5-2022

Battery Energy Storage System Mitigation Strategies for the Grid Impacts of Electric Vehicle Charging Infrastructure

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BATTERY ENERGY STORAGE SYSTEM MITIGATION STRATEGIES FOR THE GRID IMPACTS OF ELECTRIC VEHICLE CHARGING INFRASTRUCTURE

A Thesis
Presented to
the Graduate School of
Clemson University

In Partial Fulfillment
of the Requirements for the Degree
Master of Science
Electrical Engineering

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by
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May 2022

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ABSTRACT

The face of transportation is changing as a greater number of companies and private individuals switch from traditional automobiles to electric vehicles. This surge has been bolstered by improvements in technology, increased marketing, and a heightened focus on the role humanity plays in climate change. This advancement brings a growth in electrical demand caused by the charging loads of these vehicles. Due to the quick, sudden rise of this technology, the utility energy industry is still in the early stages of preparing for electric vehicle loads beyond the traditional load growth.

Though the technology for battery energy storage has been around for some time, there has been a recent resurgence of interest in using it at the grid level. Improvements in technology have made batteries cheaper and more efficient, while the interest in integrating more renewable energy sources has increased their production. With these improvements, battery energy storage may now be useful in mitigating the adverse effects of electric vehicle integration and improving the otherwise accelerated financial impact of these new charging loads.

In this thesis, the grid impacts of electric vehicle growth and integration are observed on provided models of real-world feeders. Using this data, the effectiveness of battery energy storage systems in mitigating these impacts in a manner that is economical and beneficial to the utility, the customer, and the environment is analyzed. Following this, a general approach for analyzing electric vehicle impacts and potential mitigation strategies is presented.

ACKNOWLEDGMENTS

The author would like to thank the Center for Advanced Power Engineering Research (CAPER) and the associated utility partners for supporting the research projects, *PG-01: Distributed Energy Storage and EV Holding Capacity with Value Proposition Development*, and *PG-02: Incorporating EV and EV Charging Stations into Integrated Resource Planning* that constitute the case studies within this thesis. Additionally, the author would like to acknowledge the help and support of his research partner Elaina Stuckey, and his thesis committee members Dr. Johan Enslin, Dr. Ramtin Hadidi, and Dr. Kumar Venayagamoorthy.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER ONE
INTRODUCTION

Background

Today it is hard to imagine that there was a time when the gasoline powered automobile was considered by many to be an absurdity that was, at best, a passing trend. An article written by Alexander Winton, one of the early inventers of the automobile, quotes a banker who told him "…You're crazy if you think this fool contraption you've been wasting your time on will ever displace the horse," [1]. Now, to some, there is a similar absurdity in the idea of the electric vehicle (EV). Yet, like its predecessor, it seems the adoption of the EV is continuing to progress despite objections.

This march towards the future has been spurred on and accelerated by the increased interest in combatting climate change. This is primarily accomplished by reducing dependence on fossil fuels. For the utility industry, this means making an effort to add to their renewable generation portfolios. For businesses and private individuals, switching from conventional automobiles to EVs is a great start. The transportation sector accounts for 35% of energy usage in the United States with 90% of that being attributed to the burning of petroleum gas in internal combustion engines (ICEs) [2]. Thus, reduction in the usage of petroleum could result in drastic reductions in overall carbon emissions, especially as utilities switch to more renewable fuel sources to generate the energy that will ultimately charge these vehicles.

The integration of these EVs onto the grid creates additional charging loads unforeseen by typical planning methods, mostly in the form of accelerated load growth rates and conflicts with peak demand times resulting in a need for more generation. How these new loads may affect distribution systems and expedite or alter upgrade plans is a challenge that is becoming more prevalent and more dire with each passing year.

Objectives

Case studies are taken from two projects sponsored by the Center for Advanced Power and Energy Research (CAPER). The objective of the first project, PG-01, is to investigate the value proposition and modeling of distributed energy storage and electric vehicles. Photovoltaics and EV growth are simultaneously considered, with battery storage investigated as a solution to the adverse effects.

The effects of EV integration on a highly loaded, residential distribution feeder are investigated in the CAPER PG-02 research project. The goals of this project are to predict EV growth, observe system vulnerabilities created by the EV penetration, and investigate various mitigation strategies. The primary objective is to utilize data from these investigations to determine how EVs might affect the integrated resource plan (IRP) of the utility over the next fifteen years.

The objective of this thesis is to assess the effectiveness and business case for battery energy storage systems as a mitigating technology in various deployment methods utilizing the results of the two case studies. Then, the methods and results are to be leveraged to present a general approach for evaluating the impacts of EV growth and the effectiveness of potential mitigation strategies on a single feeder or across a wider transmission network.

Contribution to Knowledge

In this thesis, a process for the prediction of EV penetration over the next 15 years in residential areas is defined. The vulnerabilities that may arise from these various penetration levels are observed. Then, different strategies for the deployment of battery energy storage systems (BESS) as a mitigation strategy are analyzed to determine their economic viability and their ability to reduce the overall impacts of EV integration on the IRP.

Layout of This Thesis

Chapter 2 introduces EVs. A definition of types of EVs and charging levels is given. Then, the growth of EV adoption by public and private customers is explored. Finally, the problems caused by integrating these new loads into the grid are discussed.

Chapter 3 defines various mitigation strategies being explored by the industry today including some already in use and others only in developmental stages. These mitigation strategies address EV loads but also other issues the grid is set to face in the near future, including possible back feed from photovoltaics (PV).

In chapter 4, the two case studies are presented. Results from PG-01 are briefly discussed prior to PG-02. For PG-02, the feeder under study is introduced in detail before methods for determining EV penetration are defined. Results are presented and discussed including system vulnerabilities, BESS mitigation, and BESS plus Time of Use strategies over the course of preselected years.

Chapter 5 discusses the results of the case studies in the previous chapter in more detail, primarily focusing on their impacts on the IRP and if these BESS mitigation strategies can be made economical.

Chapter 6 presents the general concepts that can be extrapolated from the methods and results of the two case studies. A general approach to projecting EV penetration on a residential feeder and then analyzing various mitigation strategies is discussed.

Chapter 7 offers concluding remarks and additional work to be considered.

CHAPTER TWO

THE PROMISE AND PLIGHT OF ELECTRIC VEHICLES

An Overview of Electric Vehicles

Electric vehicles can be divided into two primary categories, all-electric vehicles (AEVs) and plug-in hybrid electric vehicles (PHEVs). AEVs include battery electric vehicles (BEVs) and fuel cell electric vehicles (FCEVs). These run entirely on stored electrical energy or energy gathered from regenerative braking. In the case of FCEVs, electrical energy is generated from compressed gas stored in a tank and passed through a fuel cell. PHEVs, on the other hand, also include a small ICE which can be utilized when the battery in the PHEV is depleted, during instances of increased acceleration, or during increased usage of the heating, ventilation, and air conditioning (HVAC) system [3].

One important distinction that needs to be defined is the difference between PHEVs and hybrid electric vehicles (HEVs). HEVs also have an electric battery that certain processes within the vehicle can get energy from. However, HEV batteries are charged by the ICE while the vehicle is running or regenerative braking, and do not plug into an outlet to charge as PHEVs do.

AEVs and PHEVs are charged via connection to the grid or another external power source. The most common connection is via a conductor, called conductive charging, in which the vehicle is plugged into the external power source. In the Unites States, the common plug is the J1772, also called the J-plug. Tesla is the only manufacturer that does not utilize this plug. The other type of charging connection is wireless, known as inductive charging. In this form of EV charging, a transmitting plate creates a magnetic field that links with the receiving plate on the vehicle to charge the battery.

EV charging is accomplished at an electric vehicle charging station (EVCS), which can alternatively be known as a charging point or electric vehicle supply equipment (EVSE), among other names. These can either be domestic systems placed in the garage of a customer's home or in public locations such as gas stations, parking lots, or dedicated stations with several stalls.

Charging is typically categorized into three levels. They are level 1 charging, level 2 charging, and level 3 charging, which is more commonly referred to as DC fast charging. Level 1 utilizes $120V_{AC}$ and a maximum single-phase current of $15A$, allowing the charger to be connected to a standard household outlet. Level 2, by definition, uses $240V_{AC}$ and a maximum current of $80A$. These are the two levels that are most often found in homes and other residential spaces. Level 3 charging can use up to $1000V_{DC}$ and high currents for quick charging [4]. This is possible because the converter is in the charging equipment, not the vehicle. This allows the vehicle's converter and its current limits, which are usually lower due to space and cost constraints, to be bypassed. An example of a DC fast charger is the Tesla Supercharger V3 which can charge with a power output of up to $250kW$ per car [5]. These chargers are commonly placed in large public installations. It should be noted that the power at which a vehicle charges is dependent on the system infrastructure, safety devices, and the power rating of the vehicle electronics themselves, not just what the charger is able to supply.

The benefits of EVs are clear. Since EVs have a reduced dependence on petroleum, the tailpipe emissions are likewise reduced. In the case of AEVs, these emissions are reduced to zero, which helps in the fight against climate change and reduces the number of irritants in the air in a localized area. Additionally, electric vehicles are more efficient than traditional vehicles. Typically, an EV can convert roughly 77% of electrical energy into mechanical energy. Compare that to the 30% of stored energy in gasoline that is converted to mechanical energy in typical ICEs in the best-case scenario [6].

Growth of Electric Vehicle Adoption

In 2018, the Edison Electric Institute (EEI) conducted a study to project EV sales up to the year 2030 utilizing five independent forecasts from Bloomberg New Energy Finance, Boston Consulting Group, Energy Innovation, the U.S. Energy Information Administration, and Wood Mackenzie. Utilizing these sales projections, the EEI concluded that 18.7 million vehicles on the road would be electric by 2030, which accounts for about 7% of all vehicles [7]. Figure 2.1 and Figure 2.2 detail the data points from the EEI study.

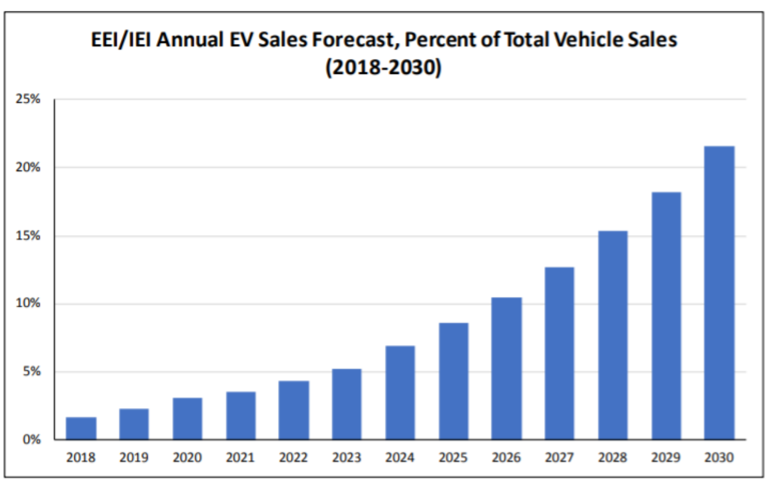

Figure 2.1. EV sales as a percentage of total vehicle sales [7]

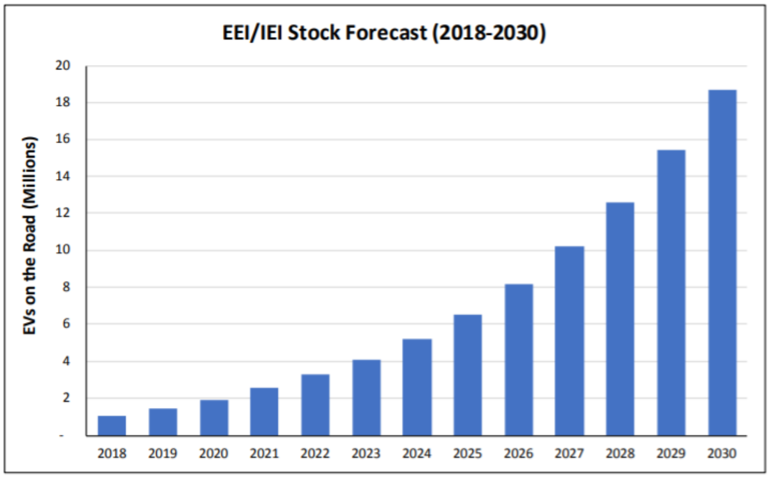

Figure 2.2. Projected EV stock in the United States [7]

The data points shown indicate a projected steady increase in EV sales and EV registration. In actuality, there may be some variation in these levels due to increased incentives to switch to EVs, increased production of EVs, or unexpected accelerated advancement of EV technology. Actual data from NCDOT regarding EV registration is shown in Figure 2.3.

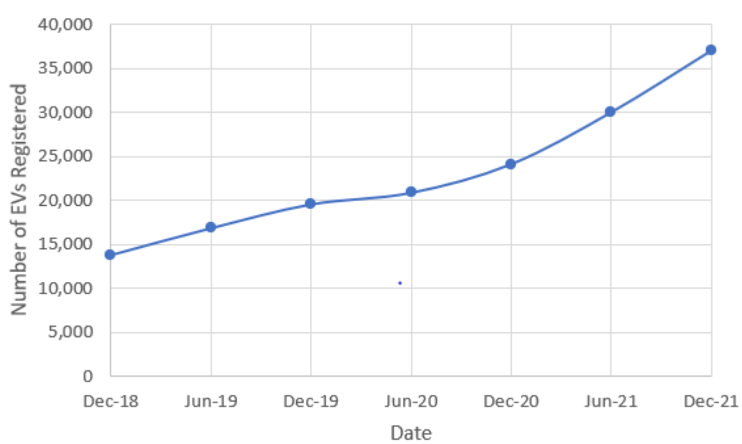

Figure 2.3. Number of total EVs registered in North Carolina [8]

Note that there is an almost steady increase between December 2018 and December 2021. The one variation occurs in the first half of 2020, during the major economic fallout from the COVID pandemic. It should be noted that the 2021 EV stock is 2.69 times greater than the 2018 EV stock according to the NCDOT data in Figure 2.3. Compare this number to the EEI study which suggests a 2021 EV stock 2.55 times greater than the 2018 EV stock. Based on this comparison, the EEI study can be considered a reliable projection.

