.08	2.31	1.73

DISCUSSION

The rate of improvement for each of the technologies was greater than I had expected. The analysis of the battery and solar PV technologies was surprising with the original assumption that the two technologies would be in mature state, but the analysis showed that trends are still decreasing. EVSE equipment, the most difficult to find reported cost information for, was surprising due to the large variability found in reported costs, but this was understood to be a common issue due to the work required for EVSE. The cost trends are less dramatic than expected, but as demand for the technology increases with wide development of the current infrastructure, a more rapid decrease in cost is expected. The remaining components for integration and controls, changed as expected due to the work leading up to the development of the cost functions. The Schatz Center experts are optimistic for the design and expect that future installations will decrease as the knowledge increases about the design and installation aspects.

The breakdown in costs over time show some components start as major contributors to cost in 2018 and end as not a major contributor by 2030. This depends on the scenario (or system size). Table 15 and Appendix B, provide cost breakdowns for each scenario. The components that show an increase in the total cost breakdown for all components are EVSE plus EVSE BOS and the site work. The most substantial changes in cost breakdown occur for the EVSE plus BOS cost for each scenario (11-18% increase by 2030). For the smaller systems, the hardware equipment shows that the battery systems, and solar PV costs become larger contributors by 2030, but only by a fraction of a percent. This observation is different for the larger systems, the battery and solar PV both decrease in contribution to the total cost to the system. On the other hand, the components which show reductions to the cost of the system for every scenario are switchgear, and programming.

EVSE plus BOS is the top contributor to cost, which suggests that Solar+ MG costs can substantially decrease by not including this component in the design. For the Medium C-Store the cost in 2018 would be 30% less if EV charging stations were not considered in the system design and 40% less in 2030. Similar trends are reported for the remaining scenarios. Although, with current trends in EV adoption, it is important for EV charging infrastructure to be developed to meet the demand for all drivers.

The costs estimated for each system depend on the size of the system. The scenarios chosen for this analysis are dependent on my understanding of C-stores and what I assume is a reasonable design. For a real-life application the size of the system will depend on the customer's site loads, existing infrastructure for the MG, and the desirable functionalities (higher duration or power capacity). Case studies for existing MGs show different ratios for the size of the battery to size of the solar PV. Each MG case will be unique but the ultimate goal is to meet the customers' needs with a system that can generate and store electricity to serve the most important loads for each customer. The results from this thesis should be used to inform those about the possible cost ranges for the installation of theoretical Solar+ systems.

When comparing the unit costs estimated for the year 2018 to the unit costs (million $/MW) presented in the literature review in Figure 4 and in Table 3, those estimated by this model are higher on average by 32%. This may be the result of not considering the value streams provided by the systems or the result of looking at much smaller systems compared to the previous studies. The Navigant study suggested that the regional unit cost for MGs in California average to 3.6 million $/MW in 2018, when this study suggests that MGs cost from 4.1 - 6.4 million $/MW in 2018. Since these two averages do not cover similar system sizes, they may not be comparable. The other studies provided in Table 3 cover systems that are closer to the average size examined in this thesis. Those studies focused only on MGs from California and only consider MGs with solar PV and lithium-ion battery systems. Here the costs range from 3.06 - 6.85 million $/MW in 2018, which are still on average 16% lower than the estimated costs from this study. The differences could be from additional features for Solar+ systems not required for the previously installed MGs.

Two major sources of error in this thesis include using secondary source information from various reports and using linear regression compared to non-linear regression. Data points used in the development of each of the cost models were mostly from secondary or third sources. For example, the battery unit cost function utilized estimated cost projections from financial market report figures. Each source was not clear about how or what data was used in the estimate, which leaves error for whether the information provided by the report figures are correct. This methods was chosen due to the limited datasets regarding battery storage project costs. Methods to obtain each of the unit cost functions utilized linear regression which results with an underestimate of the true costs, unlike non-linear regression methods. This method was chosen to easily obtain multivariable regression models that could be a part of a larger model.

