The Pennsylvania State University

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EARLY ECONOMIC FEASIBILITY OF HYBRID MICROGRID IN CALIFORNIA MARKET

A Thesis in

Architectural Engineering

by

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ABSTRACT

The Energy Policy Act of 1992 opened the legal door to distributed generation (DG). Although electricity has been deregulated for over 20 years, today 95% of electricity is generated by utility companies. At the present time concerns are rising over carbon emissions and power reliability while technological advancements are making renewable generation and electricity storage more cost effective. These converging influences are currently challenging the central grid model and encouraging customers to consider DG investment. Historically prospective customers are unwilling to invest without a favorable return on investment (ROI). At the present time DG implementation is limited to the industrial sector.

This thesis investigates the operation of a hybrid system (HMG = hybrid microgrid) comprised of combined heat and power (CHP), solar photovoltaic array (PV), and electrical storage on two commercial loads and a 150 unit multi-residential load served by the California utility Pacific Gas and Electric (PG&E). The study investigates the necessary battery characteristics to meet each facility's load. Federal investment tax credits and California's Self-Generation Inspection Program are used to calculate each system's ROI timeline. Three sensitivity analyses are conducted for battery price, natural gas fuel price, and electrical rate to determine the impact on ROI. The thesis concludes by identifying the required market conditions to yield 10, 5, and 3 year ROIs of each building. The report finds commercial loads are the most technically feasible due to the load consistency. Larger loads and consistent load factors increase the economic viability.

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Chapter 1

Introduction

Distributed generation (DG), which is the production of electricity at or near the load source, is emerging as one of the potential solutions to improve reliability and reduce emissions. DG frequently refers to CHP, but also includes fuel cells, solar photovoltaics (PV), and wind turbines. The improved renewables penetration and simultaneous generation of electricity and heat have the effect of reducing total emissions and increasing reliability. DG has been utilized by industrial facilities for decades, but has yet to see commercial and residential market penetration.

The biggest obstacle preventing DG's wide employment is the significant capital costs associated with the equipment and installation. Less than half of prospective customers expressed willingness to invest in DG if the economic return on investment (ROI) exceeds two years (ICF International, 2010). Thus far DG adoption has been limited to industrial consumers with large energy bills. Commercial and residential customers, whose energy bills are cheaper, are far less likely to recover the initial investment.

There may be opportunity to save additional energy and further reduce emissions if one or multiple DG technologies is paired with electrical storage. This design is referred to as a hybrid microgrid (HMG). Electrical storage, primarily battery storage, enables electricity generation to be separated from demand. HMG customers can take advantage of the natural market fluctuations inherent in the sale of electricity. A HMG also increases the penetration limits of renewable electricity and eliminates lost renewable generation that would occur without storage.

A HMG may increase customer savings and yield ROIs otherwise unavailable in singular DG applications. Improved ROI could increase the application of this technology for commercial and residential customers. This study explores the economic feasibility of a HMG in a specific market.

1.1 Research Objectives

1. Describe the CHP+PV+battery hybrid system design that reduces grid supplied electricity to 1% (88 hours per year) for residential, commercial, and large commercial.
2. Identify the battery characteristics necessary to meet each facility design. Characteristics include charge rate, storage size, and cycle frequency.
3. Quantify present day ROIs based upon assumed levels of CHP thermal utilization
4. Conduct sensitivity analyses to determine how ROI would improve with varying battery price, average electrical rates, and average fuel costs.
5. Identify the economic environment that would yield 10, 5, and 3 year ROIs

1.2 Description of Research

This research uses average commercial and residential electrical demand data for facilities located in California that were compiled by Pacific Gas and Electric (PG&E). From this data facility load profiles are developed for multi-residential unit homes, typical commercial office buildings and large commercial office buildings. Multi-residential homes will contain 150 individual households. Commercial office buildings are defined as facilities with less than 200 kW peak electrical demand and large office buildings have peak demand usage greater than 500 kW.

A hybrid microgrid plant consisting of CHP, a solar PV array, and electric battery storage is designed for each facility. The technical design focuses on the necessary battery characteristics to meet the 1% grid electricity delivery constraint to the site. The hybrid microgrid's operation is simulated over a year's demand cycle and key performance metrics are quantified.

The hybrid microgrid's capital and operational costs are calculated and compared to conventional electricity prices in order to determine the annual savings. Estimates incorporate government incentives to determine the true cost to the customer. The capital costs are used with annual savings to calculate the economic return on investment (ROI).

The research concludes by investigating the hybrid microgrid economics sensitivity to key cost factors. Three sensitivity analyses explore how battery price, fuel price, and electric rates influence the ROI. The economic market requirements to meet 10, 5, and 3 year payback periods are documented.

Chapter 2

Literature review

2.1 Distributed Generation Introduction

The United States central electric grid represents a key aspect of the nation's economy and remains one of the most impressive technological feats accomplished by mankind. From its modest beginnings in 1880, the central grid now supplies electricity to over 146 million end-use customers with revenue exceeding $376 billion (EIA, 2015d). In the 21st century electricity impacts every aspect of life in the United States. It enhances the standard of living, creates wealth for business, and even enables national defense. For over a century electricity generated and transmitted through a central electric grid empowered the nation's prosperity. Today the central grid model is being challenged by concerns over modern emissions and reliability.

Historically electricity has been generated using heat produced by burning coal to drive a steam turbine. The 20th century was a time of significant technological improvement spurred by two world wars, globalization, and the rise of the information age. Automobiles, aircraft, and space travel introduced new electricity generation technologies. The internal combustion engine, combustion gas turbine, solar photovoltaics (PVs), fuel cells, and nuclear fission all diversified the electricity generation portfolio and set the stage for distributed generation.

Distributed generation (DG) is the installation of power generation technologies at or near the loads which they serve. Contrary to central power generation, DG is not transmitted over long distances, avoiding the induction losses inherent in such transportation. DG's proximity to the load allows heat rejected during generation to be captured and utilized, a process known as combined heat and power (CHP) or cogeneration. The simultaneous electricity generation and heat capture increases the total energy extracted from the same consumption of fuel. CHP is the largest contributor to microgrid electricity generation and is the cornerstone of DG because of its reliability, affordability, and technical application. Other common DG examples include fuel cells, solar photovoltaic cells (PV), and wind turbines. With the exception of hydro, renewable electricity generation has yet to reach large, utility-scale installation. While the generation share of renewables is increasing, it is primarily through DG applications that these clean, emission-free sources of electricity are most utilized today.

Advancements in engineering and science during the 20th century established the technical feasibility for DG. However, the main drivers promoting DG are rooted in the increased concern over environmental impact and rising electricity dependence precipitated in the 21st century. Environmental awareness is encouraging increased energy utilization efficiency and reduced emissions. DG's ability to incorporate renewable technology, simultaneously capture heat and power, and avoid transmission losses makes its overall emissions contribution less than conventional power. Additionally, DG's close proximity to the load makes it far less susceptible to weather related outages, which account for 87% of major blackouts.

The major obstacle to DG adoption is the substantial equipment cost. The economic market still largely favors the status quo central grid model. If DG installation could successfully reduce customers' utility bills such that the initial investment would eventually be recuperated, there would be additional motivation toward DG. In this case a third driver emerges known as the economic return on investment (ROI). This is by far the strongest push toward DG in today's economy.

Three primary drivers currently exist to motivate distributed generation adoption:

1. Need to reduce CO2-eq emissions
2. Increased desire for reliability
3. Economic return on investment

These influences have developed in the 21st century as electricity dependence challenged the century old central grid model. To what extent DG is adopted in the private sector depends most significantly on the economic forces and the ROI opportunity. The public and private sector share a similar desire for DG, but the motivations not entirely parallel (see Figure 2-1). Government policies are often directed at aligning private and public motivations.

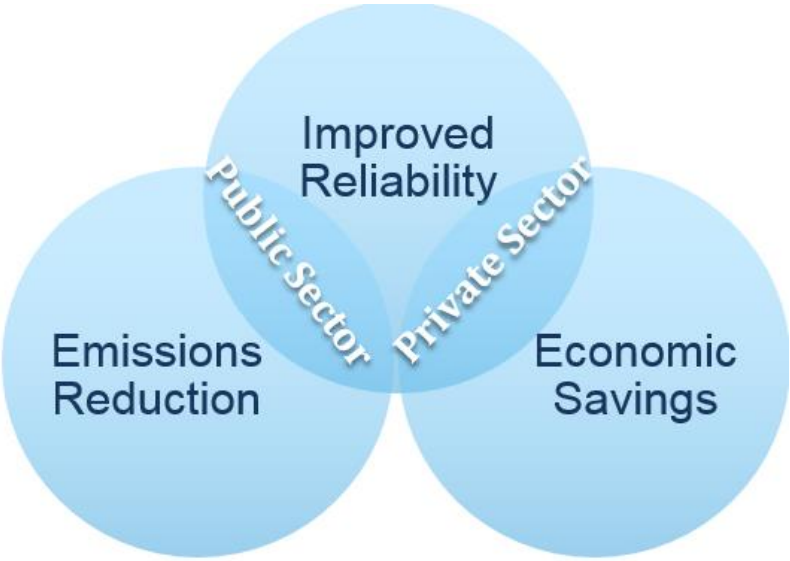

Figure 2-1: Distributed Generation Investment Motivation

Chapter 2 explores the three factors driving DG implementation shown in Figure 2-1. Public and private interests are discussed and key public policies that bridge the gap between public and private priorities are introduced. Additionally, this literature review seeks to investigate the benefits of combining multiple DG technologies with energy storage. Finally, the chapter closes by reviewing a specific market that best supports DG adoption.

2.2 Regulation History

20th century technical improvements set the stage for DG. Concurrently during this time public policy and regulatory laws evolved. These regulations protected the nation's power supply during the Great Depression and eventually opened the legal door for DG.

The centralized grid model evolved as electricity demand grew early in the 20th century. Early in the 1900s power plants were isolated and regional. These plants were eventually interconnected and by the end of the 1920s the centralized grid was formed. Through the 1920s private investments easily funded the electricity expansion. Concerns about electrical monopolies and the Great Depression forced the federal government to regulate electricity as a public good. The Public Utility Holding Companies Act of 1935 (PUHCA) outlined restrictions and regulatory oversight. Regulation expanded the grid, opened new markets in rural America, and provided market stability for consumers and investors. This began the "Golden Age of Regulation," and the structure remained unchanged for nearly 60 years.

In the 1970s, increased environmental awareness and rising oil prices from the oil embargo precipitated changes in the electrical industry. In 1978 Congress passed the Public Utility Regulatory Policies Act (PURPA), which required utilities to purchase electricity from qualifying facilities (QFs) at 'avoided costs.' These QFs had energy efficiency requirements and were required to be certified by the Federal Energy Regulatory Commission (FERC). Some states established high avoided costs that stimulated investment in independent power producers (IPPs). Inadvertently PURPA incentivized the investment in CHP even when the technology did not improve energy efficiency as was the intent. As an example, observers expected the law would increase CHP in California by a few hundred megawatts; however, entrepreneurs signed up for over 15,000 MW (Borbely & Kreider, 2001).

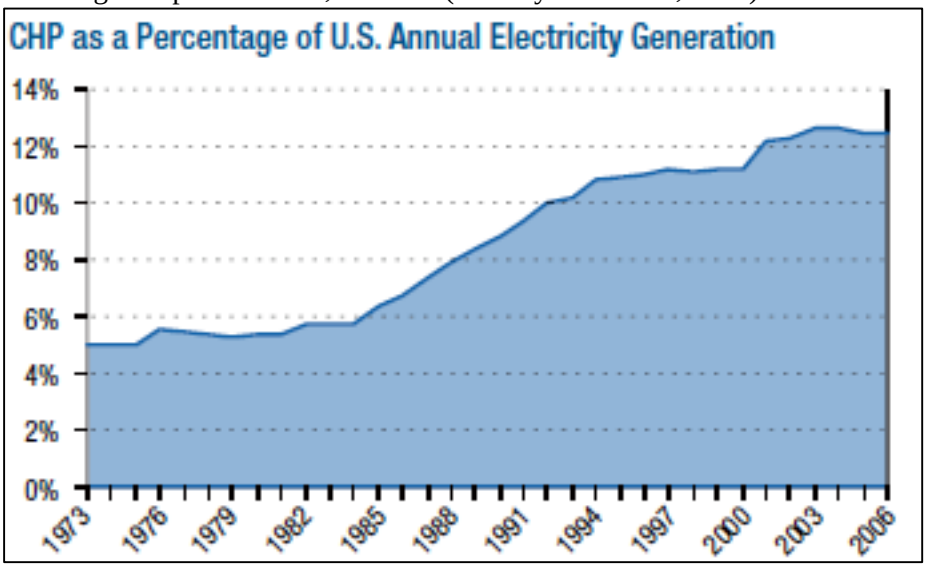

Figure 2-2: Annual CHP Growth 1973-2006
Source: (Shipley, Hampson, Hedman, Garland, & Bautista, 2008, p. 18)

By the 1990s high-price IPPs stifled competition and became a major point of contention with utilities (Borbely & Kreider, 2001). This led to Congress passing the Energy Policy Act of 1992 (EPAct). EPAct and the subsequent FERC Order 888 implemented in 1996, required transmission line owners to allow access by any electrical generator. This created access to the grid by IPPs not regulated by PUHCA and not subject to PURPA's energy efficiency requirements. EPAct of 1992 effectively created competition between utilities and IPPs and caused a massive shift in the regulatory environment. Congress left complete deregulation to the discretion of individual states. Congress effectively opened the door to utility deregulation through PURPA and legalized complete deregulation by EPAct of 1992 and FERC Order 888. (Abel, 1998) (Hirsh & Jr., 2012) (Borbely & Kreider, 2001)

2.3 Emissions

Since the 1990s scientists have communicated increasing concern over the rate of fossil fuel consumption within the United States. Significant CO2-eq emissions have created concerns over Global Warming (GW) and its harmful effect on the environment. The number of Americans who believe in GW has risen to 70% (Leiserowitz, Maibach, Roser-Renouf, Feinberg, & Howe, 2012). The concern over the consequences of GW is driving a change in culture to reduce emissions and pollution through the development of new technologies and the enforcement of new policies.

Coal is the fossil fuel that contributes the most to CO2-eq emissions (EPA, 2015b). Unfortunately it is also the cheapest fossil fuel, making its employment widely attractive. Without regard to emissions or pollution, coal is the optimum fuel choice because of its availability and affordability. Even knowing the negative environmental consequences, departure from using coal in the United States is unlikely without economic forces to encourage such action. This is true in all industries, but especially apparent in electric power plants. In the year 2000, despite the electrical generation diversity brought on in the 20th century, over half of the electricity generated in the US was accomplished through coal fired plants. That percentage decreased significantly between 2000 and 2013 as GW became a greater concern and natural gas production increased. Even with the knowledge of coal's pollutant characteristics and the increased concern over GW, the EIA projects coal will generate the most electricity through 2040 given the current market. How this plays out for the industry is significant to the US at large, because power plants are the largest contributor to carbon emissions in the country.

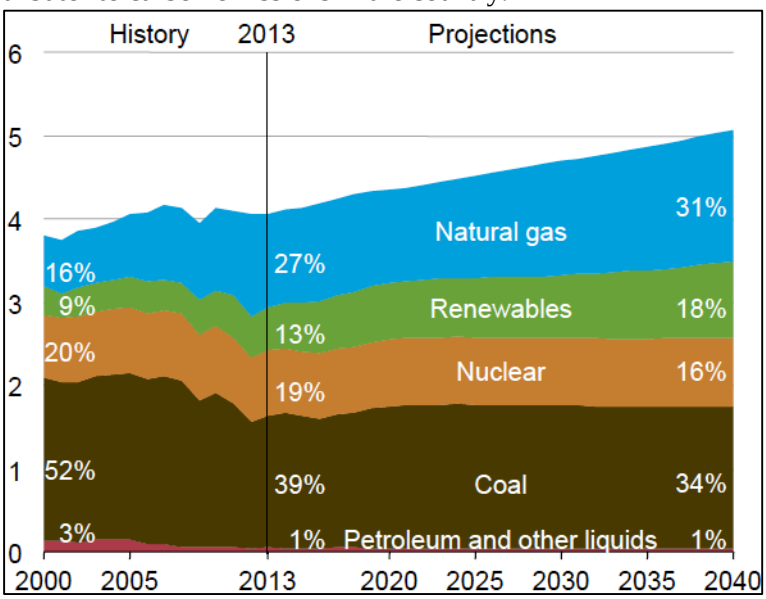

Figure 2-3: Electricity Generation by Fuel Source
Source: (EIA, 2015c, fig. 31)

DG has the potential to reduce emissions, but has yet to reach large market penetration. In 2003 3,800 billion kilowatt hours (kWh) of electricity were produced in the U.S of which, only 4.1% was non-utility generation. 3.6% was produced by industrial companies to meet the local power needs (Leo, n.d.).

Up until 2010, the United States consumed more energy any other country (EIA, 2012b). Currently the US consumes over twice the energy per capita compared to the Middle East and Europe, as displayed in Figure 2-5Figure 2-4. Fossil fuel based energy production is not possible without CO2-eq emissions as a byproduct. Based on emissions per capita, the US is contributing more than any leading economy to the greenhouse gas effect and global warming. Scientists and engineers are beginning to address the disparity, but the US still consumes more than its fair share of the world's resources and must continue to make strides to reduce CO2-eq emissions. This goal is not easily accomplished and has economic and political consequences.

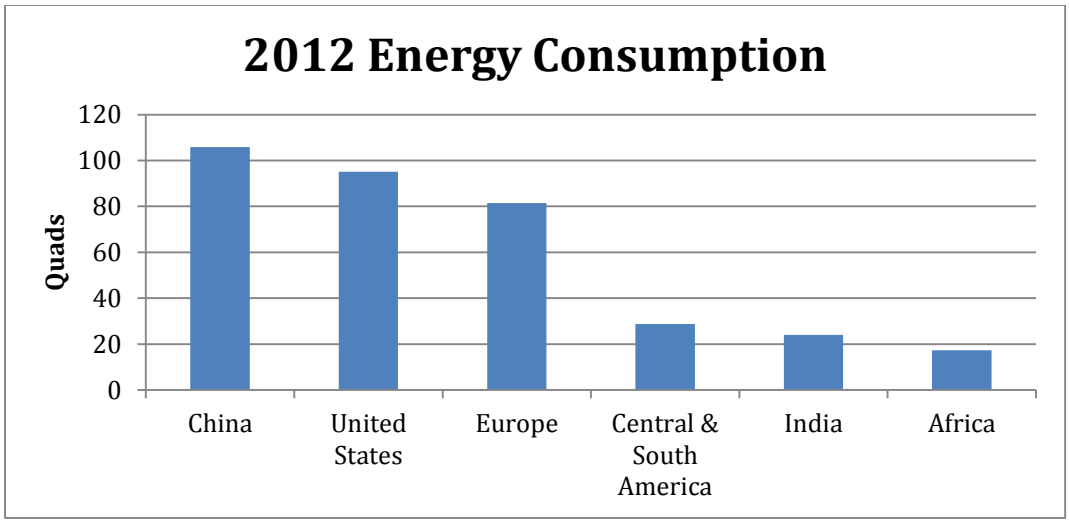

Figure 2-4: Total Energy Consumption by Country/Region 2012
Adapted from International Energy Statistics(EIA, 2012b)

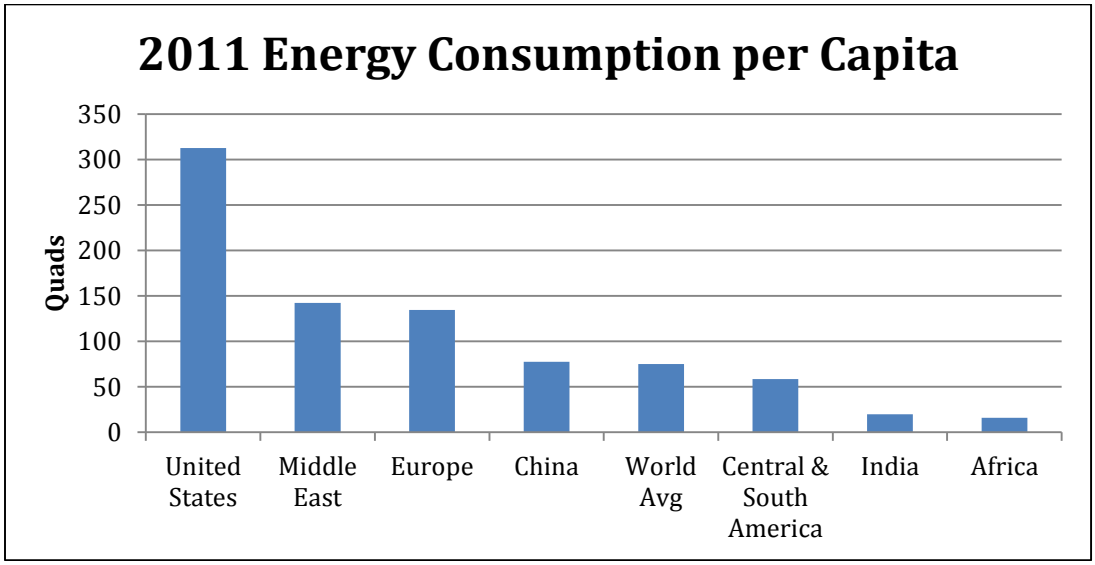

Figure 2-5: Total Energy Consumption per Capita by Country/Region 2011
Adapted from International Energy Statistics (EIA, 2012b)

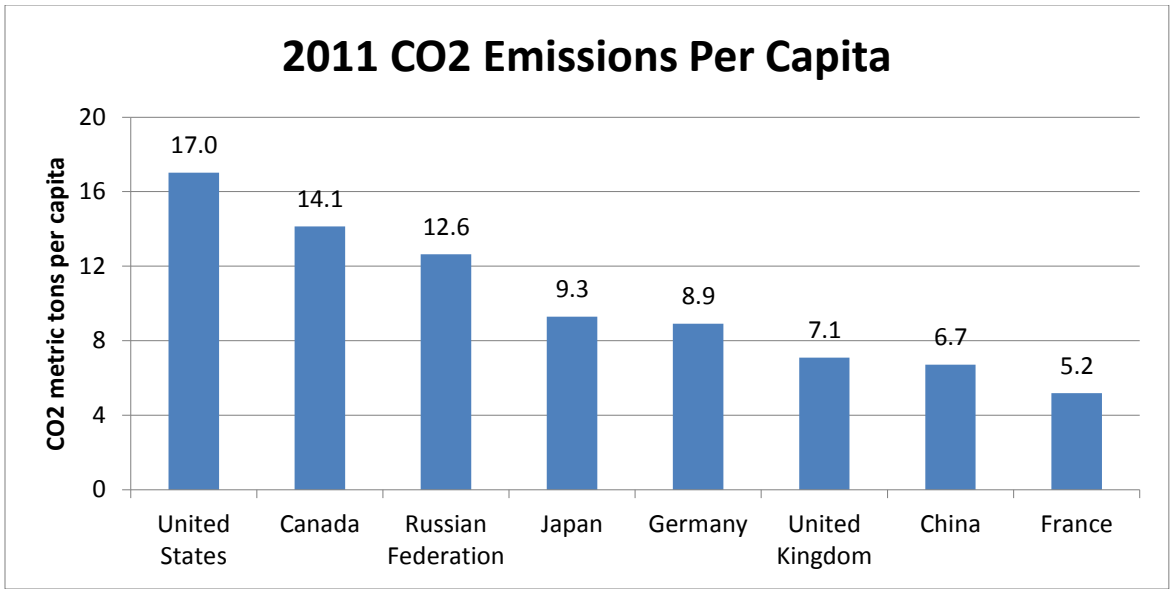

Figure 2-6: CO2 Emissions per Capita for G7 Countries and Russia
Adapted from World Development Indicators (The World Bank, 2015, Table 3.8)

2.3.1 Energy and Economics

Emissions reduction can be achieved by reducing demand or increasing system efficiency. One of the major obstacles to reducing total energy consumption is the effect on the economy. There is an inherent link between energy consumed and gross domestic product (GDP), as shown in Figure 2-7 and Figure 2-8. Wealth creation necessitates energy consumption, consequently a major obstacle to emissions reduction is the loss of capital associated with decreased energy. Nations and businesses desire to see economic progress and mandates to consume less energy carry political consequences. The likely solution to reducing emissions then is improving system efficiencies.

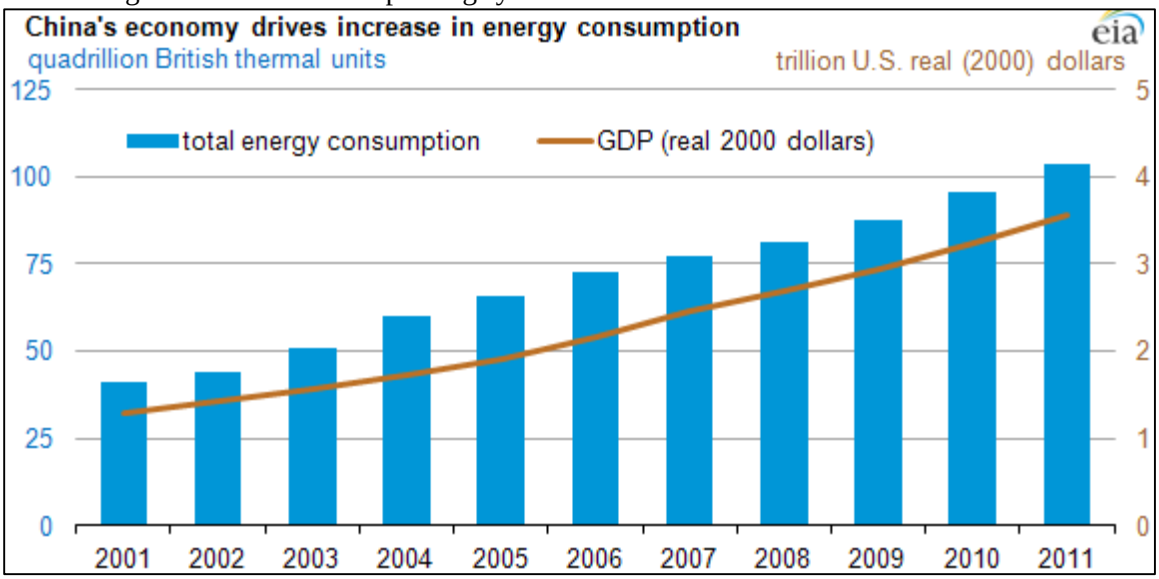

Figure 2-7: China's Total Energy Consumption and Real GDP 2001-2011
Source: Today in Energy September 21, 2012 (EIA, 2012d)

Increased energy efficiency can curb the growth in emissions, without reducing economic growth. An increase in operational efficiency decreases the required energy to accomplish the same objective. In this case it is possible for GDP to grow without a rise in energy consumption or emissions. In the US this was observable during 2000-2008, when GDP grew while total energy use remained constant.

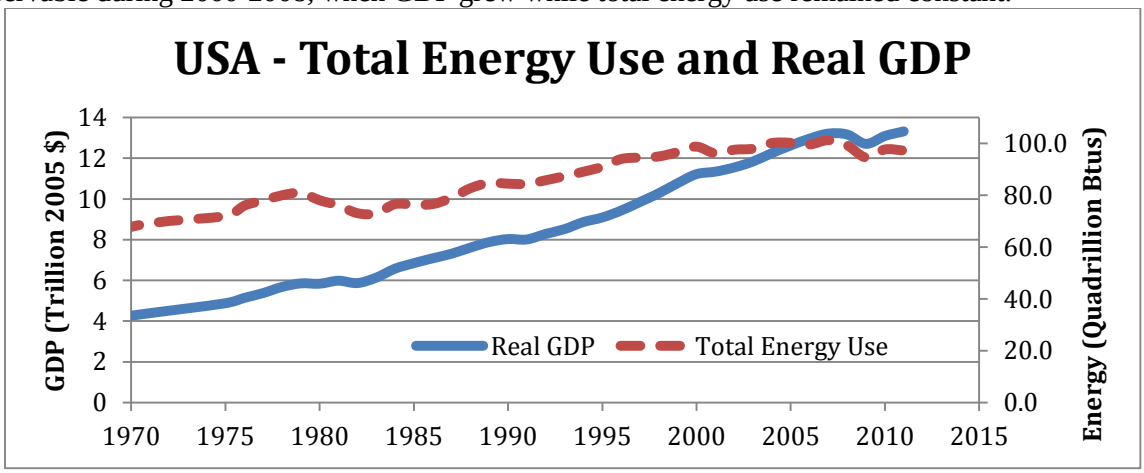

Figure 2-8: United States' Total Energy Consumption and Real GDP 1970-2011 Adapted from the 2011 EIA Annual Energy Review (EIA, 2012a, Table 1.5)

Improved system efficiency also lowers energy costs because additional work can be accomplished without additional energy. Unfortunately in order to accomplish the efficiency improvements, substantial additional capital is required, which is not always recaptured by the savings. Therefore, in a capitalist market, there is not sufficient motivation to increase efficiency and reduce emissions. Increased efficiency may be beneficial in the long-term, but the short-term consequences typically drive decisions. Efforts to regulate energy consumption and emissions rates are extremely difficult to implement because of the economic effect they have on private and public enterprise.

2.3.2 Government's Response

Despite the economic obstacles to CO2-eq emissions reduction, the United States government has taken aggressive steps to mandate or encourage a reduction in net emissions. Policies exist in a number of industries including the automobile and aircraft industry, but policies that target the power industry are most important because the power sector is the largest source of carbon pollution in the country (see Figure 2-9). This section outlines current state and federal policies regulating emission in the power industry.

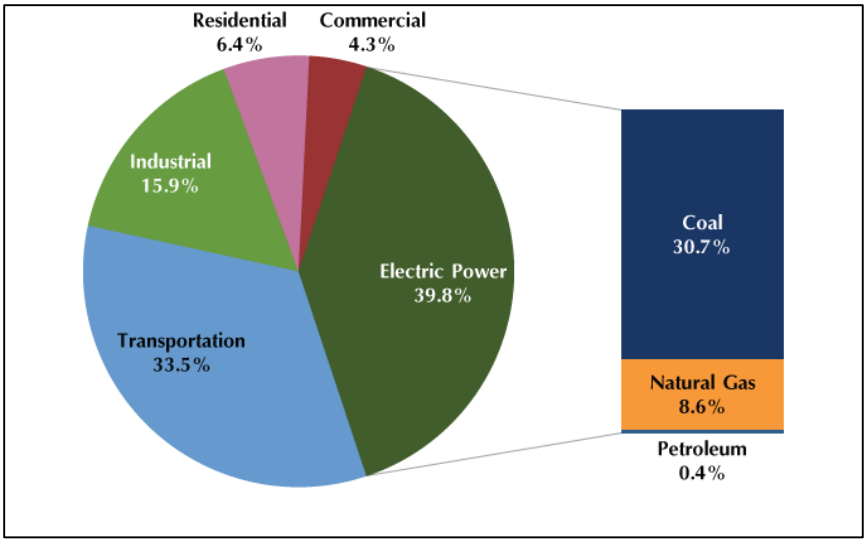

Figure 2-9: Source of CO2-eq Emissions in the United States
Source: (Center for Climate and Energy Solutions, 2015, fig. 2)

2.3.2.1 Renewable Portfolio Standards

On the supply side a total of 29 states plus the District of Columbia have implemented renewable portfolio standards (RPS). The RPS regulation requires utilities to generate a percentage of electricity from approved renewable resources. Increased renewable generation provides carbon free electricity and displaces electricity otherwise produced by coal or natural gas. Exact standards vary by state with the highest being in California which mandates 20% of electricity generation come from renewable resources. That benchmark is projected to increase to 33% by 2020. "Non-compliance penalties imposed by the states vary from $10 to $55 per megawatt-hour." (Ipakchi & Albuyeh, 2009)

2.3.2.2 Clean Power Plan

In August 2015 the federal government announced by far the most aggressive policy to cut CO2-eq emissions in the power sector. This policy, known as the Clean Power Plan (CPP), establishes limits to state's electricity generated CO2-eq emissions. The authority for this regulation is derived from the Clean Air Act of 1970. The CPP reduces carbon emissions nationwide by 32% from 2005 levels to 2030 levels. The plan requires states to begin implementation by 2020 and to achieve CO2-eq emission limits by 2030 (EPA, 2015a).

While the plan is aggressive, the EPA boasts a flexible approach to achieving this goal, and allows each state to determine how they will meet the requirements. The plan recommends four building blocks to achieve emission reduction requirements. These methods include, but are not limited to:

1. Improving the heat rate of individual sources
2. Increasing use of existing natural gas-fired capacity and lower use of existing coal-fired generators
3. Expanding the use of low- or zero-carbon generation, such as a state-wide RPS program
4. Employing the use of demand-side energy efficiency to reduce overall generation required from affected sources

The CPP also provides provisions to allow states to transfer emission credits, similar to cap & trade programs (EPA, 2015a).

The EIA investigated the CPP's effect on generation sources. Their findings, shown in Figure 2-10, predicted the plan would accelerate the reduction in coal power plants from 45% of electricity generation in 2010 to 26% in 2030 (EIA, 2015b). Because the plan accelerates the retirement of coal fired power plants, it has received push back and been criticized for the detrimental effect it will have on the economy. In particular, coal dependent states such as Kentucky and West Virginia oppose the plan. Currently 16 states are challenging the legality of the plan, arguing the plan takes to broad an interpretation of the Clean Air Act.

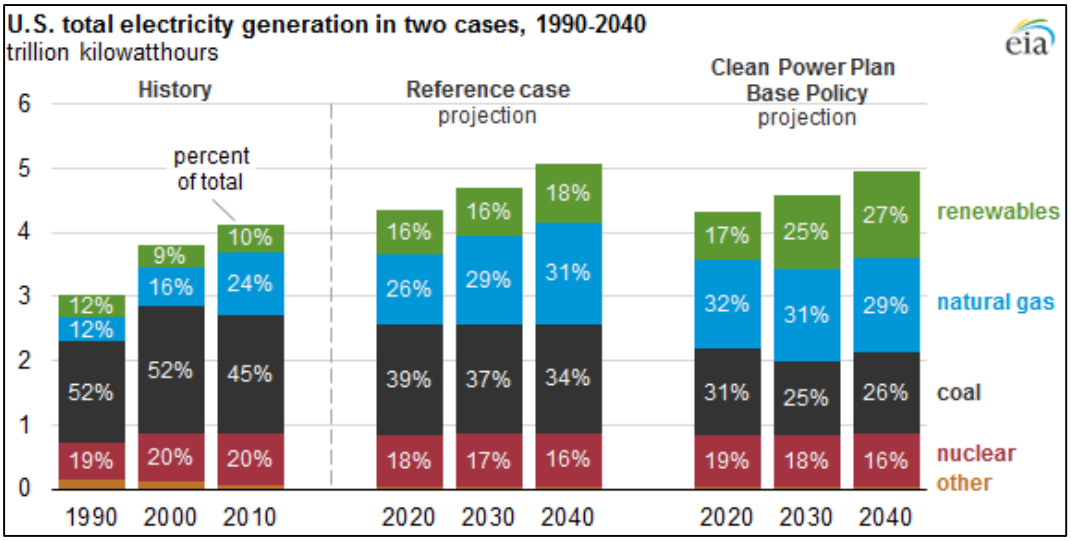

Figure 2-10: Impact of Clean Power Plan on Electricity Generation
Source: Today in Energy May 27, 2015 (EIA, 2015g)

2.3.2.3 Demand Response

Other efforts to reduce electricity greenhouse gas emissions focus on the demand for electricity. Responsible demand side management programs create shared ownership between customer and utility to address the growing emissions in the industry. These programs encourage customers to increase energy use efficiency or reduce consumption during critical periods. Effective demand side management reduces total emissions by limiting the generation capacity required. The federal government has recently looked at ways to increase customer's electricity consumption awareness.

In 2011 the Federal Energy Regulatory Commission (FERC) implemented a mandate to incentivize customers to participate in demand response. The regulation required electrical utilities to pay users to reduce consumption during peak demand. The aim of such effort is to encourage the conservation of energy during critical periods. Demand response can have significant effect on electricity consumption and is discussed later in this report. While the law remains in effect, the legality is being challenged and will be heard by the Supreme Court in 2016. (Hurley, 2015)

These policies are but a few of the efforts by the United States government to address the growing emissions within the United States. Distributed generation, such as combined heat and power (CHP) provides additional opportunities to reduce emissions by improving efficiency.

2.3.3 Carbon Tax

Another widely considered policy is the introduction of a tax on greenhouse gas emissions, known as a carbon tax. A number of countries have implemented various carbon taxes including Ireland, Great Britain, Finland, France, Germany, and Sweden. Other countries have implemented regional policies including Canada and China (Hope, 2014) (Carbon Tax, 2015). A carbon tax implementation remains a hotly debated topic, with many pointing to Australia's repeal of the carbon tax as an argument against adoption. In the US no current federal carbon tax exists, although some are advocating for it. The 113th Congress alone proposed six bills that would put a price on carbon emissions (Ye, 2014). Some regional policies have been implemented, including the Regional Greenhouse Gas Initiative (RGGI) and California's cap and trade program. The RGGI is a cooperative effort by CT, DE, ME, MD, MA, NH, NY, RI, and VT to reduce emissions, but is relatively tame with taxes only between $2-$3 per ton (Carbon Tax, 2015)(RGGI, 2013). Oregon and Washington also have legislation under construction to adopt carbon taxes (Barnhart, Holvey, & Buckley, 2015) (Bauman, 2015).

While no comprehensive federal carbon tax policy exists, such policy would promote microgrid adoption because DG's CO2-eq emissions are below conventional coal or natural gas generated electricity. A carbon tax would create financial incentives for companies to conserve energy or invest in DG technology. The discussion and anticipation of such a policy has motivated some companies in the private sector to investigate alternatives before such policy is implemented. The EIA predicts a carbon tax would drastically reduce coal generated electricity and increase the share of distributed generation technologies (see Figure 2-11).

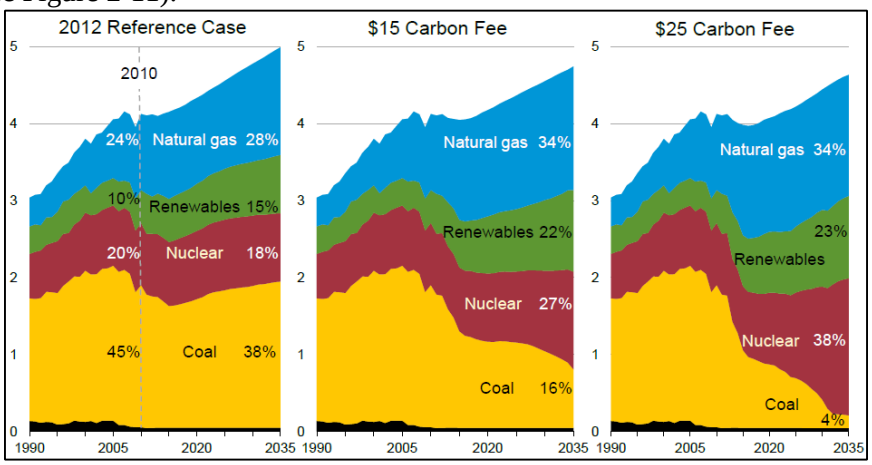

Figure 2-11: Carbon Tax Impact on Electricity Generation, in $ per CO2-eq metric ton
Source: U.S. Energy Outlook presentation (Sieminski, 2013)

2.3.4 Congressional Action:

In 1992 Congress passed the Energy Policy Act (EPAct) of 1992. This law opened transmission lines to all generation sources and effectively opened the door for distributed generation. Additionally, EPAct also created a 1.5 cent per kWh wind production tax credit (PTC), which helped stimulate wind turbine investment (Borbely & Kreider, 2001).