In addition to light-duty EV penetration, many large companies are converting either part of, or the entirety of their fleets to electric vehicles. This list of companies includes Amazon, AT&T, FedEx, and Siemens to name only a few [9][10]. Consider also that public transportation may soon be making the switch. For example, CATbus in the Clemson area has recently transitioned to an all-electric fleet.

As mentioned previously, EV adoption may vary because of any number of factors including but not limited to available incentives, vehicle availability, advancements in technology, and economic or political events. Even the studies utilized by [7] have variations in projected EV sales, with one predicting 6 million EVs will be sold in 2030 and another predicting as low as one and a half million EVs will be sold in 2030. Regardless, the stock of EVs on the road and the charging demand on the electrical grid will increase. The only question is the rate at which this will occur.

Integration of Electric Vehicles

The most glaring issue caused by the integration of EVs onto the grid is the increased load demand. Since EVs charge from a connection to the greater electrical grid in most cases, at some point during the day they must act as a charging load. Additionally, in an uncoordinated scenario, EV customers are more likely to recharge at home following work as determined by the Oak Ridge National Laboratory [11]. This is primarily due to the convenience of plugging in and charging immediately after completing the final vehicle trip of the day. Of course, this period of time coincides with the typical evening peak demand. Therefore, an increased peak demand and higher ramp rates are introduced. This is potentially dangerous as it could lead to overloaded circuits and equipment, especially during the summer months when the evening peak is higher and the capacity of equipment is lower due to raised temperatures.

Voltage profiles are affected with an increased load as well. In uncoordinated charging the likely increase of peak demand may lead to reduced voltages along distribution networks. This causes an increase in tap switching events on load tap changers and voltage regulators, effectively reducing their lifespan and increasing maintenance costs. It should be noted that as PV penetration increases, the deep valley during the midday period will only exacerbate the ramp up in the early evening, putting greater strain on voltage correction equipment to act a significant number of times over a very short period.

Another issue with the integration of EVs on the grid is the introduction of harmonic distortion as indicated in [12] and [13]. Since the primary energy source for EVs are DC batteries which are connected to the AC grid when charging, power electronics are needed. The switching events in these power electronics have the potential to create harmonic distortion that can lead to overloads on equipment, greater line losses and inefficiencies, and unnecessary action of protective devices among other problems. In [13] it is suggested that these harmonic disturbances will vary with the charging cycle and may be greatest during the low current, “trickle” portions of the cycle. It should also be noted that improvements in power electronics technology have reduced the impact of this problem.

CHAPTER THREE
MITIGATION STRATEGIES

While an increase in total harmonic distortion (THD) was mentioned in the previous chapter as a possible concern with increased EV charger penetration, it is not discussed further in this thesis. It was included for the sake of completeness. Chapter three focuses on potential mitigation strategies for issues that arise on feeders relating to overloads, undervoltage, and increased tap switching events.

These mitigation strategies are alternatives to the more traditional methods that include upgrading equipment and conductors to those which have higher power ratings and building additional power generation plants to make up for the difference between the maximum load demand and the system's generation capabilities.

Time of Use Scheduling

For the entirety of the electrical grid's existence, generation has followed load. That is to say that as load increases throughout the day generation is increased and similarly decreased. However, in a world where distributed energy resources (DER) and PV installations create potential overgeneration issues in the middle of the day, it may be possible to see load forced to follow generation. In this instance, batteries can be set to charging modes during high generation, low demand periods of the day to increase load to meet generation.

Another way for load to follow generation is to shift loads that are not time sensitive. EVs may fall into this category considering that vehicles are parked for 95% of the day and usually have a regular schedule [14].

However, customers may prefer to charge their vehicles as soon as they arrive at home at the end of the day which ensures ample time to charge before the morning commute. Thus, an incentive is needed. These incentives are known as Time-of-Use (TOU) rates. In this method, the cost of electricity to the customers is altered at specific times, typically lowered during low demand times, to encourage users to delay charging or other high-power activities until these periods.

TOU rates take on many forms. Static TOU rates have fixed prices at fixed times during the day. Dynamic TOU rates have fixed prices, but times vary depending on the day. Real-time pricing follows the wholesale cost of electricity throughout the day and may vary frequently with demand and emergency conditions. Additionally, how these rates are applied is a factor. Opt-in requires customers to actively seek the TOU plans and apply for them. Meanwhile, opt-out rates are applied by default and customers are only dropped from the rate plans if they actively choose to withdraw from them.

A downside to TOU rates is that they must be adopted and utilized for them to offer any benefit to the utility. The question then arises, how likely are customers to switch to TOU rates? This varies greatly with the attractiveness of the pricing and the enrollment strategies. In [15] it is suggested that adoption of TOU rates can fall anywhere between 1% and 43% in most cases. Adoption leans toward the higher bound in cases where the utility makes an effort to make customers aware of the TOU pricing option. The numbers are even more favorable in the case of opt-out TOU rates, where adoption rates may surpass 57%.

In the case of EVs it should be mentioned that the innovation of smart chargers that allow for programmed start times may aid in increasing the adoption of TOU rates. Trying to encourage a customer to actively go outside or into their garage at 11:00pm or 12:00pm at night to plug in is much more difficult that asking them to still plug in as soon as they arrive home but set the charge to start close to midnight automatically.

Vehicle-To-Grid

The installation of large BESS systems to reduce overloads or offer other grid support functions is one potential mitigation strategy discussed in the next section. An innovative alternative is utilizing the batteries that will already be present, EV batteries, to perform these functions at a fraction of the cost to the utility. Bolstered by the fact that most vehicles are parked 95% of the time [14] and the development of bidirectional chargers, the vehicle-to-grid (V2G) concept could become a reality in the near future.

While a single EV may not be capable of much assistance beyond support of a single residence's power, research suggests that large clusters of EVs capable of V2G, known as gridable EVs (GEVs), could be beneficial in many scenarios. For example, consider the intermittency of wind and solar, which creates fluctuation in the amount of power generated throughout the day at unpredictable times. [16] shows how SmartParks, which are large parking lots designed specifically for EVs, can be utilized to stabilize fluctuating power flows caused by changes in windspeeds near wind farms. Similarly, [17] indicates that SmartParks can be utilized as a virtual STATCOM, using the reactive power capabilities of the EVs to regulate voltage at the connected node. Additionally, the DC link capacitor in the bidirectional chargers has the ability to provide reactive power support independent of the vehicle's battery [18]. The argument for using EVs for voltage regulation is that this can happen without greatly reducing the EVs state of charge and, thus, the battery's state of health while providing up to 95% reduction in line losses [17][19].

The main obstacles to using V2G are infrastructure, customer compliance, and the current penetration levels of EVs [20]. In order to use EVs for grid support functions, the infrastructure must be present. This includes the bidirectional chargers in public as well as domestic locations, but also includes aggregators which function as the interface between the system operator and the GEVs. Of course, the infrastructure is rendered useless if the vehicles are not there to use it. Naturally, there is some resistance from customers to use their EVs for V2G functions. In the case of peak shaving or real power functions, the state of charge is diminished. Over time this reduces the battery's capability to retain a charge but, in the short term, it may cause customers to fear that when they need their vehicle it will not be charged to their desired state of charge. Beyond this, the greatest hinderance may be the penetration level. As previously mentioned, a single EV or a small group of EVs cannot provide enough real or reactive power to be beneficial due to the relatively small size of their batteries and the lower power ratings of some chargers. A large sum of GEVs with owners willing to participate in an area with the necessary infrastructure are needed for V2G to be effective, and this is a tall task to undertake, especially with the still young EV market.

Battery Energy Storage Systems

The electrical energy industry began to gain a foothold in the late 19th century. The concept of large-scale energy storage was not far behind, with the first pumped hydro facility being built in Switzerland in 1909 [21]. Energy storage technologies operate on the principle of storing energy during low demand times when the cost of energy is lower and discharging that energy during high demand times. A primary advantage of energy storage facilities is that they can reduce or eliminate the need for new power generation stations that only serve peak demand. As PV generation becomes more prevalent on the grid, they can also store the excess generation that typically occurs during the lower demand midday periods.

For utility scale applications that require long periods of power discharge, energy storage often takes the form of pumped hydro storage (PHS), compressed air energy storage (CAES), or other methods by which electrical energy is converted to potential energy. PHS works by pumping water from a lower reservoir to a higher reservoir during low demand times and releasing that water during high demand times through a series of turbines to generate power. These systems typically have 75%-85% round trip efficiency and can be activated within minutes if needed [22]. CAES operates typically by compressing air into an underground cavern during off-peak hours which is then released during on-peak hours through a generation system to generate electricity. In diabatic CAES storage, the technology that is currently in existence, some natural gas is needed to accomplish reheating of the released air, adding costs and inefficiencies to the process. Naturally, it is easy to see how these two technologies require certain geological conditions and must be built at large scales to be economical.

For short term disturbances to the utility electric grid, ultracapacitors and flywheels are useful energy storage systems. Ultracapacitors are precisely what they sound like, large capacitors that can store large amounts of energy. They can typically support many rapid charge and discharge cycles. Flywheels, in contrast to the PHS and CAES systems mentioned previously, store electrical energy as kinetic energy. During off-peak times the rotors are accelerated to great speeds, and that kinetic energy can be converted to electrical energy through the dual-purpose motor/generator when needed. A very common use of these devices is spinning reserve for frequency regulation. The major drawbacks of the flywheel are the need for strong materials to withstand high speeds, and the need for installation in underground or bunker-like locations to prevent catastrophic damage or loss of life in the event of mechanical failure. For both technologies the hardware and economic limitations restrict efficient usage to short bursts of power discharge.

The technologies listed so far have their niche applications including small scale installations with short discharge periods to large scale installations with longer discharge times that are limited by geographic location, area, and cost effectiveness. The next concern to be addressed is the need for medium scale, distributed applications seen on distribution networks. With the rise of EV loads creating system vulnerabilities through overloaded equipment and rapid voltage changes and the rise of residential PV applications creating a new demand for distributed energy storage to prevent overgeneration while also minimizing line losses, an energy storage technology is needed to fill this void.

The void is filled by electrochemical storage, otherwise known as batteries or BESS. These devices use chemical processes to store electrical energy. In the case of conventional cell batteries, two electrodes are separated by an electrolyte and the movement of ions from one electrode to the other charges and discharges the battery [23]. Flow batteries, on the other hand, keep electrolytes in separate reservoirs which, when pumped through electrochemical cells, produce electrical energy [24]. These devices are the most popular small to medium scale energy storage devices because they are space efficient, modular, flexible, and easily dispatchable [25].

Distributed energy storage along distribution feeder lines or even at the head of a distribution feeder has the problem of relatively limited available space. Due to this, a high energy density is desired. BESS technology has this characteristic, boasting one of the highest energy densities compared to other technologies as shown in Table 3.1 [26]. Additionally, the rise in EVs which require light, affordable batteries has only helped to accelerate research and improvements in this field. For example, in the first decade of the 21st century, Lithium-Ion battery technology saw an increase in energy density from $250\ Wh/L$ to $570\ Wh/L$ in some cases [21].

Table 3.1. Energy storage characteristics by technology [26]

Technology	Storage Duration	Cycling/ Lifetime	Energy Density (Wh/L)	Power Density (W/L)	Efficiency (%)	Response Time
Ultracapacitor	ms-min	10,000-100,000	10-20	40,000-120,000	80-98	10-20ms
PHS	4-12hrs	30-60yrs	0.2-2	0.1-0.2	70-85	sec-min
CAES	2-30hrs	20-40yrs	2-6	0.2-0.6	40-75	sec-min
Flywheel	sec-hrs	20,000-100,000	20-80	5,000	70-95	10-20ms
Lead-Acid Battery	1min-8hrs	6-40yrs	50-80	90-700	80-90	<sec
NaS Battery	1min-8hrs	2,500-4,400	150-300	120-160	70-90	10-20ms
Li-ion Battery	1min-8hrs	1,000-10,000	200-400	1,300-10,000	85-98	10-20ms

Modularity is the ability of a system to be broken down into separate components that are easily combined. It allows for ease of transport and installation, but also in sizing the installation close to the desired parameters without overbuilding by a vast amount and incurring superfluous costs. In the case of BESS, independent units are easily connected in various electrical configurations to scale up the system.

Batteries absorb and discharge DC power, meaning they must be connected to the AC grid through an inverter as shown in Figure 3.1. Modern bi-directional inverters are highly controllable, allowing four-quadrant control so that both active and reactive power can be absorbed or provided to either the BESS or the grid. This capability, merged with the quick reaction time of inverters, allows the BESS to be both flexible in its applications and quickly dispatchable. Thus, BESS is capable of frequency support, voltage support, peak shaving, load balancing, and power quality improvement [25].