Missing parts of this analysis include neglecting operation and maintenance costs and completing an evaluation of the characteristics for convenience stores in California. The operation and maintenance cost were not considered for this model because of the focus on capital costs incurred during installation. Having the O&M considered would make it easier to then assess the annual costs and benefits after installation. This factor will be important if the model is used to estimate the lifecycle costs for a given system. The C-store characteristics assumed in this thesis were based on the characteristics found at pilot size for the Schatz Center Solar+ MG. The C-store is a larger location than may not represent the typical electrical and structural infrastructure, and electrical demand for convenience stores in California. Knowing these parameters could inform the model by improving estimates for the site work, permitting, and additional costs not previously considered. Adding this information to the model may increase the estimates that are reported. Also, understanding the needs for C-stores would inform the typical sizing ratio for the Solar+ MG design, which may change the chosen scenarios to represent the typical C-store designs.

CONCLUSIONS

The objective of this thesis was to develop a cost framework that could estimate the total system cost for a Solar+ MG built to satisfy the gas station and convenience store industry. The cost model was originally intended to evaluate the component costs today and in the future. This thesis takes available data about the specific components for a Solar+ MG and develops a total of five individual cost functions. These cost functions predict the unit costs for battery energy storage, solar PV, EV charging stations, controls, and integration costs for today (circa 2018) out to 2030. Each model considered the year of the installation plus the following the inputs: battery power capacity (kW), duration (hours), solar PV power capacity (kW), type of modules (mono or poly), and number of EV chargers. The final cost model (the collection of the five cost functions) is then used to estimate the total cost for five Solar+ MG scenarios for gas stations and convenience stores. Three of these scenarios differ in size from small, medium, and large, and two scenarios are resilient modifications of the first small and large scenarios. The model helps assess the future costs and cost breakdowns for each scenario making it easy to understand which component costs has the greatest effect on the total cost.

Solar+ MGs incorporate a variety of new technologies which should expect declining unit costs with future research and development. As more MGs are developed, technology and innovation improvements should progressively decrease the cost of MG systems. Results from the model suggest that the total cost for Solar+ MG systems should dramatically decrease by 55 - 62% from the year 2018 to 2030. This assumes that MGs are adopted and deployed widely enough and with enough knowledge transfer to reduce costs related to manufacturing, programming, installation, and permitting.

The results of this thesis only estimate the initial costs for the construction and deployment for Solar+ MGs. On the flip side of costs, these systems are expected to provide additional value streams such as reduced electricity payments due to both solar energy generation and reduced energy consumption resulting from improved building control systems. Also, MGs are an attractive technology that can address the urgencies that climate change and natural disasters force on the grid. Future work should include the analysis of the value streams to understand how the costs and benefits balance after installation for the system.

To improve the development of the final cost model. I suggest the use of non-linear regression models to build the separate unit cost functions for each component. Data used for the development of the models also should be verified as a primary source, which will be difficult. Hopefully as more MGs are developed, there is a possibility of having a larger database available for system sizes related to those addressed in this thesis. When this happens newer cost models should be estimated to improve the final cost estimates. Further analysis with the current model should include the comparison of reported costs for MG built now until the year 2030 to evaluate the correctness of the model. With the current work presented in this thesis, it can be used to inform those within the MG field about the estimated cost projections and breakdowns for Solar+ MGs and the separate components.

REFERENCES

Albert, R., Albert, I., and Nakarado, G. L. (2004). "Structural vulnerability of the North American power grid." *Physical Review E - Statistical, Nonlinear, and Soft Matter Physics*, 69(2 2), 1–4.

Alstone, P., Gershenson, D., and Kammen, D. M. (2015). "Decentralized energy systems for clean electricity access." *Nature Climate Change*, 5(4), 305–314.