From 2005-2009, Congress passed three bills that incentivized and expanded interest in DG. Those bills were the Energy Policy Act of 2005, Energy Improvement and Extension Act of 2008, and the American Recovery and Reinvestment Act of 2009. The laws instituted a 30% investment tax credit (ITC) for solar PVs, wind turbines, and fuel cells; as well as establish a 10% ITC for CHP employment. These tax credits can also have specific requirements that tie funding to threshold efficiency levels. In the case of CHP, the 10% ITC requires the total primary energy utilization to exceed 60%.

The three bills implemented between 2005 and 2009 provided financial support to an emerging industry and helped usher in technological improvements that reduced the costs and improved efficiency. The best example of the success of these policies is that the wind ITC & PTC were not renewed and allowed to expire at the end of 2014 (AWEA, 2015). The expiration is a result of wind energy being cost competitive without the federal subsidy. Ideally solar, fuel cells, and CHP will reach the same level of competition one day. Until then the federal tax credits help increase the share of renewable energy and reduce CO2-eq emissions.

2.4 Reliability

Electricity dependence has grown considerably in the past few decades. Residential and commercial customers plan their lives and business based upon the day to day assumption that electricity will be available. Utility companies have largely created this market expectation due to the remarkable success they've exhibited in supplying power to customers. Despite their success, there remain a number of challenges to delivering uninterrupted electricity. Those challenges have continued to increase since the turn of the century.

2.4.1 Decaying Electrical Infrastructure

Many of the challenges to reliable power stem from the aging electrical infrastructure. Key equipment is beginning to age, which makes the national grid more susceptible to blackouts, storms, failures and glitches. To date 70% of the grid's transformers and transmission lines are over 25 years old; and the average power plant is now 30 years old with a life expectancy of 40 years (Campbell, 2012). 20% of the coal fired power plants are over 60 years old (EPA, 2015a). In response to aging equipment, transmission construction has increased in the past 5 years, as shown in Figure 2-12.

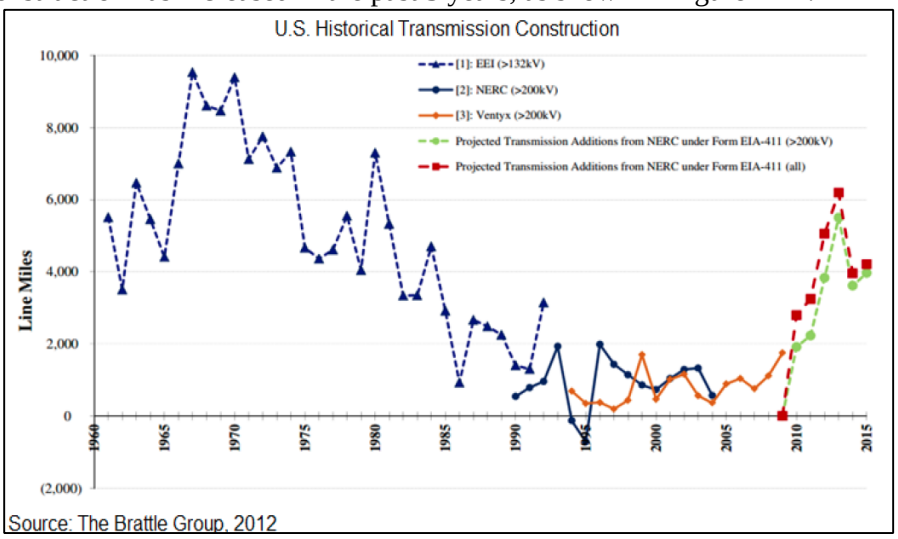

Figure 2-12: U.S. Historical Transmission Construction 1960-2015
Source: (DOE, 2013, p. 7)

Older electrical equipment is a problem to the grid because it is more susceptible to faults, failures, and storms. While the centralized electric grid could be modernized for future use, the required capital investment is substantial. The American Society of Civil Engineers estimates modernization would cost $673 billion (Campbell, 2012). Another alternative is to appropriate funds toward distributed generation technologies, such as CHP to improve power reliability. The value of DG and microgrids is it reduces the required transmission and distribution network, making customers less susceptible to weather, blackouts, and terrorism.

2.4.2 Weather Related Outages (DOE Report 2013)

The leading cause of power outages is severe weather storms. Thunderstorms, hurricanes, blizzards, flooding, and ice storms can down distribution power lines, damage transformers, disrupt electrical generation, and create equipment faults that disrupt electrical power to customers in the industrial, commercial, and residential sectors. Since 2002, 87% of all major outages (affecting more than 50,000 customers) have been the direct result of severe weather. Between 2003 and 2012 there were 679 widespread outages (DOE, 2013). NOAA reports that the U.S has sustained 178 weather and climate disasters, which caused damage in excess of $1 billion since 1980. These storms are known as "billion dollar storms." The total economic damage for these 178 disasters exceeds $1 trillion (NOAA, 2015). Seven out of ten of the deadliest storms occurred in the nine years between 2004-2012 (DOE, 2013). Statistics show there is an upward trend in weather related power outages (see Figure 2-13). This trend will create new threats to existing electrical infrastructure that are not yet apparent.

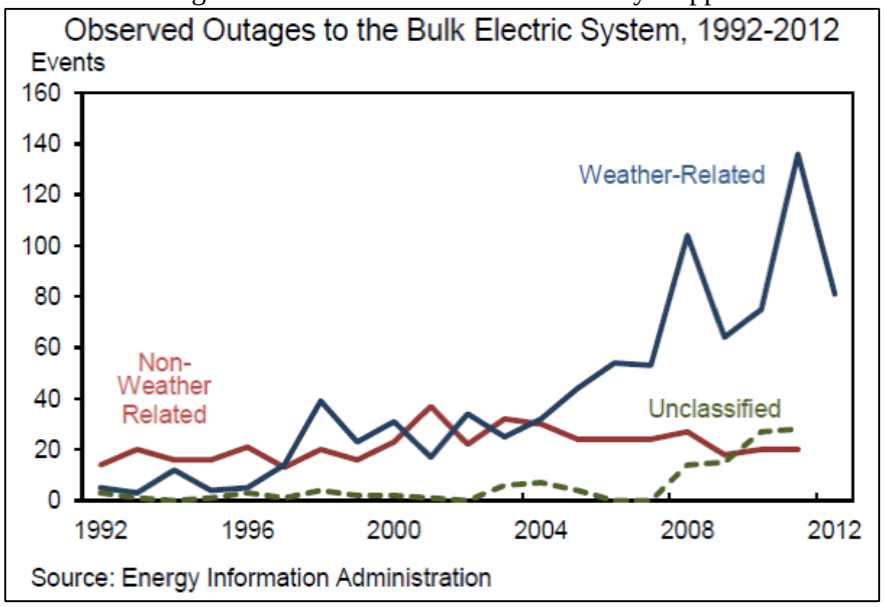

Figure 2-13: Historical Observed Electrical Outages and Cause 1992-2012
Source: (DOE, 2013, p. 8)

To mitigate outages from severe weather transmission and distribution equipment will need to be stronger and more durable, which will increase construction costs. Wide-scale DG adoption reduces construction requirements and creates a network of independent microgrids, which would increase reliability and resiliency. Investment in microgrids can be a cheaper and more reliable option in the long run.

2.4.3 Non-Weather Related Outages

Severe weather is not the only threat to the central grid. Technological malfunctions in equipment can also create outages due to the design of the central grid. Such outages can have significant societal and economic consequences.

In August 2003, 55 million people were without power largely as a result of tree branches tripping a wire (Hampson, Bourgeois, Dillingham, & Panzarella, 2013). The trip created a ripple effect that cascaded through much of the northeast United States and parts of Canada. The power outage left large metropolitan areas without electricity for two days, including Detroit, Baltimore, and New York City. Total economic loss due to the regional outage is estimated between $7-$10 billion (FERC, 2004) The majority of the economic impact came from the closure of major markets including NYC and Wall Street.

In 2011 a similar but smaller scale blackout occurred in the southwest. Millions of people lost power in southern California and Arizona, including the entire San Diego area (FERC & NERC, 2012). The outage was a result of a series of interconnected events that compounded to create the regional blackout. It took a day to restore power completely too all customers. While the event was relatively isolated and quickly addressed, it demonstrates another example of the sensitivity and vulnerability of the central electric grid. Following the event the National University System Institute estimated the outage's economic impact to the San Diego metropolitan area was $100 million (Watson, 2011).

Large power outages such as in 2003 and 2011 typically receive national media attention, but they don't paint the entire picture. Momentary outages, lasting less than five minutes, are also a problem, but not generally reported. While these momentary outages are less expensive than sustained outages, the frequency makes them more costly over time. Approximately two-thirds of the economic losses due to power interruptions are attributed to momentary interruptions (LaCommare & Eto, 2006). Sustained interruptions were only responsible for one-third of the customer's economic losses due to outages. Momentary interruptions then represent a larger problem for industrial and commercial customers. Microgrids can mitigate this problem because they are more reliable and less susceptible to unplanned interruptions.

2.4.4 The Threat of Terrorism to the Electric Grid

Since September 11th, 2001 the threat of terrorism has grown and changed the way infrastructure is constructed. This threat is proving to be applicable to utility companies as well.

In April 2013 a transmission substation operated by PG&E was attacked outside San Jose, California. Unknown suspects used sniper rifles to target 17 transformers in an effort to knock out electricity. The attack was completed within an hour and no individuals were apprehended. PG&E was able to avoid a blackout by rerouting electricity through another substation and asking customers to reduce demand and operate distributed generation equipment. In this case the presence of distributed generation prevented a significant outage PG&E reported the total damage exceeded $15 million and required 27 days to repair. Former chairman of the Federal Energy Regulation called the attack "the most significant incident of domestic terrorism involving the grid that has ever occurred." (Harris, 2013)

It's interesting to note that a 2003 study conducted by ICF Consulting identified the California transmission grid as a vulnerability to terrorism. This report was completed nearly 10 years before the isolated attacks previously noted. ICF warned "a coordinated attack in California could lead to significant economic damages." California is particularly vulnerable due to the interconnection of the transmission grid between industry sectors. In particular ICF highlighted a terrorist induced power outage would ripple and increase prices in hotels, airlines, and other services which would significantly affect the tourism industry. The report concluded by recommending "increased redundancy" and "increased distributed generation such as through promoting CHP" to mitigate outages and relieve transmission bottlenecks (Saha & Moody, 2003).

Less than a week after the attack in San Jose, CA a similar event occurred at a nuclear plant in Spring City, Tennessee. Armed trespassers traveled to the plant on boat from a nearby river. They were met by a security officer and fled the scene after shots were exchanged between the parties. The timing and similarity of the incidence raised questions whether the two events were related in any way (George, 2013).

Around the same time as both the attacks noted above, a sophisticated attack was carried out by Islamic jihadists in Algeria. In January 2013 over 30 terrorist stormed the Tigantourine gas facility near In Amenas, Algeria. The siege lasted 4 days and put a critical national asset in the hands of terrorists. The Algerian government eventually intervened to prevent the terrorists from destroying the plant, which they believed to be a primary motive (Chrisafis, Borger, McCurry, & Macalister, 2013).

Although the attacks on the San Jose and Spring City plants did not create power outages, the events demonstrate a key design consideration in post 9/11 America. These historic terrorist attacks demonstrate that national infrastructure, such as electricity, is a potential target. Electrical designs need to protect infrastructure from this threat. One possible solution to mitigate the potential damage is a move from a centralized model toward distributed generation.

2.4.5 National Economic Impact of Outages

The loss of electrical distribution whether it is due to weather, technical issues, or terrorism can have a substantial effect on the economy. Efforts to quantify the cost of outages can motivate companies or policy makers to pursue microgrid technology. Estimating the economic impact attributed to loss of load has been studied since the early 1960s (Sanghvi, 1982). In recent years more research studies have been published, as severe weather increases the number of outages and as engineers and policy makers become more concerned with the state of the electrical grid. Several estimates have been made and vary substantially.

The DOE reports outages cost the economy annually from $18 to $33 billion dollars in losses. The DOE also acknowledges damage can be significantly higher during years with large storms. In 2008 and 2012, Hurricane Ike and Superstorm Sandy are estimated to have caused up to $45 billion and $26 billion, respectively (DOE, 2013). Energy policy specialists estimate the annual damage to be $20-$55 billion annually (Campbell, 2012). LaCommare and Eto estimate the annual cost of outages is around $79 billion per year. Their study also admits the cost of interruptions could be as low as $22 billion or as high as $135 billion depending on the time of outages. Approximately three-fourths of the economic losses are to the commercial sector (LaCommare & Eto, 2006).

The large range in estimates represents the challenge scientists and economists have quantifying a precise value. The exact annual loss is not necessarily important. What is important is the economic losses demonstrate that power outages significantly impact the overall economy. It is precisely because of this economic impact that private and public entities are looking toward distributed generation to improve reliability and mitigate the effects of central grid outages.

2.4.6 DG Promotion by the Government to Improve Reliability

The extensive impact power outages have on the economy makes the grid's reliability relevant to government entities. In addition to the economic impact, power outages also affect national security and public safety. 99% of DOD installations rely on the central electric grid for power (Samaras & Willis, 2013). Grid reliability also enhances public safety by freeing up police and emergency services that otherwise provide assistance during power outages (Sullivan, Mercurio, & Schellenberg, 2009). The economy, national security, and public good are principle responsibilities for the government; therefore grid reliability is a concern for public officials at the federal, state, and local levels. To ensure the public's interests are continually protected, government has taken steps to improve grid reliability and specifically to increase DG.

It is important to note that not all DG technology will increase reliability. In order to truly improve reliability and function during incremental weather, a microgrid needs to be able to operate independent of the weather. Solar, wind or other renewables are negatively affected during incremental weather. CHP and FCs operate indefinitely during incremental weather as long as the supply of fuel is present. It is this reason that government action to improve energy reliability thru the employment of DG is focused on promoting CHP or FC technology.

2.4.7 Federal Government

Among the first contributions the federal government made to promote DG was investing resources toward information development to be used by the public. The Energy Independence and Security Act of 2007 established a CHP registry that centralized the fragmented inventory of CHP facilities. This same bill also provided partial funding for CHP feasibility studies. The Environmental Protection Agency (EPA) also published the "Catalog of CHP Technologies" in 2008 and last updated the catalog in 2014.

Monetary efforts have also been implemented to promote reliable DG. The 2009 American Recovery and Reinvestment Act allocated $4.5 billion toward 'modern grid technology.' (DOE, 2013) $156 million was specifically set aside for CHP and waste heat recovery technology. The 30% and 10% ITCs for FCs and CHP are also motivation for reliable DG investment.

In August of 2012, President Obama signed an executive order that set a national goal of 40 GW of new CHP installations by 2020 (Hedman, Hampson, & Darrow, 2013). Successfully meeting that goal would increase the CHP generation by 50% from the current 82 GW of capacity.

Federal incentives and encouragement toward CHP are important and have been influential. However, it is actually at the state level where most of the work is being done to promote CHP. Not surprisingly, the states that most aggressively encourage CHP are the same states that were significantly affected by regional storms in the past decade.

2.4.8 State Government

Some of the leading state CHP supporters include Texas, Louisiana, New York, New Jersey, and Connecticut. These states have implemented mandates, incentives or both to promote CHP installations.

Texas and Louisiana adopted somewhat similar laws in 2009 and 2012 respectively. Texas House Bill 1831 and Louisiana resolution No. 171 mandate that critical government facilities undergo a CHP feasibility assessment prior to any major renovation to identify the technical and economic viability of a cogeneration plant (Hampson et al., 2013). Examples of critical facilities include hospitals, nursing homes, prisons, and wastewater facilities. These laws passed in the wake of hurricanes Katrina, Rita, and Ike. Traditionally critical government facilities depend on backup generators, but permanent CHP plants demonstrate several advantages over backup generators, such as:

- Backup generators are seldom used and poorly maintained, leading to problems during real world emergencies
- Backup generators typically have a finite fuel supply compared to CHP plants which are typically connected to permanent underground natural gas distribution
- Backup generators require time to start after grid failure that can result in the shutdown of critical systems. A CHP plant serving as the primary source of electricity decouples the facility's electricity with the central grids supply
- Backup generators only supply electricity. CHP systems can meet power and thermal requirements within the facility
- CHP, which typically uses natural gas, is a cleaner, more efficient, and cheaper fuel compared to the standard diesel powered backup generators.
- (Hampson et al., 2013)

NY state has been a strong CHP advocate for over a decade. In the last 12 years, the New York State Energy Research and Development Authority (NYSERDA) invested over $100 million toward CHP technology. In February 2013, less than four months after Superstorm Sandy, NY governor Andrew Cuomo announced an additional $20 million investment in cogeneration projects that could provide continuous heat and power during outages (Cuomo Administration, 2013). This investment provides up to $2 million in base incentives for qualifying CHP plants. Additional incentives are available for CHP plants serving critical facilities or places of refuge and CHP plants that obtain over 60% total efficiency (NYSERDA, 2015).

New Jersey is another state aggressively pursuing CHP. In 2011 Governor Christie's administration set the goal to develop 1,500 MW of CHP generation over the next ten years (Christie Administration, 2011). In January 2013, only three months after Superstorm Sandy, the state issued a second round of the Large Scale Combined Heat and Power/Fuel Cell Program. This program allocated $25 million to CHP projects greater than 1MW. The program offers $0.55 per installed Watt for CHP plants 1MW-3MW and $0.35 per installed MW for CHP plants greater than 3MW (NJ Board of Public Utilities, 2013).

2.4.9 Microgrid Reliability Case Studies

In the aftermath of several natural disasters such as hurricanes Katrina and Gustave and superstorm Sandy, several successful case studies emerged of microgrids that continued to operate in the midst of regional outages. In particular, CHP microgrids performed well and were able to provide much needed electricity and heat. A number of these locations were established as a base of operations for emergency responders and helped expedite the recovery process. A few of those case studies are presented in this section.

South Oaks Hospital is a 245 bed health care facility is located on Long Island, NY. The hospital initially installed CHP in 1990 and was able to maintain power because of the equipment during the Northeast Blackout in 2003. In October 2012 South Oaks isolated itself from the local utility on the evening before Hurricane Sandy hit the region. South Oaks never lost power during the storm and provided thermal and electric energy for the duration of rescue efforts. The hospital admitted other patients from nearby treatment facilities and provided refrigeration for vital medicines that would have otherwise been lost due to the power outage. Power was restored to the area after five days; however, the local utility requested South Oaks to remain isolated from the grid as they stabilized power distribution. South Oaks was able to remain disconnected for 15 days, during that time they provided critical services and allowed hospital staff and local community members a place of refuge to perform tasks such as taking a shower and recharging their phones (Hampson et al., 2013).

Co-op City located in Bronx, NY demonstrated the resiliency of CHP on a large scale during Hurricane Sandy. While much of NYC and New Jersey were without power following the storm, the 40MW combined cycle CHP plant provided uninterrupted power and heating throughout the storm. This plant served 60,000 people during the storm and offered a place of refuge in an otherwise devastated area (Hampson et al., 2013).

Hurricane Katrina was another devastating natural disaster that primarily hit Louisiana in 2005. Over 1,800 people died from the storm that caused over $81 billion in property damage, making it the costliest natural disaster in the history of the United States. During the storm the Louisiana State University (LSU) campus in Baton Rouge was able to stay online and never lost power. The Lod Cook Conference Center and Hotel, located on campus, also benefited from uninterrupted power and heat. This hotel housed a number of LSU employees as they remain displaced during the storm. The campus CHP plant proved itself again in 2008 when it provided uninterrupted power after Hurricane Gustav caused extended blackouts in the area (Hampson et al., 2013).

There are dozens of similar scenarios that demonstrate CHP's dependability in otherwise disparate times. The reliability CHP demonstrated during the aforementioned natural disasters is one of the principle reasons it is receiving so much attention by engineers and legislatures. However, given the rarity of such devastating natural disasters successful implementation of a CHP plant on the basis of reliability alone is unrealistic. Even in the case of critical infrastructure, backup generators are usually preferred due to lower initial costs. While reliability is a major benefit for a CHP plant owner, the decision to install CHP is still very much motivated by economics.

2.5 Return On Investment

Distributed generation and microgrids can benefit the public with reduced emissions and increased reliability, as has already been discussed. These benefits are of principal interest to the government at all levels (federal, state, and local). However, successful large-scale distributed generation implementation relies on the private sector's capital investment (Campbell, 2012). While reduced emissions and reliability are beneficial, these factors are insignificant to a private company considering DG investment. The fact is private enterprise pursues distributed generation almost exclusively based on the economics of the decision. In particular decisions are made on the basis of the return on investment (ROI).

2.5.1 Background

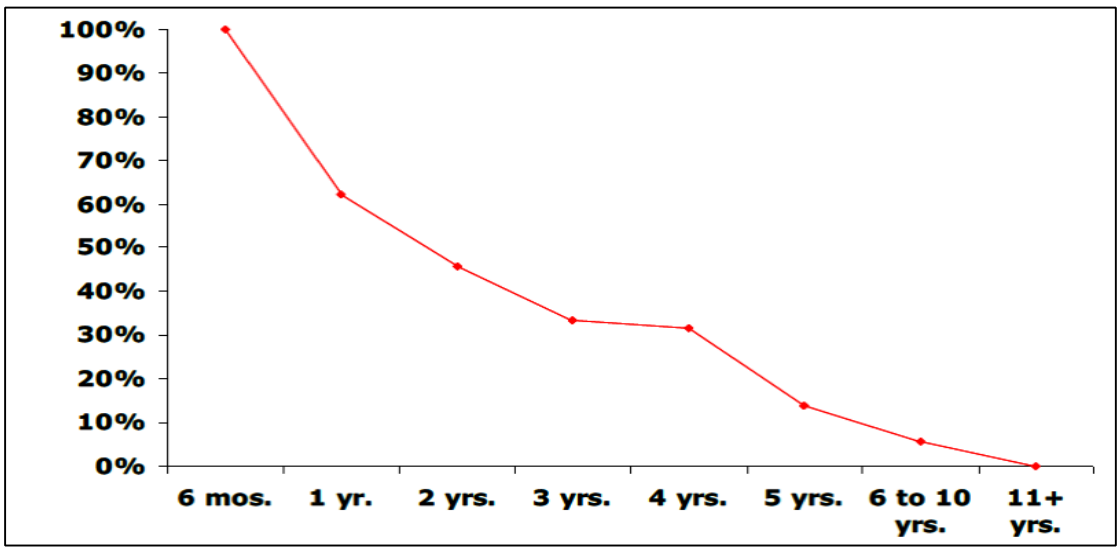

Figure 2-14: DG Investment based on ROI
Source: (Hedman & Hampson, 2010, fig. 4)

In a survey of prospective DG customers, less than half expressed a willingness to invest in CHP if the payback was less than 2 years. That percentage dropped rapidly as the payback period increased with less than 10% expressing a willingness to invest in a payback between 6 to 10 years. This strong correlation emphasizes that although emissions and reliability may be ancillary benefits, the dollar is king when choosing to invest in a microgrid (Hedman & Hampson, 2010)

A report published by ICF International that investigated a number of CHP installations captured a consistent theme regarding the benefits and decision making process:

"NYU installed the new CHP system in 2010 in order to save money and reduce the University's carbon footprint. However, the CHP system has led to a number of other benefits for the university such as allowing for energy independence from the utility, increased reliability, reduced load for Con Edison [local utility], reduced energy costs and air emissions."(Hampson et al., 2013)

This statement represents the multiple benefits at play. The principle motivator for NYU was to save money; the subsequent benefits were realized only after operation and were not mentioned as part of the motivation.

Economics therefore needs to be understood as the principle driver for the private sector. Any efforts to encourage DG implementation in the private sector that doesn't address the ROI will fail to succeed. Even if significant benefits exist, without favorable economics, the investment is unlikely to happen. Conversely, it can be expected that if the economics are favorable, but the design is limited in other benefits, the company will still likely choose to invest.

Figure 2-15 illustrates the driving forces encouraging distributed generation adoption and how those relate to the public and private sectors desires:

Figure 2-15: DG Investment Motivation

The US government recognizes the importance economics play into the decision, which is why incentives are provided through tax reductions and utility rates. These economic incentives help bridge the gap between the public and private sector priorities.

2.5.2 Primary Economic Benefit

Microgrid economics depend on a number of factors including location, system size, design, and application. Capital costs vary based upon the microgrid technology selected and the economic savings are highly impacted by the system's primary energy utilization efficiency. In the case of CHP and FCs the savings increase if the load can capture and use as much of the fuel's primary energy as possible through electrical and thermal deployment. Despite the variable economics there are a few relatively consistent factors that contribute to the operational savings.

The primary operational savings are associated with displaced utility bills. If the microgrid can generate electricity at a rate cheaper than it can be purchased, the plant will save money. In the case of solar PV and wind turbines, electricity is cheap once the system is installed due to the free availability of the "fuel." CHP and fuel cells require a natural gas supply to operate and the cost of fuel needs to be considered when comparing the price per generated kWh with the utility company.

A microgrid's magnitude of savings is important because the capital costs for a microgrid can be substantial. Annual savings depend largely on the total energy consumed and the local utility rates. The ROI or payback period improves with increasing electrical rates. Therefore, microgrids are more economical in regions with higher electrical rates. The Clean Power plan is also projected to increase electric rates, which will further improve the economic conditions for microgrid investment.

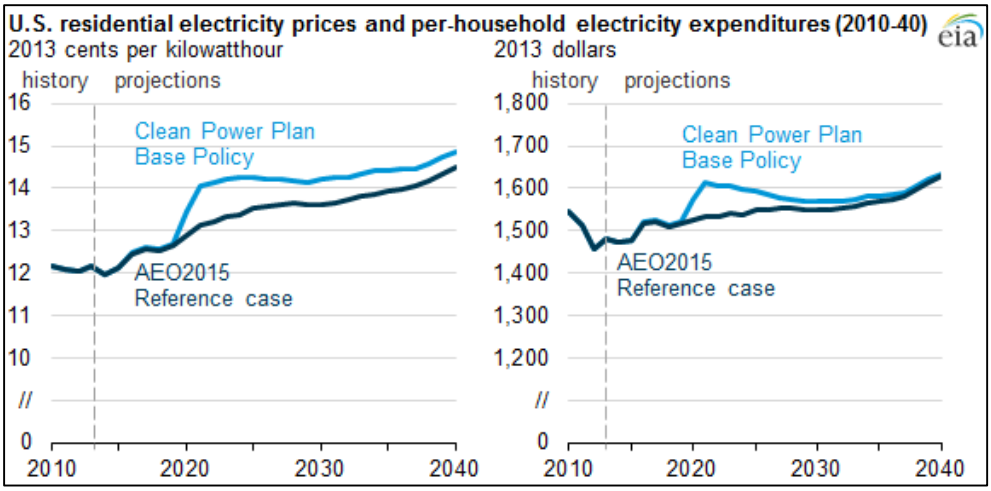

Figure 2-16: Clean Power Plan's Impact on Utility Rates
Source: Today in Energy June 11, 2015 (EIA, 2015h)

Microgrids often produce annual savings, but because of the high capital costs associated with the equipment and interconnection, savings need to be substantial to yield attractive ROIs. Every investor has different levels of tolerance for seeing a return on their investment, but typically a 3-5 year payback period is desired. Microgrids are becoming more competitive economically, but still rely on the right technical application and economic conditions (Borbely & Kreider, 2001). In CHP applications, operational savings are highly unlikely without the utilization of a significant quantity of thermal energy. Similarly solar PVs are not yet financially competitive without the 30% ITC from the government.

2.5.3 Capital Costs Decreasing

Distributed generation's economic feasibility is improving primarily because technology capital costs have recently become competitive. Advances in materials, science, and engineering have reduced the levelized cost of electricity. Additionally, manufacturing improvements and economies of scale associated with a larger market also helped lower costs. (DG Textbook)

Up through the 1970s the only significant consumer of PV technology was the U.S. Space Program. Prices exceeded $30/W during the period and were far too expensive to be used in building supplied electricity (Borbely & Kreider, 2001). During the 1980s and 1990s, prices dropped and building installation increased. Despite this improvement the majority of PVs in buildings were off-grid applications. Off-grid applications fail to increase the reliability of the central grid and meet the true intent of distributed generation. Only since 2000 have grid connected applications exceeded off-grid installations. Since the 2000s, solar investment and installation continues to increase in residential and commercial applications. Much of this is a result of the solar ITC legislated by the Energy Policy Act of 2005. Figure 2-17 shows the dramatic decrease in installation costs in 2009 which made PV more competitive. As of the end of 2013, the installation cost for residential and small commercial (≤10kW) PV was $4.69/W and large commercial (>100kW) was $3.89/W (Feldman et al., 2014). PV prices have dropped significantly for four consecutive years, which is promising for the future implementation of DG (Roselund, 2014).

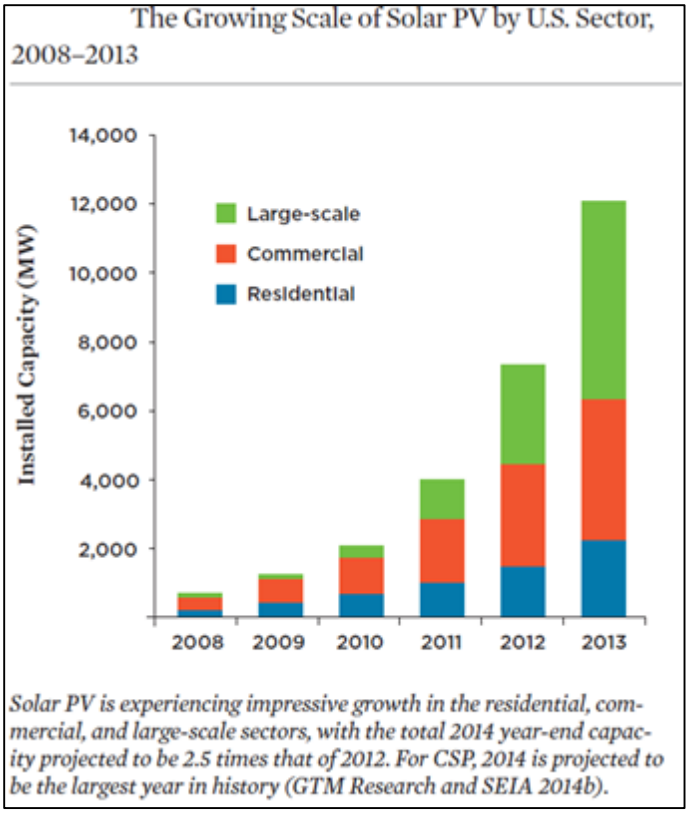

Figure 2-17: PV Installations in U.S. 2008-2013
Source: (Rogers & Wisland, 2014)

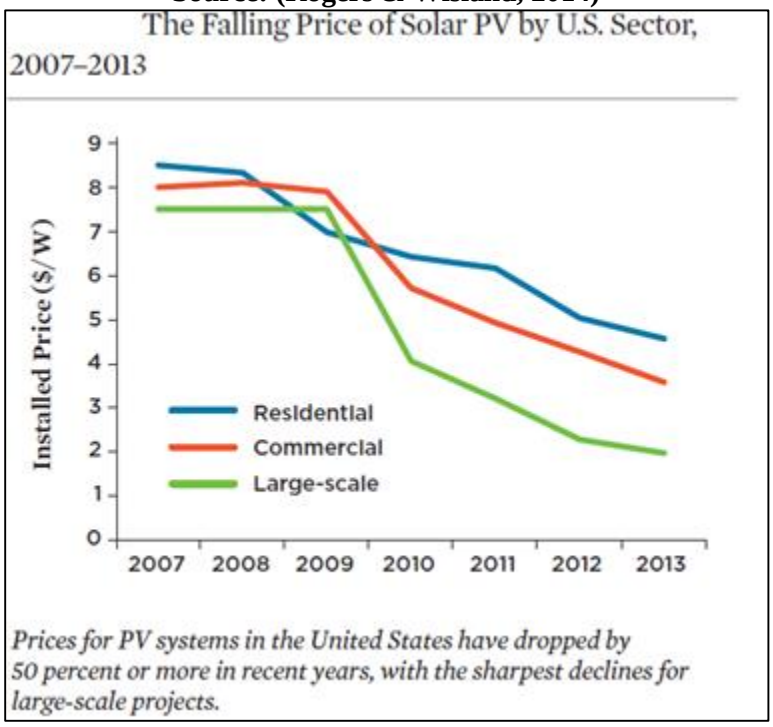

Figure 2-18: PV Installation Costs in U.S. 2007-2013
Source: (Rogers & Wisland, 2014)

Wind generated electricity increased drastically in the past 20 years, Largely precipitated by government policies. The Energy Policy Act of 1992 created a production tax credit of 1.5 cents per kWh, and the 2009 American Reinvestment and Recovery Act instituted a 30% investment tax credit. These policies enabled wind generated electricity costs to reach grid parity in the early 2000s, which increased the market penetration. Wind energy has increased drastically in the first decade of 2000 and is expected to continue. It is projected to be the largest growing renewable energy source and expected to surpass hydropower by 2040 (EIA, 2015c). Wind energy is the most economical renewable energy.

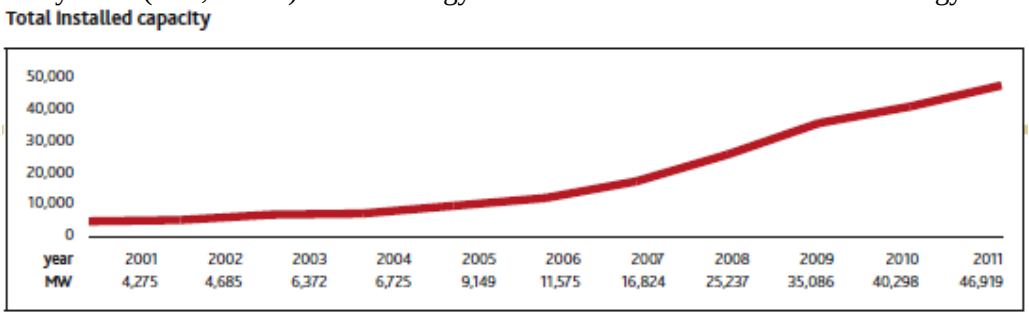

Figure 2-19: Total Wind Capacity in U.S.
Source: 2011 Global Wind Report (Fried, Shukla, & Sawyer, 2012)

Fuel cells, like solar PVs, were primarily developed during the space race between the US and Soviet Union. During that time installed costs for the technology were an astronomic $1 million per installed kW. Today the price has dropped significantly to $4,000 per installed kW. Approximate costs are $3,000/kW for the fuel cell and an additional $1,000/kW for installation. While the price has dropped significantly since the 1960s, there are several barriers preventing the technology from reaching the desired $800-$1,000/kW. At this price fuel cell technology can compete with other DG technologies strictly on the basis of cost (Borbely & Kreider, 2001). A significant limiting factor to fuel cell costs is the expensive material costs, such as platinum, used in proton exchange membrane fuel cells. The complexity of fuel cell technology also demands labor intensive manufacturing, which adds to the costs. These high capital costs are the biggest reason fuel cells don't have more market penetration (Borbely & Kreider, 2001). The lack of market penetration limits the sale volume required for economies of scale to reduce the total price. The high efficiency, low emissions, and scalability of fuel cells make them an attractive option for distributed generation. However, the high capital costs at this time limit the market potential.

Compared to the other DG technologies mentioned (wind, solar, Fuel Cells) CHP is the most affordable on a cost per kW basis. The large majority of microgrid owners use CHP to generate electricity. The enhanced reliability and lower capital cost make CHP an easy choice for investors. Internal combustion CHP plants cost around $2,000/kW and gas turbine (GT) CHP plants cost around $3,000/kW; however, prices vary by size and manufacturer. Table 2-1 compares the typical DG equipment costs discussed in this section.

Table 2-1: Current DG Technology Installation Costs

Technology	Size	Installation Cost ($/kW)	Source
Soar PV	≤10 kW	$4,690	(Feldman et al., 2014)
Soar PV	>10 kW	$3,890	
GT CHP	3,300 kW	$3,281	(Darrow, Tidball, Wang, & Hampson, 2015)
GT CHP	9,950 kW	$2,976	
IC CHP	3,300 kW	$1,800	
IC CHP	9,300 kW	$1,433	
Wind Turbine	100 kW	$1,500	(Wiser & Bolinger, 2015)
Fuel Cell	2,800 kW	$4,000	(Toby, 2015)

2.5.4 The cost of losing the grid

A facility that receives electricity from a local microgrid is not susceptible to utility service interruptions. In addition to the utility bill savings, the company will also benefit economically by avoided unscheduled utility service interruptions. Estimating the avoided economic losses that would otherwise occur is an inexact science. There is no way to know the number of outages a facility would have experienced if it were connected to the central grid. However, the losses are real and companies may find it useful to consider these potential losses to justify microgrid investment. This may be especially important to industrial customers who have sensitive equipment or require significant lead time to start and stop equipment. Studies do exist that estimate the cost of power outages. There may be benefit to factoring these losses into the economic ROI. Table 2-2 provides 2001 estimates for customer outage costs in the residential, commercial, and industrial sectors.

Table 2-2: Power Outage Cost Estimate per Duration
Source: (LaCommare & Eto, 2006)

Duration	Residential	Commercial	Industrial
Momentary interruption	$2.18	$605	$1893
Sustained interruption	$2.99	$1067	$4227
1-h interruption	$2.70	$886	$3253

The LaCommare and Eto report highlights there is an economic impact related to reliable grid power. While residential outages may only experience minor effects, an industrial outage can cost up to $3,500 per hour. Companies should factor in potential losses from electrical outages when considering DG. If momentary outages have the potential to damage equipment, that potential economic loss should be factored into the economics that influence the final decision.

2.5.5 Demand Response Programs

Demand response programs are another economic consideration that may influence the decision to invest in distributed generation. In the past decade, demand response has proven to be an effective method for utilities to address rising peak demand. Historically total energy consumption and peak electricity demand increased at the same rate making utility generated electricity fairly straightforward. Recently, as electronic devices have become more common in everyday life, peak demand has diverged from total energy consumption.

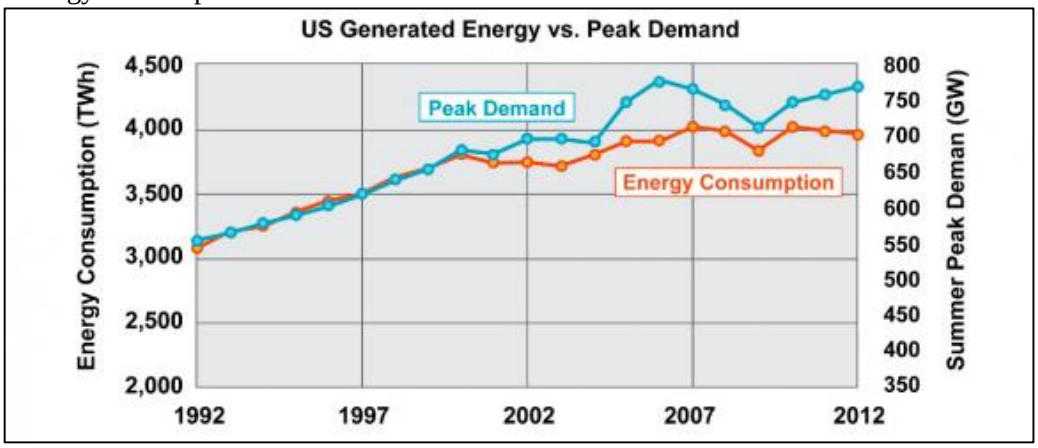

Figure 2-20: U.S. Total Energy Consumption and Peak Demand 1992-2012
Source: (St. John, 2015)

Power plants are required to meet peak demand and therefore need to increase generation capacity even if total consumption remains constant. This increases capital costs with minimal effect to the charges and operating budget. To delay investment in new equipment and to keep demand under peak generation capacity, utility companies have turned to customers that are willing to reduce demand when notified. In exchange participating customers receive economic compensation.