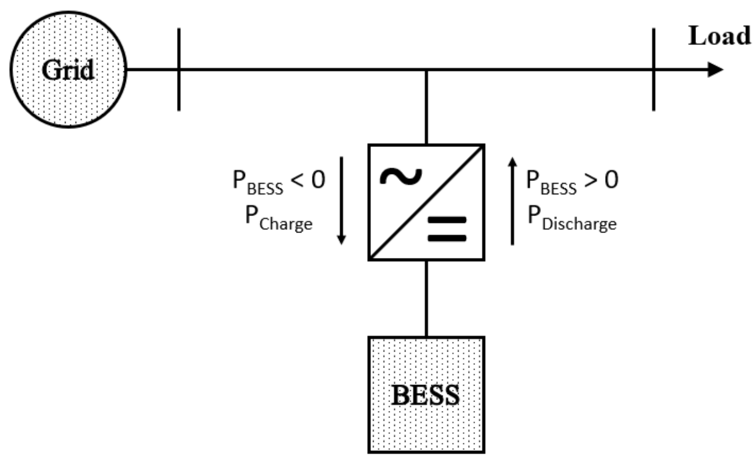

Figure 3.1. Basic configuration of BESS in a power system

Despite the many advantages of BESS, the technology does have its challenges as well. The major drawbacks of BESS are the associated costs and effective lifespan. As in most energy storage device cases, utilizing it for a single purpose rarely justifies the investment. Stacked services may provide some form of business case, but those may be limited under certain regulated environments. Even still, BESS currently involves high initial costs and relatively short lifetimes that make it difficult to recover the initial investment in peak load shaving and energy arbitrage scenarios [27]. When used for equipment upgrade deferral, the difference between the cost of BESS and cost of upgrades is massively in favor of the latter except in extreme cases [28]. It should be noted, however, that mobile BESS units may help with this business case as they can provide services where they are needed for a brief time and then be moved to another site [27].

CHAPTER FOUR
CASE STUDIES

An Earlier Case Study

PG-01 was a CAPER research project conducted from 2019 to 2021 with the expressed purpose of modeling EV penetration and PV penetration before studying the effects and value of various BESS penetration levels on provided distribution networks. While the conclusions of this project are included briefly here, methods and more in-depth analysis can be found in [28] and [29].

The first feeder of this project was a coastal, residential feeder in Florida with severely limited room for EV growth. It covered a large physical area, leading to the inclusion of several voltage regulators and additional voltage regulation equipment. Two levels of PV were observed based on average PV generation as a percentage of total net generation in certain states. Additionally, 10% EV penetration was considered for a low EV case and 20% EV penetration for a high case. Distributed BESS was then sized to alleviate system vulnerabilities and the associated costs calculated. The costs for each BESS solution compared to traditional equipment upgrades are shown in Table 4.1.

Table 4.1. Comparison of upgrade costs to BESS costs [29]

EV Penetration	Light (10%)		Heavy (20%)	
PV Penetration	15%	40%	15%	40%
Equipment Costs	$4,150,800	$4,075,800	$4,100,800	$4,060,800
BESS Costs	$9,393,200	$8,580,200	$11,348,250	$10,399,750

In each case, the BESS solution is more than double the cost of equipment replacement. It was concluded that for the Florida feeder the BESS solution was not economically practical.

The other three feeders provided for the PG-01 project were urban, commercial areas. Each had room for EV growth with one having a hosting capacity of 6.3 MW. PV was added to these feeders based on the area of commercial rooftop space determined via examination using satellite images. EV loads were added based on the amount of hosting capacity and strategically placed based on customer types with offices getting level 2 charging loads while fast charging loads were placed at parking garages and large parking areas.

However, in each of these urban cases, the number of overloads and the effects on the voltage profile of the feeder were minimal. The only equipment that could be considered overloaded in each case was the base rating of the substation transformer. Thus, the only cost worth trying to offset using BESS was that of extra maintenance costs accrued by the substation transformer operating more frequently in the secondary cooling mode. It was concluded that BESS could serve no economically practical purpose on these feeders.

It should be noted that on each of these feeders the sole method of BESS control was peak shaving. The current flowing through certain equipment was observed and, if the thermal limit was approached, the battery discharged to support the load. Other methods were not considered due to the regulated nature of the utility in the areas associated with PG-01.

The conclusion of PG-01 was that while BESS could be used to reduce overloads caused by EV loads, it would take a significant number of equipment overloads for the BESS solution costs to rival the costs of traditional equipment upgrades.

Overview of Second Case Study

In fall 2020, a CAPER research project was initiated to investigate the impacts of EV integration on the grid and on the integrated resource plan (IRP) moving forward. Expected EV penetration levels were determined for residential, commercial, and industrial scenarios and a method derived for how to allocate them in provided distribution feeder models. The impacts were observed and potential resources required to correct system vulnerabilities ascertained. Additionally, other mitigation strategies that could be useful were considered including TOU rates and BESS installation to analyze how these could help reduce the economic impact of EVs on the IRP.

Simulations were completed using the power engineering software known as CYME since the provided models were in given in that format. To simplify simulations and gather the most accurate results, the CYME Long Term Dynamics module was purchased and used. This module allows for the inclusion of curves for demand, irradiance, wind speed, and generation to perform time-series power flow simulations.

Introduction of Feeder

In the PG-02 project, three feeders were provided. This section of the thesis provides results from only one of those feeders. The general layout of the feeder is as shown in Figure 4.1.

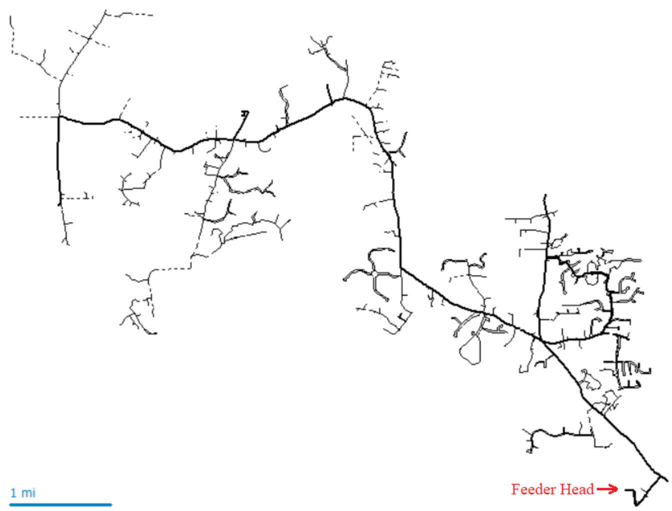

Figure 4.1. Feeder under study

The feeder under study is a highly loaded residential feeder with little room for growth. This indicates that many issues are expected to arise with the integration of EV. The composition of loads is as follows.

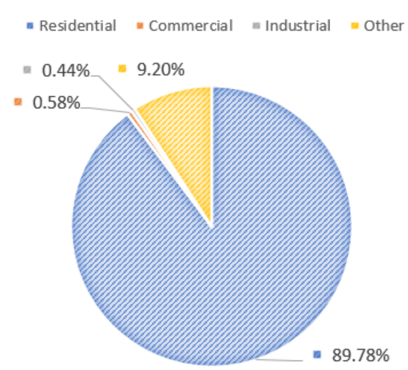

Figure 4.2. Composition of loads on feeder under study

The transformer at the head of this feeder does not have a load tap changer (LTC). Voltage regulation is accomplished by a three-phase regulator in the substation. Additionally, as the feeder is rather long, there are three other voltage regulators downstream. It should be noted that an adjacent feeder with its own voltage regulator at its head is also connected to the same transformer bank as the feeder under study.

Methods

Improvements to Feeder Model

The distribution feeder models provided by the utility have peak summer and peak winter demand data for each of the customers listed. Power equipment including voltage regulators and capacitors are also included.

A major component that is absent in most distribution models is the feeder head transformer. For the sake of this project, the effects on the transformer's ratings and LTC were important, thus it needed to be implemented. The substation transformer was added using provided transformer test reports. As mentioned previously, the results in this thesis are for a feeder that does not have an LTC on the feeder head transformer, so the LTC option in the model was left inactive. The adjacent feeder was not included in the original model file and was added in as a lump load with peak load data taken from historic data specific to that adjacent feeder. This feeder was modeled with a similar composition to the feeder under study, so the number of customers was calculated using the ratio of demand.

Data on the settings for each regulator were gathered to confirm the settings in the model were correct. Some small adjustments were made. Base cases were then run to check the simulation's number of daily tap changes against what was being seen in the real world. The simulation's results were slightly higher, but acceptable. These higher numbers are likely due to the simulation operating off of annual peak values of demand.

Customer types given in the original model were residential, commercial, industrial, and other. This list was expanded to include church, dairy farm, office, and retail store customer types. Using Google Earth, customer types were confirmed and adjusted as necessary for each spot load in the model.

In Cyme LTD, each customer type can have an associated load curve. These load curves can take the form of P and Q factors of the given demand or a P factor and the power factor as a percentage of real power to apparent power. For this project, the P, PF type of load curve was used.

Each customer type was given a load curve based on data gathered from the EPRI load shape library [30]. This library contains hourly data for multiple types of buildings, any day of the year, at various geographic locations such as Greensboro, NC, which was chosen for this research project because of its proximity to the feeder's location. It should be noted that this data is hourly and was expanded to quarter-hourly to better observe effects on the system throughout time. The adjacent feeder load shape was determined based on historic data. Finally, the dairy farm load shape was estimated based on the idea of reaching peak demand around milking times in the morning and evening. The final profiles are shown below in Figure 4.3.

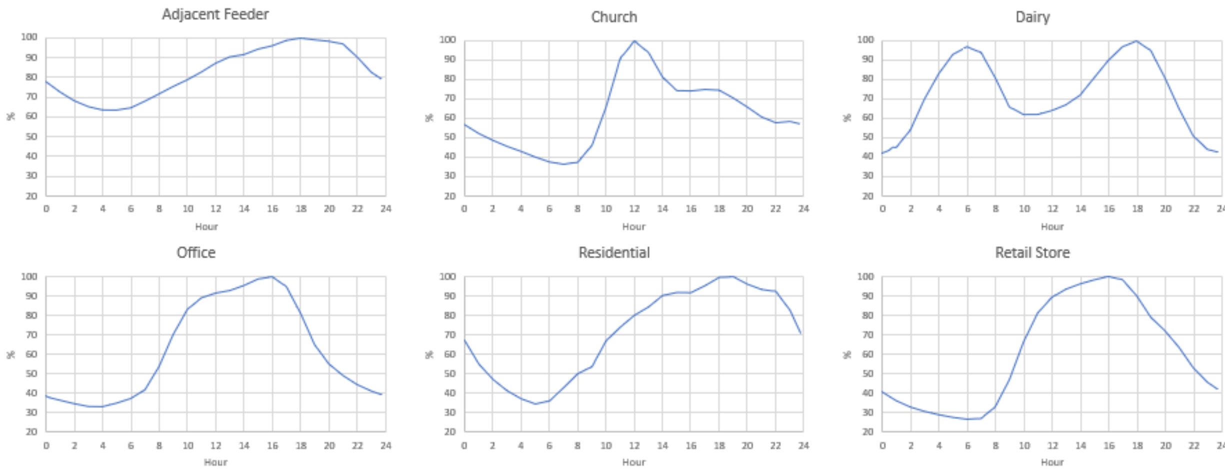

Figure 4.3. Customer demand profiles used in simulations [30]

In a following section, Section 4.3.3, the penetration cases were defined for simulation. Some of these occur in future years where load growth must be taken into account. The utility provided the expected load growth value of 1% per year. This was implemented in the model by multiplying the P factors in the load shape accordingly by 1.01^n, where n is the number of years between the model year and the year of observation. An example of how this affected the load shapes is shown in Figure 4.4.

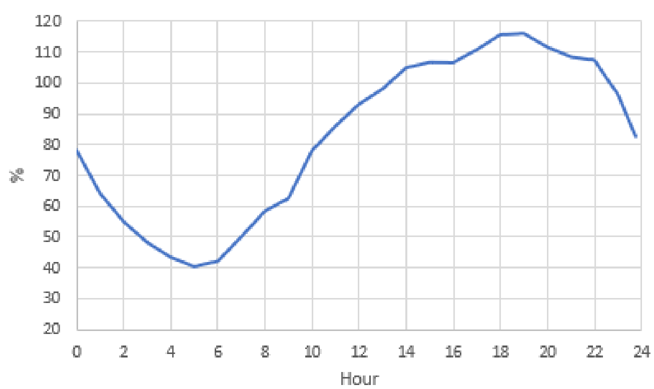

Figure 4.4. Residential demand profile with 15 years of load growth

Electric Vehicle Integration

There are many factors involved in the load an electric vehicle will present to the grid. They include the power level of the charger, the size of the battery, the range of the vehicle, and the state of charge of the battery at plug-in.

Beginning with the power levels, level 1 and level 2 charging are defined as a maximum power of $2.4kW$ and $19.2kW$ respectively [4]. However, the actual power transferred by the charger is dependent on the circuit, the charger's ratings, and the vehicle's ratings. Few level 1 and level 2 chargers will actually charge at these defined rates. Especially in the case of the level 2 chargers, it is expected the charging power will be much lower due to safety constraints in home circuits. Thus, the charging powers used in this study are as in Table 4.2.

In terms of DC fast charging, many high-level power ratings could be considered. The third generation of the Terra HP charge post is capable of up to $350kW$ per car or $175kW$ per car when both ports are in use [31]. The Tesla Supercharger V3 is capable of up to $250kW$ per vehicle [5]. However, once again, the actual charging power is limited by the capabilities of the vehicle connected. Additionally, the rollout of such chargers is dependent on how much a company or business is willing to spend to install them in their parking lots for customers or employees. Taking this into consideration, a more common $50kW$ charging power was assumed for DC fast charging, as shown in Table 4.2.