Alstone, P., Zoellick, J., Brown, R., Pritoni, M., Blum, D., and Ganion, J. (2016). *Project Narrative*.

Asmus, P. (2016). "Liberating Microgrids (and All DER) Aligning Customer Needs with Solutions Provider Offerings." *Navigant Research*.

Asmus, P., Forni, A., and Vogel, L. (2018). "Microgrid Analysis and Case Studies Report." CEC-500-20(August).

Barbose, G., Darghouth, N., Millstein, D., Lacommare, K., Disanti, N., and Widiss, R. (2017). *Tracking the Sun 10: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States*.

Bedir, A., Crisostomo, N., Allen, J., Wood, E., and Rames, C. (2017). "California Plug-In Electric Vehicle Infrastructure Projections: 2017-2025 - Future Infrastructure Needs for Reaching the State's Zero Emission-Vehicle Deployment Goals."

Black & Veatch. (2015). *SOLAR GENERATION MARKET RESEARCH Task 1: Solar Market Assessment and Cost Projections*.

Bronski, P., Creyts, J., Guccione, L., Madrazo, M., Mandel, J., Rader, B., Seif, D., Lilienthal, P., Glassmire, J., Abromowitz, J., Crowdis, M., Richardson, J., Schmitt, E., and Tocco, H. (2014). “THE ECONOMICS OF GRID DEFECTION WHEN AND WHERE DISTRIBUTED SOLAR GENERATION PLUS STORAGE COMPETES WITH TRADITIONAL UTILITY SERVICE.”

Candelise, C., Winskel, M., and Gross, R. J. K. (2013). “The dynamics of solar PV costs and prices as a challenge for technology forecasting.” *Renewable and Sustainable Energy Reviews*.

Carter, D., Marshall, M., Palmer, K., Radesky, K., Zoellick, J., and Alstone, P. (2018a). “Hardware Component Costs for Solar+ Microgrids.”

Carter, D., Zoellick, J., Chamberlin, C., Lehman, P., Chapman, G., Shoemaker, S., Marshall, M., Ganion, J., Saucedo, D., and Singh, P. (2018b). *Demonstrating a Secure, Reliable, Low-Carbon Community Microgrid at the Blue Lake Rancheria*.

CCRPC. (2014). *Electric Vehicle Charging Station Guidebook Planning for Installation and Operation*.

Curry, C. (2017). “Lithium-ion Battery Costs and Market.” *Bloomberg New Energy Finance*, 14.

Dept. of Homeland Security. (n.d.). “Critical Infrastructure Sectors.” <https://www.dhs.gov/cisa/critical-infrastructure-sectors> (Apr. 8, 2019).

Energy Information Administration. (2018). *Average frequency and duration of electric distribution outages vary by states - Today in Energy - U.S. Energy Information Administration (EIA).*

Frankel, D., Kane, S., and Tryggestad, C. (2018). “The new rules of competition in energy storage | McKinsey.” <https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/the-new-rules-of-competition-in-energy-storage> (Feb. 7, 2019).

Fu, R., Feldman, D., Margolis, R., Woodhouse, M., and Ardani, K. (2017). *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017*.

Home Depot. (n.d.). “Generac 277/480-Volt 600-Amp Indoor and Outdoor Automatic Transfer Switch-RTSN600K3 - The Home Depot.” <https://www.homedepot.com/p/Generac-277-480-Volt-600-Amp-Indoor-and-Outdoor-Automatic-Transfer-Switch-RTSN600K3/202851479> (Mar. 2, 2019).

Hyams, M., Awai, A., Bourgeois, T., Catalado, K., Hammer, S., Kraham, S., Mitchell, J., Nurani, L., Pentland, W., Perfetto, L., and Nostrand, J. (2010). *Microgrids: An Assessmest of the Value, Opportunities and Barriers to Deployment in New York State*.