Utility companies typically solicit significant electricity consumers to participate in demand response such as industrial or large commercial customers. These customers enter a contract with the utility that states customers will reduce consumption upon request. In return the utility may offer economic compensation to the customer for participation. The specific compensation and details vary between utility companies.

New England's independent system operator released an example of demand response in action during a hot and humid summer day in 2010. This event is displayed in Figure 2-21. Higher than expected temperatures occurred on the same day 1.8 GW of generating capacity experienced unplanned outages. Without the additional reserves to meet higher than expected demand, ISO-NE alerted their demand response resource network to reduce load by 669 MW shortly before 3:00pm. The reduction in demand and subsequent lower temperatures returned the demand to manageable levels. After three hours, customers were able to resume typical consumption and the crisis was averted.

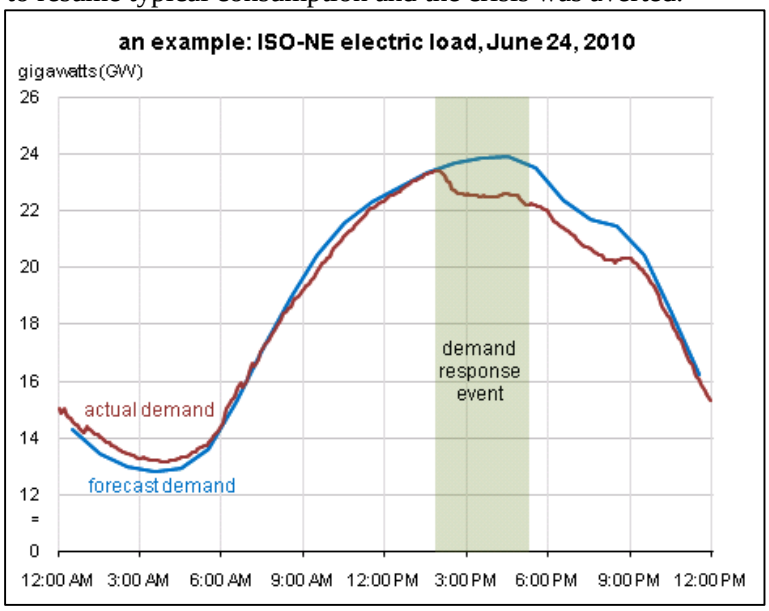

Figure 2-21: Demand Response Example
Source: Today in Energy February 15, 2011 (EIA, 2011)http://www.eia.gov/todayinenergy/detail.cfm?id=130

Significant users of electricity may be attracted to the economic benefits of enrolling in demand response with their utility company. However, the unpredictability of such a contract may pose threats to their own operations. In particular, large processing industrial facilities may have expensive equipment that requires significant time to start and stop. With a reliable distributed generation source such as CHP, these companies could benefit in a demand response program with negligible consequences.

The demand response successful model and mutual benefit to utility companies and customers has driven the popularity. Today most states have one form or another of a demand response program in place. Microgrid owners may be particularly suited to capitalize on this economic benefit, due to the additional generation capacity they have on hand. Demand response is unlikely to play a significant role in the decision to invest in distributed generation, but it can offer an additional economic benefit to microgrid owners.

2.6 Hybrid Microgrid Benefits

Microgrids are typically made up of only one DG technology, but the combination of multiple DG technologies can have positive synergistic effects. This integration of distributed generation technologies is referred to by a range of terms including, distributed multi-generation, distributed energy resources, distributed micro-generation, integrated energy systems, etc. This paper refers to the combination of CHP or FCs, renewable energy, and energy storage (electrical or thermal) as a hybrid microgrid. A hybrid microgrid (HMG) can have any combination of these sources to meet demand with increased levels of complexity and control. The goal of a HMG is to increase the total system efficiency by improving renewable energy penetration levels, without compromising the reliable supply of electricity.

2.6.1 CHP is Cornerstone/Limits of Renewables Alone

CHP is the backbone of a HMG (Chicco & Mancarella, 2009). More than anything, customers need consistent, reliable power at all times. Renewable energy sources, such as wind and PV, inherently have low capacity factors due to the volatility of the fuel source. PV and wind output electricity vary unpredictably during the course of the day. Due to the low capacity factors, renewables are unable to generate electricity on demand. With renewable technology alone it is impossible to meet a building's real time load. Figure 2-22 and Figure 2-23 show the volatility in output for wind and solar power.

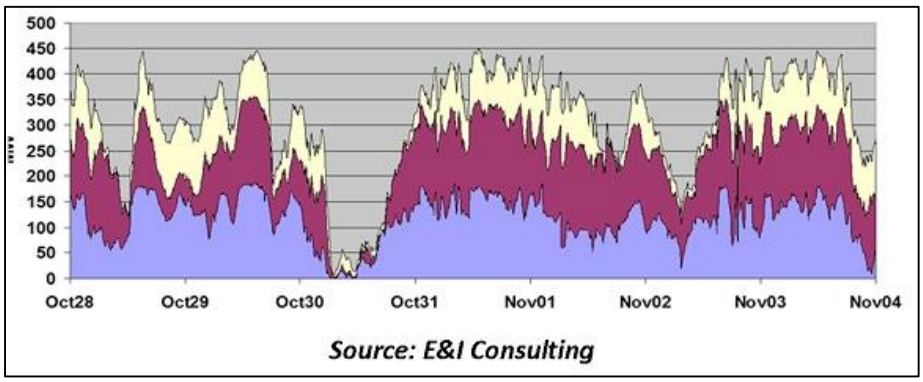

Figure 2-22: Wind Generated Electricity Over 8 Days
Source: (Energy Storage Association, n.d.-b)

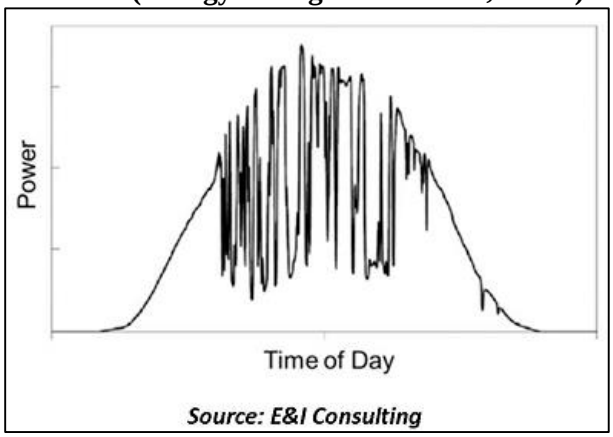

Figure 2-23: PV Output Electricity over 24 Hours
Source: (Energy Storage Association, n.d.-b)

Renewable output electricity also varies with seasons and may create generation shortfalls. CHP can meet this shortfall and provide electricity on a consistent and economically predictable basis. CHP fills the void in renewable power production and is the pillar of reliability for a facility.

Another limiting factor for renewables is space. Solar and wind need significantly more land than a CHP plant to provide the same power. A 10 MW wind farm requires ten times the land as a 10 MW CHP plant. A PV array needs twenty times the square footage required of a wind farm. The necessary footprint is documented in Table 2-3. Land is a premium resource in urban areas such as California that may not be available in a microgrid design.

Table 2-3: 10 MW Microgrid Technology Comparison
Source: (Hedman et al., 2013, Table 6)

Category	10 MW CHP	10 MW PV	10 MW Wind
Annual Capacity Factor	85%	25%	34%
Annual Electricity	74,446 MWh	21,900 MWh	29,784 MWh
Annual Useful Heat Provided	103,417 MWh_t	None	None
Footprint Required	6,000 sq ft	1,740,000 sq ft	76,000 sq ft
Capital Cost	$20 million	$48 million	$24 million

Additionally while incentives and technology improvements are reducing the costs of renewables, CHP is still significantly cheaper on a $/kW basis. By designing the hybrid microgrid with the majority of the load met by CHP, capital costs are drastically reduced.

The goal of a hybrid microgrid is to increase the penetration level of renewables, thereby minimizing the need for carbon based fuel. Completely displacing fossil fuel generated electricity is unrealistic because of reliability, size, and economic factors. CHP or fossil fuel generated electricity is the cornerstone of a hybrid microgrid.

2.6.2 Benefit of CHP Enabled Renewables

PV and wind generated electricity are emission free and cost free. Maximizing the load share of renewable technology can reduce total emissions and operational costs. CHP enabled renewable technology can effectively increase the renewable energy penetration levels, which will decrease emissions. Pearce showed that the addition of a load following CHP plant can increase the PV penetration limit from the status quo 5% to an upper limit of 25% in southern California residential applications (Pearce, 2009). Practically speaking this would require quick response CHP technology and sophisticated controls. Current market available technology prevents PV level from being realized, but the theoretical 25% limit represents a five-fold increase in PV penetration due to CHP presence. This level could be increased further with the presence of energy storage technology.

CHP captures waste heat during electricity production to address thermal demands. Typical electricity efficiencies range from 27-45%. The remaining percentage is converted to heat where a heat exchanger captures approximately 60% to be used in the facility. This creates significant heat that needs to be used by the facility or stored in order to prevent wasted energy. During the winter season there is typically sufficient thermal demand to capture and use all the rejected heat from the generator or gas turbine. However, during the summer electricity requirements increase while thermal demand decreases. In order to meet demand the CHP prime mover (PM) needs to increase its output electricity, thereby simultaneously rejecting more waste heat. In the summer months this additional waste heat is typically unusable, excluding large industrial facilities with high process loads. CHP designers then face the challenge of deciding between selecting a CHP PM that under produces electricity and maximizes the heat capture (most common) or installing a CHP PM that meets the electric demand but wastes significant energy in the process.

It is here that solar PVs complement CHP well. PV generated electricity increases during the summer months when sunlight is present for longer hours and radiation peaks are higher. The increased PV output corresponds to higher electricity demand. Combining PV and CHP in a hybrid microgrid enables a higher share of the total electricity demand to be met by the microgrid without oversizing the CHP plant. A smaller CHP plant decreases the operational costs, capital costs, and waste heat. The combination of CHP + PV has the benefit of:

- Consistent supply of electricity not otherwise available with only PV
- Greater net system efficiency since portion of electricity comes from renewables instead of 100% from CHP.
- Smaller heat loss, operational costs, and capital costs due to smaller CHP PM

2.6.3 Value of Stored Energy

No discussion of renewable technology would be complete without discussing energy storage. Scalable, cost-effective electrical storage is one of the limitations to large-scale implementation of renewable electricity generation. Renewable technology is an intermittent supply source that varies with wind speed and solar radiation. As renewable electricity supply fluctuates, the remaining grid supplied electricity needs to change output rapidly to keep supply levels consistent. This puts excessive strain on the grid and limits the grid's renewable electricity penetration.

The limited renewable supply window also prevents the full potential energy to be captured and utilized. In the absence of storage, generation must align with real-time demand. The PV generation window and residential load profile is a classic example of the missed potential. Residential loads have a short maximum in the morning as residents wake up and then peak in the evening when occupants return from work. Solar PV potential rises and sets with the sun. By the time residents return home and are consuming the most energy, renewable PV electricity is no longer available. With sufficient energy storage, such as batteries, all of the electricity can be utilized, effectively shifting the generation time. In this case, the area under each curve represents the total supply and demand.

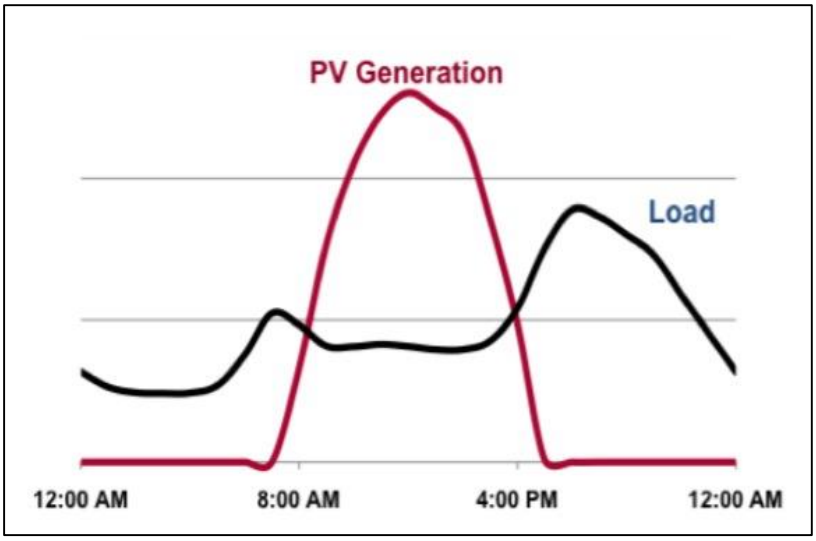

Figure 2-24: Typical PV Generation and Residential Load
Source: The Future of Residential Solar (Bushong, 2015)

Storage can also be a simplified solution in areas with congested or saturated electricity supply. As new buildings are constructed, the required electricity may exceed the transmission and distribution networks carrying capacity, as shown in Figure 2-25. Traditionally as this occurs new lines need to be installed to increase the net capacity. Alternatively, storage may be an acceptable cheaper alternative. During the period that demand exceeds the T&D carrying capacity the battery can discharge electricity to cover the difference. The necessary storage size (MWh) is the area under the curve that exceeds the T&D carrying capacity (the shaded area). This solution is economically viable if it can displace the much higher costs of new T&D infrastructure.

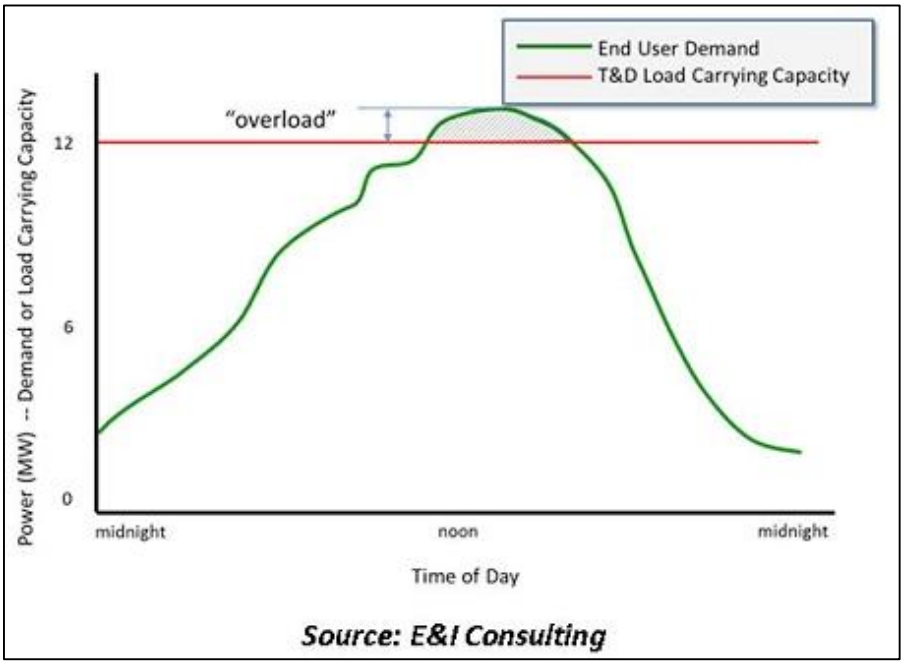

Figure 2-25: Electricity Demand and Transmission Capacity
Source: Grid Infrastructure Benefits (Energy Storage Association, n.d.-a)

Load profiles characteristically fluctuate over the course of a day and seasons. The residential load profile shown in Figure 2-24 demonstrates that demand varies in real time. Commercial building demand varies too, with higher consumption for about half the day (7am-5pm) and low usage during the night. The variations in residential and commercial load profiles drive power plant generation sizes. Total generation must be capable of meeting peak demand. Larger equipment increases costs, which is why utilities charge higher rates for peak demands. Varying load profiles influence the power quality and complicate the controls necessary to regulate electricity. More consistent or flatter load profiles simplify the electricity distribution network and reduce costs. Figure 2-26 below demonstrates how each increasing storage size (daily, weekly, and annual) reduces the peak demand and flattens the load profile.

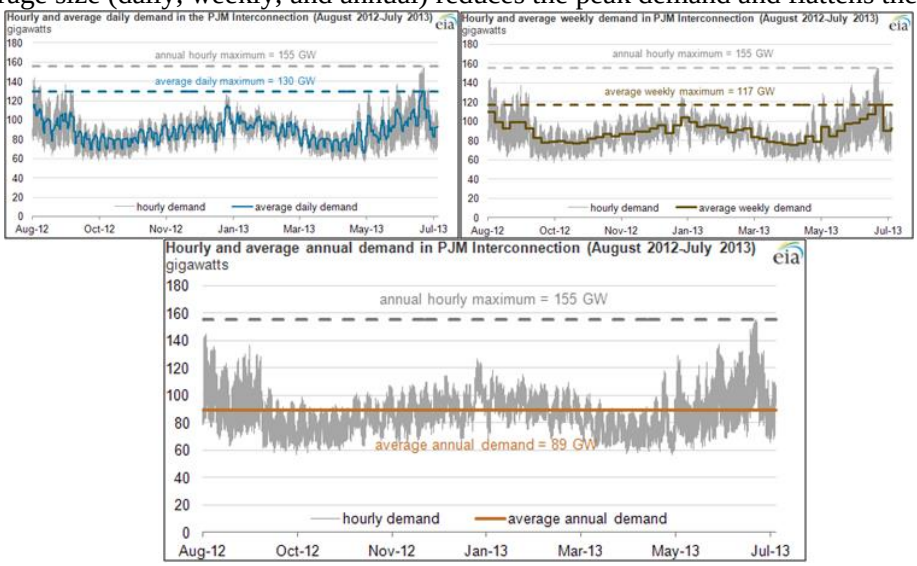

Figure 2-26: Effect of Storage on Generation Requirements: daily/monthly/yearly
Source: Today in Energy September 26 2013 (Booth, 2013)

Large scale electric storage is typically limited to pumped hydroelectric reservoirs, which accounts for more than 98% of the current electricity storage capacity (Marcy, 2015) (Bradley & Wilczewski, 2015). This storage requires specific geologic characteristics and is expensive. Smaller storage capacity can effectively reduce peak demand curves, but over shorter intervals. Battery technology is the standard non-hydroelectric storage option, but new options are being researched as advancements in battery technology stall. One potential solution is storing electricity in the form of hydrogen, known as power-to-gas. Additional electricity from renewables can be used in electrolysis to separate hydrogen from water. Germany currently has 18 experimental programs devoted to power-to-gas storage (Bradley & Wilczewski, 2015). In the US, Southern California Gas Company is currently investigating the commercial application of power-to-gas storage. This storage technology would increase the market for hydrogen powered fuel cells in microgrid technology.

Figure 2-27: Pumped Hydroelectric Storage
Source: Today in Energy June 29, 2012 (EIA, 2012c)

2.6.4 Hybrid Microgrid Studies

Several studies have shown the benefits of hybrid CHP and renewable energy over conventional cogeneration (Nosrat, Swan, & Pearce, 2013). Nosrat et al. simulated a hybrid microgrid consisting of CHP, PV, and electric battery storage installed in three residential applications. The study showed the HMG releases one-third the annual CO2-eq emissions when compared to CHP operation alone. When the hybrid system used exhaust heat for cooling (known as combined cooling, heat, and power or CCHP), the fuel utilization rate ranged from 94-105%. The above 100% utilization rate means that net energy generated by the CCHP and PV technology exceeded the fuel required to power the CCHP plant.

Elhadidy (2002) modeled a HMG made up of two renewable sources (wind and solar), diesel power, and battery storage in commercial/residential buildings in Dhahran, Saudi Arabia over a ten year period. The study gradually added components and investigated how the requirement for diesel generated electricity changed. The annual load was 702 MWh or approximately a 1,900 kWh average daily load. The addition of a 100kW wind turbine reduced the diesel generated energy by 29% and reduced the generators operating hours by 8%. A 1,000 m^2 PV array was added to the HMG and operated parallel to the 100kW wind farm and diesel generator. The wind and solar combined to generate 45% of the annual demand. Finally the study investigated the effect of a 200kW wind turbine, 24-hour peak demand electrical storage, and a diesel generator. The results showed this HMG reduced the diesel generated electricity requirement to 46% of the annual demand and the total hours of operation decreased to 4600 hours or approximately only half the year. The presence of 24 hour storage enabled over 50% of the demand to be met by the 200kW wind turbine and reduced the diesel operation time 30% more than with the 200kW wind turbine alone. Table 2-4 and Table 2-5 summarize the reduction in diesel electricity production and operation hours for the base case of an average daily load of 1,916 kWh and 8760 annual operation. The results demonstrate the potential of renewable technology and battery storage can have in reducing the total energy required by a fossil fuel based electricity production.

Table 2-4: Elhadidy (2002) Results

	100kW Wind	100kW Wind + 1000m^2 PV
Avg Daily Generated Diesel Electricity (kWh)	1391	1054
Diesel Energy Decrease	27%	45%
Annual Generator Hours	8063	N/A
Operational Hours Decrease	8%	

Table 2-5: Elhadidy (2002) Results

	200KW Wind	200kW Wind + 24 Storage
Avg Daily Generated Diesel Electricity (kWh)	1069	884
Diesel Energy Decrease	44%	54%
Annual Generator Hours	6649	4613
Operational Hours Decrease	24%	47%

Elhadidy and Shaahid (2000) completed a parametric study to investigate the best combination of wind + solar + battery + diesel generated electricity in order to satisfy an annual load of 41.5 MWh. This load represented a typical residential four-bedroom house (~2100 SF) located in Dhahran, Saudi Arabia. The optimum HMG included 2x10kw wind turbines, 30 m^2 PV array, 3 day battery storage, and a diesel generator to meet any additional electricity. This combination reduced the diesel generated electricity requirement to 27% of the annual load, which far exceeds typical distributed generation technology currently operating. However, without storage the diesel generated requirement is 48% of annual load. This study highlights the impact energy storage can have on reducing carbon based electricity consumption.

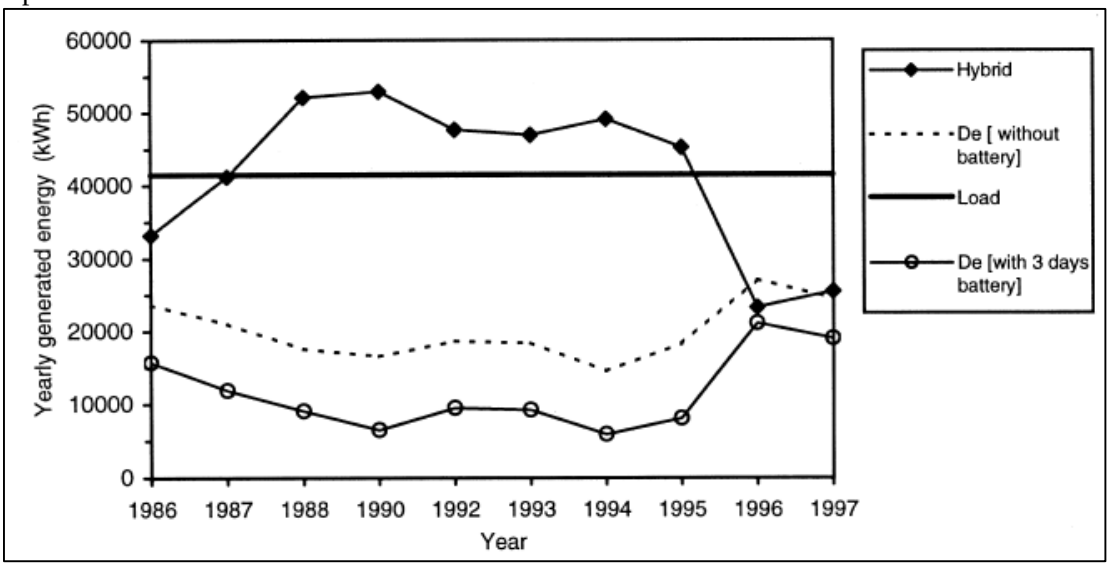

Figure 2-28: Diesel Generation Requirements with and without Electricity Storage
Source: (Elhadidy & Shaahid, 2000)

2.7 Why California?

HMGs technically can work in applications across the country. Site conditions and load demands dictate the relevant levels of site generation, renewable resources, and thermal or electric storage. Theoretically any HMG can be correctly matched to reduce emissions and increase reliability. However, practically these investments will only be made where the market conditions are favorable for profit and a return on investment. California stands above the rest of the country as a potentially profitable economic market environment.

2.7.1 Favorable Utility Rates

The largest economic driver for microgrid technology is the local utility rates. Local utility rate structure determines the avoided energy purchase costs and therefore, the economic savings associated with DG. It is precisely for this reason that states with the highest electricity rates were the first to deregulate in the 1990s (Borbely & Kreider, 2001). Similarly studies investigating the effect of market changes on CHP investment show that rising electric costs are the biggest contributor to CHP investment. The increased rate reduces the ROI quicker than lower capital costs or reduced fuel prices.

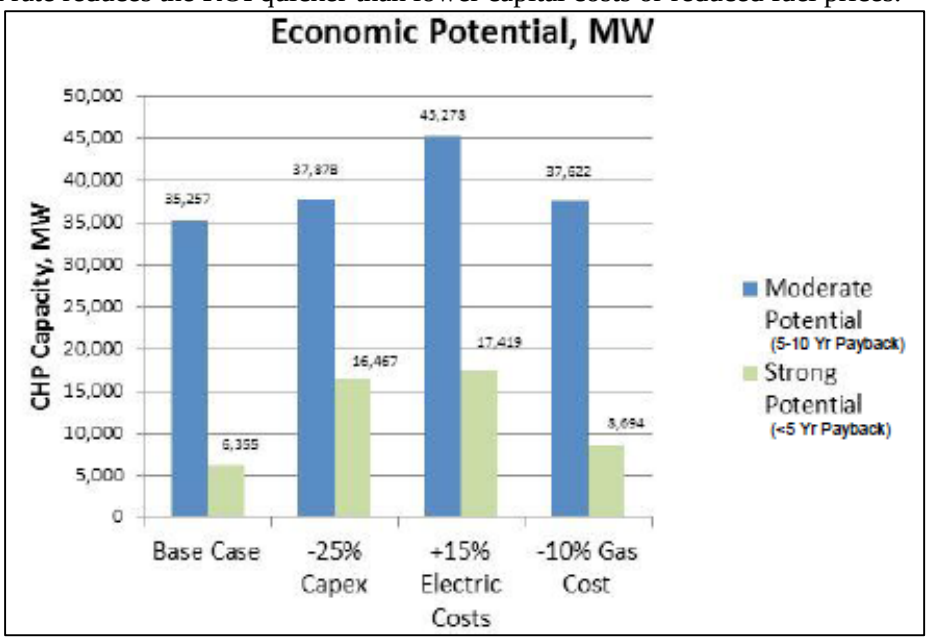

Figure 2-29: CHP Economic Potential Based Upon Economic Conditions
Source: (Hedman et al., 2013, fig. 22)

California's electricity rates are one of the 10 most expensive in the contiguous United States (Jiang, 2011).

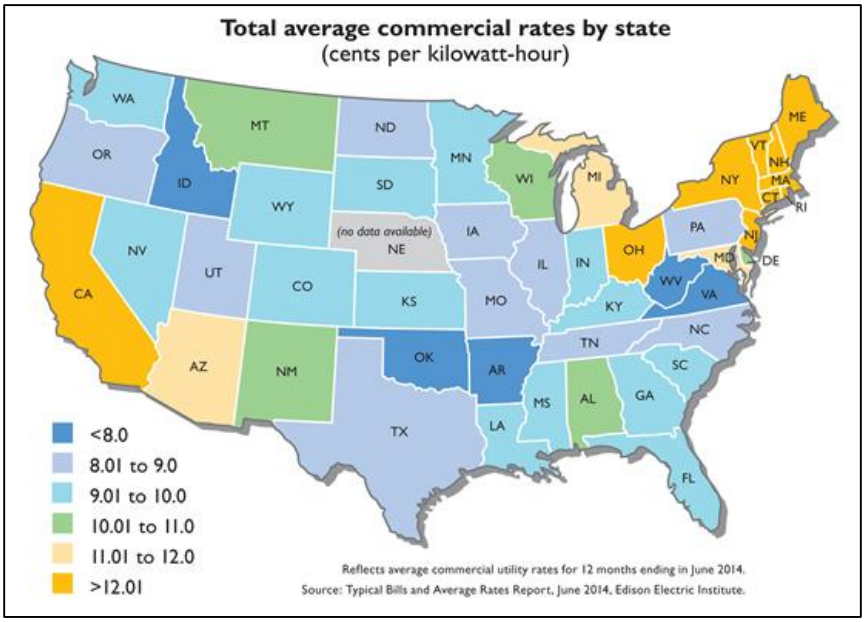

Figure 2-30: National Commercial Electrical Rates
Source: Commercial Price Comparison (Pacific Power, 2014)

The three largest utility companies in California: Pacific Gas and Electric (PG&E), San Diego Gas and Electric (SDG&E), and Southern California Edison (SCE) all advertise baseline residential usage rates around 17 cents per kWh (PG&E, 2015)(SCE, 2015)(SDG&E, 2015). 2014 average national residential rates were 12.5 cents per kWh (EIA, 2015e, sec. Table 5.3). In July 2014 SCE hiked residential rates for customers in tier 1 and 2 up 12% and 17%, respectively. Current projections forecast continued increased rates as utility companies seek to reduce the number of tiers from four to two, in part of a larger restructure (Roth, 2014).

In reality, electricity rates vary in real time. Electricity consumption during peak demand is more expensive. SCE advertises residential rates that are four times higher for on-peak consumption than night time electricity consumption (SCE, 2015). A hybrid system that can increase electricity generation during off-peak hours and reduce consumption during on-peak times can capitalize on the natural market fluctuations and save on energy bills. Even better would be a microgrid that could generate electricity during off-peak hours and sell it during on-peak consumption. The high utility rates in California make the market more favorable than in other locations.

Table 2-6: SCE Residential Electrical Rates
Source: (SCE, 2015)

Residential Time-of-Use TOU-D-A* (price/kWh)		
Time of Day	**Summer (June – September)**	**Winter (October – May)**
On-Peak: 2 p.m – 8 p.m. (non-holiday weekdays only)	46¢	36¢
Super Off-Peak: 10 p.m. – 8 a.m. (every day)	11¢	11¢
Off-Peak: 8 a.m. – 2 p.m. and 8 p.m. – 10 p.m.	30¢	26¢

California's higher than average utility rates exist across residential, commercial, and industrial sectors (EIA, 2015e). Rates historically are higher than average during the summer months, when demand is high and reach national averages during the swing season. The largest difference in electricity costs is in the industrial sector, as shown in Table 2-7. This is significant because the industrial sector consumes the most electricity and has the greatest opportunity for a ROI. CHP microgrid investment is largest in the industrial sector because of the favorable economics. The high average electricity prices in California further increase this potential.

Table 2-7: July 2014 California Electrical Utility Rates
Source: Electric Power Monthly: July 2014 (EIA, 2014b, sec. Table 5.6.A)

Sector	California (cents/kWh)	National Average (Cents/kWh)
Residential	17.67	13.05
Commercial	17.89	11.16
Industrial	13.89	7.49

2.7.2 California's Electricity Consumption

Principle energy savings in microgrid operations come from the ability to reduce peak demand charges. A microgrid provides a more consistent pricing model since natural gas fuel costs are less volatile than electricity prices. With peak consumption costing four times the rate during off-peak hours, peak demand charges can add up quickly. California, and especially Southern California, is a good market for a microgrid because the peak demand is highest in the nation. Peak electrical demand in southern California is nearly twice as much as the average load. This high value will correspond to greater energy bills from utility companies, which need to have capacity on hand to meet the demand. Higher energy bills make the market for a microgrid more favorable and shorten the payback period. As the home of the highest peak levels, California has higher potential for economic savings.

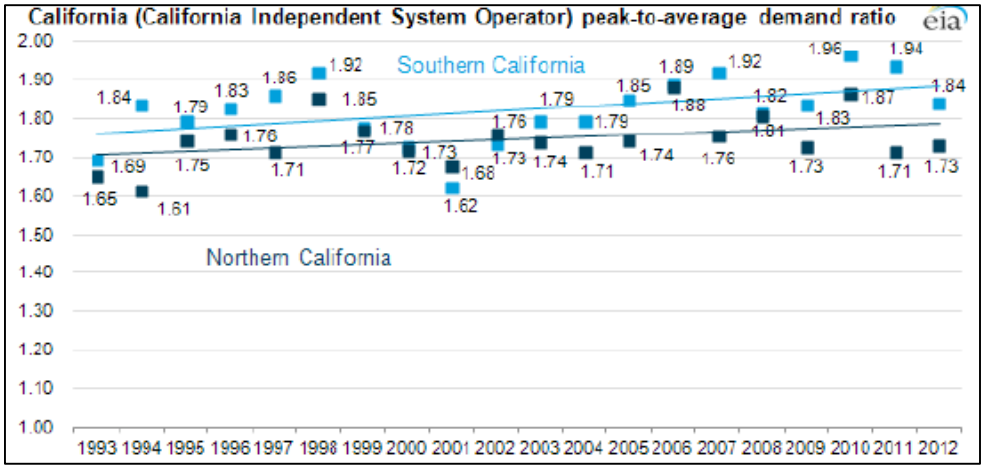

Figure 2-31: California Peak-to-Demand Ratio
Source: Today in Energy February 18 2014 (Shear, 2014)

California is one of the largest consumers of electricity in the nation; second only to Texas for the total kWh consumed in a year (EIA, 2015f, p. Table F21). One of the problems California faces is a lack of generation capacity within the state to meet demand. About 25% of the electricity California consumes is generated outside the state. This contributed to the energy crisis in 2000 and 2001 where electricity prices spiked, shown in Figure 2-32 (EIA, 2014a).

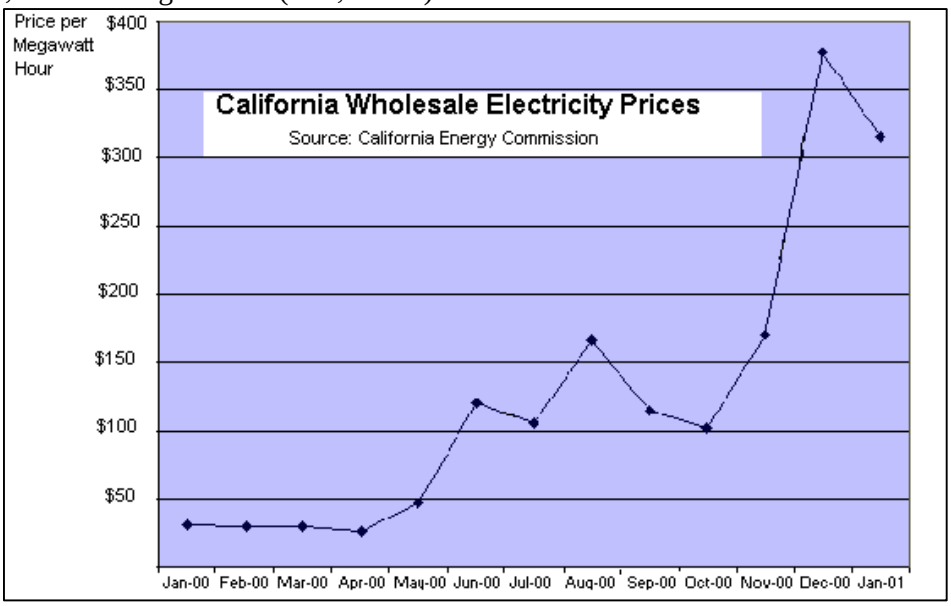

Figure 2-32: California Electrical Prices 200-2001
Source: Neural Energy Consulting (Miner, 2012)

Up until 2012, 20% of California's electricity generation was in the form of nuclear power. In 2013, in an effort to reduce dependency on nuclear power, California permanently shut down two reactors, cutting the electricity supply from nuclear power in half (EIA, 2014a). This decreased generation has created a market for new sources of electricity and opened the door for increased DG. Renewables and CHP are particularly suited to meet this void.

2.7.3 Renewable and CHP Technical Potential

The reduction in electricity supply from nuclear and the over-dependence on out of state generation motivates politicians to increase generation capacity within the state. Government policy also focuses on promoting renewable sources to meet that need. From public officials' perspective, renewable energy is attractive due to the emission free electricity generated. Figure 2-33 shows technical potential for wind and solar energy in California is also among the highest in the country.

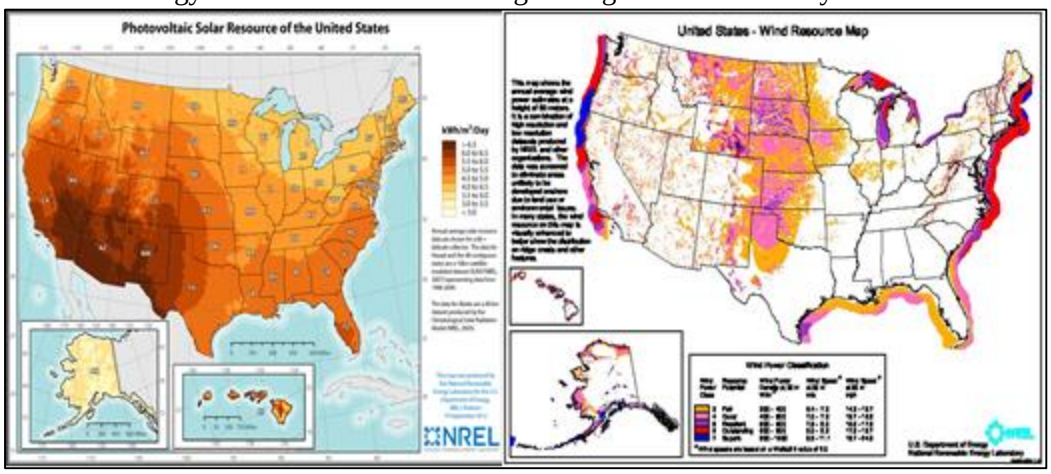

Figure 2-33: PV and Wind Resource Map
Source: (Roberts, 2012)(NREL, 2015)

In the first half of 2014, California installed approximately 850 MW of solar and 230 MW of wind generation potential. During this period California was second only to Florida for total electrical generation installed. Florida installed 1.2 MW of combined cycle generation (Lee, 2014). The additional wind and solar installation in 2014 continues the California trend of increasing the total generating capacity of renewable energy. The support of the state government and the favorable market conditions enabled California to become the first state to produce 5% of its annual electricity from solar renewable technology (McFarland, 2015).