Table 4.2. Charging power assumptions

Charging Type	Charging Power (kW)	Percent of Residential Charging
Level 1	2	20%
Level 2	10	80%
DC Fast	50	0%

Also, in Table 4.2 a percentage of customers is listed for level 1 and level 2 charging. Only these two levels of charging are likely to be installed in homes. How a customer decides which level to have installed is dependent on cost, desired recharging speed, and available infrastructure in their residence. Thus, a ratio of level 1 to level 2 charging must be estimated. It is far more likely, especially in the future as technology improves and costs decrease, that level 2 charging will be seen more often than level 1 charging due to how quickly it allows the vehicles to recharge. This is the case even today, as indicated in [32] where level 2 charging made up 74% of the charging and level 1 made up 23.4%. It is from these numbers that the assumptions in Table 4.2 were determined.

The next step was to determine how long the batteries will need to charge. This is based on the battery size and how much it is depleted. Determining an appropriate battery size can be gathered by looking at various EVs on the market today. For example, the 2021 Tesla Model X has a battery size of $100kWh$ and is capable of $371mi$ on a full charge [33]. $100kWh$ is actually at the upper bounds of battery sizes available today, but is likely to become the norm in the near future as technology improves. For this study, $100kWh$ was assumed as the battery size for this reason, but a reduced range of $200mi$ was considered. This is a highly conservative estimate for the EV range that produces a lower state of charge (SOC) and a longer charge time. This estimate was taken as it provides a charging duration that is slightly higher than expected, providing for room for some variations in vehicle range and vehicle usage among customers.

The SOC at plug in was assumed to be the same for each EV owner. This was determined using the vehicle specification assumptions taken above and the average miles driven per day. The average miles driven per day were collected from the Bureau of Transportation Statistics for suburban drivers in North Carolina, shown in Table 4.3, as this best describes the feeder's location. This yields an average SOC of 77%.

Table 4.3. Average daily miles traveled and trips per vehicle [34]

State	Mean Census Tract estimate by urban group					
	Vehicle miles traveled			Vehicle trips		
	Urban	Suburban	Rural	Urban	Suburban	Rural
North Carolina	32.73	46.14	56.81	4.39	5.58	5.41

The charging duration for each level can then be calculated using this SOC, the size of the battery, and the charging level. These values are listed in Table 4.4.

Table 4.4. Charge duration per charging level

Charging Level	Duration of Charge
Level 1	11h 30m
Level 2	2h 18m
DC Fast	28m

Finally, starting times for the charge cycle needed to be determined. For the uncoordinated case, as previously explained, it is expected drivers will plug in their EVs immediately as they return home from work. Four start times were assumed, spaced fifteen minutes apart, starting at 5:45pm. The resulting collection of EV load shapes are shown in Figure 4.5.

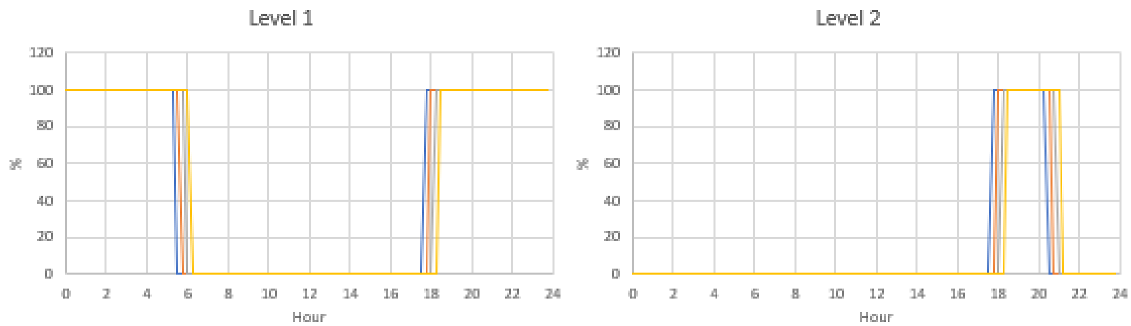

Figure 4.5. EV charging load shapes used in simulations

It can be observed that the charging power is assumed to be a constant 100% throughout the entirety of the cycle. In many real-world instances the charging cycle actually features a ramp up to initiate the charge and a trickle down during the final phases of the cycle to prolong battery life. The full power cycles indicated in Figure 4.5 represent a worst-case scenario on demand and voltage profiles which was desired for this study.

EVs were added to the model by adding new spot loads at each of the spot loads on the feeder. More specifically, two new spot loads were added at each existing load, the first representing level 1 charging and the second representing level 2 charging. The addition of multiple loads instead of one to represent EV at each point is due to each customer type only being allowed a single load shape in CYME Long Term Dynamics.

To calculate the amount of EVs to add and where to add them for each penetration case, the CYME model's database was altered using a specifically crafted MATLAB code. The code applied EV load to the level 1 and level 2 spot loads as desired while iterating through the complete list of loads on the feeder. Options allowed for varying EV penetration levels, home charging percentages, charging power levels, time of use adoption rates, number of cars per home, and different EV application strategies depending on customer type.

Determination of EV Penetration

It was determined that it would be important to view system vulnerabilities at multiple points in time over the next fifteen years. This is to help determine when specific issues will likely begin to occur. Three years of observation were set, 2025, 2030, and 2035, with 2020 being the base case. Thus, a penetration level for each of the years needed to be determined.

As mentioned previously, the EEI released an updated report on the growth in EV sales and the stock of EVs in the United States until 2030 [7]. These projections are similar to the medium level cases found in [35], a report presented in 2019 by the grid integration tech team and integrated systems analysis tech team with U.S. DRIVE. This increase in EV stock is shown in Figure 2.2. This projection needed to be extended to 2035 for the sake of this project. That was accomplished using Microsoft Excel's forecasting tool. The data was then converted to percentages using the expected total number of vehicles on the road. This updated plot is shown in Figure 4.6. It should be noted that this results in a 2035 average penetration slightly higher than that projected by [35], but the decision was made to remain with this penetration level as it presents a worse case that is still realistic.

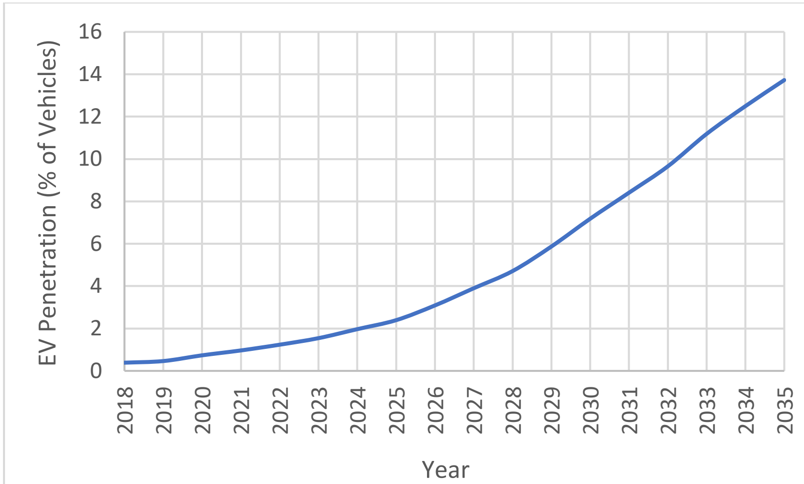

Figure 4.6. Forecasted EV penetration rates [7]

These values represent the national stock of EVs as a percentage of all vehicles on the road. Of course, different regions of the country will have higher percentages than others. This is dependent on the income of the region, available incentives, and the presence of EV infrastructure. Figure 4.7 shows the relation of the EV penetration in each North Carolina county to the state average.

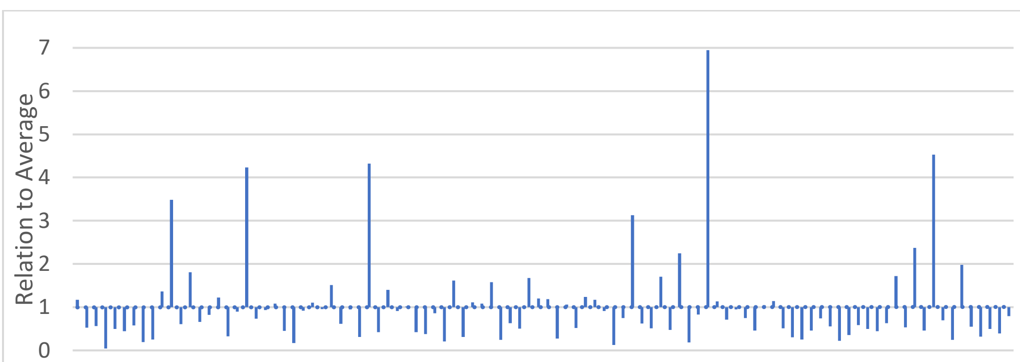

Figure 4.7. Penetration levels per county in NC compared to state average [8]

The minimum is 0.0410 times the average and the maximum is 6.9498 times the average. Some variation is to be expected, and so multiple penetration levels were determined for each year to represent a low, average, and high penetration case. The cases are all listed in Table 4.5.

Table 4.5. Penetration cases for vulnerability identification

Year	EV Penetration		
2020	0%		
2025	1%	2%	7%
2030	2%	7%	23%
2035	5%	15%	50%

While it has been implied, the definition of EV penetration is now expressly defined. EV penetration is the percentage of all vehicles that are electrically powered. In this study, each EV is considered to be plug-in, so not an HEV.

To apply these penetration levels, the total number of vehicles must be considered. The total number of residential customers is known from the provided model. The average number of vehicles per household in the United States is 1.9 [36]. So, in this study it is assumed that each customer has two vehicles and a maximum of one EV per household for simplicity.

One final constraint is placed on the penetration levels listed. The penetration level consists of the number of EVs on the feeder, but what is needed is a number for the amount of EVs expected to charge on the feeder. It is assumed in these cases that 80% of residential EV owners charge at home while 20% charge at public or workplace locations.

Summary of Assumptions

Many assumptions for the system vulnerability assessment are discussed in the previous sections. For ease of consumption, those assumptions are summarized in this section in Table 4.6.

Table 4.6. Summary of Assumptions

Parameter	Value
Feeder Annual Load Growth	1%
Level 1 Charging Power	$2kW$
Level 2 Charging Power	$10kW$
DC Fast Charging Power	$50kW$
Percent Level 1 Charging	20%
Percent Level 2 Charging	80%
Battery Size	$100kWh$
Range of Vehicle on Full Charge	$200mi$
State of Charge at Plug in	77%
Percent Charing at Home	80%
Cars per Household	2
Maximum EVs per Household	1

BESS Sizing and Placement

Several feeder bottlenecks, defined as either a single piece of overloaded equipment or a series of overloaded lines in this study, were identified through the system vulnerability studies. A BESS unit was then added downstream of each of these bottlenecks. In a practical environment, placement at these specific locations may not be possible, but this served primarily to determine the capacity and power ratings of batteries downstream of each bottleneck to defer system upgrades.

BESS units were sized to eliminate the overload on each specific bottleneck. That is, each BESS unit monitored the through power of the nearest upstream bottleneck to prevent overloads. The process began with the most downstream BESS device and simulations were run with a highly oversized battery to determine the necessary storage capacity and rating. The parameters of the device were adjusted and the simulations run again to confirm them before moving upstream to the next BESS device. This was repeated until all the system overloads were resolved.

Time of Use Assumptions

In latter portions of this thesis, BESS mitigation strategies are considered with TOU scheduling to determine if TOU can aid in making BESS more economical. Some assumptions that need to be made to incorporate these TOU schedules include the percentage of customers willing to switch to and utilize TOU rates and the start time of these TOU rates.

To the first point, there are some promising research results when it comes to willingness to adopt TOU rates. It should be noted, first, that TOU adoption rates are defined in this thesis as the percentage of EV customers actively using TOU scheduling to shift their charging loads to off-peak hours. As it stands currently, just 1% of residential customers in North America use TOU rates, but a major cause of this could be that only 5% of utilities provide customers with the option [37]. One study conducted in Britain suggested 39% of people surveyed were willing to switch to TOU rates if the option was provided, while 36% were not willing to switch [38]. The Likert scale of results is shown in Figure 4.8. Another paper examined various types of TOU rates to determine likelihood of adoption and how different approaches may increase this value. It revealed a large variation in adoption rates, but determined they are likely to fall between 1% and 43%, while opt-out TOU rates could see adoption rates upwards of 57% [15].

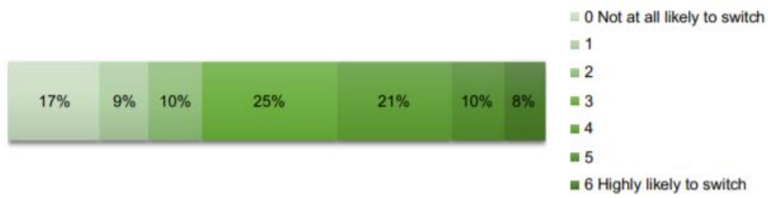

Figure 4.8. Variation in willingness to switch to TOU rates [38]

Taking all of these statistics into mind, two TOU adoption rates were considered. They consist of a low estimate of 10% adoption and a high estimate of 40% adoption of TOU rates. In other words, 10% or 40% of EV customers switch to TOU rates and charge at the off-peak hours. Due to the assumed duration of charge for level 1 charging, only level 2 charges are switched over to TOU rates in the simulations. On average, those customers with only level 1 chargers would be unable to charge to full capacity if they began at 12am.