Idaho National Laboratory. (2015). “What were the Cost Drivers for Workplace Charging Installations?” (May), 1–4.

Key, T., and Peterson, T. (2009). *Solar Photovoltaics: Status, Costs, and Trends*.

Kittner, N., Lill, F., and Kammen, D. M. (2017). “Energy storage deployment and innovation for the clean energy transition.” *Nature Energy*.

Korus, S. (2017). *The Future of Autos and Trucks Is Electric*.

Liu, G., Starke, M. R., and Herron, A. N. (2016). *Microgrid Controller and Advanced Distribution Management System Survey Report*.

Maloney, P. (2018). “Not so fast: Battery prices will continue to decrease, but at a slower pace, GTM says | Utility Dive." *Utility Dive*, <https://www.utilitydive.com/news/not-so-fast-battery-prices-will-continue-to-decrease-but-at-a-slower-pace/518776/> (Feb. 7, 2019).

Marshall, M., Radesky, K., Zoellick, J., and Carman, J. (2019). "Integration Costs and Considerations for Microgrids and Electric Vehicle Charging Stations."

Mouton, V. (2017). "the Impact of Microgrids on the." 2016–2017.

National Association of Convenience Stores. (2018). "NACS | U.S. Convenience Store Count." <https://www.convenience.org/Research/FactSheets/ScopeofIndustry/IndustryStoreCount> (Apr. 3, 2019).

North American Electrical Reliability Corporation. (2017). "Distributed Energy Resources: Connection Modeling and Reliability Considerations." (February).

Norwall Power Systems. (n.d.). "Generac 800 Amp ATS 277/480 3 Phase NEMA 3R Cabinet - Norwall PowerSystems." <https://www.norwall.com/products/Generac-800-Amp-ATS-277480-3-Phase-NEMA-3R-Cabinet-RTSN800K3/?cid=google_feed&dfw_tracker=6374-752&gclid=CjwKCAjw6-_eBRBXEiwA-5zHaY3LJcUenJNAFlACVIwcubzcS30qty27EIpccc9iaf_wBanmvImJxRoCxsIQAvD_BwE%2F> (Mar. 2, 2019).

NREL. (n.d.). "The Open PV Project." <https://openpv.nrel.gov/search> (Jun. 14, 2018).

NREL. (2017). "Annual Technology Baseline." <https://atb.nrel.gov/electricity/2017/index.html?t=sd>.

PSI Control Solutions. (n.d.). “Eaton Magnum Automatic Transfer Switch | PSI Control Solutions.” <https://www.psicontrolsolutions.com/custom_product/eaton-magnum-automatic-transfer-switch/> (Mar. 2, 2019).

Schwaegerl, C. (2009). “Advanced architectures and control concepts for more microgrids: Report on the technical, social, economic, and environmental benefits provided by microgrids on power system operation.” *Siemens AG, STREP project SES6-019864, Analysis of technical, social, economic and environmental benefits*, 2(1), 1–145.

Soshinskaya, M., Crijns-Graus, W. H. J., Guerrero, J. M., and Vasquez, J. C. (2014). “Microgrids: Experiences, barriers and success factors.” *Renewable and Sustainable Energy Reviews*.

SPW Industrial. (n.d.). “Asco J07ATBB30400N5XC Series 7000 400A 480V Automatic Transfer Switch - New - SPW Industrial.” <https://spwindustrial.com/asco-j07atbb30400n5xc-series-7000-400a-480v-automatic-transfer-switch-new/?gclid=Cj0KCQiAlIXfBRCpARIsAKvManzP1RGt0jYMWce9wwudWVZ0ZLrOr1ifIlBLAtCswKx4sGYkwU0yPBYaAisfEALw_wcB> (Mar. 2, 2019).

Stadler, M., Cardoso, G., Mashayekh, S., Forget, T., Deforest, N., Agarwal, A., and Schönbein, A. (2016). “Lawrence Berkeley National Laboratory Value Streams in Microgrids : A literature Review.” 162(October 2015), 980–989.