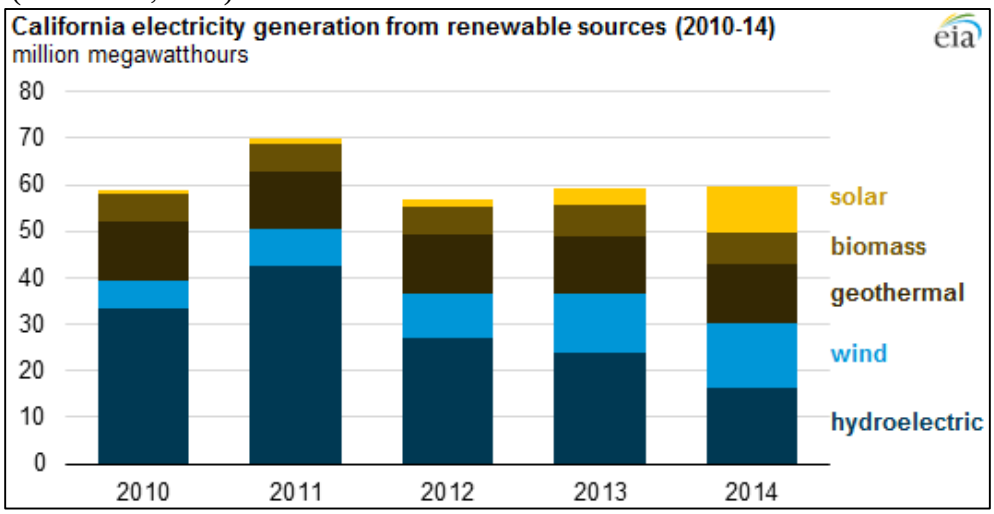

Figure 2-34: California Generation by Renewable Technology
Source: Today in Energy March 24, 2015 (McFarland, 2015)

In addition to renewable energy, CHP can share an increased portion of the generation capacity. Based upon the technical infrastructure and economic market conditions, California is the number one state for potential CHP additions, with the technical potential exceeding 14,000 MW for new CHP installations (Hedman & Hampson, 2010) (Hedman et al., 2013). To capture this potential, California's Governor Brown set the goal of an additional 6,500 MW of CHP capacity by the year 2030 in the 2010 California Clean Energy Jobs Plan (Weisenmiller et al., 2012).

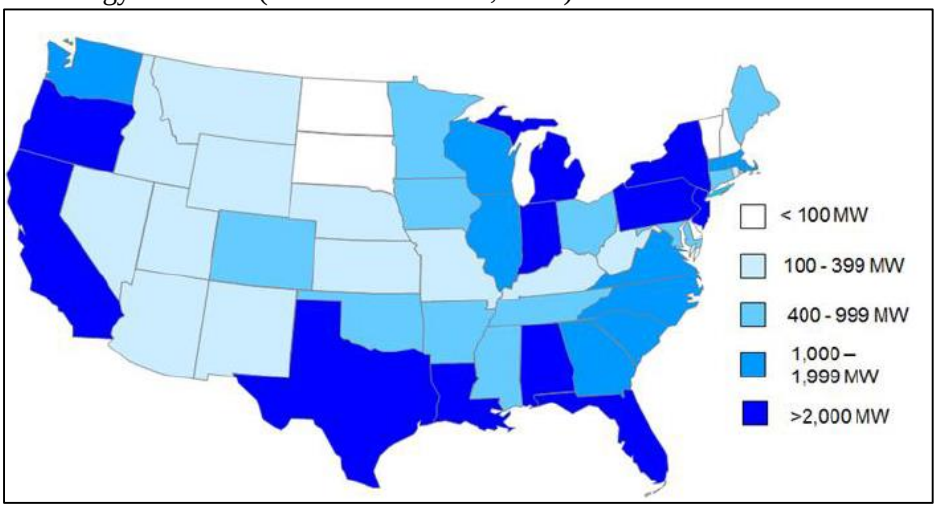

Figure 2-35: National CHP Technical Potential
Source: (Hedman et al., 2013, fig. 10)

2.7.4 California Government Policy

One of the largest factors contributing to the increase in DG and renewable resources in California is the support by the state government. California has employed a number of aggressive policies to incentivize or mandate change in order to reduce emissions. The success of these policies is evident in California's rank as 49th in energy consumption per capita.

In 2012, California began a cap and trade program to limit the state's total greenhouse gas emissions. The market-based policy sets a cap on the total emissions levels and issues a limited number of permits that quantify the emissions allowed. These permits can then be purchased or sold across business sectors (the "trade"). Large businesses may be motivated to purchase permits if they can obtain a permit for higher emissions cheaper than they could reduce emissions. Permit owners may be motivated to sell their permits if they can receive more monetary compensation for the permit than they would from reducing emissions. This provides an incentive for both buyers and sellers, effectively creating a market for greenhouse gas emissions reduction where businesses can profit without compromising the total emissions levels (Cook, Smidebush, & Gunda, 2013).

Another significant policy California implemented in 2002 was renewable portfolio standards (RPS). RPS quantifies the percentage of electricity generation that must come from renewable forms of energy. A few of the eligible technologies include PV, wind, hydroelectricity, and geothermal. The original RPS targeted 20% renewable electricity by 2010. In 2007 that target number was increased to 33% by 2020. As of March 2013, 29 states and Washington DC had binding RPS targets in place. California's goal of 33% by 2020 is the most ambitious of any state (Cook et al., 2013).

In response to the 2001 energy crisis, CA implemented the Self-Generation Incentive Program (SGIP). This program encourages DG investment, by providing the following financial incentives:

- Wind Turbines = $1,007/kW
- Fuel Cells = $1,650/kW
- CHP = $440/kW
- Advanced Energy Storage = $1,460/kW

Eligible projects will receive 50% of the incentive up front and can receive the additional 50% over the next five years. The last 50% will pay out a maximum of 10% per year if the plant meets expected performance metrics. If the DG equipment is manufactured by a California supplier an additional 20% incentive is added to the final incentive. The SGIP incentive can be used in conjunction with federal ITCs; however, customers are responsible for at least 40% of the projects cost. The generous incentives offered by the California Public Utilities Commission, can significantly reduce the capital costs of a microgrid installation. It is particularly advantageous for a HMG that advance energy storage is also subsidized, since this technology plays a critical role in shifting peak demand (Center for Sustainable Energy, 2015).

Finally, California has a feed-in tariff available to stimulate CHP deployment. This tariff allows CHP generated electricity to be distributed to the grid at the avoided utility costs. This framework establishes long-term contracts fixed to the price of natural gas. The tariff provides security for investors by enabling access to the grid where CHP plants can export electricity to help recuperate costs. In order to qualify for the tariff, CHP plants must meet a minimum efficiency of 62% (EPA, 2012).

2.7.5 California Standby Rates

One of the final hurdles in assessing the economic feasibility of a CHP microgrid is standby rates. Standby rates are the charges levied by the utility in the event a CHP plant is taken down by an outage or unexpected maintenance. These rates are typically a combination of energy usage and peak demand requirements. Standby rates vary drastically by state and utility company. Some utility companies use high standby rates to discourage the use of CHP. From the utility company's perspective, DG does not allow them to downsize their equipment because sufficient generation is still required to meet demand if a microgrid fails. This requires spinning reserves to be made available and complicates operations. High demand charges by the utility company are thus claimed to be a motivator for CHP system owners to manage their peak demand. On the other hand, microgrid owners argue that utility companies fail to acknowledge the benefit that highly efficient and reliable DG provide to the utility company, including increased grid reliability, improved power quality, and reduced distribution losses. Differing opinions cause utility companies to vary how they approach standby rates. The different standby rates can have a significant impact on the ROI and influence investors' perception of the perceived risk. Standby rates are incredibly important and have the capacity to terminate an otherwise favorable CHP investment. In 2009, the EPA investigated the impact standby rates have on CHP and DG economics. According to the study: "appropriately designed rates can promote the development of CHP and other clean DG, which leads to enhanced system reliability, state economic development, and reduced environmental impacts while protecting utility ratepayers from excessive costs." (Weston, Bluestein, Hedman, & Hite, 2009) The report highlighted the states which value the costs and benefits of DG. California was identified as one of four states that have two or more utilities that have favorable standby rates for DG.

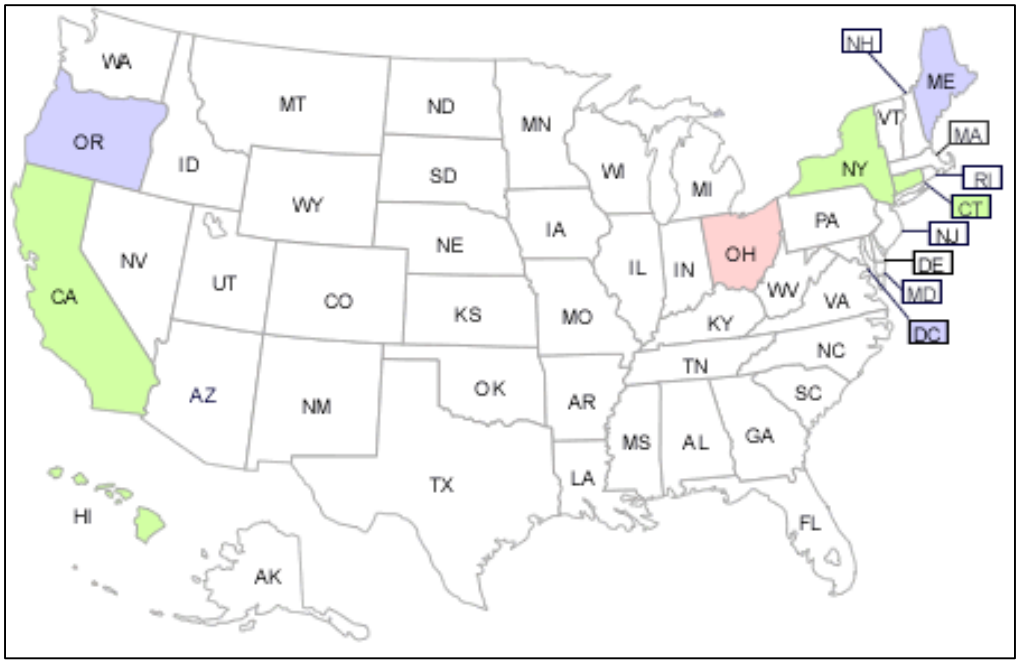

Figure 2-36: National Standby Rates
Favorable standby rates are shown in green and blue
States with pending action in red
Source: Combined Heat and Power Partnership (EPA, n.d.)

The states that have favorable standby rates correlate with high electricity rates; further emphasizing that the states embracing change to the electricity markets are those with high utility costs and the most to benefit (Weston et al., 2009).

The combination of expensive utility rates, above average peak loads, renewable energy technical potential, CHP market potential, favorable government policies, and standby rates that recognize the importance of DG make California an ideal location for a HMG installation. California has long sought to be a national leader in reducing greenhouse gas emissions. The policies they've implemented as well as the beneficial geography make them a likely candidate to usher in any change toward DG that may occur in the electrical industry.

2.8 The Need For Research

Whether HMGs have strong future potential market penetration is not yet apparent. Technically the argument can be made that these microgrids will effectively increase renewable penetration, reduce emissions, and increase reliability. But the successful adoption of such technology is dependent on the installation's economic benefits. Increased reliability and reduced emissions, while important, are not economically quantified sufficiently to motivate private industry to invest in HMGs. The private sector first and foremost is interested in an economic return on investment. The combination of more affordable renewable technology, deregulation of the electric grid, and increased public policy and economic incentives are just now making distributed energy a cost-effective endeavor.

Investment in HMG installation is just beginning to occur. In the fall of 2014, Southern California Edison announced contracts to purchase distributed solar PVs, automatic demand response, behind-the-meter battery storage, and CHP technologies. These purchases are part of a larger contract to procure 1.8 GW of additional capacity in the grid-stressed west Los Angeles region in order to meet long term capacity goals. This contract is in direct response to a California mandate to install 1.3 GW of electricity storage by 2020 (Marcy, 2015). In many ways this contract is a "real-world experiment in grid-edge economics" aimed at identifying the best way forward into the new grid market (St. John, 2014).

Another example of recent investment into HMG technology was accomplished by the utility provider Xcel Energy in Minnesota. Xcel is currently testing a wind energy battery-storage system, consisting of sodium-sulfur (NaS) battery technology. The battery can store up to 7.2 MWh and has a charge/discharge rate of 1 MW. The goal of the battery system is to level output electricity from a nearby 11 MW wind farm. The project costs $4.2 million (Xcel Energy, 2008).

Despite these investment examples, HMGs are not widely available on the grid today. A large reason for this is likely due to the importance of storage in making the microgrid functional, which is still relatively expensive. In 2011 the DOE highlighted that "most current [energy storage] technologies are not competitive in capital cost or life cycle cost for broad market penetration."(DOE, 2011) Battery storage also has limited life expectancies compared to other DG technologies.

Despite the current high prices of energy storage limiting HMG adoption, many are predicting they are the future of the central grid. Currently they represent the best way forward for clean, reliable electricity generation. Some public officials and utility companies are betting on the importance of storage in the future and investing in storage with the hopes it will be profitable in the future. Officials in California and New York as well as electric service providers in Hawaii and Texas have taken steps to invest in utility-scale storage (Marcy, 2015). However, these entities are the minority; the fact is investment is limited because utility-scale storage is not cost competitive save a few markets. In order to increase the public & private investment additional studies are required to demonstrate potential savings and quantify economic feasibility for potential customers.

DG, especially CHP, has already begun to see success in the industrial sector. These customers use the most energy and will save the most from implementing CHP. Often an industrial customer can justify the investment using only one DG technology. Piecemealing additional renewables and energy storage will no doubt increase the ROI, but those technologies are not necessary to make the investment affordable.

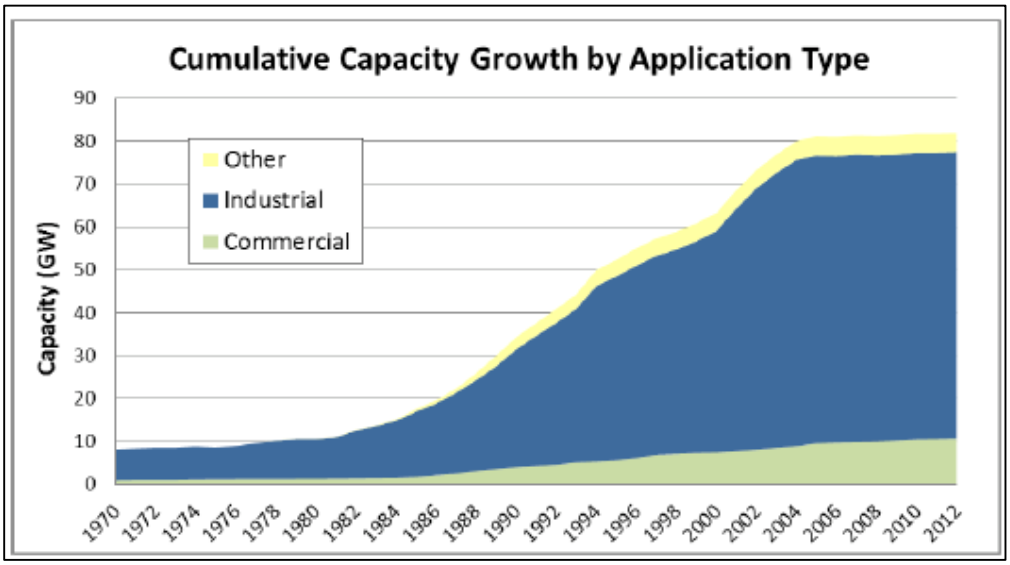

Figure 2-37: CHP Capacity by Industry
Source: (Hedman et al., 2013, fig. 3)

Commercial and residential buildings are far less likely to adopt CHP because of the lack of electricity consumption compared to industry. For these facilities a HMG is more likely to generate the necessary ROI than a single DG source. The possibility of a HMG installation should be explored in these facilities. While they don't consume as much electricity as industrial buildings they are far more common. There are over 28 million multi-family residential homes (EIA, 2013a, Table CE.1.1) and 5.6 million commercial buildings (EIA, 2015a, Table 1) in the US. The total number of industrial facilities is fewer than 350,000 (EIA, 2013b, Table 9.1).

With industrial facilities already showing a strong potential for distributed generation, commercial and residential facilities are the next target for potential integration. This literature review discussed the benefits and reasons to pursue DG. However, decentralized energy will not completely replace the centralized model. Nor is the centralized model going to be the only application for future infrastructure. The future of electricity generation will be a mixture of centralized and decentralized systems operating parallel to each other (Alanne & Saari, 2006). The difference will rely on whether decentralized energy returns a favorable ROI. HMGs may be the key to improving the ROI within commercial and residential buildings. Given the substantial first costs of the equipment, near term HMGs are most likely to achieve favorable ROIs where the economic market and public policy promote DG adoption. At the present time, Southern California is one of the best places in the United States for DG. Therefore, there is much to be gained from investigating the market potential of a HMG installation in residential and commercial facilities in Southern California.

Chapter 3

Methodology

3.1 Problem Statement

The United States is a worldwide leader in CO2-equivalent emissions per capita (EIA, 2012b). The majority of the nation's CO2-eq emissions are produced by coal fired power plants, which generate 39% of the nation's electricity (EIA, 2015c). The US also suffers more power outages per year than any developed nation (Clark, 2014). The central electric grid's lack of reliability is largely due to need to modernize aging electrical infrastructure. 70% of the central grid's transformers and transmission lines are over 25 years old and the average power plant is 30 years old (DOE, 2013).

The central grid's pollution and lack of reliability have environmental and economic repercussions that need to be addressed. CO2-eq emissions contribute to global warming (GW) and increase the chances of severe weather. The frequency of power outages cost the American economy $79 billion annually (LaCommare & Eto, 2006). The grid could be modernized but would require $673 billion to achieve such a goal (Campbell, 2012). The American Recovery and Reinvestment Act of 2009, although a significant capital investment by the government, only contributed $4.5 billion.

Distributed generation (DG) is a promising strategy that can improve reliability and decrease total emissions. Integrating multiple DG technologies with electrical storage into a hybrid microgrid (HMG), could increase customer savings, expand renewable penetration, and enable generated electricity to be stored and used to meet later demand requirements. The primary obstacle preventing DG and HMG installation is the high capital costs. Utility customers are historically unwilling to participate in DG unless there is a strong economic return on investment (ROI) (Lenssen, Byrnes, & McNulty, 2003). To date DG has only seen significant adoption by industrial customers.

The purpose of this study is to model a hybrid microgrid's operation on residential and commercial load profiles and calculate the present day economic ROI. A sensitivity analysis is also accomplished to determine the economic conditions required to achieve 10, 5, and 3 year payback periods, specifically in California's market utility environment

3.2 Research Objectives

1. Describe the CHP+PV+battery hybrid system design that reduces grid supplied electricity to 1% (88 hours per year) for residential, commercial, and large commercial.
2. Identify the battery characteristics necessary to meet each facility design. Characteristics include charge rate, storage size, and cycle frequency.
3. Quantify present day ROI based upon assumed levels of CHP thermal utilization
4. Conduct sensitivity analyses to determine how ROI would improve with varying battery price, average electrical rates, and average fuel costs.
5. Identify the economic environment that would yield 10, 5, and 3 year ROIs

3.3 Technical Design and Simulation

This section outlines the methodology executed to accomplish objectives 1 and 2. Objectives 1 and 2 focus on the technical design of the HMG. The HMG is made up of steady-state combined heat and power (CHP), a solar photovoltaic array (PV) subjected to transient solar flux input, and electrical energy storage in the form of battery technology. These three individual components are referred to as the hybrid microgrid (HMG) and supply electricity to meet demand.

This section begins by describing key design simplifications and characterizing the electricity load profiles. The methodology executed to design each HMG component is then described. The PV array is designed first followed by an iterative trial-and-error process to design the steady-state CHP and battery. This section concludes by outlining the key performance characteristics extracted.

3.3.1 Hybrid Microgrid Design Overview

A fully developed hybrid microgrid (HMG) system involving CHP, Solar PVs, and a electrical battery system that follows a facility's electrical and thermal load is complicated to model. Real time changes in the facility's demand profiles and solar PV output occur simultaneously. The CHP prime mover needs to respond to these changes by following the electric load and varying its output as required by instantaneous demand and electric storage charge state deficiencies. Load following CHP plants are available, but they introduce additional design constraints and consideration such as variable heat rate, variable output thermal energy, ramp speed constraints, and cycle fatigue. Therefore the challenge to modeling a real world HMG's operation is that input variables (solar flux, facility electric use demand, battery charge state, etc.) change simultaneously and determine the performance of the hybrid system. In short the hybrid system consists of a highly coupled, non-linear set of input-output relationships among key components. For each additional degree of freedom added, several more constraints are also introduced. Such complexity requires sophisticated software to truly analyze (Shah, Mundada, & Pearce, 2015). In the absence of such software and in an effort to focus the research on the economic viability of a HMG, and not the technical limitations of its system components, two major design simplifications are made.

The first simplification to the operation and control of the HMG is that the CHP plant will operate at steady-state. Steady-state CHP operation simplifies the CHP+PV output electricity. The HMG's battery will discharge or charge the difference between the facility's demand and CHP+PV output electricity. This operation simplifies the CHP+battery design and eliminates additional constraints from the analysis, such as engine cycle fatigue. Steady-state CHP output electricity will remain constant during an entire day; however, the steady-state CHP output value will consist of six different set points to accommodate for the change in seasonal demand. The intent is to limit real time CHP variations that complicate the design and prevent oversizing the battery component.

The second simplification to the methodology is the angle of PVs. Output electricity varies with a number of parameters including latitude, time, and angle of incidence. TMY data provides total radiation on horizontal surfaces for every hour of the year in select locations. To convert this value for a tilted PV requires either cumbersome calculations or advanced software. Instead this methodology simply uses horizontal radiation values to generate the output PV electricity. Horizontal surface values are approximately 10% lower than a tilted surface. For this sake of this project that relative error is acceptable.

3.3.2 Characterize Building Load Profile

This project analyzes three facility load profiles: multi-residential, commercial and large commercial. Residential, commercial, and large commercial buildings are defined by the utility rate tariffs as having peak demands of 2-3kW, less than 200kW, and greater than 500kW, respectively.

The California based utility company Pacific Gas and Electric (PG&E) records average electricity consumption dating back to 2000. Hourly electricity demand is available for a range of facilities from residential to industrial in exportable Microsoft Excel files. The schedules and tariffs that correspond to the three facilities of interest are identified from PG&E's database. The PG&E data extracted in this project comes from load profiles and electrical schedules labeled E-6, A-10, or E-19. They are renamed for clarity to residential (E-6), commercial (A-10), and large commercial (E-19)

Data from fifteen years (2000-2014) is downloaded from PG&E's website for each facility. The residential load profile (E-6) is multiplied by 150 to simulate a multi-residential complex. Annual electrical energy usage is calculated for each year. A representative year is chosen by averaging the most current ten years (2005-2014) and then selecting the year which is closest to the ten year average, as shown in Table 3-1. Hourly data from the representative year is extracted to simulate the facility's annual electrical demand, which the HMG is ultimately designed to meet.

Table 3-1: Representative Year Selection Example - Commercial

Year	Annual Load (kWh)
2000	252,103
2001	225,212
2002	231,419
2003	235,014
2004	235,098
2005	231,136
2006	227,533
2007	230,254
2008	253,377
2009	248,361
2010	233,565
2011	240,950
2012	231,526
2013	223,747
2014	220,799
10 yr avg	234,125

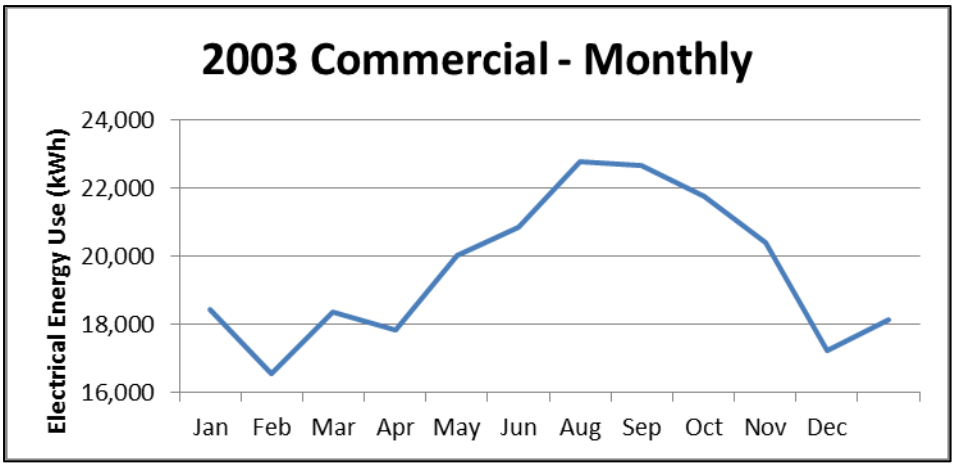

Figure 3-1: Monthly Energy Profile Example - Commercial

Hourly electrical data from the representative year is used to generate electricity demand profiles over smaller intervals. Monthly, daily, and hourly electricity curves are created to display the annual load characteristics such as seasonal fluctuations, peak demand, annual base load, load volatility, and energy demand range. Careful understanding of these characteristics and the demand profile at multiple levels enable the HMG's design. Hourly demand curves are generated by selecting data from identical weekdays in four different seasons. Selected days should avoid known holidays such as Thanksgiving or Christmas, where energy consumption is significantly lower

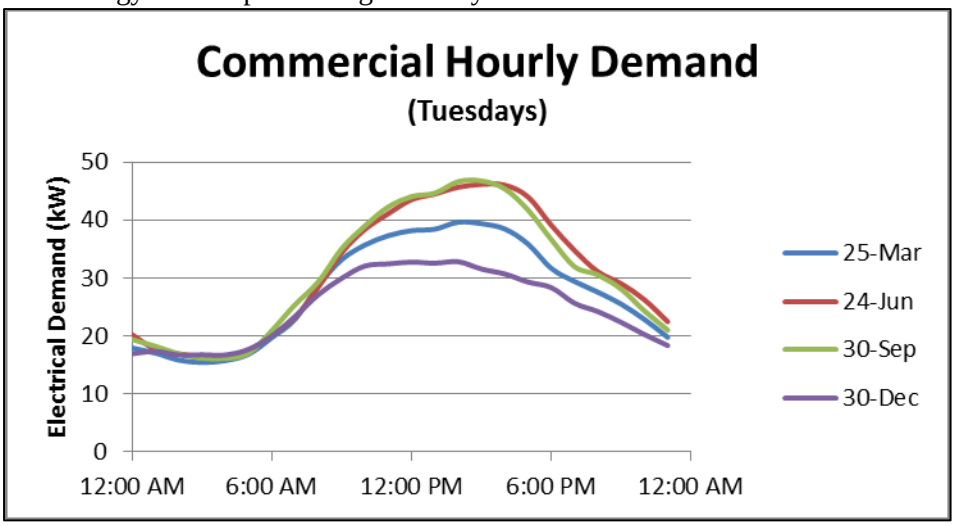

Figure 3-2: Hourly Energy Profile Example - Commercial

3.3.3 Define PV Electrical Contribution

The first HMG component sized and simulated is the solar PV array. Output PV electricity is the product of incident solar radiation (W/ft^2), PV system efficiency (%), and PV array size (ft^2).

Los Angeles, California solar radiation values are downloaded from typical meteorological year 2 (TMY2) data. TMY2 data offers several values for solar radiation and illumination. This methodology uses the Global Horizontal Radiation, which is the combined direct and diffuse radiation on a horizontal surface. In an effort to simplify the output electricity for the PV array, the panel is assumed horizontal on the Earth's surface. This eliminates the need to develop a complex solar flux model, which is not the focus of this project. It should be noted that the use of a horizontal panel provides conservative results to the project. In reality PVs are typically installed tilted 11-20 degrees south, which would provide approximately an additional 10% of electricity, based on

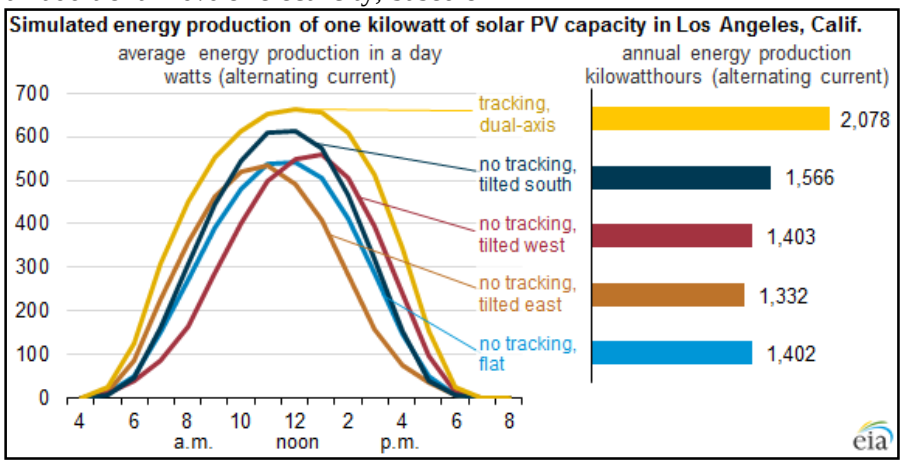

Figure 3-3: PV Output Based on Orientation
Source: Today in Energy November 18, 2014 (Comstock, 2014)

TMY2 data provides radiation values in W/m^2 for each hour of the day. This project converts the value to W/ft^2, which is consistent with English standard units. These hourly values provide total sunlight incident on the PV array throughout the entire year.

Several versions of TMY data are available. This project uses TMY2 data, with the reasonable assumption that solar radiation values remain constant over the past 50 years. TMY2 data is preferred because the data contains measured values for solar radiation. These values include the fluctuations in radiation due to daily sky cover conditions. This provides realistic data with which to design the HMG. The newer TMY3 data replaced measured radiation values with modeled solar radiation data (Wilcox & Marion, May 28). This project prefers actual data over modeled values.

Only a fraction of the incident radiation will be converted to electricity by the PV array. Current PV panels convert 15% of incident radiation to useful electrons. The electricity output from PV panel is in the form of direct current (DC) and needs to be converted to alternating current (AC) to be compatible with equipment and conventional power supply. This is accomplished by an inverter, which is typically 92-96% efficient (Perez, 2006). This project therefore assumes a total PV system efficiency of 14%, which reflects the current state of the industry.

The last required specification to calculate the output PV electricity is the total array size. The array's surface area is an independent variable defined on the basis of space available. User defined array size enables real world space limitations to be accounted for. Additionally, the defined array size has the benefit of reducing the HMG design complexity by constraining one of the three system components. The CHP and battery components are sized independently and without impacting the PV array. This project uses 50'x50' array for commercial, 50'x100' for residential and 100'x100' for large commercial.

PV output electricity is calculated as the product of horizontal direct and diffuse radiation (W/ft^2), PV system efficiency (%), and PV array size (ft^2). Output electricity is simulated for all 8,760 hours in the year. Output PV electricity will vary hourly and seasonally as shown in Figure 3-4. Total annual PV contribution is the sum of each hourly power output. The PV system's fractional contribution is calculated by dividing the total PV output electricity by the annual demand.

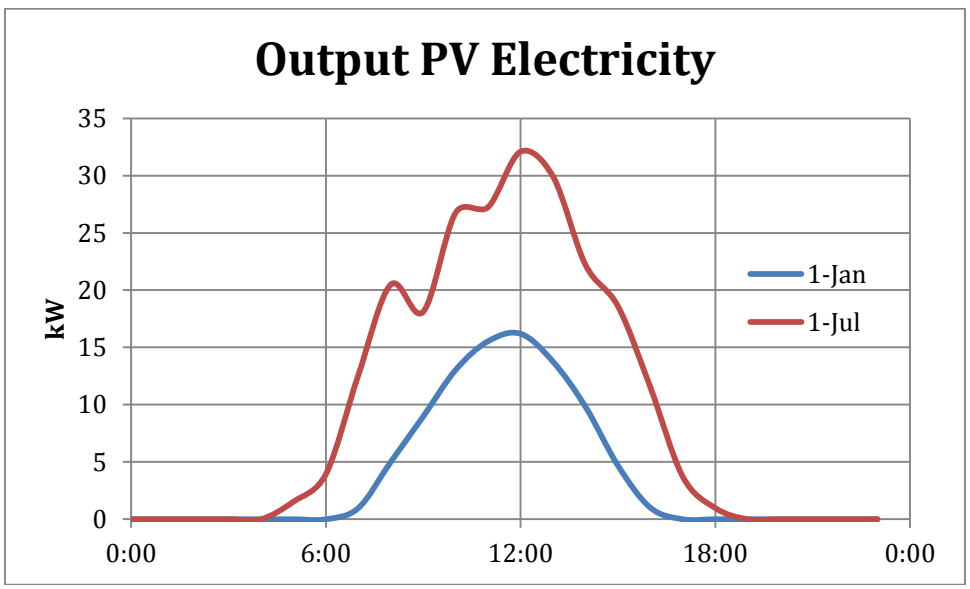

Figure 3-4: Variable PV Generation during Winter and Summer Adapted from TMY2 Data

3.3.4 Set Steady-State CHP Electricity Generation

The second sub-system of the HMG to be calculated is the CHP component. In practical applications, CHP is designed based on thermal and electrical load profiles. This project designs the CHP component exclusively off electric demand profiles and only quantifies the heat generation. Additionally, practical CHP operation varies throughout the day to enable supply electricity to meet demand. Load following CHP introduces additional factors to be considered such as variable heat output, cycle fatigue, ramping speed, and variable heat rate or efficiency. A thorough analysis of HMG operation would include all of these parameters, but also complicate the model and increase the scope. The initial analysis presented in this project introduces steady-state CHP, which eliminates the additional variables and enables analysis under the investigation resource constraints. Steady-state CHP requires hourly load variation to be met entirely by PV+battery supplied electricity. Since the PV array size is constant, this approach effectively shifts all the variability to the battery in order to simplify the design and allow for analysis.

Steady-state CHP is used to simplify the design; however, modulating the steady-state CHP output electricity with seasons is necessary to avoid oversimplification. Seasonal temperature differences vary the electrical demand and one steady-state CHP value is likely to meet demand for only a brief period of the year or it may necessitate the battery storage to be unrealistically large. To balance these competing interests, six seasons are established with different steady-state CHP values. Seasonal steady-state CHP design enables the HMG flexibility to meet demand and reduce the battery's initial size and cost. Each seasonal steady-state CHP output is met by the same prime mover operating at different levels of part load. The season's range is defined for each facility and not limited to two months per season.

Monthly electrical demand metrics are compiled to quantify the electricity required by the facility throughout the year. These metrics include total monthly electrical energy consumption (kWh), peak monthly electrical demand (kW), and average monthly electrical demand (kW). The load profiles and monthly metrics are used to estimate the best seasonal breakdown.

Table 3-2: Monthly Electricity Demand Metrics Example - Commercial

Month (data points)	(kWh)	Peak (kW)	Avg (kW)
(3-746) Jan	18,432	39.2	24.8
(747-1418) Feb	16,530	38.7	24.6
(1419-2162) Mar	18,359	41.7	24.7
(2163-2882) Apr	17,820	42.0	24.7
(2883-3626) May	20,035	54.7	26.9
(3627-4346) Jun	20,863	54.8	29.0
(4347-5090) Jul	22,789	53.4	30.6
(5091-5834) Aug	22,671	57.4	30.5
(5835-6554) Sep	21,747	54.4	30.2
(6555-7298) Oct	20,403	49.2	27.4
(7299-8018) Nov	17,245	39.8	24.0
(8019-8762) Dec	18,136	38.3	24.4

After seasons are defined the corresponding metrics are gathered for each time frame. Seasonal data is compiled for peak electrical demand, average demand, and base load. These metrics represent the seasonal fluctuations and are used to design the CHP component. Each seasonal steady-state CHP output value is set as a percentage of the corresponding average demand. Exact seasonal steady-state CHP output is determined by trial and error, which is described in detail in section 3.3.6. Initial steady-state CHP settings compliment the fractional PV electricity supplied. For example if the PV array supplies 10% of the annual demand an initial seasonal steady-state CHP setting should be 90% of the average demand. Seasons with large solar radiation such as the summer are expected to require less than 90% while winter months are expected to require more than 90% of the seasonal average.

Table 3-3: Seasonal Electricity Demand Metrics Example - Commercial

Winter (Nov-19 Feb, 1-14 Mar)		Spring (20-28 Feb, 15 Mar-12 May)	
Peak Demand (kW)	39.8	Peak Demand (kW)	42.0
Avg Demand (kW)	24.4	Avg Demand (kW)	24.7
Base Load (kW)	15.0	Base Load (kW)	14.9
Shoulder (13 May-Jun)		**Summer (Jul-Aug)**	
Peak Demand (kW)	41.7	Peak Demand (kW)	57.4
Avg Demand (kW)	24.8	Avg Demand (kW)	30.6
Base Load (kW)	14.9	Base Load (kW)	16.1
September		**October**	
Peak Demand (kW)	54.4	Peak Demand (kW)	49.2
Avg Demand (kW)	30.2	Avg Demand (kW)	27.4
Base Load (kW)	16.1	Base Load (kW)	15.5

3.3.5 Model the Battery Storage

With CHP+PV electrical supply complete for every hour the required battery performance is modeled by taking the difference between the electrical demand and CHP+PV output. If CHP+PV output electricity exceeds the facility's demand, the battery will charge. Conversely if the CHP+PV electricity falls short the battery will discharge the difference in order to meet demand. Charge/Discharge rates are determined for each hour of the year.

Using the battery's charge/discharge rate the battery charge state (kWh) is calculated based upon the previous hour's charge and the current hour's demand. A running total of the battery charge is calculated for the entire year to quantify the total battery size required. When the CHP+PV+battery electrical output falls short of demand additional electricity needs to be provided by the grid. Grid Power = Demand – $(\text{CHP+PV+battery})_{\text{output}}$. The total number of hours that grid electricity is required are counted and documented by season and for the entire year.

Lastly the total battery state charge is graphed over the course of a year. The battery charge graph and the required grid hours provide the necessary feedback loop for the user to correct errors in the design. Design improvements aim to reduce the total battery size and required grid hours. This is the next stage of the HMG's trial and error process.

3.3.6 Refine Hybrid Microgrid Design

Balancing the seasonal steady-state CHP output and battery charge is a trial and error process. Adjustments to seasonal CHP settings will change the battery's charge state and the corresponding season's required grid hours. The trial-and-error process continues until the total annual grid hours are approximately 1% or 88 hours. The design stops at 1% of grid hours because decreasing the grid requirement to 0% drastically increases the battery's size. The two output parameters used to refine the HMG design are the battery charge state graph and the seasonal grid hours required.