Next, the time for the start of TOU rates must be assumed. [37] worked to determine the best time for TOU scheduling that aided the utility by reducing peak loads and voltage problems while also completing the vehicles' charge before 7am at the latest. It was found the best time for both parties was between 11pm and 12am. Another study surveyed the times customers preferred their vehicles to charge. Those results, shown in Figure 4.9, indicate most customers prefer to charge during work hours in the midday or in the evenings before midnight [39]. Based on this, the assumed time for the beginning of off-peak rates is assumed to be 12am.

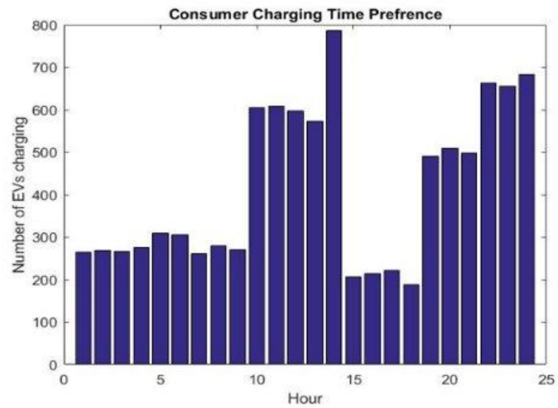

Figure 4.9. EV customer charging time preferences [39]

The final element of TOU assumptions to be considered is when those customers who have adopted the TOU rates will initiate the charging of their vehicle within the time period of the reduced rates. It is expected that many users will program their chargers to begin charging at the onset of TOU off-peak rates [37]. This can, admittedly, create a massive spike right at the beginning of the off-peak period which can come with its own problems. However, for the sake of presenting a worst-case scenario, even in the TOU cases, it is assumed all users participating in TOU rates will initiate EV charging at the onset of off-peak hours, at exactly 12am. Those not participating will charge as assumed previously.

Results

EV Hosting Capacity

A hosting capacity analysis was performed in each of the case study years to determine, on top of load growth, how many EVs the feeder would be able to support. This primarily focused on overloads of equipment at feeder bottlenecks including lines, regulators, and the feeder head transformer. The maximum allowable EV beyond these points was calculated and is reported in Table 4.7. Assuming a uniform penetration throughout the feeder, the minimum penetration level in each column, excluding 0%, represents the maximum EV penetration level that minimizes upgrade necessity and costs in that case. Those devices with a 0% EV penetration hosting capacity would need to be replaced regardless of anticipated EV growth.

Table 4.7. Maximum EV penetration hosting capacity beyond feeder bottlenecks

Equipment	2025	2030	2035
Line 1	2.2%	0.2%	0%
Line 2	3.7%	1.5%	0%
Regulator 1	13.8%	12.8%	11.1%
Regulator 2	0%	0%	0%
Regulator 3	0%	0%	0%
Substation	5.1%	3.3%	1.5%

Change in Demand

When the load growth and EV penetration are applied to the feeder as previously discussed, the demand for each year is as follows in Figure 4.10.

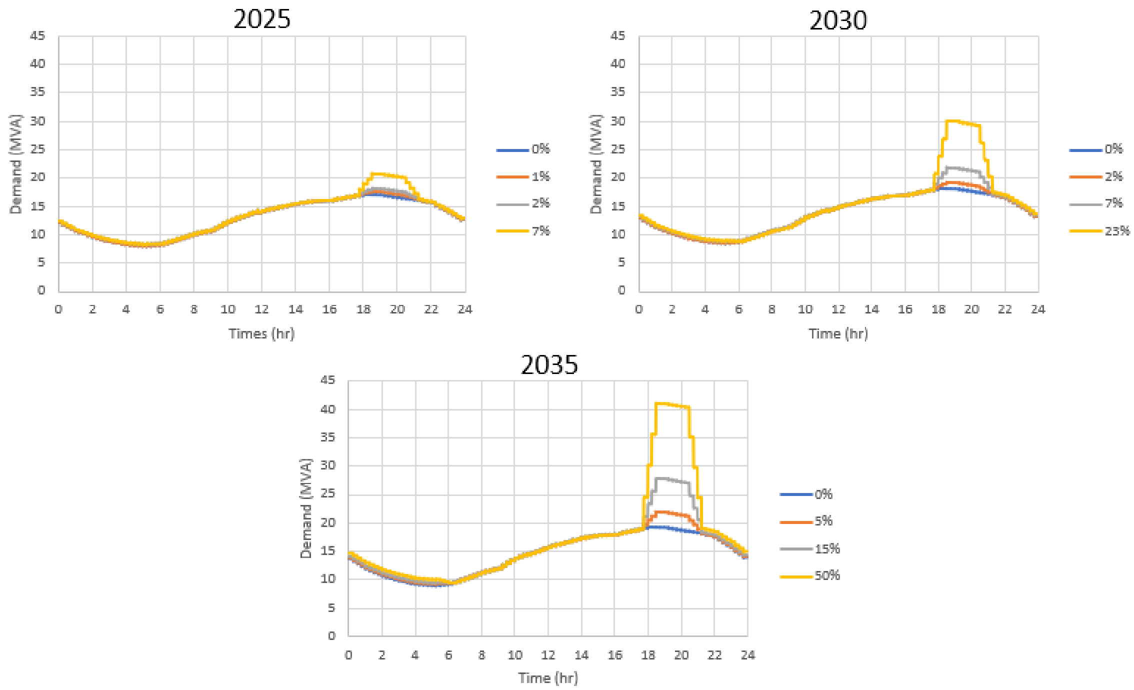

Figure 4.10. Feeder demand profiles for each year considering assumed EV penetration levels

The massive peak in each plot is completely attributed to EVs. This shape is a result of the assumption that chargers will act as constant power output throughout the charging cycle and charging start times are offset by fifteen minutes. This represents a worst-case scenario for uncoordinated charging.

System Vulnerabilities

Due to the highly loaded nature of the feeder under study, vulnerabilities were to be expected, even without EV integration. Several vulnerabilities including line overloads, equipment overloads, and undervoltage were identified throughout the feeder with increasing magnitude as the study looked further into the future with more load growth and greater penetration of EVs.

The following table, Table 4.8, shows the number of EVs added and the associated maximum EV demand in the uncoordinated case. This gives an idea of the expected demand growth due to the assumptions considered.

Table 4.8. Number of EVs added per case and their demand

Year	EV Penetration	Level 1's Added	Level 2's Added	Peak EV Demand (kw)
2025	1%	10	41	430
	2%	21	83	872
	7%	73	290	3,046
2030	2%	21	83	872
	7%	73	290	3,046
	23%	238	954	10,016
2035	5%	52	207	2,174
	15%	155	622	6,530
	50%	518	2,073	21,766

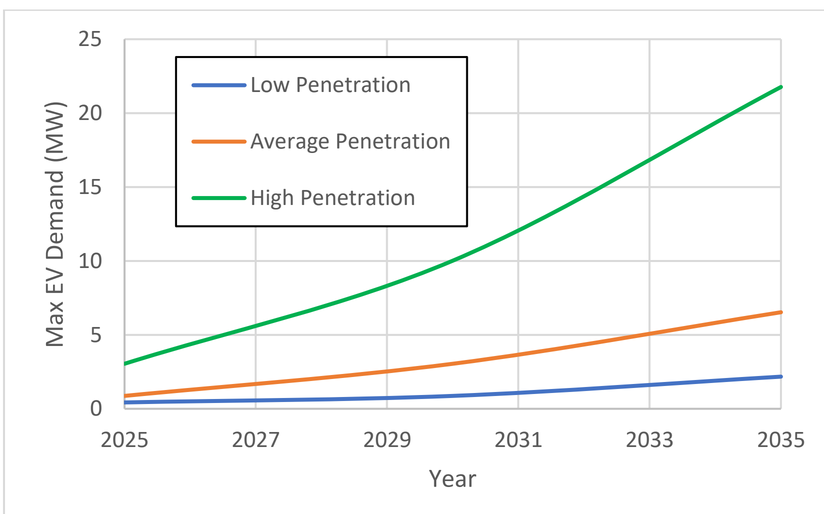

Figure 4.11. Graph of max EV demand through time per penetration level

Before supplying further results of the system vulnerabilities studies, one point must be mentioned. The 2035 50% EV penetration case did not converge. Adjustments were made to solution constraints, but convergence was still not met due to the load creating a major voltage drop on the feeder. This makes sense considering, as shown in Table 4.8, that the maximum uncoordinated EV load is, on its own, over the maximum rating of the substation transformer. This indicates that the feeder as it stands is unable to support 50% EV penetration with uncoordinated charging in the year 2035 given the assumptions made. In the tables below this case is indicated as "NC" to represent the status of non-convergence.

Line overloads observed in each penetration case are shown in Table 4.9. The data is given in terms of the total combined length of the lines affected as this is important for economic evaluation of different mitigation strategies later. Affected lines are those which have a current greater than 100% of the current rating of the line.

Table 4.9. Length of overloaded lines per penetration case

Year	Low Penetration	Average Penetration	High Penetration
2025	0 ft	0 ft	6,284.7 ft
2030	5,654.6 ft	6,284.7 ft	18,377.1 ft
2035	6,970.8 ft	12,713.0 ft	NC

The next table, Table 4.10, shows overloads of feeder equipment. This includes regulators, switches, breakers, and fuses. Notice this does not include the substation transformer or individual distribution transformers, both of which are analyzed in later parts of the study. Again, the affected equipment is included in this table if it has a current greater than its current rating on at least one of the phases.

Table 4.10. Number of equipment overloads

Year	Penetration	Regulators	Switches	Fuses	Breakers
2025	Low	2	0	1	0
	Average	2	0	1	0
	High	3	0	2	0
2030	Low	2	0	1	0
	Average	3	0	2	0
	High	4	0	3	0
2035	Low	3	0	2	0
	Average	4	0	3	0
	High	NC			

Substation transformer statistics are included in Table 4.11. In this table, three cooling modes are listed which correspond to the three ratings of the transformer. At the nominal rating of 12 MVA, the transformer is in oil air (OA) mode. The next mode accommodates power transfer between 12 MVA and 16 MVA by using a forced air (FA) cooling mode. The final rating is 20 MVA and power transfer between 16 MVA and this upper bound initiates the forced oil and air (FOA) cooling mode. Anything above this tertiary rating is considered overloaded.

Table 4.11. Substation transformer cooling mode statistics

Year	Penetration	Hours in Each Cooling Mode			
		OA	FA	FOA	Overload
2020	0%	10.25	11.5	2.25	0
2025	Low	9.5	8	6.5	0
	Average	9.5	8	6.5	0
	High	9.25	8.25	4.5	3
2030	Low	8.75	6.25	9	0
	Average	8.75	6.25	6.5	2.5
	High	8.5	6.25	5.75	3.5
2035	Low	7.75	5.75	7.75	2.75
	Average	7.75	5.75	7	3.5
	High	NC			

Figure 4.12 below shows the hours in each cooling mode for each of the average penetration cases in a graphical format.

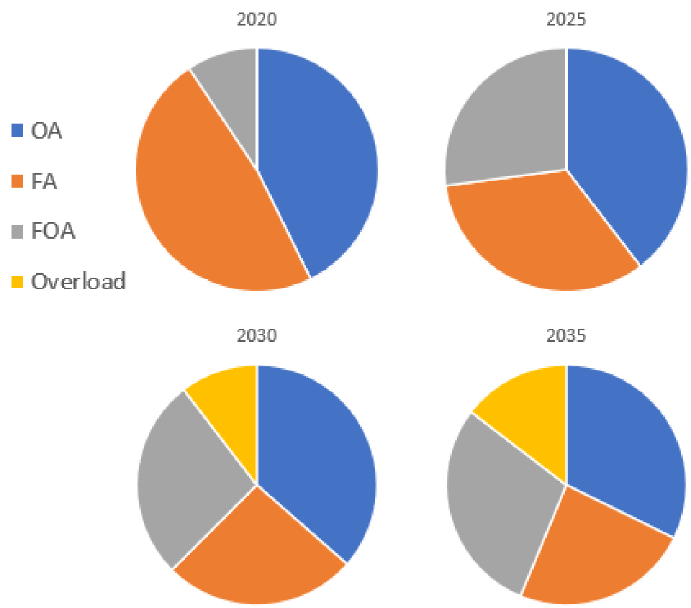

Figure 4.12. Hours in each cooling mode for average penetration cases

The next point of interest is undervoltage along the feeder caused by the increase in load. In CYME LTD a total number of nodes that enter undervoltage conditions at some point during the simulation is not easily gathered. Thus, the voltage on six nodes throughout the feeder were watched. These included the upstream side of each of the regulators and two other nodes in other parts of the feeder as shown in Figure 4.13.

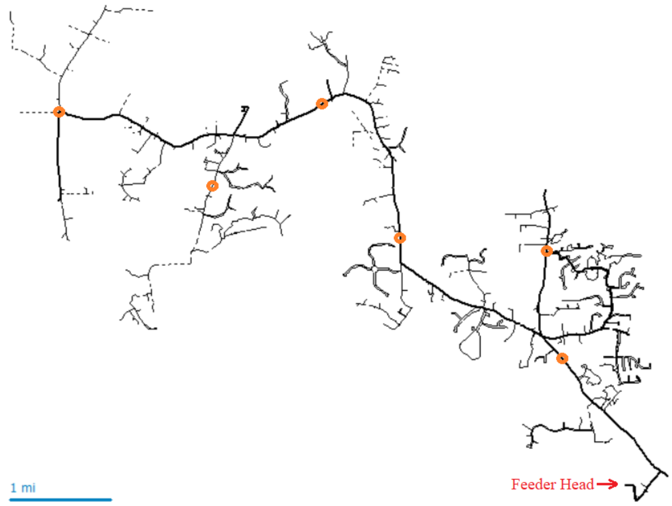

Figure 4.13. Location of observed nodes along the feeder under study

The total number of these watched nodes in each case that experience undervoltage conditions during the simulation are recorded in Table 4.12. While this does not give a total number of nodes undervoltage, it gives an idea of the areas along the feeder where voltage issues may arise. It should be noted that undervoltage is considered any voltage under $0.95\ pu$ or $11.875\ kV_{LL}$ on this feeder.