Thompson, E. (2018). “Cost Forecast Opinions of EV Manufacturers.”

Ton, D. T., and Smith, M. A. (2012). “The U.S. Department of Energy’s Microgrid Initiative.” *The Electricity Journal*, 25(8), 84–94.

Zheng, C., and Kammen, D. M. (2014). “An innovation-focused roadmap for a sustainable global photovoltaic industry.” *Energy Policy*.

APPENDICES

Appendix A. Definitions of Microgrids from Expert Sources

Source	Definition
Department of Energy	"A MG is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode," (Ton and Smith 2012).
NERC	"An aggregation of multiple DER types behind the customer meter at a single point of interconnection that has the capability to island. May range in size and complexity from a single "smart" building to a larger system such as a university campus or industrial/commercial park," (North American Electrical Reliability Corporation 2017).
Siemens AG	MG is, "an integration platform for supply-side (micro-generators) and demand-side resources (storage units and (controllable) loads) located in a local distribution grid," (Schwaegerl 2009).
Copernicus Institute of Sustainable Development	"A microgrid is a small scale, discrete electricity system consisting of interconnected renewable and traditional energy sources and storage with energy management systems in smart buildings,".... "At the same time, a microgrid can operate independently without connecting to the main distribution grid during islanding mode," (Soshinskaya et al. 2014).

Appendix B-1. Estimated average, median, standard deviation, interquartile range, covariance, fraction of interquartile range to median, and 5% and 95% quantile ranges for all scenarios in year 2018.

Scenario	**Small**	**Medium**	**Large**	**Resilient**	**Large Resilient**
Mean ($)	545000	809000	1360000	641000	1650000
Median ($)	545000	808000	1360000	643000	1650000
Standard Dev. ($)	23000	40000	80800	35200	125000
IQR ($)	32000	55000	110000	48000	176000
COV (%)	4.2%	4.9%	5.9%	5.4%	7.5%
IQR/Median ($/$)	0.058	0.068	0.081	0.075	0.106
5% Quantile ($)	508000	748000	1230000	586000	1450000
95% Quantile ($)	580000	878000	1490000	699000	1860000

Appendix B-2. Estimated average, median, standard deviation, interquartile range, covariance, fraction of interquartile range to median, and 5% and 95% quantile ranges for all scenarios in year 2022.

Scenario	**Small**	**Medium**	**Large**	**Resilient**	**Large Resilient**
Mean ($)	401000	604000	1030000	469000	1230000
Median ($)	401000	603000	1030000	469000	1230000
Standard Dev. ($)	18500	30300	58100	25000	96000
IQR ($)	25000	45000	83000	35000	136000
COV (%)	4.6%	5.0%	5.6%	5.3%	7.8%
IQR/Median ($/$)	0.061	0.074	0.080	0.076	0.110
5% Quantile ($)	370000	556000	936000	430000	1070000
95% Quantile ($)	431000	652000	1120000	511000	1390000

Appendix B-3. Estimated average, median, standard deviation, interquartile range, covariance, fraction of interquartile range to median, and 5% and 95% quantile ranges for all scenarios in year 2026.

Scenario	**Small**	**Medium**	**Large**	**Resilient**	**Large Resilient**
Mean ($)	292000	453000	791000	341000	925000
Median ($)	292000	453000	791000	340000	926000
Standard Dev. ($)	13200	23300	45900	18700	70000
IQR ($)	18100	31800	60300	25500	100000
COV (%)	4.5%	5.1%	5.8%	5.4%	7.5%
IQR/Median ($/$)	0.061	0.0702	0.076	0.074	0.108
5% Quantile ($)	271000	416000	712000	310000	815000
95% Quantile ($)	314000	493000	866000	372000	1040000

Appendix B-4. Estimated average, median, standard deviation, interquartile range, covariance, fraction of interquartile range to median, and 5% and 95% quantile ranges for all scenarios in year 2030.