The appropriate steady-state CHP output size is determined by observing the battery's charge state. Since the battery charges/discharges in response to the difference in CHP+PV and site demand electricity, changes to the seasonal steady-state CHP output electricity will impact the battery's charge. Figure 3-5 demonstrates the CHP+battery interdependency. The figure graphs the battery's charge when steady-state CHP output is set to 55%, 60%, and 65% of peak demand. A 55% peak CHP output fails to generate sufficient electricity and the battery continues to discharge without limit. Similarly 65% peak CHP setting overproduces electricity. The middle setting of 60% peak demand appears to be the appropriate size because there is a balance between the storage charge and discharge

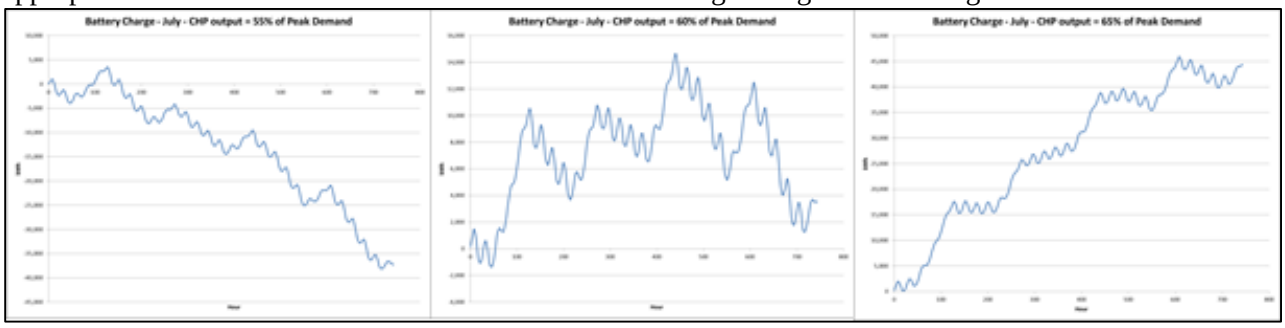

Figure 3-5: CHP Sizing Trial-and-Error Process

The trial-and-error adjustments to the steady-state CHP set points are continued for each season until the total number of hours grid electricity is required is approximately 88 (1%). Seasonal grid hours required are documented in order to identify the appropriate seasonal CHP output to change.

Table 3-4: Seasonal CHP Set Points and Required Grid Hours Example - Commercial

CHP Winter Avg Demand Design %	84.0%	CHP Spring Avg Demand Design %	66.9%
SS CHP Output - (kW)	20.5	SS CHP Output - (kW)	16.5
Required Grid Hours	11.0	Required Grid Hours	24.0
CHP Shoulder Avg Demand Design %	78.9%	CHP Summer Avg Demand Design %	71.0%
SS CHP Output - (kW)	19.6	SS CHP Output - (kW)	21.7
Required Grid Hours	0.0	Required Grid Hours	8.0
CHP September Avg Demand Design %	76.8%	CHP October Avg Demand Design %	78.1%
SS CHP Output - (kW)	23.2	SS CHP Output - (kW)	21.4
Required Grid Hours	8.0	Required Grid Hours	0.0

In addition to limiting the grid supplied electricity to 1% the focus of the trial-and-error design is to minimize the required battery size and achieve good utilization of the total storage capacity. In addition to tweaking the seasonal CHP output, two minor adjustments are made to limit the required battery size. 1) Seasonal boundaries are adjusted as necessary to combine similar demand and radiation periods. Identical seasonal settings are not expected for each facility. 2) The battery's initial charge date is adjusted to prevent large singular peaks. Battery state is not required to begin charging on January 1st. Figure 3-6 shows the completed operation over the course of a day. An example of the completed HMG operation over a day is shown in Figure 3-6.

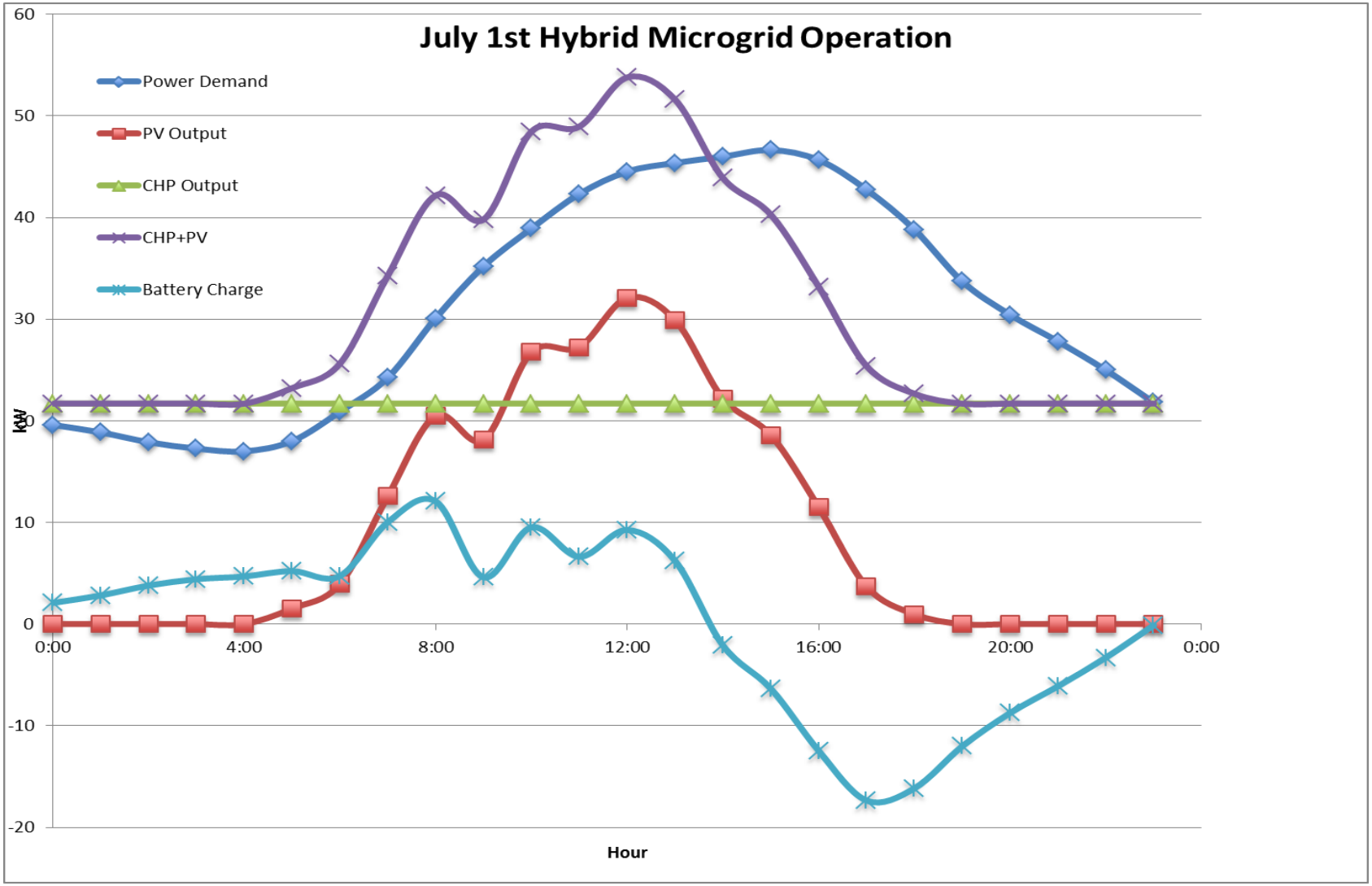

Figure 3-6: Hybrid Microgrid Operation Over 24 Hour Period

3.3.7 Quantify Hybrid Microgrid Performance

After the HMG's design is complete the performance and equipment specifications are compiled to achieve the technical objective of the research. An appropriate CHP technology based off the steady-state CHP design is selected from the Environmental Protection Agency's (EPA) Catalog of CHP Technologies. An effort is made to avoid part load operation by selecting CHP technology that matches the design needs. Specifications from the EPA's catalog and the site electrical demand are used to calculate the CHP's electrical and thermal performance for the year. The CHP plant is assumed to operate with an average heat rate equal to the catalog's specification. The following CHP parameters are extracted from the specification sheet or calculated by the simulation:

- Nominal CHP size (kW)
- Electric heat rate (Btu/kWh), high heating value (HHV)
- Total electricity generated (kWh) and percentage of total load
- Natural gas fuel requirement HHV (MMBtu)
- Total thermal exhaust (MMBtu)
- Theoretical maximum thermal utilization (80% of thermal exhaust)

This project neglects thermal loads from the HMG's technical design to focus on the electrical loads and simplify the analysis. It should be noted that, practically speaking, CHP plants are primarily designed to the thermal load demand characteristics of the facility (Meckler et al., 2010). Despite a favorable utility market environment, it is likely still necessary to capture significant thermal output from the CHP plant to provide a reasonable ROI. For this reason CHP thermal energy output (MMBtu) is quantified. The economic value of this thermal energy is calculated in section 3.4.4 and included in the ROI analysis.

The PV's performance is quantified based on the array's input size, because arrays are adaptable and able to be built custom to the design's needs. The following PV parameters are quantified in addition to the PV surface area already defined.

- Maximum electrical output (kW)
- Annual electricity generated (kWh)
- Percentage of total load

Similar to PV arrays, battery technology is modular and adaptable to the design's needs. The selection or recommendation of the ideal battery technology is not the focus of this research. Instead emphasis is placed on the required battery characteristics the HMG requires in order to meet the facility's demand. To accomplish this objective, the following battery characteristics are measured from the annual simulation.

- Size required (kWh)
- Storage size (days of average load)
- Max charge/discharge rate (kW)
- Average charge/discharge rate (kW)
- Total energy supplied (kWh)
- Percentage of total load supplied
- Cycle frequency (t^{-1})
- Average cycle depth (kWh) and (% of total capacity)

Quantifying the CHP+PV+battery performance metrics completes the technical design and annual simulation. The HMG design and characteristic description are first two research objectives. The metrics also enable the calculation of initial costs and annual savings. These calculations are used to determine the baseline economic ROI. The baseline ROI is the focus of the next section.

3.4 Baseline Economic ROI

This section outlines the methodology executed to calculate the baseline economic ROI, which is the focus of objective 3. First conventional electricity costs are calculated, which represents the cost to use energy without a HMG. This calculation is accomplished using PG&E electrical schedules. The HMG annual operational costs are then calculated using PG&E's standby schedule. Annual savings are determined by subtracting the conventional costs by the HMG operational costs. HMG initial costs are calculated using installation estimates and available government incentives. Finally a baseline ROI is determined by dividing the initial costs by the annual savings.

3.4.1 Calculate Conventional Electricity Costs

The HMG's savings are determined by the offset electrical utility costs. Thus to determine the savings and ROI it is first necessary to calculate conventional electricity costs or the cost to acquire the electrical energy if the grid supplies 100% of the power demand. PG&E publicizes current electrical schedules and rates for each facility studied in this project. The conventional cost of electricity is calculated using the applicable rate structure and the facility's electrical energy demand. Commercial electric rates consist of three charges: customer charge, demand charge, and energy charge. Table 3-5 shows an example of PG&E's electrical rate structure for a 50kW commercial facility.

The customer charge is a flat service expense PG&E charges each month, and is independent of the electricity quantity consumed. This value is calculated by multiplying the price per meter, the number of meters, and the days in the month. In the multi-residential facility the number of meters is 200. The two commercial facilities use only one meter each.

Table 3-5: PG&E Commercial Electric Rate Structure

Rate Schedule	Customer Charge	Optional Meter Data Access Charge	Season	Demand Charge (per kW)	Time-of-Use Period	Energy Charges (per kWh)
A-10 TOU Secondary (Table B) Customers with high electric use and medium to high load factors generally benefit under Schedule A-10 TOU. Part of customer's bill varies according to the customer's maximum monthly electric demand.	$4.59959 per meter per day	$0.98563 per meter per day	**Summer**	$16.23	Peak	$0.17891
					Part-Peak	$0.17087
					Off-Peak	$0.14642
			Winter	$8.00	Part-Peak	$0.12750
					Off-Peak	$0.10654

Energy charges are the costs per kWh of electricity and are the majority of the total cost. Energy charges vary with time based on supply and demand. PG&E publicizes the energy charges as well as the corresponding time the charges apply. Energy charges are highest during the afternoon (peak) and lowest during the overnight hours (off-peak). The time-of-use periods and rates differ based upon the facility type. Using PG&E's time-of-use periods, energy rates are generated for each hour of the year. The hourly rates ($/kWh) are multiplied by the corresponding hourly energy use (kWh) to calculate the energy charge. The total annual energy charge can then be determined by adding each hour's energy charge.

The third charge by the utility is based upon the required maximum monthly power (kW) the facility requires. Monthly demand charges are calculated by multiplying the month's maximum power required by the applicable demand charge. There may be multiple demand charges such as a peak demand charge *and* a mid-peak demand charge. These charges are also likely to be higher in the summer than the winter.

After calculating all three charges (customer, energy, and demand) the annual conventional costs are determined by adding all charges for the entire year. The conventional cost of electricity is used to determine the annual savings from operating the HMG. To simplify the electrical rate structure an average electrical rate ($/kWh) is calculated by dividing the total conventional electricity cost by the total electricity generated during the year. This average energy rate will be the baseline cost for the electrical rate sensitivity analysis.

3.4.2 Calculate Hybrid Microgrid Operational Costs and Annual Savings

PG&E offers a specific standby rate tariff to customers with electrical generation equipment not owned by the utility. This tariff is offered to customers who use grid electricity only as a backup source in the event local generation is unavailable. The tariff differs from conventional tariffs and includes additional charges. In all there are seven expenses that contribute to the HMG's operational costs. Of these expenses four are levied by the utility for access to standby power and three are operation and maintenance (O&M) costs. The HMG annual expenses are:

- Standby reservation charge
- Standby customer charge
- Standby TOU meter charge
- Standby energy costs
- Natural gas fuel
- CHP Maintenance
- Battery Maintenance

PG&E levies a standby reservation charge equal to $3.76 per kW per month. This charge is applied to 85% of the reservation capacity. The HMG's reservation capacity is determined by adding the largest steady-state CHP output (kW) to the PV size (kW).

The customer and time-of-use meter charge recurring expenses from the utility for access to grid electricity and necessary equipment. Prices vary based upon the facility. The relevant prices are compiled in Table 3-6.

Table 3-6: PG&E Standby Tariff – Customer & TOU Meter Charge

Customer Class	Customer Charge ($/meter/day)	TOU Meter Charge ($/meter/day)
Residential	$0.16427	$0.12813
50-500kW Power	$4.9959	$0.17741
500-1000kW Power	$19.71253	-

Standby energy rates have the same time-of-use periods as conventional energy rates, but the rates are more expensive. The increased costs incentivize customers to minimize grid electricity consumption. Grid electricity required in addition to the HMG's generated electricity is calculated using PG&E's standby energy rates shown in Table 3-7.

Table 3-7: PG&E Standby Energy Costs

Classification	Time of Use	Energy Rate ($/kWh)
Summer:		
Off-Peak	9pm-8am (weekdays) & all day on weekends	$0.18415
Part-Peak	8am-12pm (weekdays)	$0.28851
Peak	12pm-6pm (weekdays)	$0.53786
Winter:		
Off-Peak	9pm-8am (weekdays) & all day on weekends	$0.12405
Mid-Peak	8am-9pm (weekdays)	$0.15360

CHP generates electricity by converting thermal energy into electrical energy through combustion of natural gas. Therefore the cost of electricity is dependent on the price of the fuel. The CHP fuel required is calculated by multiplying the heat rate and total electricity generated. The baseline natural gas price is assumed to be $6.50 per million British thermal units (MMBtu). The fuel cost to generate electricity is the product of the fuel price, heat rate, and electricity generated.

$$Fuel\ Cost = (Fuel\ Price) * (Heat\ Rate) * (electricity\ generated)$$

$$[\$] = \left[\frac{\$}{MMBtu}\right]\left[\frac{Btu}{kWh}\right][kWh]$$

In addition to fuel, the HMG will require regular maintenance. CHP maintenance costs are extracted from the EPA's CHP Catalog of Technologies based on the size of the microturbine. Prices are shown in Table 3-8.

Table 3-8: CHP Microturbine Maintenance Costs
Source: (Darrow et al., 2015)

Maintenance Costs	System					
	1	2	3	4	5	6
Nominal Electricity Capacity (kW)	30	65	200	250	333	1000
Fixed ($/kW/yr)	---	---	---	$9.120	$6.847	---
Variable ($/kWh)	---	---	---	$0.010	$0.007	---
Average @ 6,000 hrs/year operation ($/kWh)	---	$0.013	$0.016	$0.011	$0.009	$0.012

Battery maintenance is more expensive than CHP maintenance due to the chemical components and required expertise. As batteries achieve larger market penetration, maintenance costs should decrease. There are fewer resources available to estimate battery maintenance cost. Based on a customer survey and literature review, this project assumes the annual maintenance costs are equal to 1% of the pre-incentive initial cost. A $2 million battery is estimated to cost $20,000 per year to maintain. Results show this estimate yields battery maintenance costs approximately 2.5 times greater than CHP maintenance. It is important to note the 1% estimate is likely the least accurate HMG operational expense. Battery maintenance has a significant impact on the total annual operational costs (approximately 20%). Therefore excluding the estimate entirely is less accurate. The 1% of initial cost estimate represents a best guess.

After calculating the contributing HMG expenses, the individual components are added to determine the annual HMG operational costs. Annual savings are calculated by subtracting the operational costs from the conventional electricity costs calculated in section 3.4.1. This calculation is shown in Table 3-9. It is important to note the annual savings calculated assume zero thermal utilization from the CHP component.

Table 3-9: Annual Savings Calculation

HYBRID MICROGRID ANNUAL SAVINGS	
Conventional Electricity	$42,155
HMG O&M costs	
Standby Reservation Charge	$2,197
Standby Customer Charge	$1,679
Standby TOU Meter Charge	$65
Standby Energy Costs	$45
Fuel Costs	$17,747
CHP Maintenance Costs	$2,285
Battery Maintenance Costs	$5,970
Total HMG Costs	$29,989
Annual Savings	$12,166

3.4.3 Calculate Hybrid Microgrid Initial Costs

Initial costs of each HMG component are calculated using reported price estimates per installed kW or kWh. This estimate includes material and labor costs associated with making the technology fully functional. The installation costs per kW for each HMG component are shown in Table 3-10,

Table 3-11, and Figure 3-7. The CHP prime mover and battery technology used in this project are microturbines and advanced lead acid, respectively.

Table 3-10: 2014 Projected Solar PV Prices

Application	Approximate Size	Cost in 2014 ($/W)
Residential	5 kW	$3.71
Commercial	223 kW	$2.61
Utility-Scale	185 MW	$1.92

Adapted from: PV System Pricing Trends, NREL
Lawrence Berkeley National Laboratory (Feldman et al., 2014)

Table 3-11 Average Microturbine CHP Installation Costs
Source: Catalog of CHP Technologies, EPA (Darrow et al., 2015)

	System					
	1	2	3	4	5	6
Electric Capacity						
Nominal Capacity (kW)	30	65	200	250	333	1000
Net Capacity (kW)	28	61	190	240	320	950
Total Equipment ($)	*$75,300*	*$129,300*	*$401,900*	*$441,200*	*$566,400*	*$1,627,600*
($/kW)	*$2,689*	*$2,120*	*$2,120*	*$1,840*	*$1,770*	*$1,710*
Total Installed Cost ($)	$120,400	$196,400	$598,500	$652,600	$826,300	$2,374,900
($/kW)	$4,300	$3,220	$3,150	$2,720	$2,580	$2,500

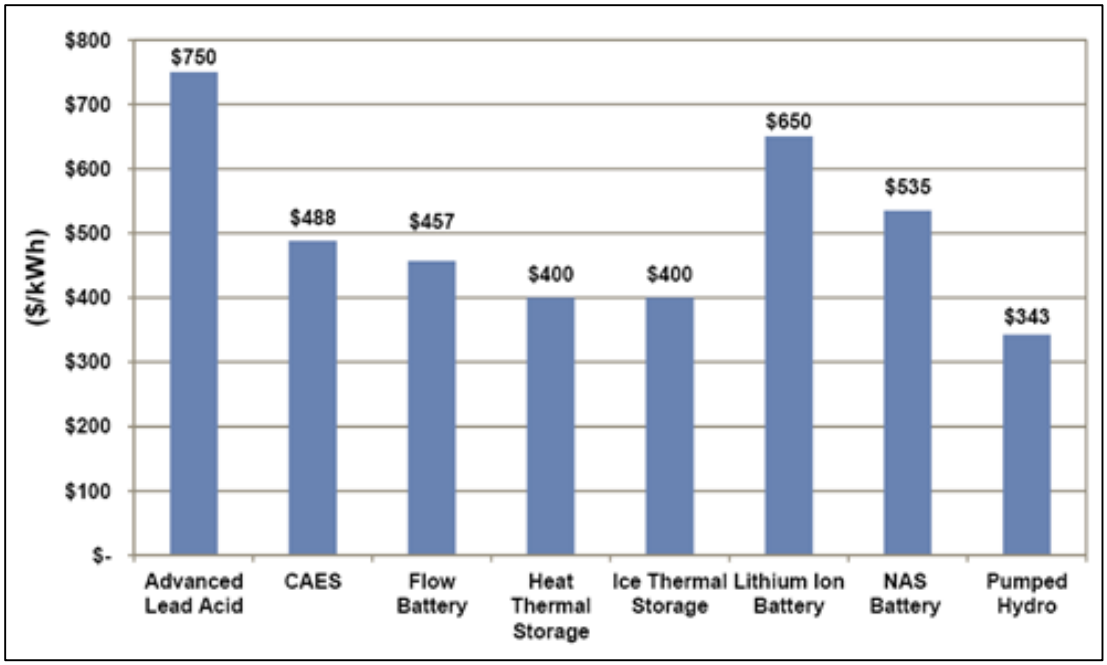

Figure 3-7: Battery Technology Installation Costs
Source: Pike Research

$$Initial\ Costs = (\$/kW)_{PV} * (PV\ installed\ kW) + (\$/kW)_{CHP} * (CHP\ installed\ kW) + (\$/kWh)_{Battery} * (Battery\ installed\ kWh)$$

Government incentives offset initial investment costs (as discussed in Chapter 2) and are used in this project. The two government incentives used are the federal investment tax credit (ITC) and California's Self-Generation Incentive Program (CA SGIP).

The federal ITC reduces the tax requirements for companies that install CHP and PV to their facility's demand. The current CHP and PV ITCs are 10% and 30% of the installation cost, respectively. This project assumes these installations meet the required efficiency standards and that the company has sufficient tax liability to claim the ITC. The total federal ITC is calculated using the equation:

$$Total\ ITC = 10\% * (Installation\ Price)_{CHP} + 30\% * (Installation\ Price)_{PV}$$

California's SGIP is the second government incentive used to reduce the initial investment required. The CA SGIP incentives in Table 3-12 are used to calculate the reduced cost for the CHP+battery. This incentive can be claimed in conjunction with the federal ITC; however, users are responsible for at least 40% of the project costs. Additionally, the incentive is capped at 3MW per project. Advanced energy storage incentives are paid on a declining tier for systems over 1 MWh. The battery incentive is 100% for the first MWh, 50% for 1-2 MWh, and 25% for 2-3 MWh. 50% of the CHP incentive is provided at the time of construction. The remaining 50% is paid in 10% increments over the following five years based upon successfully meeting performance metrics. To simplify the calculation, this project assumes 100% of the incentive is received upon installation. This project calculates the CA SGIP using the incentives in Table 3-12 along with the declining tier for batteries greater than 1 MWh and ensures incentives are capped at 3 MWs.

Table 3-12: California Self-Generation Program Incentives

Eligible Technology	Incentive ($/W)
Micro-turbine CHP	$0.44
Advanced Energy Storage	$1.46

Adapted from Self Generation Incentive Program (Center for Sustainable Energy, 2015)

$$CA\ SGIP = (kW)_{CHP} * (\$440/kW) + (kWh)_{battery} * (\$1{,}460/kWh)$$

The net HMG cost is calculated by subtracting the incentives from the initial cost. This value is the total price the customer must pay for the system and is the value used to calculate the ROI.

$$Net\ HMG\ Cost = \ Initial\ Costs - (Total\ ITC + Total\ SGIP)$$

It is worth noting that there are additional real world factors that are not captured in this project's initial cost estimate. For example the initial cost calculation uses installation price estimates for individual components. Integration of the HMG components will require more equipment and expertise that will increase the total price. The extent of price markup is not currently known because these systems are not common on the scale this project analyzes. Another expense for customers to consider is the cost for grid interconnection. Unless the system operates as a stand-alone unit, utility companies will charge the customer to ensure the HMG safely interacts with the existing grid distribution. The central grid is designed to transmit electricity in one direction. Distributed generation enables electricity to flow in the opposite direction. Additional safety features need to be installed by the utility to protect equipment and workers. This process typically entails the utility to review the design and visit the site before providing a quote for the total cost. This is not feasible for this project and so the interconnection fee is neglected.

Increased costs from component integration and grid interconnection are only two examples of expenses that could change the economic outlook for a real world HMG. It is not the intent of this project to capture all technical and economic factors, but rather to provide an early assessment of the necessary conditions before such a system would be economically feasible. It is left to future work to include these and other factors that may provide a more detailed assessment.

3.4.4 Calculate Baseline ROI

After the annual savings and net HMG cost are determined the simple ROI is calculated by division. The ROI is the primary focus of the economic evaluation because of the impact on prospective distributed energy customers (Lenssen et al., 2003). Calculating the ROI is a primary objective of the project.

$$Simple\ ROI_{0\%} = \frac{Net\ HMG\ Cost}{Annual\ Savings_{0\%}}$$

Since the annual savings were determined on the basis of electricity alone, the initial ROI is for 0% thermal utilization. This ROI can be adjusted to include the impact of thermal exhaust utilization. While this project does not analyze the facilities ability to use the CHP's thermal output, it does determine the HMG's ROI if a hypothetical percentage of heat were captured. In section 3.3.7 maximum theoretical thermal utilization is calculated to be 80% of the total CHP exhaust. The value of capturing this heat is determined in increments of 25% using the equation below.

$$Heat\ Value = \frac{(CH4\ Cost) * (theoretical\ max\ \ heat) * (\%\ captured)}{Boiler\ efficiency}$$

Boiler efficiency is assumed to be 85%, the cost of natural gas is assumed to be $6.50 per MMBtu and the percentage of heat captured is adjusted in increments of 25%. The corresponding heat value is then added to the previously calculated annual savings. The new annual savings are then divided into the net HMG cost to calculate the new ROI as shown in Table 3-13.

Table 3-13: Baseline ROI Calculation

ROI based on thermal capture (% of theoretical maximum)					
	0%	25%	50%	75%	100%
Heat Value	$0	$3,261	$6,523	$9,784	$13,045
Annual Savings	$12,166	$15,427	$18,689	$21,950	$25,211
Payback years	35.2	27.8	22.9	19.5	17.0

The results compiled in Table 3-13 represent the facility's baseline ROI. These values use the present day economic market conditions and represent how long the initial equipment would need to operate to recuperate the initial investment. The 50% thermal capture baseline ROI would be adjusted to determine how the ROI would improve with different economic factors.

3.5 Sensitivity Analysis

A series of sensitivity analyses are conducted to determine how changes in economic conditions impact ROI. Each sensitivity analysis uses 50% thermal utilization ROI as the reference. The economic conditions varied and observed are battery price ($/kWh), average natural gas price ($ per MMBtu), and average electrical rate ($/kWh). Following the sensitivity analyses economic conditions that yield 10, 5, and 3 year ROIs are identified. These ROIs represent the necessary economic conditions to achieve weak, moderate, and strong market penetration. The sensitivity analyses and identifying favorable economic conditions are the focus of objectives 4 and 5.

3.5.1 Battery Sensitivity Analysis

Baseline ROI calculations use the battery estimate of $750 per kWh. This value is adjusted from $100 to $1,000 per kWh and the impact on ROI is recorded. Variations in battery price impact the CA SGIP reimbursement. The CA SGIP only reimburses the first 3 MWh and is capped at 60% of the total battery cost. The sensitivity analysis ensures these CA SGIP rules are abided. The sensitivity analysis fixes natural gas prices at $6.50 per MMBtu and average electric rates remain at the price determined by the application of PG&E's tariff. Upon completing the battery sensitivity analysis the ROI is plotted vs. battery price.

3.5.2 Fuel Price Sensitivity Analysis

The baseline ROI uses natural gas fuel costs equal to $6.50 per MMBtu, $750 per kWh battery price, and the average electrical rate based on PG&E's applicable tariff. In this sensitivity analysis, natural gas prices are adjusted from $1 per MMBtu to $9 per MMBtu while battery and electrical prices are held constant. Adjustments to fuel costs will impact the HMG operational costs and the thermal heat value calculated in section 3.4.4. The change in heat value is included because it will impact the ROI. Upon the completion of the fuel price sensitivity analysis the ROI is plotted vs. natural gas fuel cost.

3.5.3 Electrical Rate Sensitivity Analysis

Conventional electricity costs are calculated for each facility with the applicable PG&E tariff. The annual average electricity cost is calculated by dividing annual costs by annual electricity consumed.

$$Avg\ electric\ rate = \frac{Conventional\ Costs\ (\$)}{Electricity\ Consumed\ (kWh)}$$

The calculated average is the baseline electricity cost manipulated in the sensitivity analysis. Increasing the electrical rate will increase the annual savings from avoided electricity purchases. The electric rate is varied up to $0.50 per kWh while the battery price remains constant at $750 per kWh and fuel costs are fixed at $6.50 per MMBtu. Upon completion of the electrical rate sensitivity analysis, the ROI is plotted against the average electrical rate.

3.5.4 ROI Market Conditions Analysis

Given the importance of the ROI in motivating customer investment, the necessary market conditions required to achieve 10, 5, and 3 year ROI are determined. Fuel price is fixed at $6.50 per MMBtu and battery price is adjusted from $750 per kWh to $100 per kWh. At each battery price the average electrical rate is adjusted until the targeted 50% thermal utilization ROI is achieved as shown in Table 3-14. For each ROI the required electrical rate is plotted verse the battery price.

Table 3-14: Five Year ROI Economic Conditions

Required Prices for 5 year ROI (50% thermal)		
e- Price	Battery Price	CH4 Cost
$0.510	$750	$6.50
$0.395	$500	$6.50
$0.360	$400	$6.50
$0.325	$300	$6.50
$0.290	$200	$6.50
$0.255	$100	$6.50

3.6 Summary

This chapter outlined the method to design a HMG and analyze the economic feasibility. Annual load profiles published by PG&E are downloaded and characterized. Hourly electric demand is extracted based on the 10 year average annual load. TMY2 hourly solar radiation data for Los Angeles, CA is used to generate PV output electricity based on the defined array size. Additional electricity is supplied by CHP steady-state operation where six set points are developed through trial and error. The CHP technology is selected from the EPA's Catalog of CHP Technologies. The HMG charges an electrical energy storage battery when CHP+PV output exceeds demand and draws electricity from the battery when production falls short of demand. The CHP+PV+battery HMG is sized to reduce required grid electricity to 1%. The HMG's annual technical performance is quantified.

Conventional electricity costs are calculated using publicized PG&E schedules. HMG annual operation costs are calculated using PG&E's standby tariff, assumed average fuel costs, and maintenance costs published in the EPA's Catalog of CHP Technologies. Annual savings are calculated by subtracting the HMG annual costs from the conventional electricity costs. HMG initial costs are calculated using price per installed kW or kWh estimates and federal and state incentives currently available. A simple baseline ROI is calculated by dividing the HMG initial costs by the annual savings assuming different levels of thermal utilization. Three sensitivity analyses are accomplished based on battery price ($/kWh), average fuel costs ($/MMBtu), and average electrical rate ($/kWh). The methodology concludes with identifying the electrical price required to achieve 10, 5, and 3 year ROIs based on independent battery and natural gas prices.

Chapter 4

Technical Analysis Results

This chapter presents the results from the technical design outlined in Chapter 3. This chapter focuses on fulfilling objectives 1 and 2. HMG design and performance results are presented for commercial, multi-residential, and large commercial facilities. Additionally the battery characteristics to meet the facility demand are quantified. Component sizes and performance metrics from this chapter are used to generate the HMG economics in Chapter 5.

4.1 Commercial Results (A10)

PG&E's A10 load profile represents typical commercial building served by the utility. This average profile consumes 235 MWh annually. The average hourly demand is approximately 27 kW, with a 57 kW peak. On average the commercial facility consumes 644 kWh per day, but varies up to 40% due to seasonal fluctuations. The HMG discussed in this section was designed to meet this annual load. A10 was the smallest of the three load profiles studied in this project. Additional information on the electrical consumption and demand is available in Appendix A. An example of the HMG's performance during a day of operation is available in Appendix C.

4.1.1 Commercial Hybrid Microgrid Design

The HMG's CHP+PV+Battery component sizes are compiled in Table 4-1. The 50 feet by 50 feet PV array generates a maximum of 33.3 kW. CHP output electricity varied from 16.5 kW to 23.2 kW during the year as shown in Table 4-2. To meet this demand a 30 kW microturbine (MT) was selected from the EPA's Catalog of Technologies. Based on the results from Table 4-2, the MT's minimum part load operation is 55% with an average annual capacity factor of 67%. The MT's EPA specifications are located in Appendix B. Only 51 hours during the year required grid electricity.

Table 4-1: Commercial (A10) HMG Design

Component	Size (kW)	Electricity Supplied (kWh)	Annual Load %
Annual Load		235,029	
CHP	30	175,755	75%
PV	33.3	59,123	25%
Grid	-	231	0.1%
Battery		27,875	12%

The design resulted in approximately equal CHP and PV sizes. Despite the equivalent sizes the MT produced 75% of the annual electricity. The remaining 25% is generated by the PV array. Table 4-2 shows CHP's output electricity as a percentage of the average demand. As expected the CHP demand percentage is greater during the winter months when less sunlight is available.

The MT's electricity production yielded 2,132 MMBtu of thermal exhaust. This analysis assumes 80% of that exhaust could theoretically be captured and used for space loads or thermal storage. Therefore, 1,706 MMBtu is the assumed maximum thermal output of the CHP MT.

Table 4-2: Commercial (A10) CHP Setpoints and Required Grid Hours

Setpoint	Setpoint Dates	Output (kW)	% of Avg demand	Required Grid Hours
1	Nov-19 Feb; 1-14 Mar	20.5	84.0%	11
2	20-29 Feb; 15 Mar - 12 May	16.5	66.7%	24
3	13 May - June	19.6	68.3%	0
4	July-August	21.7	71.0%	8
5	September	23.2	76.8%	8
6	October	21.4	78.1%	0
	Annual	20.1	74.8%	51

4.1.2 Commercial Battery Characteristics

The required battery size for the commercial design was just under 800 kWh. This corresponds to 1.2 days of the average electricity consumption. This battery size enabled 12% of the energy produced by CHP+PV to be stored and delivered at a later period. To meet the facility's demand the battery must be capable of charging and discharging electricity at 29.8 kW and 28.9 kW, respectively.

Table 4-3: Commercial (A10) Battery Specifications

Battery Specifications	
Size Required (kWh)	796
Storage Size (days)	1.2
Max Charge Rate (kW)	29.8
Max Discharge (kW)	-28.9

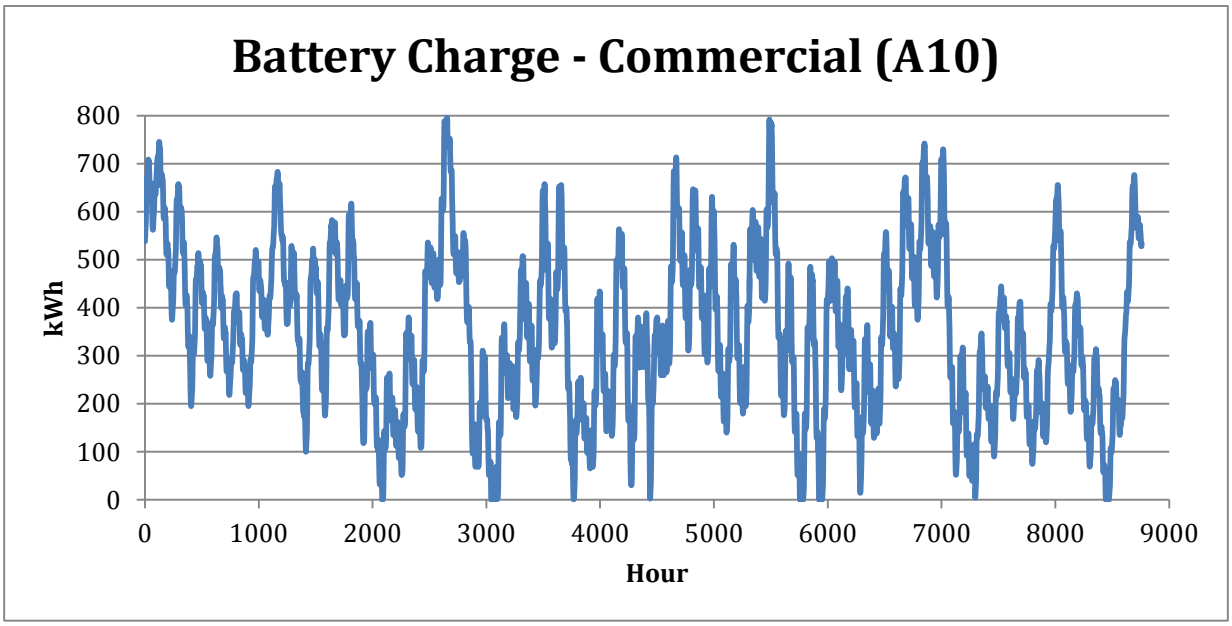

Figure 4-1: Commercial (A10) Annual Battery Charge

Figure 4-1 displays the battery state's condition over a year's operation. The HMG is assumed to begin operation on Nov 1st, with the battery's charge equal to zero at midnight. The battery fluctuates extensively throughout the year and achieves good utilization over the full range of storage. Analysis of Figure 4-1 shows the battery appears to cycle weekly, with approximately 52 local maximum points. Careful observation over shorter time increments reveal the battery is also required to discharge daily to smaller depths and with quicker frequency, as shown in Figure 4-2. The battery has a daily charge/discharge frequency and a weekly charge/discharge frequency, with seven daily cycles within one weekly cycle. Daily cycles discharge much smaller percentages of total battery capacity than weekly cycles.

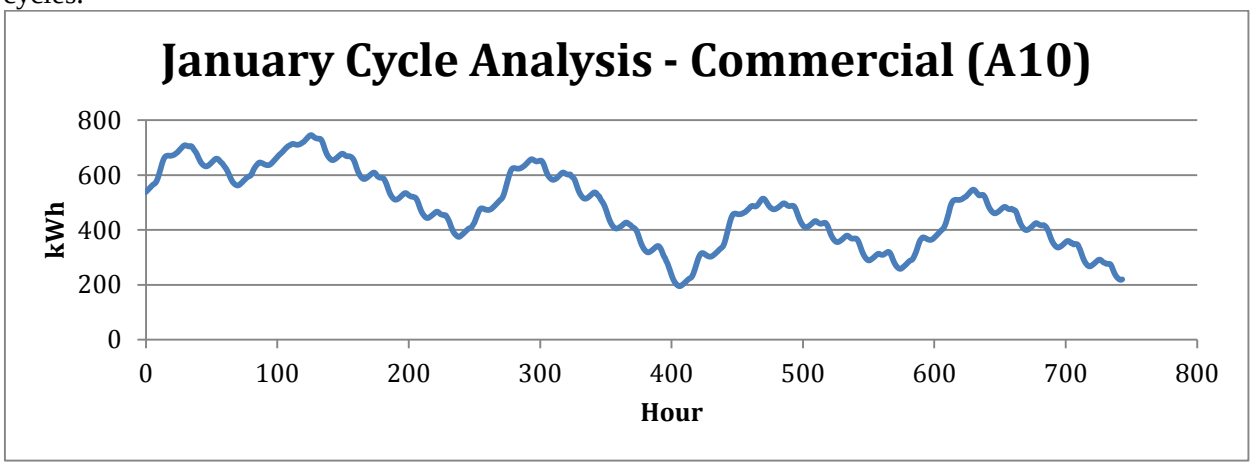

Figure 4-2: Commercial (A10) Battery Cycle Frequency

Table 4-4 compiles the daily and weekly cycles the battery progresses through during the year. Negative values represent the battery is discharging instead of charging. On average the daily discharge depth is much smaller than the weekly discharge depth, but both cycles display unpredictable patterns. Large daily discharge depth can exceed the weekly discharge depths. Conversely small weekly cycles may have smaller discharge depths than many daily cycles. Despite these differences on the whole weekly cycles exceed daily discharge depths. It is worth noting that the maximum weekly cycle discharges 85.2% of the total battery storage capacity. This high percentage suggests the HMG is effectively utilizing the storage capacity to meet seasonal fluctuations. In other words the higher the storage percentages depth of discharge, the less likely the battery is oversized.