Table 4.12. Number of observed nodes (out of 6) with voltage abnormalities

Year	Low Penetration	Average Penetration	High Penetration
2025	0	0	0
2030	0	0	5
2035	1	5	NC

The feeder, as previously mentioned, is equipped with several voltage regulators to help avoid the undervoltages indicated in Table 4.12. Increased load, and the increased variation in load throughout the day, can affect the number of tap changes throughout the day on these pieces of equipment. This change in the number of switching events, likely an increase, has the potential to increase wear and tear, thus decreasing the lifetime of the equipment. Therefore, this value is important to utilities to observe as EV penetration increases. For this feeder, the total number of tap changes for all voltage regulators combined in each case is shown in Table 4.13.

Table 4.13. Total number of daily tap changes per case

Year	Low Penetration	Average Penetration	High Penetration
2020		113	
2025	143	142	181
2030	144	169	306
2035	183	285	NC

Figure 4.14 shows the increase in tap changes from the 2020 base case as a percentage for each of the cases. Notice the drastic increase in the number of changes throughout the timespan of the study, especially in the high penetration case.

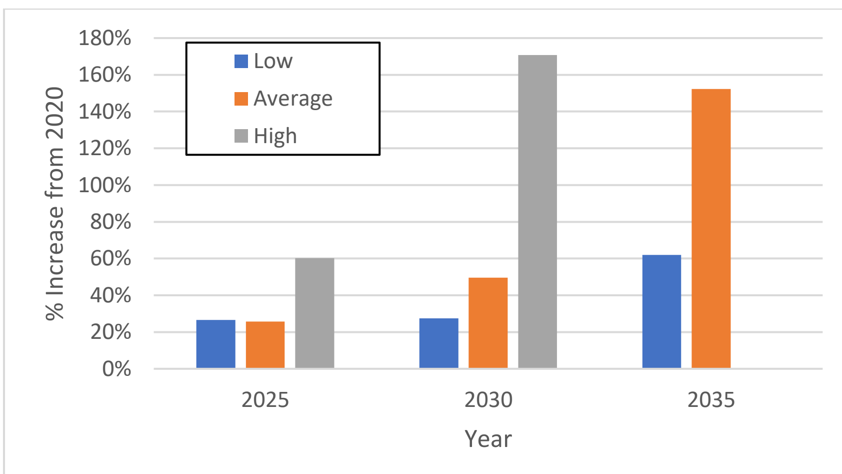

Figure 4.14. Percent increase in total tap changes from 2020 base case

As expected, in each of the observed parameters given throughout this section, the number of abnormal, undesired events increases with time and with an increase in EV penetration.

BESS Mitigation

For each of the average penetration cases, a BESS solution was determined. Batteries were installed downstream of estimated overloads and sized to be a small as possible while still reducing overloads below 100% of the thermal rating. While each solution typically consisted of multiple installations throughout the feeder, only the total combined energy capacity and power rating is presented in Table 4.14.

Table 4.14. BESS sizing for vulnerability mitigation in various EV penetration cases

Year	EV Penetration	Energy (MWh)	Rating (MW)
2025	0%	7.5	1.2
	2%	9	1.6
2030	0%	16.56	2.04
	7%	21.55	3.2
2035	0%	23.25	2.4
	15%	37.01	6.3

For each year listed in Table 4.14, the 0% EV penetration case is given. In each of these cases a battery solution was needed despite the absence of EV due to the load growth of the feeder. However, it can be noted that the presence of EV does increase the necessary energy capacity by a significant amount, adding costs to the solution.

Another concern is that in the 2035 15% penetration case there is at least one BESS unit on the feeder that is unable to charge from 20% to full capacity through the course of the morning. This indicates that this solution would only work in situations where the overload does not occur on concurrent days, at least not to the same severity. The diversity in demand profiles from day-to-day would suggest it is unlikely to reach the same severity every day, but the overloads would be likely to occur daily during the summer months.

The BESS solution in each case was sized to eliminate overloads but naturally aided with the voltage abnormalities found in the previous section. During high demand times that would normally create the overload and draw current from the source some distance away, the BESS systems provide a generation source much closer to the load, reducing the line losses and voltage drop. This can be seen through the minimum observed voltage for each average penetration case shown in Table 4.15.

Table 4.15. Minimum observed voltage per BESS case

Year	2025	2030	2035
EV Penetration	2%	7%	15%
Without BESS	0.966 pu	0.952 pu	0.903 pu
With BESS	0.967 pu	0.956 pu	0.949 pu

A reduction in the number of tap changes was also observed. This is due to the reduction in difference between the highest and lowest demand on the feeder caused by the peak shaving action of the BESS units during high demand times and the charging functions during demand valleys. This change is shown in Table 4.16.

Table 4.16. Number of cumulative tap changes per BESS case

Year	2025	2030	2035
EV Penetration	2%	7%	15%
Without BESS	142	169	285
With BESS	112	114	149

Notice the drastic effect the distributed batteries had on the number of tap switching events. In the 2035 case the number of switching events reduced by almost 50%. This benefit would only occur in the case of distributed BESS units, but does show how BESS could be very beneficial in reducing voltage fluctuation throughout the day on long, highly loaded feeders while simultaneously reducing overloads.

A final point to look at is the time the substation transformer spent in each of the cooling modes, which is presented in Table 4.17. As discussed earlier, the BESS units throughout the feeder were sized to reduce overloads, so the overload is completely eliminated. However, the time spent in the other cooling modes is still important because increases in certain modes may result in a shorter lifespan for the transformer and increased maintenance.

Table 4.17. Substation transformer cooling mode statistics for BESS cases

Year	With/Without BESS	Hours in Each Cooling Mode			
		OA	FA	FOA	Overload
2025 (2% Pen)	Without	9.5	8	6.5	0
	With	9.5	11.5	3	0
2030 (7% Pen)	Without	8.75	6.25	6.5	2.5
	With	5	15	4	0
2035 (15% Pen)	Without	7.75	5.75	7.75	3.5
	With	6.25	11.25	6.5	0

For each BESS case it can be observed that the time in the forced air mode increases until the substation spends the majority of the day in this mode. This is due to the combined action of the downstream BESS units reducing the cumulative feeder load to just below the threshold for the tertiary cooling mode. However, it is also due to the increase in demand after midnight as the batteries begin to charge. This charging load can, in some cases, be shifted or dispersed over a wider range of time using more complex control methods.

BESS Mitigation with TOU

The cumulative battery sizes for each case listed in Table 4.14 are rather high. For this reason, it may be advantageous to pursue two mitigation strategies simultaneously. The second is TOU mitigation which, as discussed previously, seeks to shift demand to later in the night, thus reducing the peak. This section explores how TOU adoption rates of 10% and 40% can help reduce the necessary size of the BESS installations.

The TOU adoption rates were applied, and BESS sized as before to reduce overloads throughout the feeder. The resulting total energy storage capacity and power rating for the BESS solution in each cast is presented in Table 4.18.

Table 4.18. BESS sizing for vulnerability mitigation in TOU adoption scenarios

Year	TOU Adoption	Energy (MWh)	Rating (MW)
2025 (2% Pen)	10%	9.00	1.60
	40%	8.80	1.50
2030 (7% Pen)	10%	20.95	3.10
	40%	20.21	2.90
2035 (15% Pen)	10%	34.95	5.65
	40%	33.30	5.00

Comparing the results in Table 4.14 and Table 4.18, the expected decrease in the energy storage capacity of the BESS system and the power rating is present. The needed storage capacity of the BESS system reduces a minimum of 0% in the 2025 case and a maximum of 10% in the 2035 case. The necessary combined BESS power rating decreases 0% in the 2025 case but decreases by 21% in the 2035 case. This shows that the TOU rates aid more in the reduction of the peak than in the decrease of overload duration. They also make a greater impact in later years as the number of EVs contributing to the peak and the number of EVs capable of switching to TOU scheduling increases.

As before, the inclusion of BESS helps in the reduction of undervoltage along the feeder. These voltages are further improved due to the TOU scheduling reducing the peak load.

Table 4.19. Minimum observed voltage per BESS+TOU case

Year	2025	2030	2035
EV Penetration	2%	7%	15%
BESS+10% TOU	0.968 pu	0.959 pu	0.957 pu
BESS+40% TOU	0.970 pu	0.961 pu	0.952 pu

The cumulative tap changes are, however, adversely affected. Shown in Table 4.20, the number of tap changes increases in each case from the BESS cases without TOU scheduling. The change is minor, but present. This is due to a second, smaller peak occurring after midnight when the BESS units attempt to charge and EVs on the TOU rate begin their charging cycles.

Table 4.20. Number of cumulative tap changes per BESS+TOU case

Year	2025	2030	2035
EV Penetration	2%	7%	15%
BESS+10% TOU	112	113	152
BESS+40% TOU	114	115	155

Again, the statistics for the substation transformer are considered and shown in Table 4.21. The overloads are eliminated due to the BESS sizing, while time in each of the other cooling modes is very similar to the cases without TOU. It can be concluded in this specific study that TOU has little effect on the number of hours in each cooling mode when paired with BESS.

Table 4.21. Substation transformer cooling mode statistics for BESS+TOU cases

Year	TOU Adoption	Hours in Each Cooling Mode			
		OA	FA	FOA	Overload
2025 (2% Pen)	10%	9.25	11.75	3	0
	40%	9	14.25	0.75	0
2030 (7% Pen)	10%	5	15	4	0
	40%	5	15.25	3.75	0
2035 (15% Pen)	10%	6.25	11.25	6.5	0
	40%	6.25	9.5	8.25	0

CHAPTER FIVE
APPLICATION TO THE INTEGRATED RESOURCE PLAN

In an IRP, future loading scenarios are considered, and strategies made for meeting those projected demands. This includes an examination of distribution lines, transmission lines, substation transformers, protection equipment, and generation capabilities, among others, to outline a list of resources to be upgraded, built, or acquired in a reliable and financially sound way.

The results acquired in the studies outlined in this thesis can contribute to resource planning by indicating in what role BESS may be the most financially viable for utilities. While the results here are specific to certain feeders, the general concepts and methods can be applied to a broad spectrum of feeders to determine an estimate of the overall investment to be placed in BESS in the coming years.

Costs of Equipment Upgrades

The typical course of action in the event of projected system vulnerabilities is simply to upgrade the equipment. When it comes to overloads this means reconductoring lines or replacing other equipment with new equipment of a higher current rating. In dealing with voltage issues, this may include the installation of more regulation equipment along the feeder.

For the first use case, upgrade costs are as listed in Table 4.1. It was found that costs for that specific feeder were around \$4 $Million$ in each case. This included reconductoring of overloaded lines and replacement of two sets of voltage regulators.

To create an estimate of equipment upgrade costs for the second case study, pricing was taken from the San Diego Gas and Electric Unit Cost Guide which was last updated in March 2020 [40]. Some important values utilized in these calculations are listed in Table 5.1.

Table 5.1. Estimated unit costs for equipment upgrades [40]

Equipment	Unit Cost
28MVA Substation Transformer	$\$1,250,000$
Overhead Reconductoring (Rural)	$\$253/ft$
Voltage Regulator	$\$614,300$

Using the results from the previous chapter, the estimated total equipment upgrade costs per case were calculated and are presented in Table 5.2. These calculations assume that no other mitigation strategies are put in place.

Table 5.2. Estimated system upgrade costs for average penetration cases

Year	EV Penetration	Cost of Equipment Upgrades
2025	2%	$\$1.23\ Mil.$
2030	7%	$\$4.68\ Mil.$
2035	15%	$\$6.92\ Mil.$

Costs of Utility Scale BESS Solutions

The cost of battery technology has decreased over the past few decades and is expected to continue to do so. However, the costs are still quite high today. The batteries themselves must be purchased along with inverters, transformers, protection equipment, and, in some cases, land to place the system on.

For the PG-01 use case, costs for the BESS solution for each case are indicated in Table 4.1. A range of $\$8.58\ Million$ to $\$11.35\ Million$ was found for the BESS solution.

In each case, the costs of the BESS solution are more than two times the costs of equipment upgrades. The inclusion of PV by homeowners on the feeder reduced the costs of the BESS solution by 8% between the 15% and 40% PV penetration cases. However, system upgrades were still the most economical solution.

For the PG-02 use case, the costs for the BESS solution were calculated using the summary of costs associated with BESS installation shown Table 5.3 below.

Table 5.3. Estimated costs for Lithium-ion BESS systems [41]

Parameter	Cost
Capital Cost – Capacity	$\$271/kWh$
Power Conversion System	$\$288/kW$
Balance of Plant	$\$100/kW$
Construction & Commissioning	$\$101/kW$

Using the BESS sizing results from the previous chapter, the estimated costs of the battery solutions were determined. These are shown in Table 5.4.