Scenario	**Small**	**Medium**	**Large**	**Resilient**	**Large Resilient**
Mean ($)	205000	335000	608000	241000	690000
Median ($)	204000	335000	608000	242000	688000
Standard Dev. ($)	10300	17000	37000	14400	53000
IQR ($)	14000	24800	51100	20200	72900
COV (%)	5.0%	5.3%	6.1%	5.9%	7.7%
IQR/Median ($/$)	0.068	0.074	0.084	0.083	0.106
5% Quantile ($)	187000	305000	547000	217000	607000
95% Quantile ($)	221000	365000	671000	265000	778000

Appendix C. Percent Contributions to total cost for Small C-store Scenario

Component	**2018**	**2022**	**2026**	**2030**
Battery	5.8%	5.7%	5.6%	5.8%
Battery BOS	4.6%	4.3%	4.4%	5.0%
Solar PV + BOS	21%	20%	20%	22%
EVSE	13%	15%	18%	22%
EVSE BOS	6.5%	7.8%	9.7%	12.4%
Switchgear	10%	9.9%	7.7%	2.9%
Site Work	5.5%	6.6%	7.9%	9.8%
Engineering	19%	18%	17%	17%
Controller	4.6%	3.6%	2.9%	2.4%
Interconnection	0.5%	0.5%	0.5%	0.4%
Programming	8.2%	7.6%	5.2%	0.0%

Appendix D. Percent Contributions to total cost for Small Resilient C-store Scenario

Component	**2018**	**2022**	**2026**	**2030**
Battery	19%	19%	19%	19%
Battery BOS	3.9%	3.7%	3.8%	4.3%
Solar PV + BOS	18%	17%	17%	18%
EVSE	11%	13%	15%	18%
EVSE BOS	5.5%	6.6%	8.3%	10%
Switchgear	8.8%	8.4%	6.7%	2.4%
Site Work	4.7%	5.7%	6.8%	8.4%
Engineering	16%	16%	15%	14%
Controller	3.9%	3.1%	2.5%	2.1%
Interconnection	0.4%	0.4%	0.4%	0.3%
Programming	7.0%	6.4%	4.4%	0.0%

Appendix E. Percent Contributions to total cost for Large C-store Scenario

Component	**2018**	**2022**	**2026**	**2030**
Battery	15%	14%	13%	12%
Battery BOS	3.0%	2.8%	2.7%	2.8%
Solar PV + BOS	29%	27%	26%	25%
EVSE	21%	24%	26%	30%
EVSE BOS	10%	12%	14%	17%
Switchgear	4.7%	4.5%	3.5%	1.3%
Site Work	2.2%	2.6%	2.9%	3.3%
Engineering	7.7%	7.1%	6.4%	5.8%
Controller	1.8%	1.4%	1.1%	0.8%
Interconnection	0.2%	0.2%	0.2%	0.1%
Programming	3.3%	2.9%	1.9%	0.0%

Appendix F. Percent Contributions to total cost for Large Resilient C-store Scenario

Component	2018	2022	2026	2030
Battery	32.8%	32.4%	31.0%	29.7%
Battery BOS	6.5%	6.1%	6.0%	6.4%
Solar PV + BOS	23.9%	22.9%	22.6%	22.7%
EVSE	13.6%	15.0%	17.3%	19.7%
EVSE BOS	6.7%	7.9%	9.5%	11.5%
Switchgear	4.0%	3.8%	2.9%	1.2%
Site Work	1.8%	2.2%	2.5%	2.9%
Engineering	6.4%	5.9%	5.5%	5.1%
Controller	1.5%	1.2%	0.9%	0.7%
Interconnection	0.2%	0.2%	0.1%	0.1%
Programming	2.7%	2.5%	1.6%	0.0%