Table 4-4: Commercial (A10) Battery Depth of Discharge

Daily Cycles			Weekly Cycles		
Number of Cycles	362		Number of Cycles	50	
	kWh	Storage %		kWh	Storage %
Max Discharge Depth	-325.9	40.9%	Max Discharge Depth	-678.1	85.2%
Median Discharge Depth	-80.7	10.1%	Median Discharge Depth	-328.2	41.2%
Min Discharge Depth	-0.4	0.1%	Min Discharge Depth	-118.1	14.8%

4.2 Multi-Residential Results (E6)

PG&E's E6 residential TOU service load profile was scaled to simulate a multi-residential facility comprised of 150 individual units. This profile consumes an annual 1,541 MWh. An average 176 kW demand is required hourly with a 397 kW peak. The multi-residential building consumes an average 4.2 MWh, but can increase to 6.0 MWh during peak usage. The challenge the multi-residential load profile presented to the HMG design was the unpredictable energy use. The commercial load profiles predictably consumed the most electricity in the summer and the least in the winter. The multi-residential profile required 13% more electricity in December than August, due to the holidays. Similar unexpected changes in electricity consumption during the year required more detailed CHP design and quicker battery cycles to accurately meet the facility's demand. Additional details regarding the multi-residential demand are available in Appendix A. An example of the HMG's operation during the course of a day is graphed and presented in Appendix C.

4.2.1 Multi-Residential Hybrid Microgrid Design

Table 4-5 displays the total HMG electricity generation. The 50'x100' PV array supplied 7.7% of the electricity. This is 17% less than the A10 PV supply percentage and more realistic given current PV penetration levels. A 200 kW MT is selected from the EPA's Catalog of Technologies to meet the output setpoints tabulated in Table 4-6. The MT's minimum part load operation is 72% with an average annual capacity factor of 81%.

The multi-residential load profile proved to be more volatile than the commercial profiles and required more detailed design as a result. There are several factors that indicate the energy demand's volatility. First CHP output varies by 28% during the year (143 kW to 198 kW) in order to meet large seasonal differences. Another indicator of the load volatility is the HMG's control requires the battery to discharge 225 kW. This electricity supply exceeds the maximum CHP output. The cause of this high discharge specification is a short sudden spike in demand that occurs when steady-state CHP output is low due to meet the average seasonal demand. The rapid drains in electricity from the battery can be seen in Figure 4-3. Finally the breakdown of CHP output dates are more detailed than the HMG designed to meet the A10 & E19 load profiles. The additional dates, shown in Table 4-6, are necessary to meet the rapid change in energy consumption without oversizing the system's battery.

Due to the E6 load volatility the HMG design compensates by requiring a high battery discharge rate. Ultimately this specification highlights the limitation of the steady-state CHP control simplification made in this research. By limiting the CHP output setpoints to six, the battery is forced to compensate for volatile demand that would otherwise be solved through additional CHP setpoints. A more detailed control could reduce the battery's discharge rate (kW) in addition to the total storage capacity (kWh).

Table 4-5: Multi-Residential (E6) HMG Design

Component	Size (kW)	Electricity Supplied (kWh)	Annual Load %
Annual Load		1,541,254	
CHP	200	1,419,823	92.1%
PV	67	118,246	7.7%
Grid	-	6,725	0.4%
Battery		167,785	11%

Table 4-6: Multi-Residential (E6) CHP Setpoints and Required Grid Hours

Setpoint	Setpoint Dates	Output (kW)	% of Avg demand	Required Grid Hours
1	24 Nov-5 Jan; 15 Feb-18 Apr	198.1	97.2%	0
2	12 Jan - 9 Mar; 9-27 Nov	170.0	94.8%	4
3	10-31 Mar; 1-15 May	147.9	91.4%	10
4	16 May - 23 Jun; 1-9 Sep	146.0	87.5%	4
5	24 Jun - Aug; 10-30 Sep	166.4	89.9%	67
6	Apr; Oct - 8 Nov	143.0	91.8%	0
	Annual	162.1	92.1%	85

4.2.2 Multi-Residential Battery Characteristics

In order to perform within the necessary requirements of the simulation, the battery must be designed according to the specifications in Table 4-7. The E6 HMG's battery is designed to be approximately 5 MWh, corresponding to 1.2 days of the average facility demand. The battery needs to charge as quickly as 88 kW and be capable of discharging 225 kW of electricity. As previously discussed this large difference between the charge and discharge rates highlights the study's CHP simplification limitations.

Table 4-7: Multi-Residential (E6) Battery Specifications

Battery Specifications	
Size Required (kWh)	4,961
Storage Size (days)	1.2
Max Charge Rate (kW)	88.0
Max Discharge (kW)	-225.3

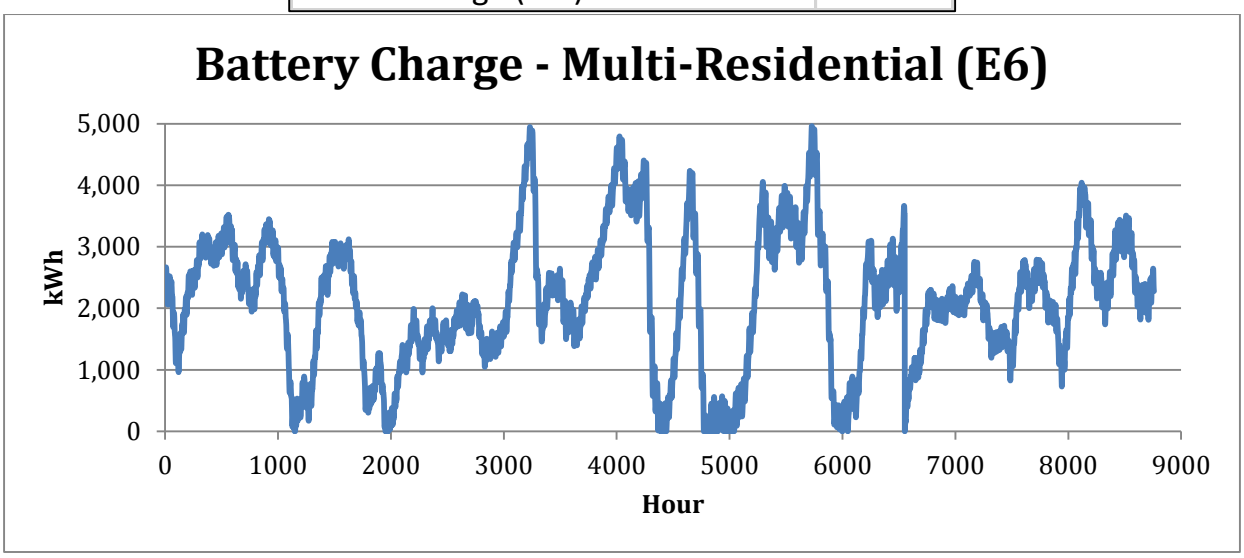

Figure 4-3: Multi-Residential (E6) Annual Battery Charge

Figure 4-3 shows the battery's total charge as a function of time for the entire year. The HMG is assumed to begin operation on October 1st, with the battery charge equal to zero at midnight. Comparison of this plot to the commercial battery charges shows the multi-residential battery discharges large percentages of electricity in short periods. This is evident by the large, quick cycles the battery exhibits during the middle of the year (hours 4000-5000). Over the course of 10 days from July 5th to July 14th the battery charges from 0 kWh to 4,199 kWh. By July 18th the battery discharges the entire stored energy to meet the facility's demand, draining 85% of the storage capacity in 4 days. This cycle is the facility's largest, but there are several quick cycles required by the multi-residential battery that are not required by the commercial equivalent.

The battery cycle frequency and discharge depth, which are shown in Table 4-8, display similar results to the commercial design. The battery exhibits daily and weekly cycles, with a median weekly cycle discharging twice the depth of a daily cycle. The maximum weekly discharge of 70% indicates the HMG effectively utilizes the full range of storage. Cycle frequency and discharge depth will affect the life expectancy of the battery and the ROI. To what extent the life expectancy is impacted is left up to the battery manufacturers. This research focuses on quantifying the required battery characteristics and not the impact to performance.

Table 4-8: Multi-Residential (E6) Battery Depth of Discharge

Daily Cycles			Weekly Cycles		
Number of Cycles	365		Number of Cycles	52	
	kWh	Storage %		kWh	Storage %
Max Discharge Depth	-1738.7	35.0%	Max Discharge Depth	-3485.0	70.2%
Median Discharge Depth	-411.8	8.3%	Median Discharge Depth	-806.0	16.2%
Min Discharge Depth	-87.0	1.8%	Min Discharge Depth	-389.0	7.8%

4.3 Large Commercial Results (E19)

PG&E's large commercial (E19) facility is the largest energy user studied in this report. The annual demand is 2,742 MWh, which is over ten times the typical commercial (A10) consumption. The average power requirement is 313 kW with a peak demand of 545 kW. Of the three load profiles, the large commercial's energy consumption is also the most predictable and consistent. This is evident in E19's 57% capacity factor, compared to A10's 47% and E6's 44%. The consistent electricity demand is also apparent in the hourly load profile graph located in Appendix A. The performance of the large commercial HMG over a 24 hour period is available for reference in Appendix C.

4.3.1 Large Commercial Hybrid Microgrid Design

The large commercial HMG component sizes and annual energy generation are compiled in Table 4-9. The 100'x100' PV array is capable of producing a maximum of 133 kW based on the solar radiation levels. A 333 kW MT is selected to meet the required 312 kW maximum CHP output. The MT's minimum part load operation is 73% with an average annual capacity factor of 86%. 91.4% of the annual electricity is generated by the MT. The specifications for the MT are extracted from the EPA's Catalog of CHP Technologies and available in Appendix B. The presence of battery enables 8% of electricity generation to be stored and supplied when demand increases. The presence of storage enables the CHP+PV portion of the HMG to generate 99.8% of the facility's annual electric consumption.

Table 4-9: Large Commercial (E19) HMG Design

Component	Size (kW)	Electricity Supplied (kWh)	Annual Load %
Annual Load		2,742,461	
CHP	333	2,505,627	91.4%
PV	133	236,493	8.6%
Grid	-	5,808	0.2%
Battery		221,379	8%

Steady-state CHP electrical setpoints are listed in Table 4-10. The design separates the summer months August, September, and October into individual setpoints. The remaining nine months are met by three steady-state CHP setpoints. These setpoints vary from 88.1% to 94.3% of average demand depending on the electrical output from the PV array. This schedule enables the HMG to meet the facility's demand 98.9% of the time. Only 93 hours in the year cannot be met by the HMG's design.

Table 4-10: Large Commercial (E19) CHP Setpoints and Required Grid Hours

Setpoint	Setpoint Dates	Output (kW)	% of Avg demand	Required Grid Hours
1	24 Nov-5 Jan; 15 Feb-18 Apr	272.1	93.0%	43
2	6 Jan - 14 Feb; 1-23 Nov	284.3	93.9%	0
3	19 Apr - Jul	283.7	88.1%	30
4	August	305.6	91.0%	0
5	September	312.0	90.2%	12
6	October	300.3	94.0%	8
	Annual	286.0	91.4%	93

4.3.2 Large Commercial Battery Characteristics

In order for the HMG to perform as described the battery is required to have slightly less than 7 MWh of energy storage. This corresponds to less than one day of average energy usage. This is a 25% size reduction compared to the normalized sizes of both the commercial and multi-residential batteries. The smaller size is attributable to the facility's high capacity factor enabling the battery to balance charging & discharging.

Table 4-11 reflects this balance in the relatively similar charge and discharge rates.

Table 4-11: Large Commercial (E19) Battery Specifications

Battery Specifications	
Size Required (kWh)	6,915
Storage Size (days)	0.9
Max Charge Rate (kW)	168.2
Max Discharge (kW)	-195.4

Figure 4-4 plots the large commercial battery charge during a year of operation. The HMG is assumed to begin operation on January 1st, with the battery charge equal to zero at midnight. Compared to the multi-residential battery plot in Figure 4-3, the large commercial charge is uniform and symmetrical. Battery cycles appear to be regular and consistent. On the whole the control is simpler and more predictable, which highlights the benefit to installing a HMG on a commercial loads rather than a residential.

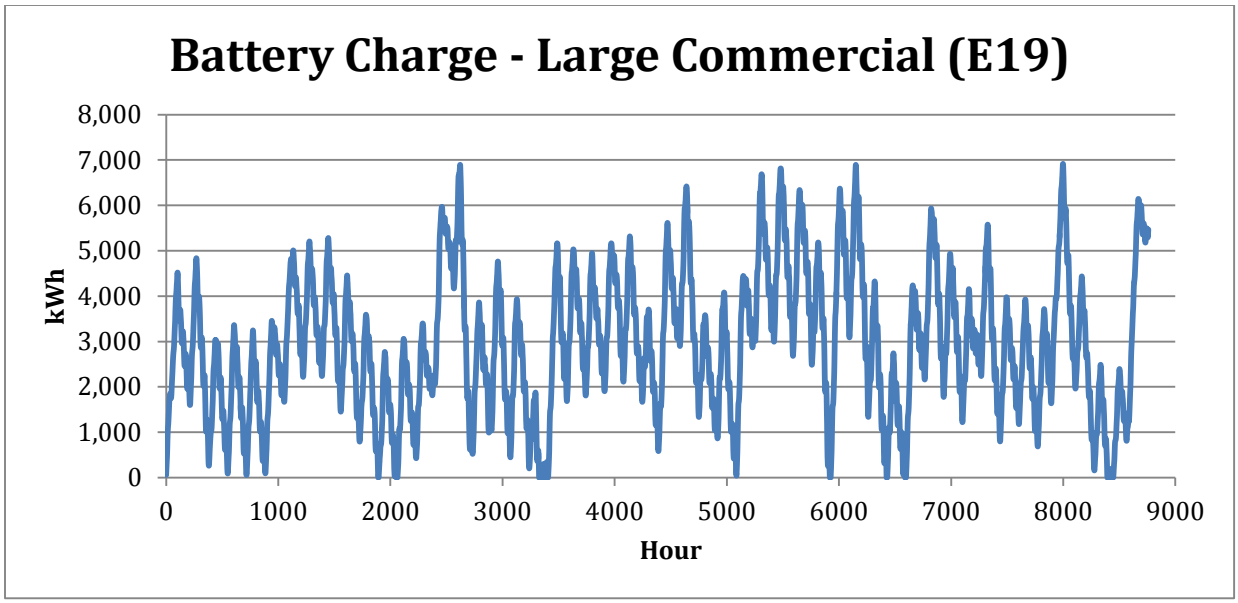

Figure 4-4: Large Commercial (E19) Annual Battery Charge

Table 4-12 organizes the large commercial battery storage cycles and discharge depths. In this case the number of daily cycles more closely aligns with the number of weekdays in a year, which are 260. Unlike the other two loads, the large commercial building has sufficient electricity over the weekend when consumption decreases and so the battery cycles less during the year. On the other hand weekly cycles are just as common. The weekly battery cycles for this load discharge significant levels, about 40% on average. In one week the HMG discharged 92% of the battery's charge. These high percentages demonstrate effective battery capacity utilization by the design. The fewer daily cycles and the high discharge depths reflect the relatively flat load profile. Such a profile enables the battery to effectively be used as a capacitor by responding to fluctuations over short durations.

Table 4-12: Large Commercial (E19) Battery Depth of Discharge

Daily Cycles			Weekly Cycles		
Number of Cycles	286		Number of Cycles	50	
	kWh	Storage %		kWh	Storage %
Max Discharge Depth	-2003.0	29.0%	Max Discharge Depth	-6370.6	92.1%
Median Discharge Depth	-800.4	11.6%	Median Discharge Depth	-2793.0	40.4%
Min Discharge Depth	-0.4	0.0%	Min Discharge Depth	-1574.8	22.8%

4.4 Technical Analysis Summary

This section presented the results to each facility's HMG design and performance. Battery specifications and performance where quantified to describe the necessary characteristics required for each HMG. These results fulfilled objectives 1 and 2.

The battery for each facility displayed two different cycle frequencies, daily and weekly. Daily cycle frequencies occurred every day in the commercial and residential HMGs, but mostly occurred on weekdays for the large commercial facility. The commercial batteries were able to discharge around 40% of capacity during weekly cycles, which exceeds the residential 16% depth of discharge average. Battery presence enabled 8-12% of electricity generation to be shifted to later demand. Figure 4-5 consolidates results from the weekly cycle battery discharge depths for each facility. The results show the commercial facilities better utilized the battery size with greater discharge depths than the multi-residential building.

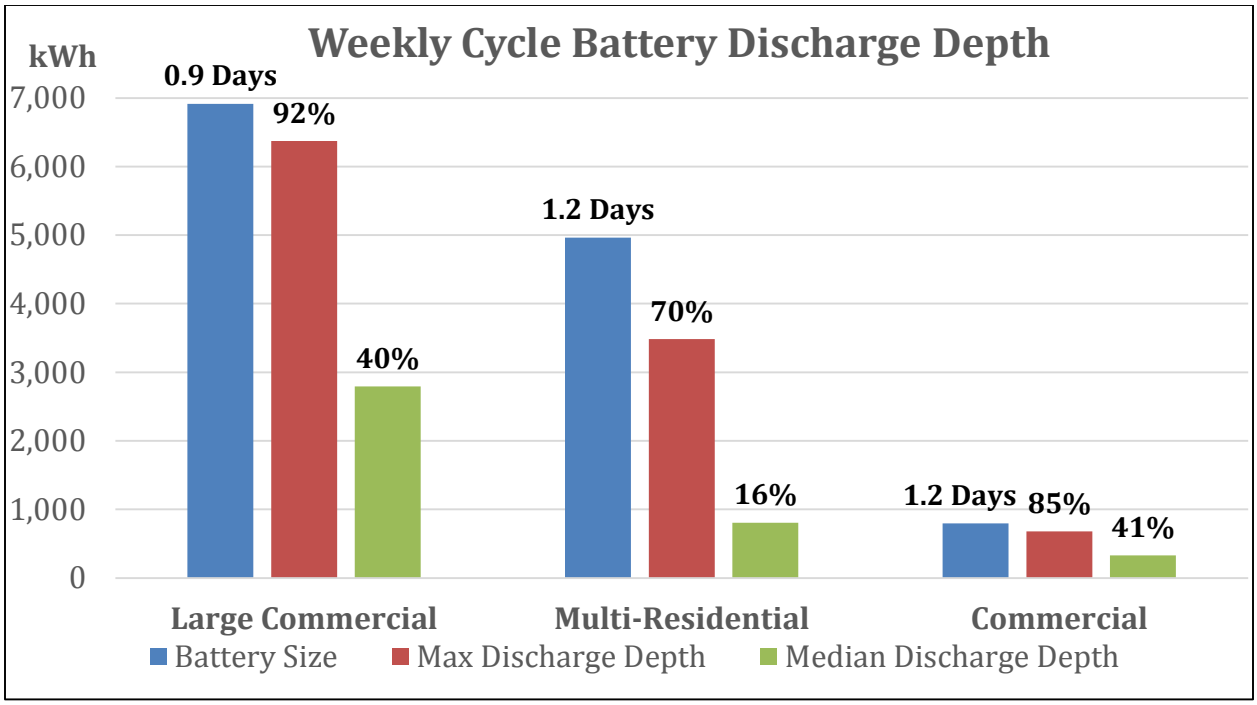

Figure 4-5: Consolidated Weekly Cycle Battery Discharge Depth

HMG design was most notably different between the residential and commercial loads. Due to the load volatility, steady-state CHP output control required more detail for the residential load. This also caused a disparity between the charging and discharging rate requirements for the residential battery. The commercial loads generally had simpler CHP control periods and greater depths of battery discharge.

The large commercial load profile proved to be the simplest design with the greatest capacity utilization. Battery size for this facility was less than a day of average consumption and 25% smaller than the normalized sizes of the other two batteries. The large capacity factor enabled the battery to operate effectively as a capacitor to fluctuating demand. This is more effective than operating the battery similar to a third electricity source, which reflects the case in the residential load.

Chapter 5

Economic Analysis Results

This chapter presents the results of the economic calculations outlined in Chapter 3. Technical metrics from Chapter 4 are used to calculate initial costs, annual savings, and return on investment (ROI). Three sensitivity analyses are conducted to determine the change in ROI based on market conditions. The chapter concludes by identifying the necessary battery and electrical prices required to yield 10, 5, and 3 year ROIs. This analysis assumes natural gas prices are $6.50 per MMBtu and the facility successfully captures 50% the available heat from CHP. At the 10, 5, and 3 year ROI price points investment interest is anticipated to be weak, moderate, and strong based on past surveys (Lenssen et al., 2003). This chapter is focused on accomplishing objectives 3, 4, and 5.

5.1 Baseline Return on Investment Results

This section presents baseline ROI results using the methodology outlined in Chapter 3. Current technology prices and government incentives are used to calculate initial costs. Conventional electricity costs are calculated using PG&E's applicable tariffs. Fuel consumption and maintenance costs are determined using the microturbine (MT) specification sheets in Appendix B. ROI results are plotted based upon the total thermal utilization. Baseline ROI calculation is the 3rd objective of this thesis.

5.1.1 Commercial ROI Results

Initial costs to install HMG equipment in the commercial facility are shown in Table 5-1. Technology costs were $4,300 per kW, $3.71 per W, and $750 per kWh for the CHP MT, PV array, and battery technology, respectively. Net prices for each component where calculated by subtracting the federal investment tax credit (ITC) and California Self-Generation Incentive Program (SGIP) reimbursements. Of the two government incentives the state SGIP provided 88% of the total incentives.

Due to the generous incentives the final initial costs are approximately half the cost of the HMG technology. This quantifies the financial impact of the available government incentives and emphasizes the importance they play in generating customer investment. Comparing Table 5-1 to Table 4-1 shows the battery technology is responsible for 56% of the total cost, but only provides 12% of the electricity. CHP on the other hand delivers 75% of the electricity while only costing 24% of the total cost. This reveals the importance of minimizing the battery size and effectively using CHP to meet demand. Additional analysis should be researched to determine if the battery size used in this simulation could be reduced with better control.

Table 5-1: Commercial (A10) HMG Initial Costs

Description	Price	Percent of Total Price
Net CHP Price	$102,900	24%
Net PV Price	$86,471	20%
Net Battery Price	$238,652	56%
Pre-incentive Costs	$849,159	
Total Gov't Incentives	$421,137	50%
Net HMG Price	**$428,023**	**50%**

HMG conventional electricity and operational costs are shown in Table 5-2. The average electrical rate paid for conventional central grid electricity is $0.1794 per kWh. Standby reservation charges were $3.76 per kW-month and calculated using the maximum CHP output during the year, 24 kW. Fuel costs are the most significant expense and contribute 60% of the total operational costs. Installation of the HMG design reduces the annual energy bill by $12,166 or 29% of conventional electricity costs.

Table 5-2: Commercial (A10) Annual Savings

HYBRID MICROGRID ANNUAL SAVINGS	
Conventional Electricity	$42,155
HMG O&M costs	
Standby Reservation Charge	$2,197
Standby Customer Charge	$1,679
Standby TOU Meter Charge	$65
Standby Energy Costs	$45
Fuel Costs	$17,747
CHP Maintenance Costs	$2,285
Battery Maintenance Costs	$5,970
Total HMG Costs	$29,989
Annual Savings	$12,166

Simplified ROI calculations are calculated by dividing the initial costs by annual savings. Assuming no thermal heat capture, it takes 35.2 years to recover the investment. By this time CHP and battery equipment need replacement and the investment would never be recovered. In producing 175 MWh to meet facility demand, CHP generates 1,706 MMBtu of usable heat energy assuming the average heat rate is equal to the specification. If some or all of this energy could be utilized to offset the cost of energy from an 85% efficient boiler the ROI would improve. The ROI based on percentage of thermal utilization is plotted in Figure 5-1. If all the heat energy was effectively utilized the ROI would be 17 years. The level of heat recovery has a significant impact on the ROI. The baseline ROI assuming 50% thermal utilization is 22.9 years.

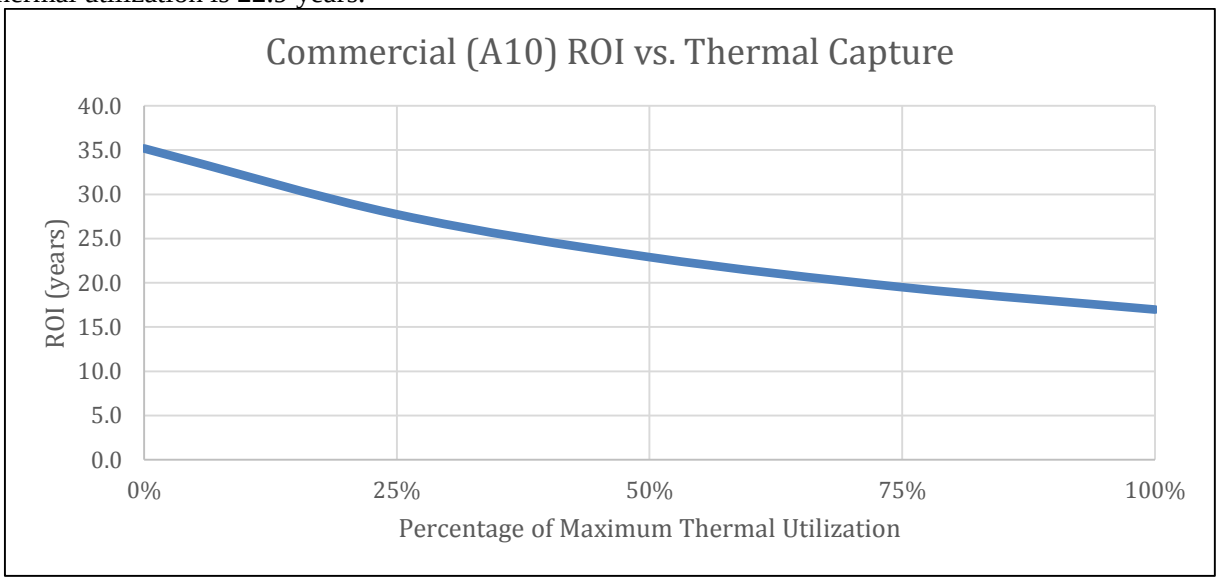

Figure 5-1: Commercial (A10) Baseline Return on Investment

5.1.2 Multi-Residential ROI Results

Multi-residential HMG initial costs are shown in Table 5-3. CHP MT, PV array, and battery technology price estimates were $3,150 per kW, $3.71 per W, and $750 per kWh, respectively. The battery SGIP maxed out at 3 MWh and 60% of the total price. 94% of the total government incentive came from the SGIP. The residential battery costs 70% of the total HMG cost and supplies 11% of the facility's electricity. The volatile load profile discussed in section 4.2 makes limiting the battery size difficult, which is reflected in the total system price. The customer's total initial cost is reduced by 53% due to the government incentives available, which is the largest relative reduction of any of the three HMG designs.

Table 5-3: Multi-Residential (E6) Initial Costs

Description	Price	Percent of Total Price
Net CHP Price	$479,000	22%
Net PV Price	$172,942	8%
Net Battery Price	$1,488,443	70%
Pre-incentive Costs	$4,598,168	
Total Gov't Incentives	$2,457,783	53%
Net HMG Price	**$2,140,385**	**47%**

Multi-residential HMG operational costs and annual savings are displayed in Table 5-4. PG&E's E6 residential electric rates averaged out to $0.2024 per kWh. Unlike commercial standby rates, residential standby rates do not include a customer charge. Instead the customer charge is rolled into the time-of-use (TOU) meter charge. Fuel costs for the CHP system account for 55% of the total operational costs. The HMG operation reduces the annual electric energy bill by $95,583 or 31% from conventional grid costs.

Table 5-4: Multi-Residential (E6) Annual Savings

HYBRID MICROGRID ANNUAL SAVINGS	
Conventional Electricity	$311,965
HMG O&M costs	
Standby Reservation Charge	$10,186
Standby TOU Meter Charge	$7,015
Standby Energy Costs	$1,320
Fuel Costs	$118,351
CHP Maintenance Costs	$22,717
Battery Maintenance Costs	$56,793
Total HMG Costs	$216,382
Annual Savings	$95,583

Without thermal utilization the simplified ROI is 22.4 years. By this point HMG equipment would exceed life-expectancy and require replacement which would prevent the ROI from being realized. The CHP MT generated 1,541 MWh to meet the residential electric demand. Assuming a constant thermal output and the ability to capture 80% of the total exhaust, 10,692 MMBtu of usable thermal energy are produced by the MT. The impact of utilizing any or all of the thermal heat is graphed in Figure 5-2. Complete thermal heat utilization would reduce the ROI to 12.1 years. Thermal utilization is more likely in residential building than typical commercial building. 100% thermal utilization is still unlikely unless CHP were specifically designed to thermal loads and thermal storage was installed. The baseline ROI used for the sensitivity analysis is 15.7 years, which assumes 50% of the heat is captured and utilized.

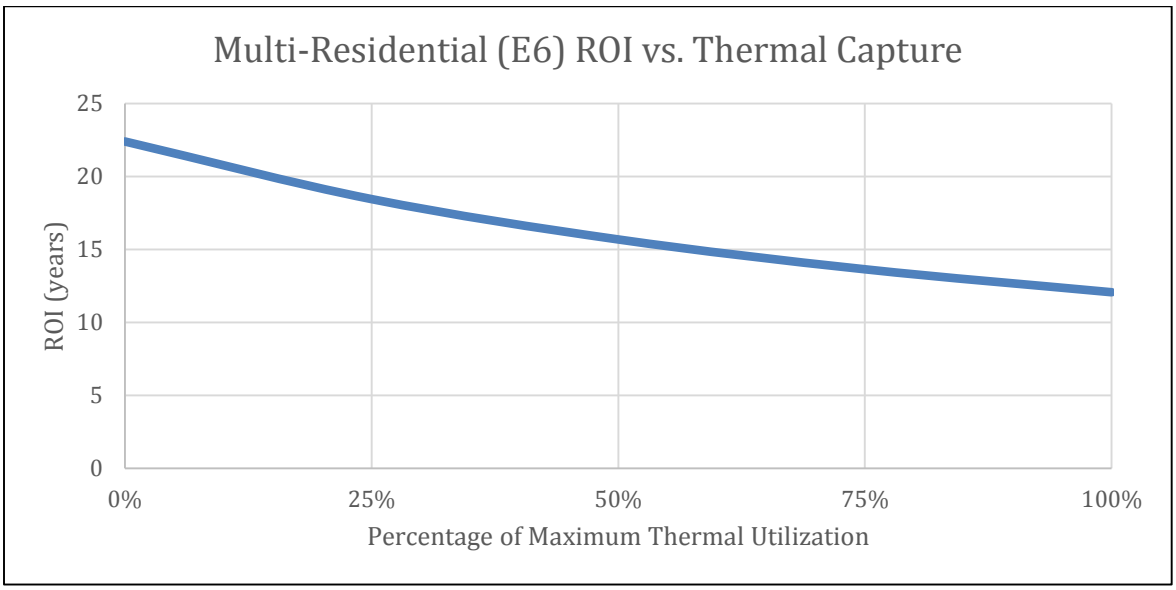

Figure 5-2: Multi-Residential (E6) Baseline Return on Investment

5.1.3 Large Commercial ROI Results

Table 5-5 contains initial HMG costs for the large commercial facility. Price estimates used were $2,580 per kW, $2.61 per kW, and $750 per kWh for the CHP MT, PV array, and battery technology. The battery incentive for this project maxed out the CA SGIP at 60% of the total cost. 93% of the price reduction is due to the SGIP incentive. Out of the three HMG designs, the large commercial HMG receives the smallest relative price reduction, equal to 44% of the initial equipment cost. There is also the largest discrepancy between the battery price and electricity supplied. The battery successfully stores and supplies 8% of the annual electricity, but accounts for 76% of the total bill.

Table 5-5: Large Commercial (E19) HMG Initial Costs

Description	Price	Percent of Total Price
Net CHP Price	$626,706	17%
Net PV Price	$243,330	7%
Net Battery Price	$2,715,435	76%
Pre-incentive Costs	$6,393,240	
Total Gov't Incentives	$2,807,768	44%
Net HMG Price	**$3,585,472**	**56%**

Table 5-6 documents conventional electricity and HMG operational costs. PG&E's electrical tariff cost an average of $0.1559 per kWh, which is the cheapest rate of the three buildings due to the quantity of electricity consumed. The fuel costs are responsible for 65% of the total HMG operational costs. This higher percentage is due to the reduction in non-fuel costs from the economies of scale. The HMG's operation reduces the annual energy bill $124,339 or 29%. This relative value is comparable to the other two facilities.

Table 5-6: Large Commercial (E19) Annual Savings

HYBRID MICROGRID ANNUAL SAVINGS	
Conventional Electricity	$427,450
HMG O&M costs	
Standby Reservation Charge	$17,074
Standby Customer Charge	$7,195
Standby Energy Charge	$1,634
Fuel Costs	$198,664
CHP Maintenance Costs	$22,551
Battery Maintenance Costs	$55,994
Total HMG Costs	$303,111
Annual Savings	$124,339

The simplified ROI without thermal utilization is 28.8 years. Similar to the other two HMG ROIs this timeline exceeds the life-expectancy of the equipment. Chapter 4 discussed a HMG design is better suited for large commercial than multi-residential loads. Despite the technical benefits, the residential HMG's ROI is more favorable than the large commercial. This is due to the different electrical rates charged by PG&E. At the average residential rate, the large commercial ROI reduces from 28.8 years to 14.2. The large commercial CHP system generates 17,605 MMBtu of useful heat. Utilization of this heat quickly improves the ROI. The ROI maxes out at 13.8 years if 100% of the thermal heat is captured. The baseline ROI used in the sensitivity analysis is 18.7 years, which assumes 50% thermal heat utilization.

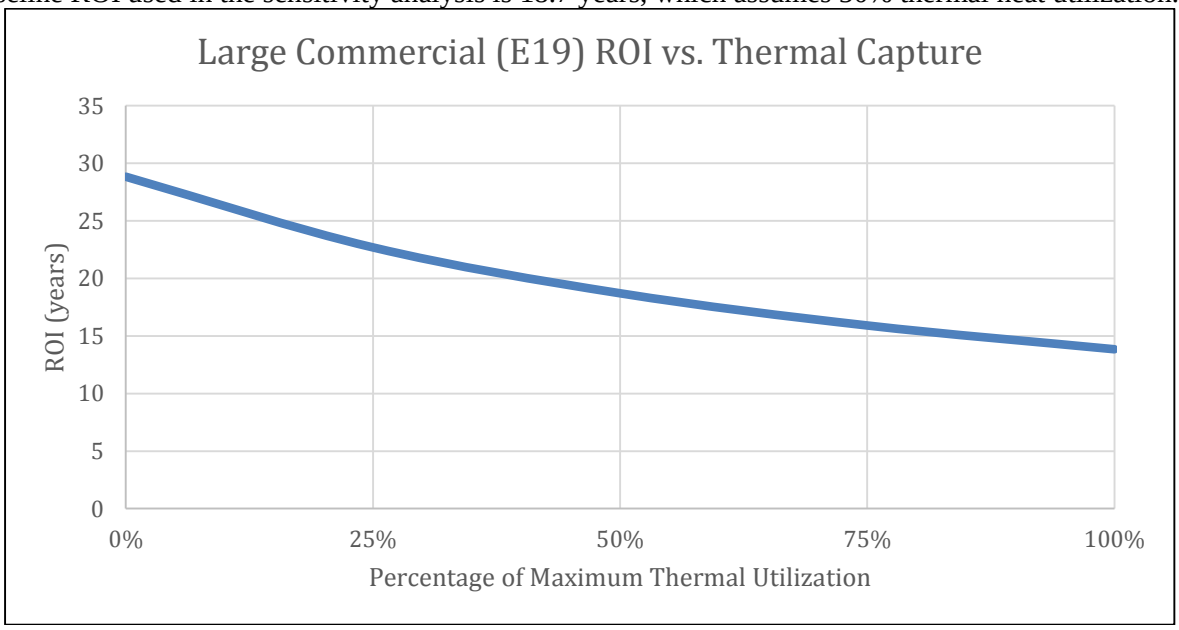

Figure 5-3: Large Commercial (E19) Baseline Return on Investment

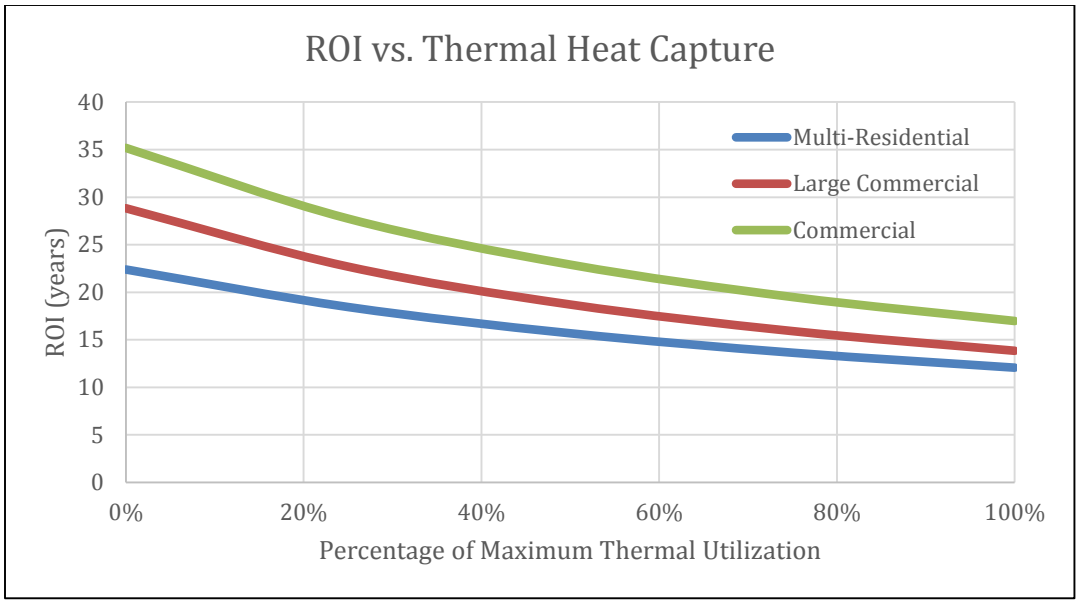

Figure 5-4: Consolidated Baseline ROI

Figure 5-4 presents the baseline ROI for each building. Based on the economics multi-residential has the most favorable ROI due to the high electrical rates. However, real world residential savings may fall short of estimates from this project due to the complex battery control discussed in Chapter 4.