Table 5.4. Estimated BESS solution costs for average penetration cases

Year	EV Penetration	Cost Attributed to Load Growth	Cost Attributed to EV Loads	Total Cost of BESS Solution
2025	2%	$\$2.62\ Mil.$	$\$0.60\ Mil.$	$\$3.22\ Mil.$
2030	7%	$\$5.59\ Mil.$	$\$1.92\ Mil.$	$\$7.40\ Mil.$
2035	15%	$\$7.47\ Mil.$	$\$5.64\ Mil.$	$\$13.11\ Mil.$

The values in Table 5.4 show that the BESS solution does cost more than double the system upgrades in each case. This is only accounting for front end costs. BESS systems also require regular maintenance throughout their lifetime, including a greater investment to extend that lifetime. Fixed maintenance costs are estimated to be an average of $\$13/kw-yr$ for Lithium-ion technology. Variable costs are harder to determine as they depend on the depth of discharge and number of cycles, however ¢ $0.03/kWh$ is taken as a good general assumption for energy usage related maintenance costs [41].

The majority of Lithium-ion batteries investigated in [41] have a lifetime between ten and twenty years, with most leaning towards the lower end. Assuming the average lifespan of fifteen years, and a minimum annual usage of 80% depth of discharge daily during the peak month for electrical energy demand the following lifetime costs were calculated.

Table 5.5. Estimated BESS solution lifetime costs for average penetration cases

Year	EV Penetration	Lifetime Maintenance Costs	Total Lifetime Costs of BESS Solution
2025	2%	\$0.31 $Mil.$	\$3.53 $Mil.$
2030	7%	\$0.63 $Mil.$	\$8.03 $Mil.$
2035	15%	\$1.23 $Mil.$	\$14.34 $Mil.$

Costs of Utility Scale BESS Solutions with Time of Use

As discussed previously, TOU scheduling is a concept in which incentives are offered to customers to delay their EV charging times or other large loads to later in the night to avoid increasing the peak demand. The reduction in the peak should help reduce the sizing of BESS units along the feeder, therefore potentially improving the business case.

Two TOU adoption cases were taken, a low estimate of 10% adoption and a higher estimate of 40%. Batteries were then sized as before, but with the altered peaks. These results are included in the following table, Table 5.6. Note that the cost attributed to load growth is not recorded in this table as it is the same as before. See Table 5.4 for costs attributed solely to load growth.

Table 5.6. Estimated BESS solution costs for BESS+TOU average penetration cases

Year	EV Penetration	TOU Adoption	Cost Attributed to EV Loads	Total Cost of BESS Solution
2025	2%	10%	$\$0.60\ Mil.$	$\$3.22\ Mil.$
		40%	$\$0.50\ Mil.$	$\$3.12\ Mil.$
2030	7%	10%	$\$1.71\ Mil.$	$\$7.19\ Mil.$
		40%	$\$1.41\ Mil.$	$\$6.90\ Mil.$
2035	15%	10%	$\$4.76\ Mil.$	$\$12.23\ Mil.$
		40%	$\$3.99\ Mil.$	$\$11.47\ Mil.$

Again, each of these systems requires regular maintenance to remain in working order. Using similar assumptions as before, the following numbers can be gathered for the total lifetime costs of the BESS system.

Table 5.7. Estimated BESS solution lifetime costs for BESS+TOU average penetration cases

Year	EV Penetration	TOU Adoption	Lifetime Maintenance Costs	Total Lifetime Costs of BESS Solution
2025	2%	10%	$\$0.31\ Mil.$	$\$3.53\ Mil.$
		40%	$\$0.29\ Mil.$	$\$3.41\ Mil.$
2030	7%	10%	$\$0.61\ Mil.$	$\$7.80\ Mil.$
		40%	$\$0.57\ Mil.$	$\$7.46\ Mil.$
2035	15%	10%	$\$1.11\ Mil.$	$\$13.34\ Mil.$
		40%	$\$0.98\ Mil.$	$\$12.45\ Mil.$

A final cost comparison of each of the BESS solutions is shown in Figure 5.1.

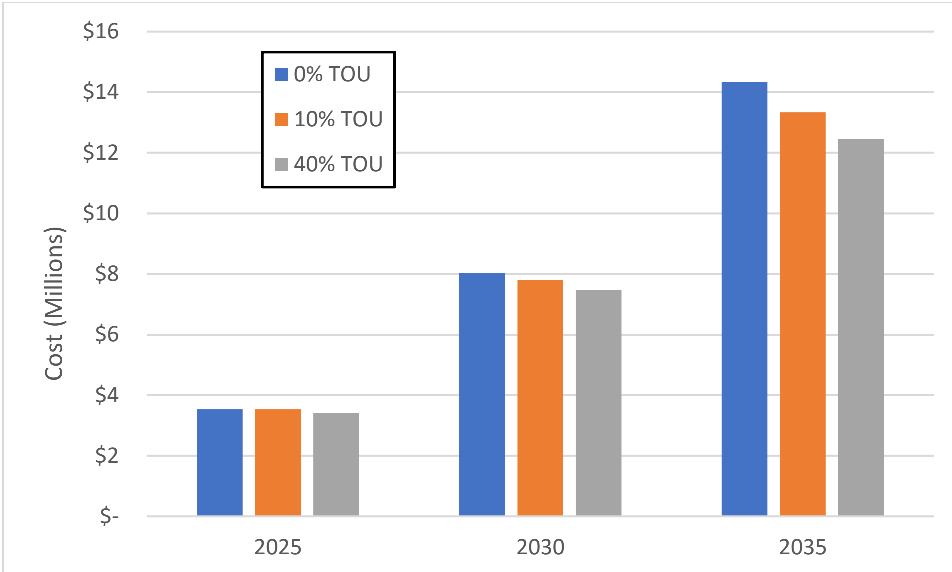

Figure 5.1. Comparison of lifetime costs of different BESS solutions

The decrease in BESS size results in a corresponding decrease in BESS cost throughout the system's lifetime. In 2025 and 2030 this decrease is minor, but in later years the decrease is more significant, reaching a reduction of 7% in the 10% TOU adoption case and 13% in the 40% TOU adoption case.

Regardless of the decrease in costs caused by the usage of TOU rates, the costs of the BESS solutions are still greater than the costs of system upgrades. Additionally, significant percentages of TOU adoption require active recruiting on the part of the utility which costs time and money along with losses in revenue that are not discussed here.

Using BESS as an Alternative to New Generation Facilities

The costs of BESS are much higher compared to traditional mitigation methods. These traditional methods also have the added benefit of having longer lifespans with fewer maintenance costs. However, another key component to look at is the rise in peak demand creating a need for more generation. As uncoordinated EV charging in residential areas tends to take place at the same time as the traditional peak, the peak demand of the distribution feeder is raised as seen in Figure 4.10. Some of this greater demand peak on the transmission network will need to be covered by new generation. It should be mentioned that some studies suggest EV penetration would have to reach very high rates, in excess of 50%, before requiring the construction of new generation [42]. However, these analyses are still valuable as BESS may be able to replace aging peaking generation plants, or peaking plants that contribute to carbon emissions, as well as newer generation stations.

Another problem with the previously mentioned distributed BESS systems is a need for space further down the feeder for placement of such batteries. This may be easy in some rural areas, but urban areas and dense residential areas will present problems. For this reason, the easiest implementation of BESS may be simply at the feeder head on the substation grounds already owned by the utility. This will require the upgrade of downstream equipment, but could provide cost benefits when compared to the costs of new generation.

In 2021, the Energy Information Administration published a report detailing the cost and performance characteristics of many generation technologies [43]. Values of interest for cost comparison calculations are list in Table 5.8.

Table 5.8. Costs of new generation facilities [43]

Technology	Capital Costs ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Lifetime (yrs)
Hyrdropower	$2,796	$42.01	$1.40	100
NGCC	$2,471	$27.74	$5.87	30
Battery	$489	$13.00	$0.30	15

In order to compare costs between using BESS as a source for peak demand or using new generation facilities some assumptions must be taken. Naturally, these plants would not serve single distribution feeders, but large transmission areas. However, the demand is observed here only at the distribution level. It is assumed that the peak demand in the 2020 0% EV penetration case, $15{,}394\ kW$, is the maximum generation capability of the utility. Thus, any demand over this peak must be covered by either a new facility or a BESS installation at the feeder head. These energy and power demands are indicated in Table 5.9. Note that these values are for the average EV penetration levels and do not consider the TOU cases.

Table 5.9. Estimated growth in peak demand

Year	EV Penetration	Demand Over 2020 Peak (kW)	Daily Energy over 2020 Peak (MWh)
2025	2%	1,605	4.5
2030	7%	4,620	15.9
2035	15%	9,361	34.4

The capital costs of the equipment for the average EV penetration cases in each observed year were then calculated using values from Table 5.9 and Table 5.8.

Table 5.10. Estimated costs of new generation stations of various technologies to cover growth in peak demand

	2025	2030	2035
Hydropower	\$4.49 $Mil.$	\$12.92 $Mil.$	\$26.17 $Mil.$
NGCC	\$3.97 $Mil.$	\$11.42 $Mil.$	\$23.13 $Mil.$
Battery	\$2.01 $Mil.$	\$6.58 $Mil.$	\$13.89 $Mil.$

Comparing the capital costs in Table 5.10 and the fixed and variable operation costs in Table 5.8, it is clear to see the economic benefit of BESS over other peaking technologies.

Other benefits of BESS over typical peaking generation are a reduced footprint due to their increased energy density, reduction of line losses as power is delivered over a shorter distance during peak times, and no additional associated carbon emissions beyond those associated with the generation technology charging the BESS.

However, it should be mentioned that the lifetime of these systems is an average of fifteen years [41] wile NGCC plants can have a lifetime of thirty years and hydropower stations can have a lifetime of one hundred years. Thus, the BESS system would have to be entirely replaced at least once within the span of the NGCC's life and five times during a hydro plant's life. This makes the economics of each solution more even.

Behind the Meter Batteries

Utility scale battery systems are expensive in terms of capital costs and maintenance costs. Additionally, in order to aid in the reduction of downstream system vulnerabilities they must be distributed along the feeder, which has the potential to create issues in acquiring land for BESS placement.

An option that installs more energy storage on the grid with less of an economic impact on the utility company is the incentivizing of behind the meter (BTM) batteries. These batteries, like the Tesla Powerwall, can be integrated into a customer's home electrical network. There, they are owned and maintained by the customer, thus reducing the economic burden on the utility.

These BTM systems still offer many advantages to the utility. The batteries can be used to shift loads, similar to TOU scheduling. They can be set to charge during low demand times, and discharge specifically to charge a customer's EV, thus eliminating the charging demand during peak times from the greater grid. With proper infrastructure and permission from the customers, the batteries can also be employed for grid support functions, including peak shaving. This is already done in Massachusetts, effectively using residents' installed BTM BESSs as a virtual power plant [44].

Financial incentives can take the form of tax credits, rebates, and bonuses offered at the state level, federal level, or by utilities themselves. Examples of such incentives already in place include Massachusetts' SMART program [45] or the federal government's investment tax credit [46]. In addition to financial compensation, BTM BESS serves as a backup power source in the event of an outage. If the homeowner has a PV system installed, the BTM BESS can store excess energy during generation and use it during peak times to use the generation system more efficiently and save on utility bills in areas where the net metering payback policy is not one-to-one. Together, these incentives can be marketed to customers to improve their opinion and adoption of BTM BESS.

CHAPTER SIX
GENERAL CONCEPTS

Throughout this document, case studies were performed to examine the effects of EV integration onto specific feeders over the next several years. However, in this chapter a generalized approach to examining impacts of EV growth is drawn from the procedures and results of the previously discussed studies. Figure 6.1 shows a flow chart of the general process, which is then discussed further in the following subsections. Note that these methods describe an approach to primarily residential feeders.

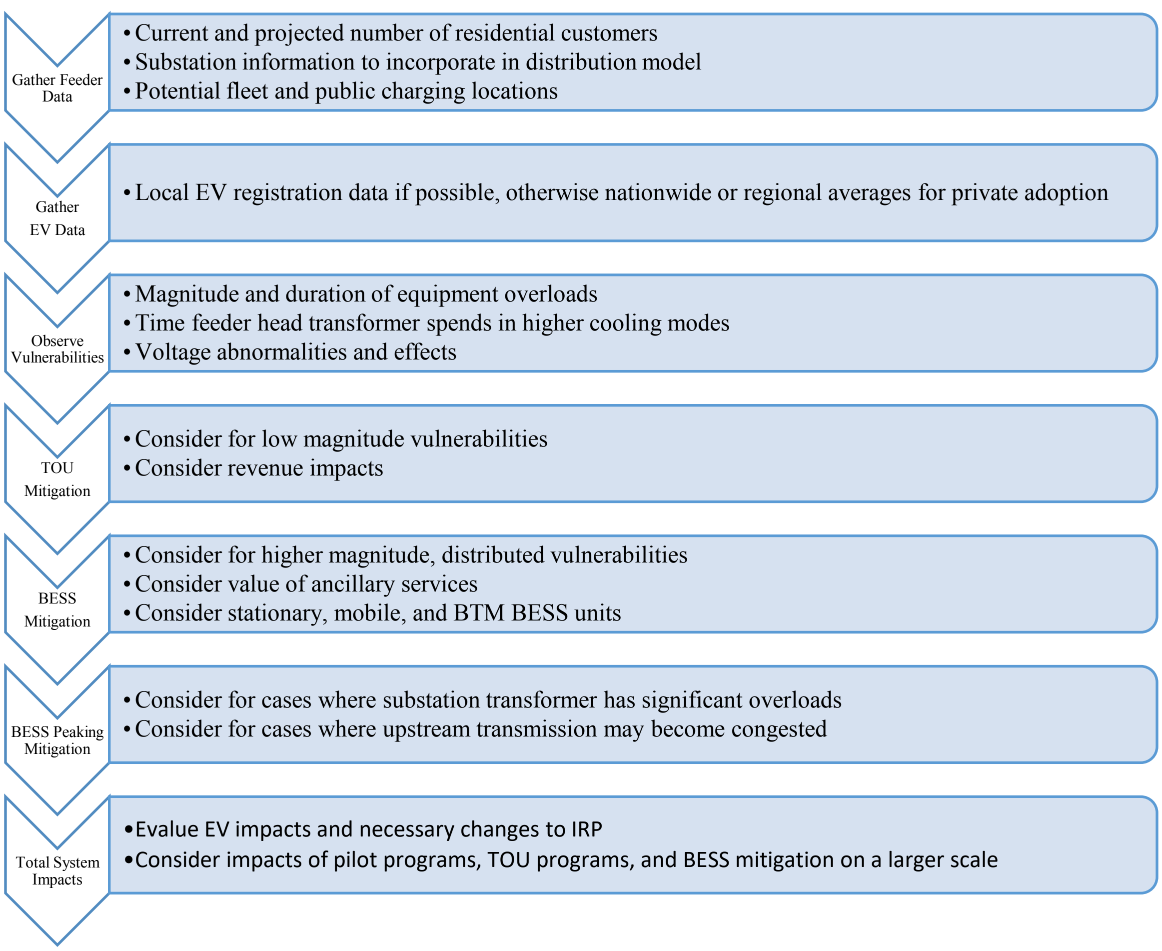

Figure 6.1. Flowchart for general approach to EV integration impacts

Gathering Feeder Data

For the purposes of EV penetration assumptions, the total number of vehicles on the feeder must be considered before assuming what percentage of those vehicles are electric. This can be determined using data already in distribution models. These models list the number of residential customers, and assuming the average of two vehicles per household in the United States, the total number of vehicles can be assumed to be twice the number of residential customers.

As previously mentioned, to best determine the impacts of EV integration on a feeder, the substation equipment should be included in the models used. Results in both case studies show increases in operational time of cooling processes and increases in switching operations that may be substantial. This equipment can sometimes be the most expensive to replace while also being some of the most critical equipment as its failure brings down the entire feeder, thus excluding it overlooks a major component in vulnerability studies. Substation data, including the substation transformer test reports, information on load tap changers, adjacent feeder loads, or feeder head regulators should be gathered in order to include this equipment in the distribution model.

While the studies included in this document focus on primarily residential feeders, there is the possibility of large parking areas or fleet lots being present even on these feeders. Customer data should be observed, or satellite mapping software, to ensure there are no potential areas for fast charging or fleet charging loads. Parking garages, large parking lots, warehouses, bus lots, and distribution centers are some points of interest for such loads. If such points of interest exist along the feeder, they should be marked and considered. These charging loads can be rather large, as discussed previously, and leaving them out could result in fewer vulnerabilities being projected than might actually emerge.

Gathering Data for Electric Vehicle Projections

Determining the most accurate EV penetration assumptions for a specific feeder is highly dependent on the amount of data available. Each location has specific characteristics that influence the likelihood of EV adoption. Thus, if specific data can be found regarding past EV growth on that specific feeder, it should be leveraged. However, chances of feeder specific EV data are low. So, another concept is to gather registration data from the local department of transportation (DOT), as was done in the PG-02 study. In this case, the EV penetration over several years can be determined for a specific county to determine EV penetration assumptions. As a last resort, several studies observe expected EV growth on a national level, such as the EEI study, and these assumed penetration levels can be utilized.

Additionally, multiple penetration levels should be assumed for an individual feeder to determine the sensitivity of the observed vulnerabilities to small changes in the number EV loads.

The approach considered in the two case studies looks at worst case charging load shapes where chargers ramp up to full power and then remain at full power output until the EV batteries reach a full charge. In reality, charging load shapes vary widely based on manufacturer specific algorithms that are usually considered proprietary and protected as such. For this reason, worst case charging curves are recommended for planning purposes. However, if specific load shapes are known, or charging schedules in the case of fleet vehicles, these should be gathered and implemented.

Observing System Vulnerabilities

Several parameters should be observed when determining system vulnerabilities. Clearly, equipment should be watched for potential overloads. This includes lines, regulators, and fuses as observed in the PG-02 case study but should also consider distribution transformers if possible. In addition to this, the time that the substation transformer spends in each cooling mode should be noted. At higher cooling modes, maintenance costs will increase while the lifetime of the transformer will decrease. Finally, the excessive EV load has the potential to create major undervoltage conditions, so either all or a strategically selected set of nodes along the feeder should be watched for these abnormalities. LTC and regulator switching events should be recorded, as the high ramp rates introduced by uncoordinated EV charging have the potential to greatly impact the number of actions over a selected period, reducing the lifespan of the equipment.

Analyzing Mitigation Strategies

Of course, the EV penetration assumptions and the vulnerabilities assessed are merely projections. While the idea of EVs is old the data is new, and the market is still fairly young and volatile. Mitigating the potential vulnerabilities caused by increased EV integration is important, but these projections may not come to fruition. However, alternatives to traditional system upgrades should be considered because if they do not offer a cheaper solution what they may offer is the gift of more time. This time will allow utilities to determine if their projections are actually accurate or should be adjusted to ensure upgrades are effective but not excessive.

The first mitigation strategy to analyze is time of use scheduling. This is primarily because it requires the least amount of investment from the utility in terms of costs. Some revenue will be lost and some investment may need to go towards recruiting programs, but otherwise no large scale equipment needs to installed. However, as shown in the results for the BESS+TOU cases, the decrease in overload magnitude may be small except in very high TOU adoption rates. Due to this, this mitigation strategy will only be useful in cases where overloads and other abnormalities are small in magnitude and primarily due to loads that are movable. After implementing this mitigation strategy, losses in revenue should be compared to the reduction in necessary infrastructure investment to determine if the business case is valid in addition to solving projected vulnerabilities.

The range of likely TOU adoption rates is large. Studies suggest they are highly dependent on several factors including financial benefit to the customer, opt-in versus opt-out programs, and recruitment efforts by the utility, among others. A low case of 10% adoption and a high case of 40% adoption was considered in the PG-02 case study. However, if the utility company is willing to put great effort in this mitigation strategy, surveys can be completed within a certain area to determine a more accurate adoption rate to assume before completing system vulnerability identification simulations.

If TOU mitigation strategies seem unlikely to succeed, distributed BESS is the next strategy to consider. Before continuing with analyzation of this strategy, the population density of the feeder should be considered. If there is little room downstream of potential overloads for several distributed BESS systems, this strategy will be rendered impractical regardless of its business case.

However, if it is likely enough land can be found downstream for battery placement, necessary BESS sizing can be completed as done in both case studies where distributed units are placed downstream of overloads and the size adjusted until the overload is mitigated. It should be noted that control scheme optimization is very important in this mitigation strategy. Different combinations of charging and discharging thresholds and time periods may allow BESS units to be smaller in size, thus reducing their associated costs, or may allow BESS to be more economical due to lower costs of the energy charging the battery.

After sizing and optimization of control schemes are complete, it is likely that the costs of BESS units will still outweigh system upgrades. This conclusion is drawn in both case studies. Nonetheless, stacking services can reduce the associated BESS costs. Some utility companies have positive values associated with ancillary services. So, if additional abnormalities exist on the feeder, the BESS should be employed to mitigate these as well so that these values can benefit the business case.

Should utility-scale distributed BESS units prove to lack a valid business case, BTM BESS can be considered. If only residences exist beyond an overload, a percentage of homeowners that would need to have a BTM BESS to effectively eliminate that overload could easily be gathered utilizing the previous sizing and an average residential BTM BESS size. From this number, the practicality of BTM BESS as a solution can be assessed. These units are relatively small, so for large peaks or abnormalities that are long in duration it is unlikely this solution will work on residential batteries alone. If an industry or commercial building that may be willing to install a much larger BESS unit is downstream of an overload the practicality of this solution may improve. Since BTM BESS is beneficial to the utility and the customer, even if it does not completely solve vulnerabilities, programs to encourage customers to install battery units should be considered regardless.

Since, as previously mentioned, these mitigation strategies are likely temporary in nature until the necessary upgrades can be efficiently determined, planned, and implemented, the BESS units may not need to be stationary. One advantage of BESS is that it is modular, thus easy to transport. Mobile BESS units may serve their purpose for a short period of time while vulnerabilities are more accurately assessed and then moved to a new location. This has the potential to improve the business case for such units as they can provide mitigating assistance to several areas during their lifetime and provide relief in emergency situations.

Finally, if distributed BESS cannot solve downstream abnormalities in an economic manner, then BESS may still be considered for peaking generation. This should be considered in cases where the substation equipment is projected to experience overload or heightened operation in higher cooling modes. Additionally, this should be considered in cases where upstream transmission equipment could experience overloading in peaking scenarios. In this case, utilizing a BESS at the feeder head can eliminate the need for expensive substation or transmission upgrades. The costs and environmental advantages of BESS as peaking sources were discussed in Chapter Five, and show some promise.

A More General Approach

If it is desired that a more general approach be taken that does not involve extensive analysis on a feeder-by-feeder basis, that can be completed using a representative feeder for each feeder type. For example, the feeder in PG-02 represents a highly loaded residential feeder. Another feeder type may be a lightly loaded commercial feeder. Each type of feeder would, naturally, have variances in EV impacts. From this, a general cost of different solutions can be applied. These costs can then be applied to a completely different feeder, reducing or increasing the value with reference to the size of the feeder.

This is, obviously, a significantly less accurate approach. Each feeder, even of similar composition, will have different quantities and magnitudes of system vulnerabilities based on the installed equipment. However, this approach can give a high-level estimation of necessary investment on the wider transmission network. If assumptions based on pilot programs are analyzed on the representative feeders then, again, the effects of those programs can be easily analyzed on a higher level using this more general method.

CHAPTER SEVEN
CONCLUSION

The continued growth of EV adoption by businesses and private citizens alike seems imminent and the consequences of these new charging loads inescapable. In this study, the projected growth in EV adoption on multiple representative feeders was examined. Using the expected general load growth and estimated EV charging loads in uncoordinated cases, the vulnerabilities such new loads may cause were determined. In these uncoordinated cases, it was demonstrated that EV charging loads, especially at higher penetration levels, have the potential to drastically increase the peak load and exacerbate ramping rates.

In the PG-01 use case, the system was considered in its 2025 state with both PV and EV integration. BESS was deployed to mitigate the system vulnerabilities and the costs of BESS installation compared to the costs of equipment upgrades was found to be greatly in favor of the latter.

In the second use case of this study, BESS installations were analyzed as a potential solution to the issues caused by EV integration and typical load growth, without photovoltaics. The feeder was studied in 2025, 2030, and 2035 to observe effects over time. In every observed year the BESS solution costs outweighed the costs of traditional system upgrades with or without TOU scheduling. TOU scheduling, while reducing the peak demand and the necessary size of the BESS installations still only reduced costs associated with the installation by a maximum of 13% in the cases observed. In this case, 40% of EV users must adopt TOU scheduling, which requires a significant recruiting effort from the utility. Therefore, utility owned and operated distributed BESS for the purpose of overload reduction and equipment upgrade deferral is not an economically viable solution.

In terms of reducing overloading conditions, the results and the projected EV growth rate make the installation of permanent BESS an inefficient solution. If the BESS is oversized to meet 2035 demand, it will not be used to its full potential earlier in its lifetime and will need to be fully replaced by the time it is. Sizing it to the earlier demand will require constant additions every few years and will lead to portions of the BESS being older than others, which is often not recommended. However, such installations can provide temporary alleviation of problems during planning and implementation of other mitigation strategies. Mobile BESS may provide the best economic benefit in this case as it can be moved to other areas of need afterwards or be used in emergency situations when not being used for overload mitigation.

Results observed in the second use case and associated economic analysis indicate that BESS will find its most economic use in offsetting the need for new peaking generation, or the replacement of those peaking plants that already exist. Capital costs of new peaking plants may be double the capital costs of BESS and typically come with higher variable O&M costs due to the cost of fuel. An additional benefit is that BESS installations do not contribute to carbon emissions. As the greater electrical grid becomes "greener" BESS can act as peaking sources instead of traditional peaking plants and reduce the carbon footprint of the energy industry.

Additionally, batteries do not have to be owned by the utility to be useful. Both businesses and private customers can benefit from having onsite BTM BESSs through financial incentives and as sources of backup power in the event of outages. Then, those batteries may also help the utility as customers can use them to shift load. With proper infrastructure, such batteries can even be used directly by the utility for peak shaving and other grid supporting functions, effectively operating them as a virtual power plant. While it would take a large percentage of customers installing BTM BESS to make an impact on overloads caused by EV, as is the case with TOU scheduling, the active marketing of such technologies to customers is worthwhile. This will become even more true as PV installations on private residences continue to rise.

A general process by which EV impacts can be observed and mitigation strategies analyzed was then formulated using methods and data from the case studies. This was presented in Chapter Six along with a high-level approach using various representative feeders.

Future Studies

These studies were conducted while analyzing summer demand patterns. This was due to the fact that EV charging has a major impact on the larger evening peak during the summer months on residential feeders, thus the summer demand characteristics represent a worst case. However, different load patterns in different months may affect the usage of the BESS units, altering charging patterns and the number of cycles per year. Looking at various load characteristics throughout the year will help determine at what frequency and to what degree system vulnerabilities occur and how often BESS units will need to be utilized.

Another key component not observed in this document is the upgrade of distribution transformers directly connecting the distribution system to the customer. EV loads may cause these devices to overload as well at peak times, necessitating their replacement. This will, naturally, incur additional upgrade costs to the utility. TOU mitigation strategies and BTM BESS may aid in the reduction of the number of these transformers that need to be replaced. Utility scale BESS on the distribution system will not.

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