5.1.4 Impact of California's Self-Generation Incentive Program

It is important to note the impact government incentives play in improving the economics of a HMG. Figure 5-5 plots the ROI for the large commercial HMG with and without California's SGIP reimbursement. The results show installation without this incentive drastically increases the ROI timeline. Without the SGIP it is unlikely customers would invest in such technology for economic reasons. This is the case despite California's high electrical rates (Pacific Power, 2014). Thus it is expected that such an application is entirely unrealistic in the majority of the US where electrical rates are cheaper and there are no state funded incentives. At the very least, economic conditions would need to change significantly before any investment in HMG technology on the loads discussed would begin to occur.

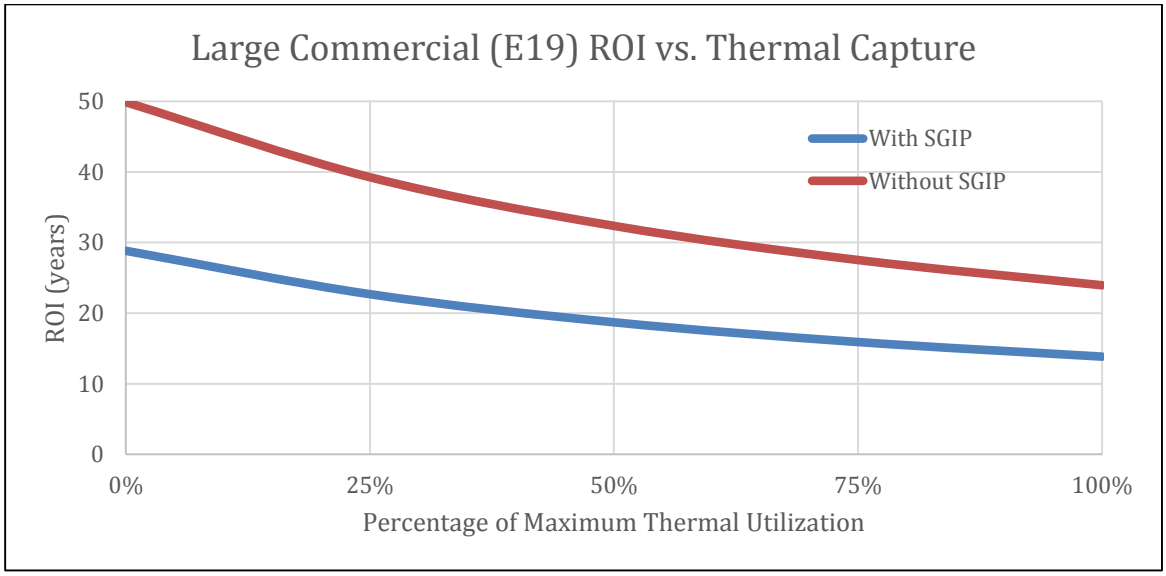

Figure 5-5: Impact of California SGIP on Large Commercial HMG ROI

5.2 Sensitivity Analyses Results

ROI calculations were accomplished in section 5.1 based on present day economic conditions and the level of heat recovery. This section investigates how the ROI varies with changes in economic conditions. A sensitivity analysis is executed based on battery price, natural gas fuel price, and electrical rate. The corresponding ROI for each facility is overlaid on the same plot. Each sensitivity analysis assumes 50% of the thermal heat is output is recovered and used to meet space loads. This section focuses on accomplishing objective 4.

5.2.1 Battery Price Sensitivity Analysis Results

The battery price sensitivity analysis plots the ROI as a function of battery price ($/kWh). Fuel price is assumed to be $6.50 per MMBtu for the analysis and electrical rates are equal to the average values determined by PG&E's tariffs. The commercial rate is 17.94 ₵ per kWh, multi-residential rate is 20.24 ₵ per kWh, and large commercial rate is 15.59 ₵ per kWh. The ROI's sensitivity to battery price is presented in Figure 5-6 for all three buildings.

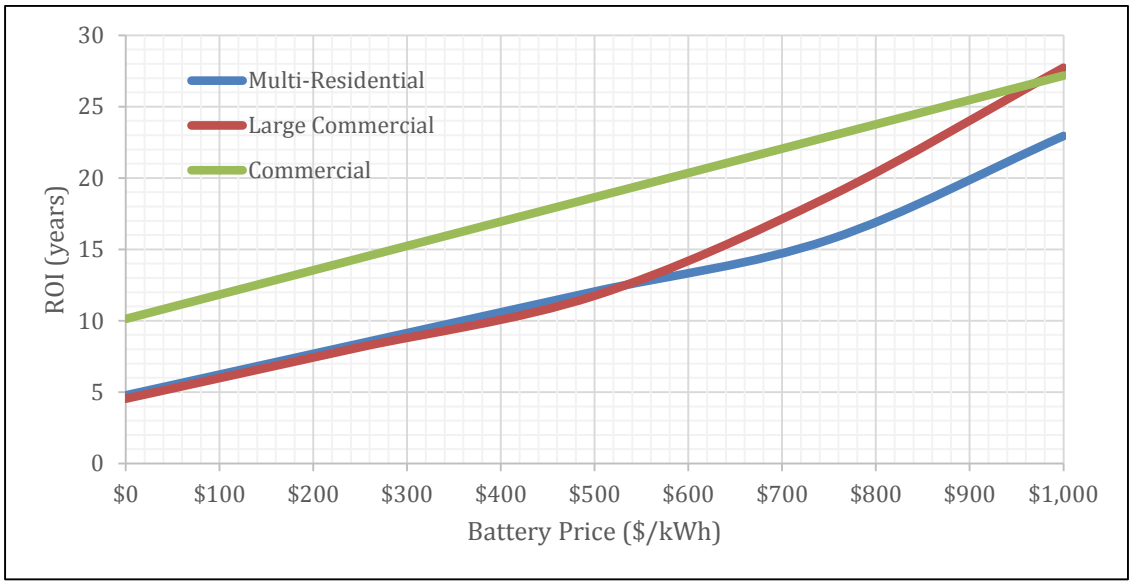

Figure 5-6: Battery Price Sensitvity

At the current $750 per kWh battery price a multi-residential HMG has the most favorable ROI. As battery prices decreases to $500 per kWh large commercial and multi-residential HMG's have equal ROIs. It should be noted that both the large commercial and multi-residential HMG's max out the CA SGIP incentive between $500-$750. The ROI curve changes slope where the SGIP maxes out.

At approximately $375 per kWh, the HMG achieves a 10 year ROI for the large commercial building. Similar results occur for the multi-residential load at $340 per kWh. Recent literature predicts battery prices to drop in the near future, with some estimates as low as $100 per kWh (Naam, 2015) (Parkinson, 2014). At $100 per kWh the large commercial and multi-residential HMGs achieve a 6.0 and 6.2 year ROI, respectively. This ROI could very well generate investment interest from both types of customers. It should be noted that this assumes the CA SGIP is still available. If the SGIP is revoked at lower technology prices, which is traditionally the case for government incentives, an adjustment to the analysis is required to determine the new ROI.

5.2.2 Natural Gas Fuel Price Sensitivity Analysis Results

The fuel price sensitivity analysis plots ROI as a function of natural gas prices ($/MMBtu). The sensitivity analysis fixes the battery price at $750 per kWh and the electrical rates based on PG&E's tariffs. The analysis assumes 50% of the heat output is utilized. The results for each facility are shown in Figure 5-7.

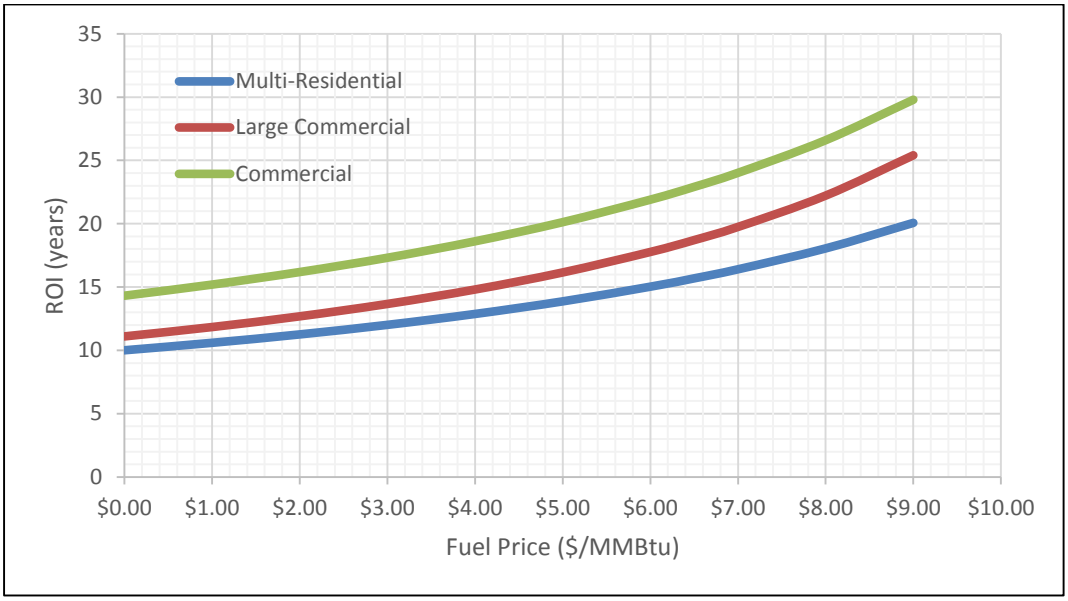

Figure 5-7: Fuel Price Sensitivity

The fuel sensitivity analysis reveals the limited impact natural gas prices have on the ROI. Even if the fuel could hypothetically be obtained for free the ROI would never drop below 10 years. Large changes in price will yield visible results, but minor changes to the price (<$1.00 per MMBtu) only have noticeable impact at higher prices. Changes in battery technology price and electrical rates are more likely to generate investment interest than fuel price fluctuations.

5.2.3 Electrical Rate Sensitivity Analysis Results

Figure 5-8 displays the ROI electrical rate sensitivity analysis results. The sensitivity analysis assumes natural gas prices are $6.50 per MMBtu and battery technology costs $750 per kWh. The analysis assumes 50% of the heat generated by CHP is utilized by space loads. Each facility curve begins at PG&E's tariff rate and the price is increased to $0.50 per kWh.

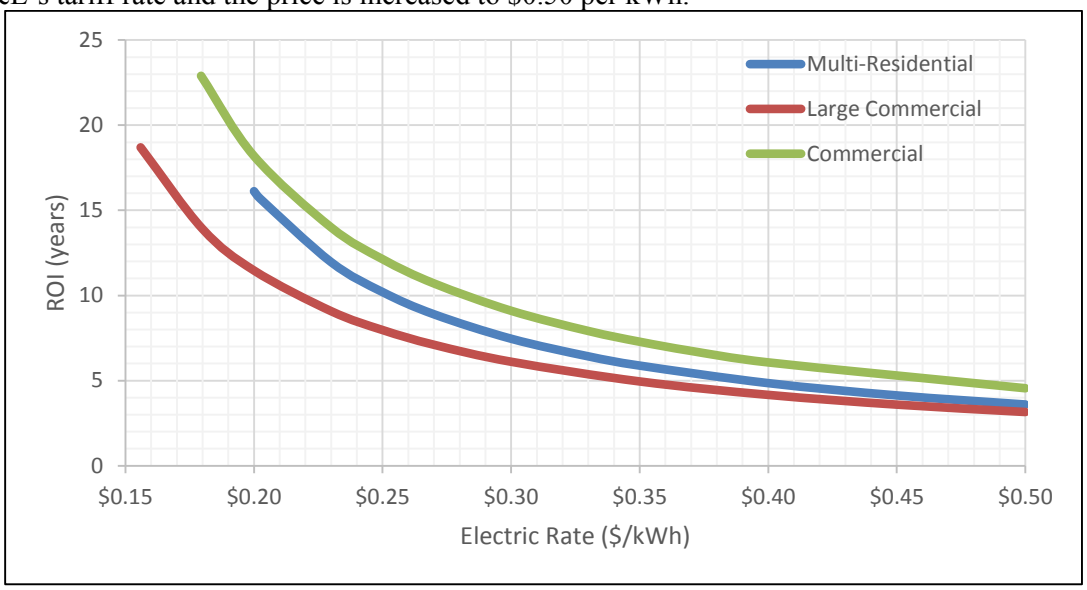

Figure 5-8: Electrical Rate Sensitivity

The sensitivity analysis reveals electrical prices have a strong impact on the HMG ROI. At equal electrical rates the large commercial load has the most favorable ROI, followed by multi-residential. The large commercial HMG achieves a 10 year ROI at $0.22 per kWh and a 5 year ROI at $0.35 per kWh. At the current rate of $0.1559 per kWh, electrical prices need to increase 41% for a 10 year ROI and 125% for a 5 year ROI. The multi-residential HMG attains a 10 year ROI at $0.25 per kWh and a 5 year ROI at $0.40 per kWh. At the current market rate of $0.2024, prices need to increase 24% and 98% to return a 10 year ROI and 5 year ROI, respectively.

5.3 Market Condition Thresholds

Section 5.1 demonstrated that present day economic conditions failed to provide a 10 year ROI for any of the building's studied. It is of interest to identify what market conditions are required to yield 10 year, 5 year, and 3 year ROIs. At these ROIs survey suggest such technology would achieve weak, moderate, and strong market penetration (Hedman & Hampson, 2010).

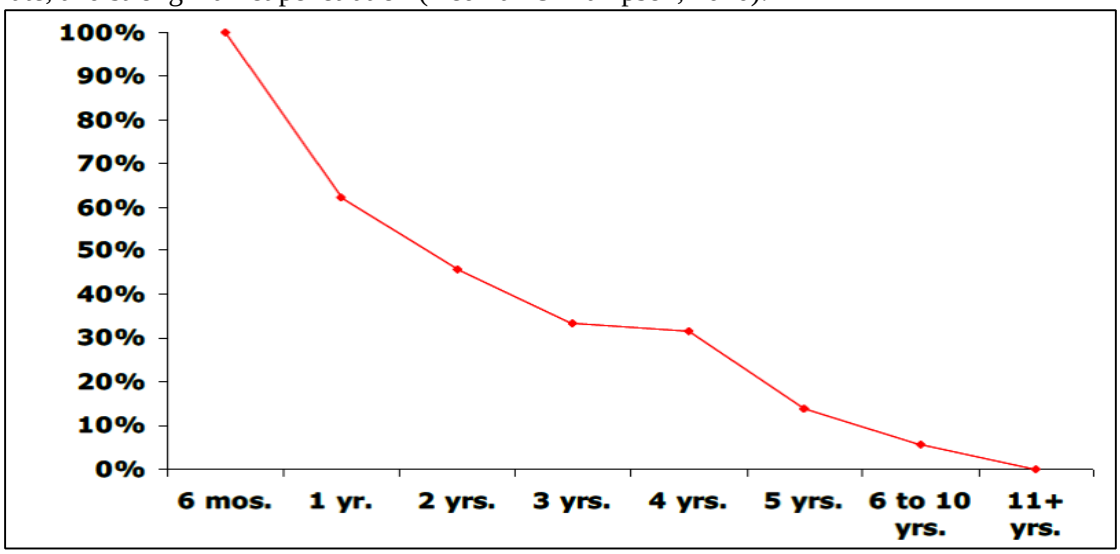

Figure 5-9: DG Investment based on ROI
Source: (Hedman & Hampson, 2010, fig. 4)

This section identifies the electrical rate required to achieve these ROI thresholds based on battery technology price. The analysis assumes natural gas prices are $6.50 per MMBtu and 50% of the thermal heat used. Results for each facility are overlaid on the same plot and grouped by ROI timeline. ROI thresholds for individual facilities are graphed and presented in Appendix F. This section focuses on fulfilling objective 5.

5.3.1 10 Year ROI Market Conditions

Figure 5-10 contains the results for 10 year ROIs for each facility. The graph indicates the investment returns will occur first for the large commercial HMG, followed by the multi-residential, and lastly the typical commercial HMG. If the battery technology decreased 50% from the current $750 per kWh mark, the large commercial HMG would obtain a 10 year ROI if electrical prices are $0.155 per kWh. That price is less than the current PG&E rate. At a battery price of $375 per kWh multi-residential requires approximately $0.205 per kWh, which is close to the current rate. Typical commercial would require a rate of 23₵ per kWh. If battery technology drops to $100 per kWh as some experts predict, the large commercial and multi-residential loads would easily obtain a 10 year ROI given current electric rates. The commercial facility would require an electric rate of 19.5₵ per kWh, or a 9% increase in electricity rates.

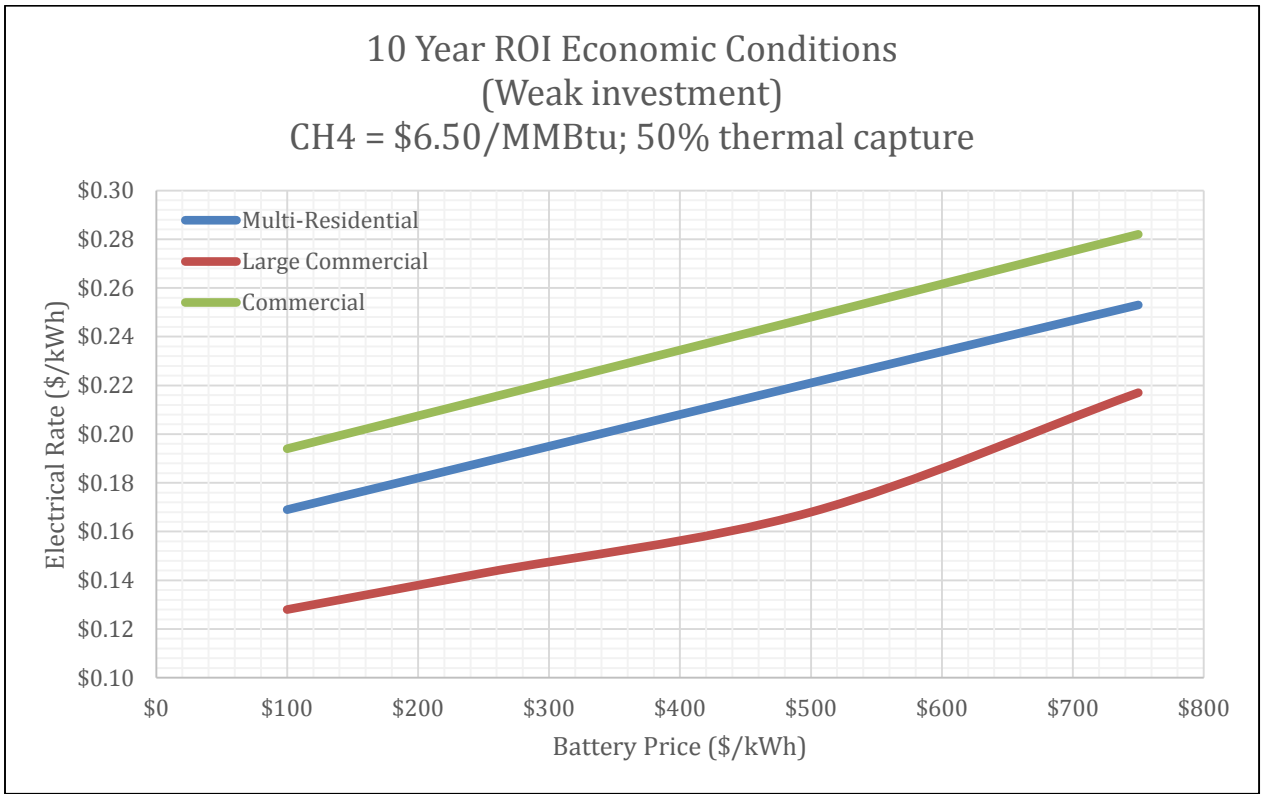

Figure 5-10: 10 Year ROI Market Threshold

5.3.2 5 Year ROI Market Conditions

The 5 year ROI economic threshold conditions are presented in Figure 5-11. Results suggest the payback is more difficult to obtain and would require significant changes battery and electricity prices. At the present cost of $750 per kWh for battery technology, electricity needs to cost 35₵ per kWh before the large commercial HMG yields a 5 year ROI. This is over twice the current rate and not likely to occur anytime soon. If battery prices drop to $100 per kWh the required electric rate for large commercial and multi-residential is 17₵ and 22.5₵ per kWh, respectively. This is approximately a 10% increase in the current electrical rate. These economic adjustments may be within the realm of possibility in the next ten years. Currently experts are predicting battery technology to fall and electricity rates to rise. Higher electricity rates are viewed as necessary to offset the capital costs required by utilities to replace aging electrical equipment.

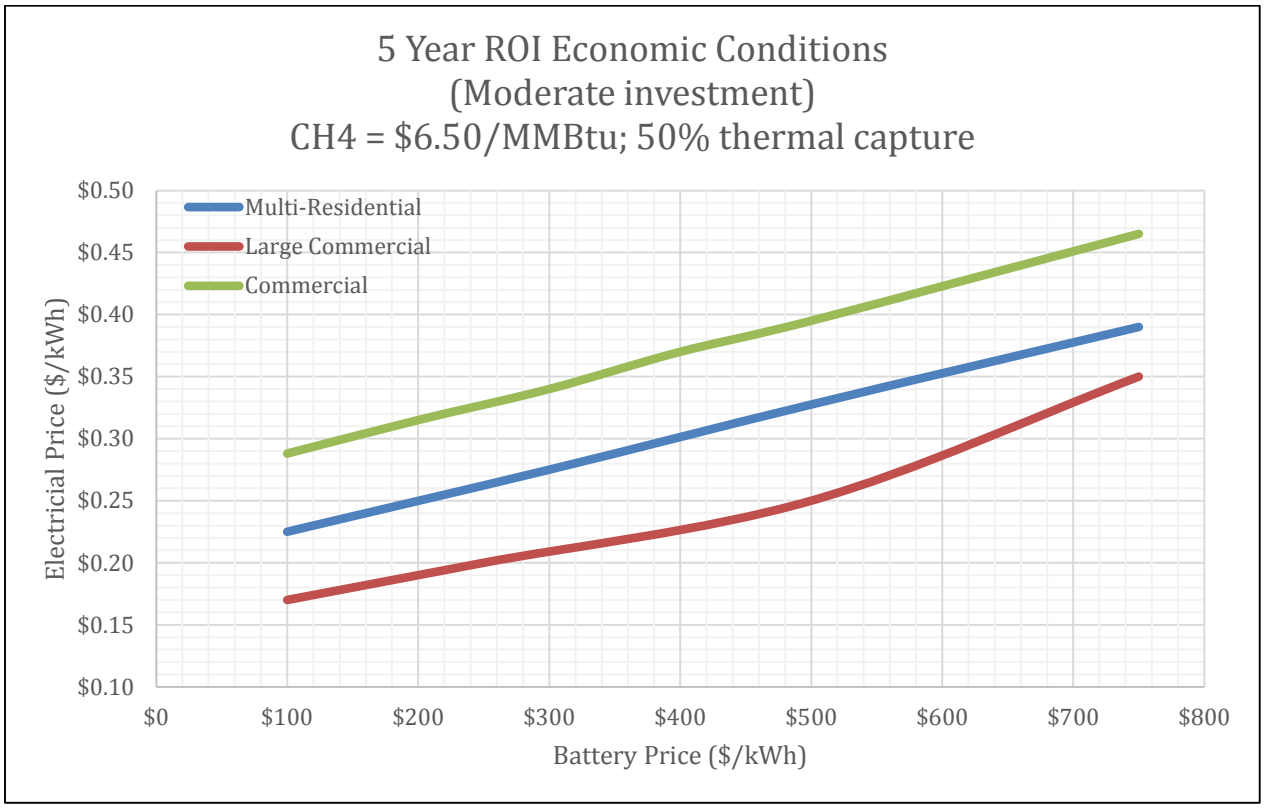

Figure 5-11: 5 Year ROI Market Threshold

5.3.3 3 Year ROI Market Conditions

Market threshold conditions for each HMG to achieve a 3 year ROI are graphed in Figure 5-12. A 3 year ROI represents an ambitious benchmark that would likely achieve strong investment due to the limited risk. At this point electricity is far too cheap for rate of return to be achieved in the near future. At the battery cost of $100 per kWh, electricity rates for the large commercial and multi-residential buildings would need to increase 40%-50%. The likelihood of this occurring in the next ten years is extremely low. These results reinforce the results from Chapter 2, which indicated distributed generation's adoption is limited to industrial customers. These users are the largest consumers of energy with significant thermal loads.

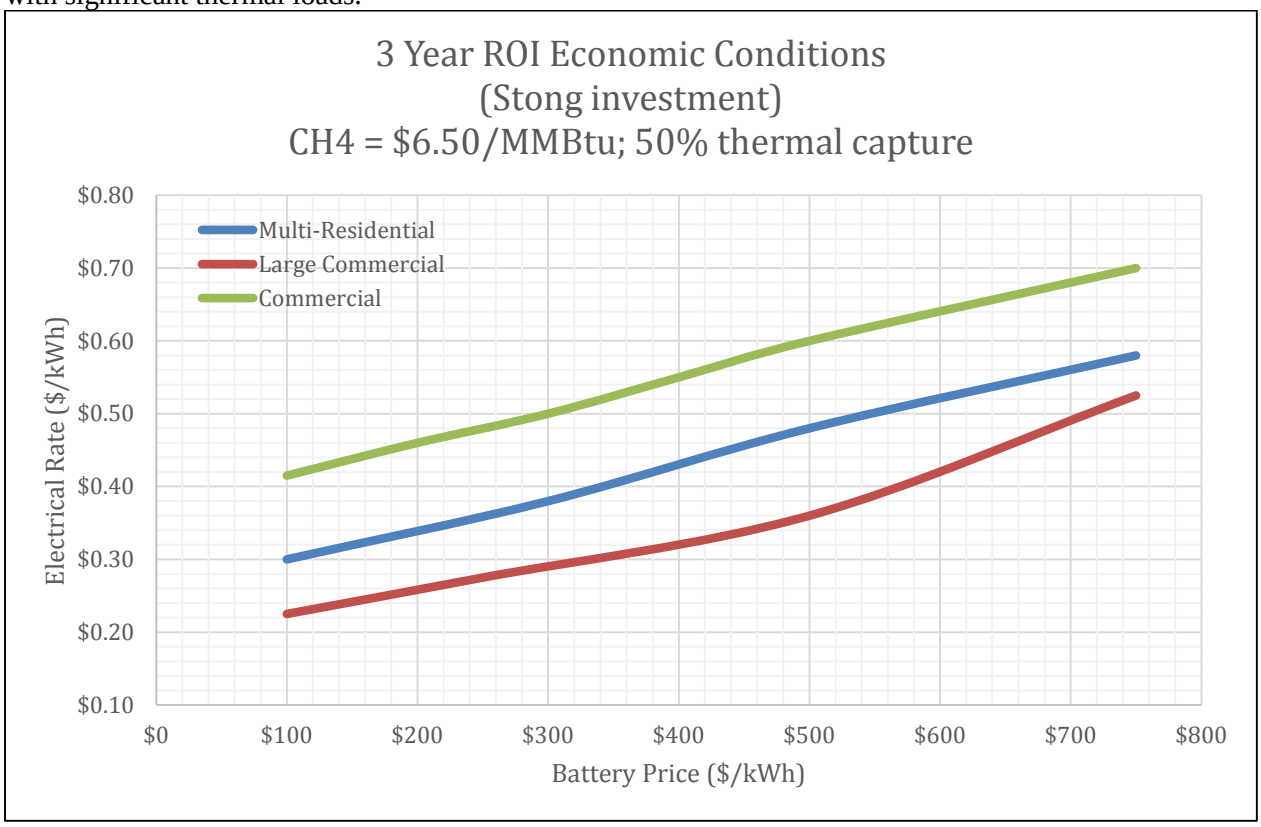

Figure 5-12: 3 Year ROI Market Threshold

5.4 Economic Analysis Summary

This chapter explored the baseline ROI, executed three sensitivity analyses, and investigated to what degree electrical rates and battery prices need to change before the HMG technology is competitive.

Baseline ROI calculations revealed the ability to utilize CHP's thermal output has a significant impact on ROI results. All three HMG applications had ROIs greater than 20 years for 0% thermal utilization. The multi-residential HMG proved to have the most favorable ROI given the present market conditions, mostly due to the increased cost of electricity for residential customers. The results from this analysis revealed the ROIs are too high for every application to justify the investment based on economics. This section also emphasized without the availability of California's SGIP, the payback timeline would be significantly longer.

A battery sensitivity analysis demonstrated that a 50% drop in battery price yields 10 year ROI for large commercial & multi-residential HMG. If battery technology fell to $100 per kWh the same facilities could see 6-7 year payback periods. The fuel price sensitivity analysis appeared to have minimal impact on the ROI. High fuel prices can make the investment cost prohibitive, but low prices are unlikely to motivate investment. The final sensitivity analysis proved electric rates have the largest impact on returns. At equivalent electric rates, the large commercial HMG provides the most favorable ROI. At 30₵-35₵ per kWh, ROIs become viable for all three HMGs.

The final analysis investigated the necessary changes to market conditions in order to achieve 10, 5, and 3 year ROIs. Some forecasters predict battery technology to reach $100 per kWh in the near future (Naam, 2015) (Parkinson, 2014). If this does occur the large commercial and multi-residential HMGs would achieve a 10 year ROI based on current electric rates. A 5 year ROI is also a possibility for these two HMGs, but would require a 10% increase in electricity rates. 3 year ROIs appear unlikely to occur in the near future.

This analysis presents results for the current economic environment in California. The emphasis is on an early and comprehensive economic feasibility. This analysis is focused on identifying the necessary price points to generate interest and not detailed ROI calculations. The model does have limitations and would benefit from more detailed analysis. This is left to future work. Additional improvements could be made by increasing the HMG level of control, including interconnection fees, investigating commercial tax liability, improving the battery maintenance estimates, estimating the cost to integrate such technology and predicting how price reductions may impact the California SGIP. The results rely heavily on California's SGIP incentive. Cancellation of this program will impact the analysis results.

Overall the model effectively incorporates the breadth of factors impacting the economics. While the control is limited, it is sufficient to generate a realistic, early assessment. Results should be viewed as estimates that will require additional detailed analysis before investment. There is confidence that the model produced valid results, but only as an indication of the early economic feasibility.

Chapter 6

Discussion and Conclusions

This research investigated the technical and economic implications of a hybrid microgrid consisting of CHP, PV, and electrical storage in commercial and residential applications. This analysis was applied to three building load profiles: a typical commercial (57 kW peak), a 150 multi-unit residential (397 kW peak) site, and a large commercial (545 kW peak) application. This research had five key objectives.

1. Describe the CHP+PV+battery hybrid system design that reduces grid supplied electricity to 1% (88 hours per year) for residential, commercial, and large commercial.
2. Identify the battery characteristics necessary to meet each facility design. Characteristics include charge rate, storage size, and cycle frequency.
3. Quantify present day ROIs based upon assumed levels of CHP thermal utilization
4. Conduct sensitivity analyses to determine how ROI would improve with varying battery price, average electrical rates, and average fuel costs.
5. Identify the economic environment that would yield 10, 5, and 3 year ROIs

With the help of the committee a methodology was developed to accomplish these objectives. This chapter presents a summary of the results.

6.1 Objective 1

CHP proved to be the cornerstone of each HMG generating over 90% of the annual electricity for the multi-residential and large commercial load profiles. The presence of battery technology enabled 8%-12% of electrical generation to be shifted to later demand. Higher supply shifts occurred where greater PV electricity was supplied. CHP needed to fluctuate to different setpoints in order to limit the battery size and respond to the seasonal variations in PV output electricity. It was necessary to control CHP output on the residential load with more precision due to the volatility of the demand profile.

6.2 Objective 2

The necessary storage capacity was 1.2 days for the typical commercial and multi-residential HMGs in California. Large commercial required storage capacity of 0.9 days at average consumption. Each facility required the two battery cycle frequencies: daily and weekly. Daily cycles discharged on average 10% of the total charge capacity and weekly discharge depths were approximately 40% in commercial facilities and 20% in the residential analysis. However, maximum day discharge depths exceeded some weekly requirements.

Total battery charge reflected weekly trends in electricity consumption. Commercial loads tended to charge the battery over the weekend and slowly draw down over the course of the week. Unpredictable increases in demand rapidly discharged battery storage and required sufficient storage. The large commercial facility discharged 92% of the total storage capacity within a week. In general the commercial batteries operated in more predictable patterns and placed less strain on the battery. The residential profile required the battery to respond in quick, unpredictable ways due to the nature of the load profile.

6.3 Objective 3

Present day ROI calculations indicated the multi-residential HMG had the highest ROI, followed by large commercial. In reality multi-residential customers are probably less likely to invest than commercial customers due to the lack of cash available to make such an investment. In each building type the payback period is too long to generate any customer interest. Additionally the ROI likely outlasts the life expectancy for key equipment. The results also showed that maximizing the thermal recovery is critical to improving the ROI. Lastly, it was apparent that the ROIs depended heavily on the generous reimbursements provided by California Self-Generation Incentive Program.

6.4 Objective 4

The battery sensitivity analysis showed the large commercial and multi-residential HMGs could achieve 6 year ROIs if battery prices fell to $100 per kWh and if at least 50% of the heat output was captured. Natural gas fuel price sensitivity analysis indicated fuel price reductions are unlikely to generate additional interest. Electrical rates have the most significant impact on ROIs. Based on the results from the electrical rate sensitivity analysis, the large commercial HMG produces the most favorable ROI when electrical rates are equal. The sensitivity analysis indicates electrical rates need to be 30₵-35₵ per kWh before generating favorable returns for each facility.

6.5 Objective 5

Electrical rates necessary to achieve 10, 5, and 3 year ROI were investigated based on the battery price. The pretext for this analysis was the prediction that battery prices may fall from $750 to $100 per kWh in the near future. At this price and while utilizing 50% of the useful heat output, the large commercial and multi-residential HMGs would surpass the 10 year ROI and could achieve 5 year ROIs if electrical rates increased 10% from current prices. 3 year ROIs are less likely and would require much higher electricity rates. The large commercial electric rate would need to be 22.5₵ per kWh and the multi-residential rate would need to be 30₵ per kWh.

6.6 Future Research and Recommendations

The methodology and analysis presented in this research were intended to provide a first order understanding and could be made more comprehensive by including more financial factors. The intent of this research was a straightforward model that would provide an early feasibility assessment in a specific market environment. A more detailed approach could improve the results and expand the scope.

This methodology limited the CHP output by using seasonal steady-state setpoints. More advanced control load following electric generation would decrease the required battery size, initial cost, and ROI. Additionally the model could be expanded over multiple years to observe how the HMG may need to modulate during consecutive years.

The economic analysis could improve by including additional factors. The model could be expanded to investigate how selling electricity back to the grid during favorable periods could improve the ROI. Additional economic details could be included such as including interconnection fees, investigating commercial tax liability, improving the battery maintenance estimates, and estimating the cost to integrate such technology. Finally the methodology could be expanded to other favorable markets with similar state incentives and in geographic regions of applications that would more readily utilize captured engine heat rejection constantly.

6.7 Context of Research

There is still significant work required to identify the nature and scope of the problem presented in this research. The electrical utility regulatory environment is full of intricate details that have accumulated over 80+ years of regulatory add-ons. Laws vary by municipality and utility ownership is a murky mix of public and private enterprise. Successful efforts to reduce emissions in the electric industry will require the integrated knowledge of lawyers, businessmen, economists, engineers, and politicians. Currently there is still significant work to be done to untangle the problem and identify the significant factors at play before any real progress can be made in developing solutions. One of the aims of this research was provide a little more clarity on the subject in support of future work.

Many of the solutions that will come will likely require significant cultural changes. Technological improvements and innovation can solve the problems presented in this study, but the cultural outlook is slower to change. Changes in urban planning and expanded demand response are two examples of technical solutions that require culture changes to truly succeed. At the time of this study in 2015, the US Executive branch issued a national plan to reduce electricity generated emissions 32% by 2030. Four months later the US Senate voted to block the plan. These events illustrate the divide in the way American's believe the problem should be addressed. At the present time there is also optimism that countries can unite globally to reduce emissions during the 2015 United Nations Climate Change Conference.

6.8 Conclusion

This study showed CHP, PV, and electrical energy storage could be integrated to levelize electricity supply for three various load profiles. Batteries were shown to shift 8-12% of electricity generation to meet later demand requirements. Technically this would require one day electricity storage and require daily and weekly battery cycles. Commercial facilities were better suited for this installation than residential due to electrical demand consistency.

Economically the current market conditions do not favor HMG investment. Investment is most likely to occur first in the large commercial application, second in the multi-residential building, and least likely in the typical commercial facility. In order to generate any customer investment interest battery prices need to fall to $100 per kWh while electricity rates increase 10%. Additionally, any HMG needs to effectively use significant levels of CHP thermal output.

An economic environment that encourages the economic investment in such technology could feasibly occur. However, it is unlikely the economy will change enough in the next decade. This study indicates substantial investment is unlikely to occur unless electricity rates exceed 30₵ per kWh or battery prices drop to around $100 per kWh. Even at those favorable market conditions the building application will need to utilize a significant quantity of heat energy and rely heavily on government subsidies such as California's SGIP.

This paper presented a new system approach as a potential solution. Given the scope of the electric grid and the problems challenging the central model, no one solution will suffice. Multiple approaches will be required such as improving system efficiencies, increasing renewable generation, expanding demand response programs, advancing the energy storage capabilities, additional economic factors such as a carbon tax or government incentives, and many more. This research showed the economics need to change before the system proposed will occur at the commercial and multi-residential levels. However, there are solutions that can be explored without waiting for the economy to change. For instance we can look toward changing our load profiles by combining residential and commercial loads. This would require a different approach to urban planning, similar to what China currently does. Such a solution is not typically considered in American design and construction due to the different lifestyle inherent in the culture.

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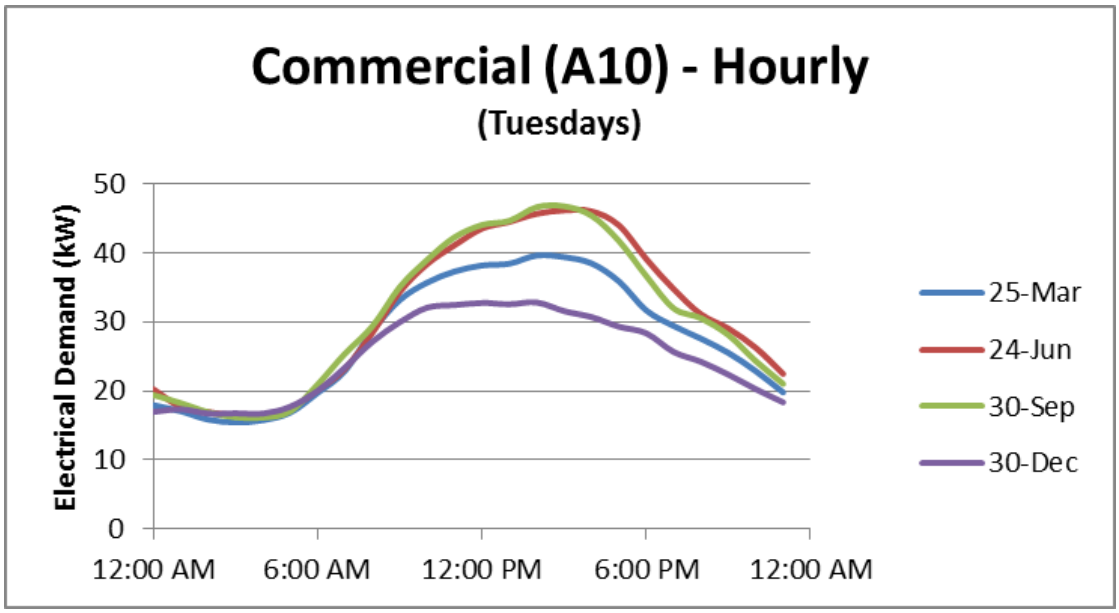
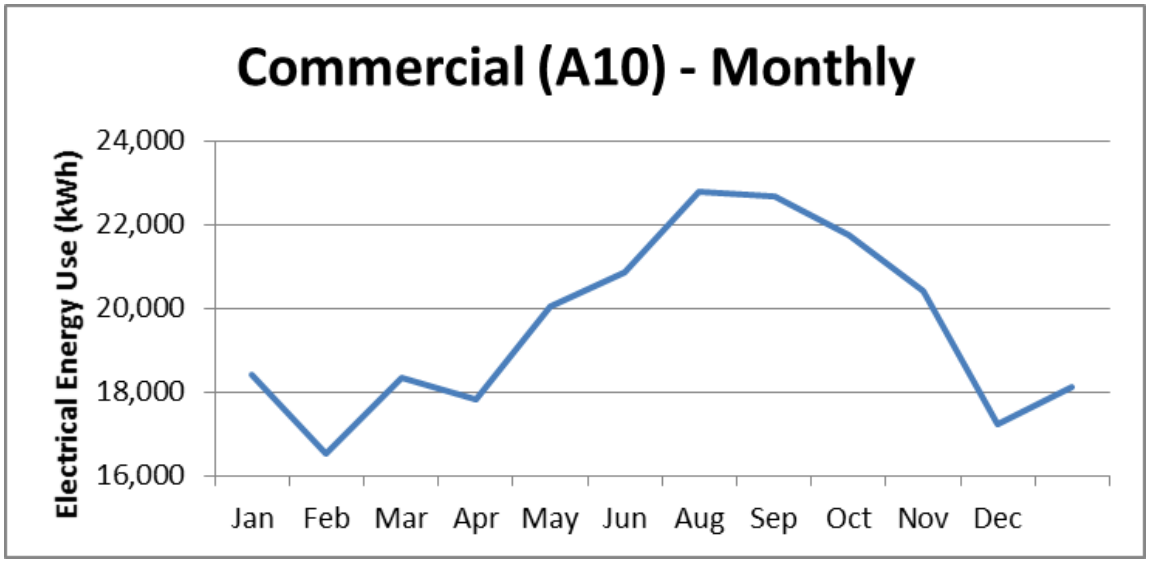
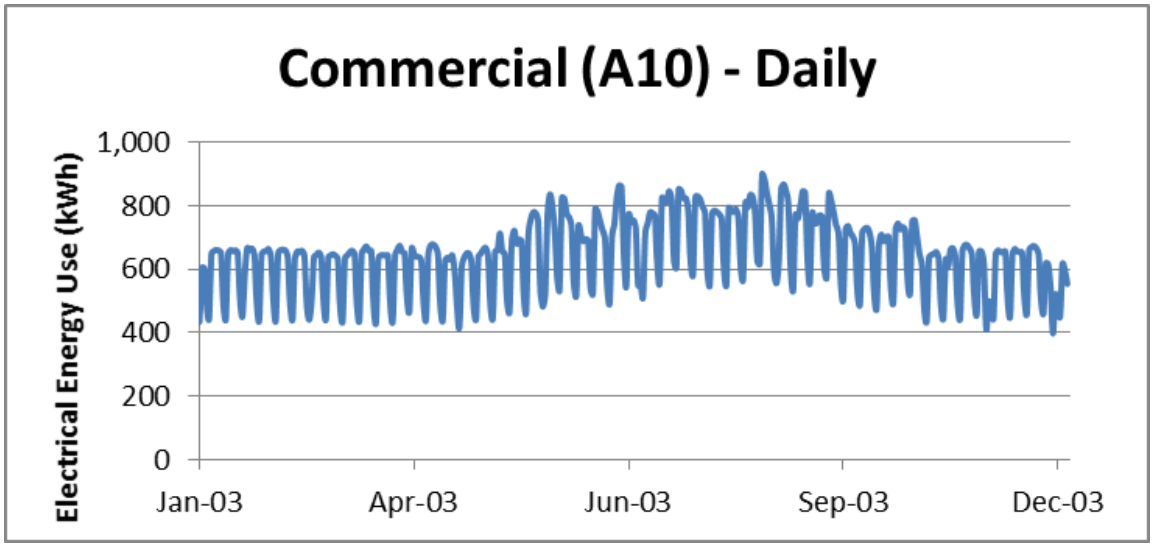
Appendix A
Facility Energy Use

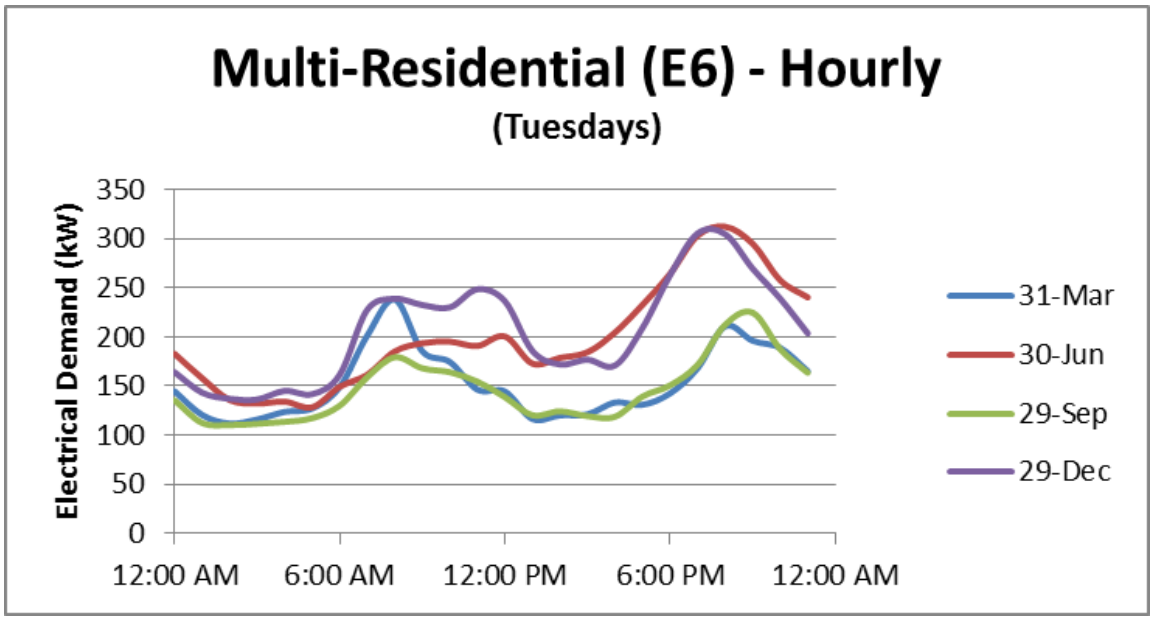
Commercial (A10) Annual Consumption			
Month	**Total (kWh)**	**Peak Demand (kW)**	**Avg Demand (kW)**
Jan	18,432	39.2	24.8
Feb	16,530	38.7	24.6
Mar	18,359	41.7	24.7
Apr	17,820	42.0	24.7
May	20,035	54.7	26.9
Jun	20,863	54.8	29.0
Jul	22,789	53.4	30.6
Aug	22,671	57.4	30.5
Sep	21,747	54.4	30.2
Oct	20,403	49.2	27.4
Nov	17,245	39.8	24.0
Dec	18,136	38.3	24.4
Annual	235,029	57.4	26.8

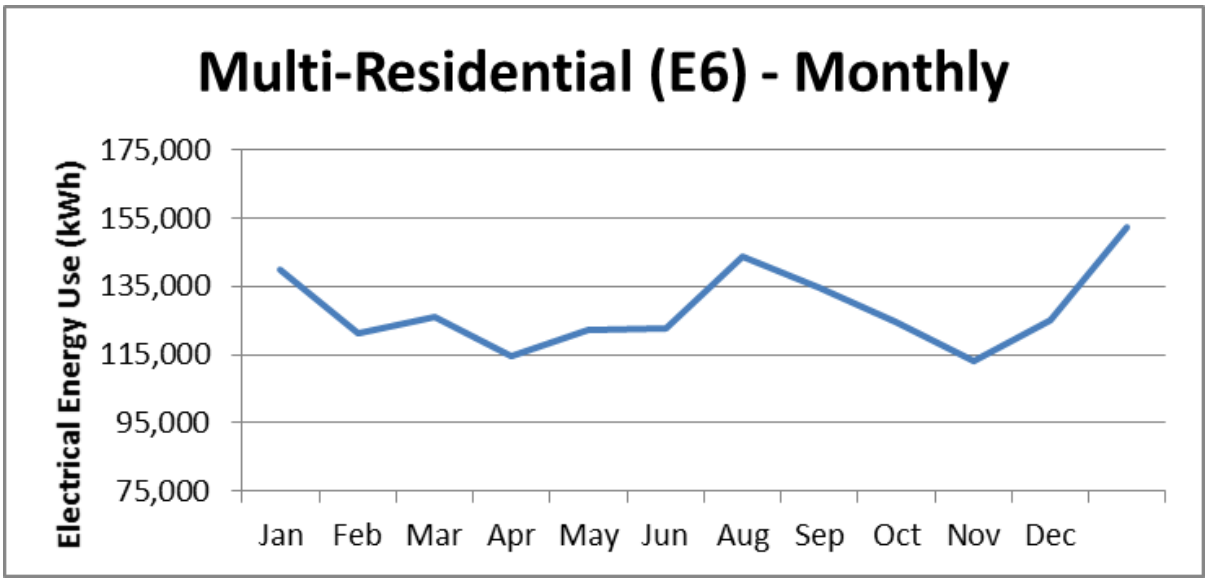


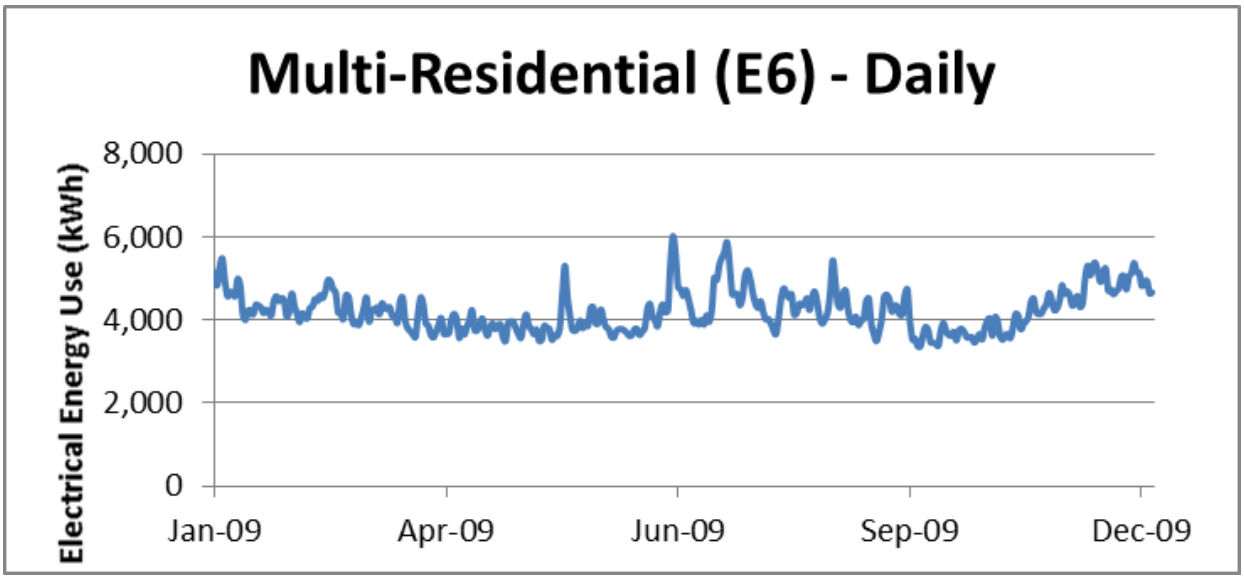

Commercial (A10) - Monthly
Electrical Energy Use (kWh)
24,000
22,000
20,000
18,000
16,000
Jan
Feb
Mar
Apr
May
Jun
Aug
Sep
Oct
Nov
Dec


Commercial (A10) - Daily
Electrical Energy Use (kWh)
1,000
800
600
400
200
0
Jan-03
Apr-03
Jun-03
Sep-03
Dec-03

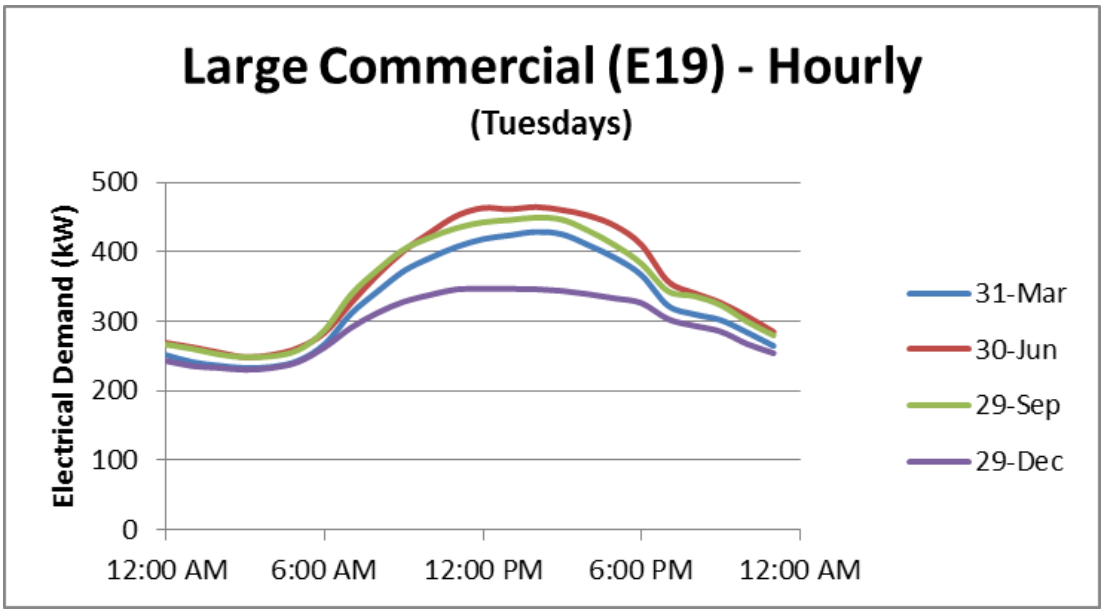
Multi-Residential (E6) Annual Consumption			
Month	**Total (kWh)**	**Peak Demand (kW)**	**Avg Demand (kW)**
Jan	139,901	311.8	188.0
Feb	121,252	278.6	180.4
Mar	126,014	274.7	169.4
Apr	114,761	253.1	159.4
May	122,340	352.4	164.4
Jun	122,858	391.7	170.6
Jul	143,818	397.4	193.3
Aug	134,585	374.8	180.9
Sep	124,753	311.7	173.3
Oct	113,317	248.5	152.3
Nov	125,137	280.7	173.8
Dec	152,518	340.3	205.0
Annual	1,541,254	397.4	175.9

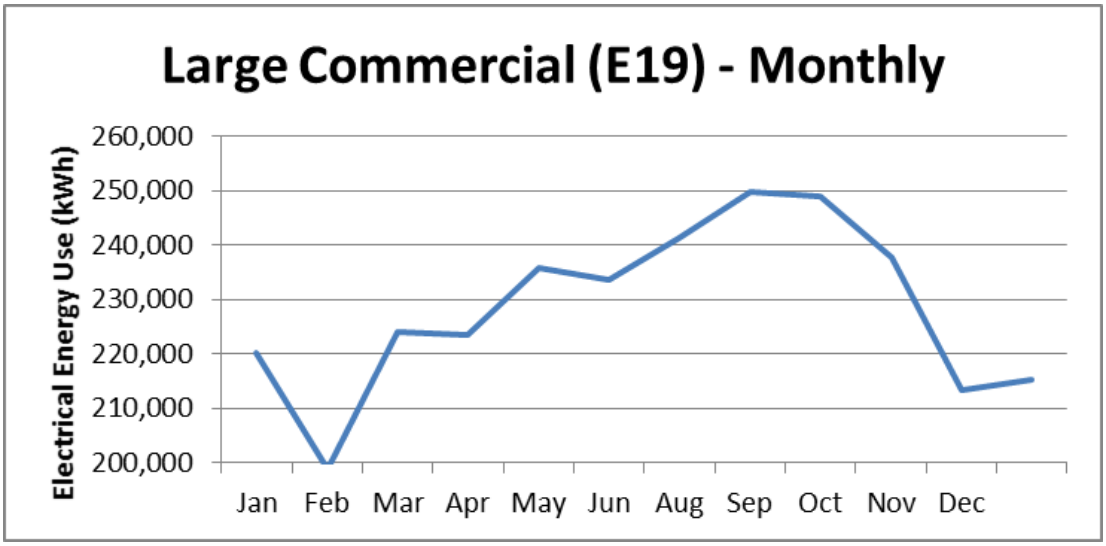


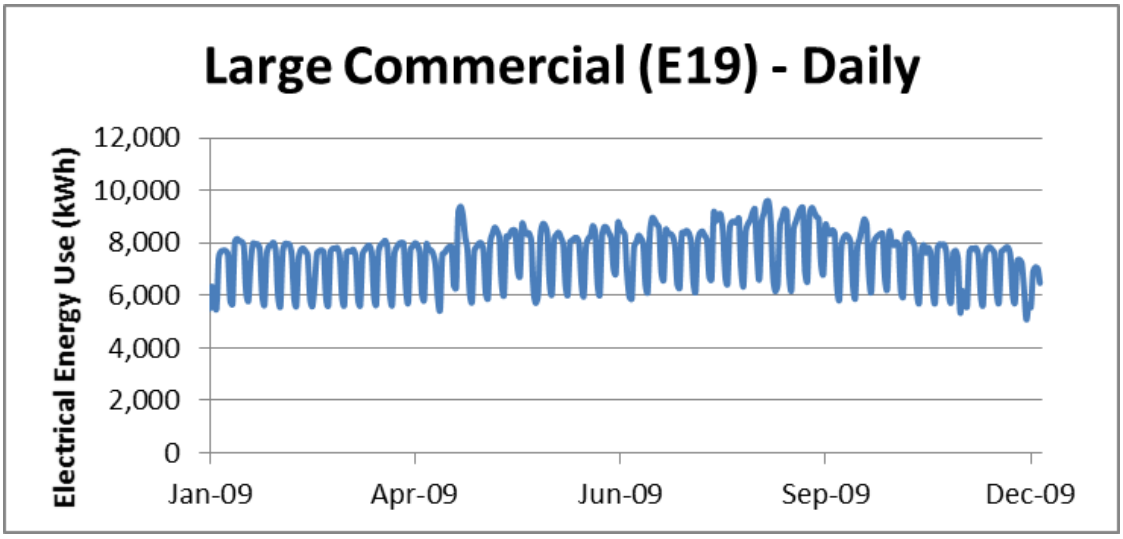

Multi-Residential (E6) - Monthly
Electrical Energy Use (kWh)
175,000
155,000
135,000
115,000
95,000
75,000
Jan
Feb
Mar
Apr
May
Jun
Aug
Sep
Oct
Nov
Dec


Multi-Residential (E6) - Daily
Electrical Energy Use (kWh)
8,000
6,000
4,000
2,000
0
Jan-09
Apr-09
Jun-09
Sep-09
Dec-09

Multi-Residential (E19) Annual Consumption			
Month	**Total (kWh)**	**Peak Demand (kW)**	**Avg Demand (kW)**
Jan	220,257	438.4	296.0
Feb	198,942	432.6	296.0
Mar	223,964	441.5	301.0
Apr	223,475	532.8	310.4
May	235,844	491.3	317.0
Jun	233,571	481.3	324.4
Jul	241,160	490.7	324.1
Aug	249,831	525.8	335.8
Sep	249,026	544.5	345.9
Oct	237,653	486.6	319.4
Nov	213,392	470.3	296.4
Dec	215,345	414.1	289.4
Annual	2,742,461	544.5	313.0




Large Commercial (E19) - Monthly
Electrical Energy Use (kWh)
260,000
250,000
240,000
230,000
220,000
210,000
200,000
Jan
Feb
Mar
Apr
May
Jun
Aug
Sep
Oct
Nov
Dec


Large Commercial (E19) - Daily
Electrical Energy Use (kWh)
12,000
10,000
8,000
6,000
4,000
2,000
0
Jan-09
Apr-09
Jun-09
Sep-09
Dec-09

Appendix B

CHP Specifications

Microturbine Characteristics [1]	System					
	1	2	3	4	5	6
Nominal Electricity Capacity (kW)	30	65	200	250	333	1000
Compressor Parasitic Power (kW)	2	4	10	10	13	50
Net Electricity Capacity (kW)	28	61	190	240	320	950
Fuel Input (MMBtu/hr), HHV	0.434	0.876	2.431	3.139	3.894	12.155
Required Fuel Gas Pressure (psig)	55-60	75-80	75-80	80-140	90-140	75-80
Electric Heat Rate (Btu/kWh), LHV [2]	13,995	12,966	11,553	11,809	10,987	11,553
Electric Efficiency (%), LHV [3]	24.4%	26.3%	29.5%	28.9%	31.1%	29.5%
Electric Heat Rate (Btu/kWh), HHV	15,535	14,393	12,824	13,110	12,198	12,824
Electric Efficiency (%), HHV	21.9%	23.7%	26.6%	26.0%	28.0%	26.6%
CHP Characteristics						
Exhaust Flow (lbs/sec)	0.68	1.13	2.93	4.7	5.3	14.7
Exhaust Temp (°F)	530	592	535	493	512	535
Heat Exchanger Exhaust Temp (°F)	190	190	200	190	190	200
Heat Output (MMBtu/hr)	0.21	0.41	0.88	1.28	1.54	4.43

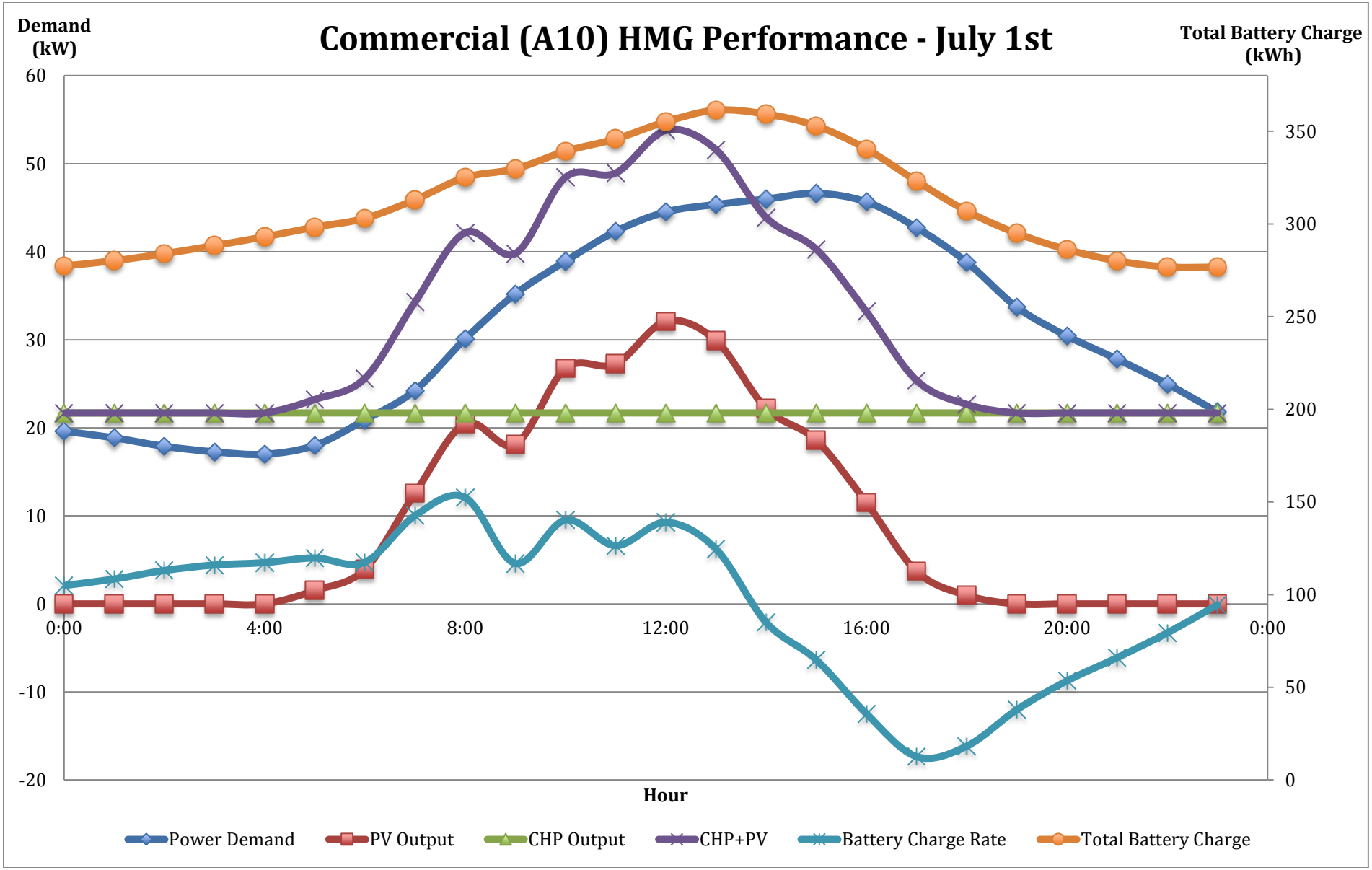
	System					
	1	2	3	4	5	6
Electric Capacity						
Nominal Capacity (kW)	30	65	200	250	333	1000
Net Capacity (kW)	28	61	190	240	320	950
Equipment Costs						
Gen Set Package	$53,100	$112,900	$359,300	$441,200	$566,400	$1,188,600
Heat Recovery	$13,500	$0	$0	$0	$0	$275,000
Fuel Gas Compression	$8,700	$16,400	$42,600	$0	$0	$164,000
Interconnection	$0	$0	$0	$0	$0	$0
Total Equipment ($)	***$75,300***	***$129,300***	***$401,900***	***$441,200***	***$566,400***	***$1,627,600***
($/kW)	***$2,689***	***$2,120***	***$2,120***	***$1,840***	***$1,770***	***$1,710***
Installation Costs						
Labor/Materials	$22,600	$28,400	$80,400	$83,800	$101,900	$293,000
Project & Construction Mgmt	$9,000	$15,500	$48,200	$52,900	$68,000	$195,300
Engineering and Fees	$9,000	$15,500	$44,200	$48,500	$56,600	$162,800
Project Contingency	$3,800	$6,500	$20,100	$22,100	$28,300	$81,400
Financing (int. during const.)	$700	$1,200	$3,700	$4,100	$5,100	$14,800
Total Other Costs ($)	*$45,100*	*$67,100*	*$196,600*	*$211,400*	*$259,900*	*$747,300*
($/kW)	*$1,611*	*$1,100*	*$1,035*	*$881*	*$812*	*$787*
Total Installed Cost ($)	**$120,400**	**$196,400**	**$598,500**	**$652,600**	**$826,300**	**$2,374,900**
($/kW)	**$4,300**	**$3,220**	**$3,150**	**$2,720**	**$2,580**	**$2,500**

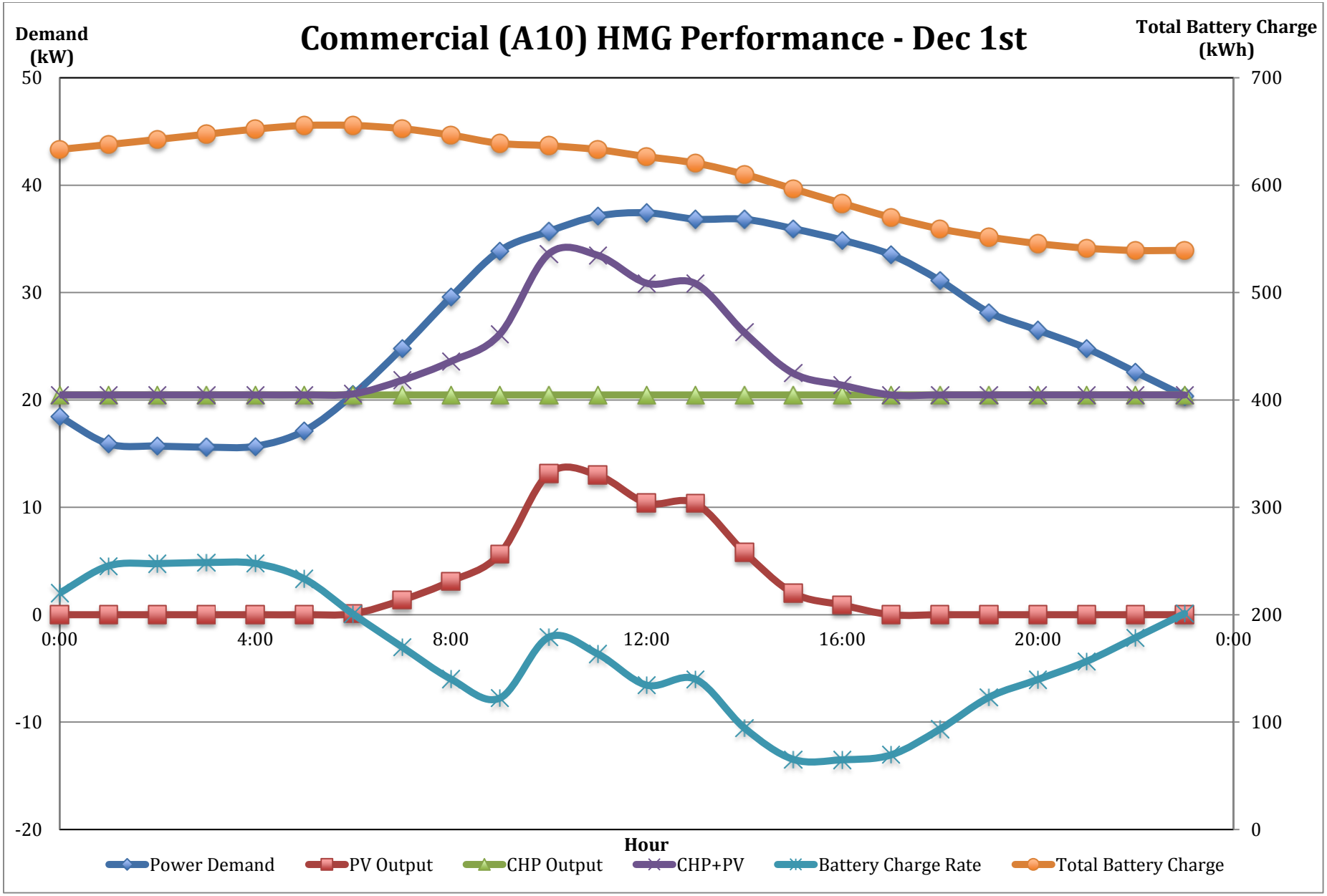
Maintenance Costs	System					
	1	2	3	4	5	6
Nominal Electricity Capacity (kW)	30	65	200	250	333	1000
Fixed ($/kW/yr)	---	---	---	$9.120	$6.847	---
Variable ($/kWh)	---	---	---	$0.010	$0.007	---
Average @ 6,000 hrs/year operation ($/kWh)	---	$0.013	$0.016	$0.011	$0.009	$0.012

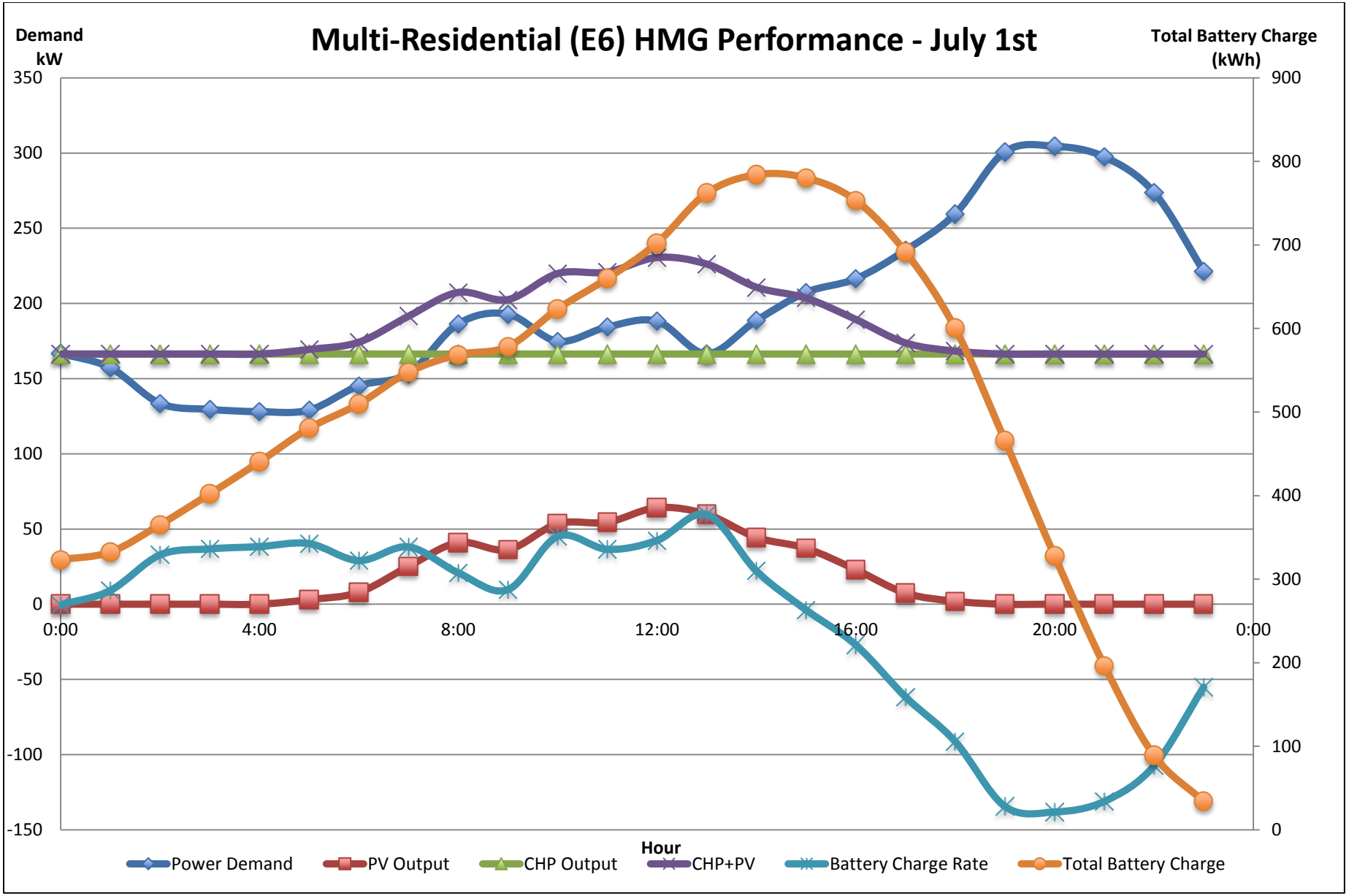
Appendix C

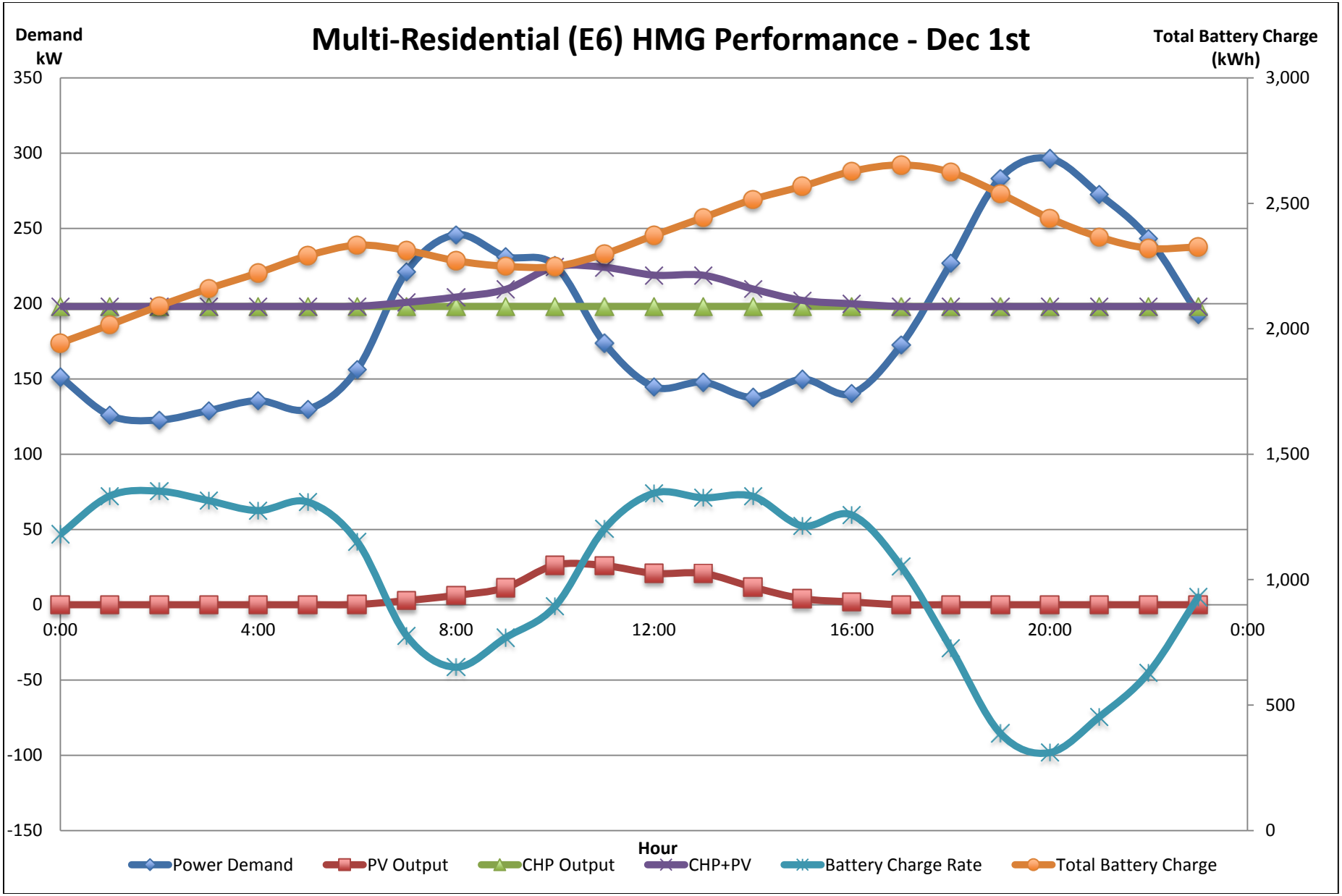
Hybrid Microgrid Operation Examples

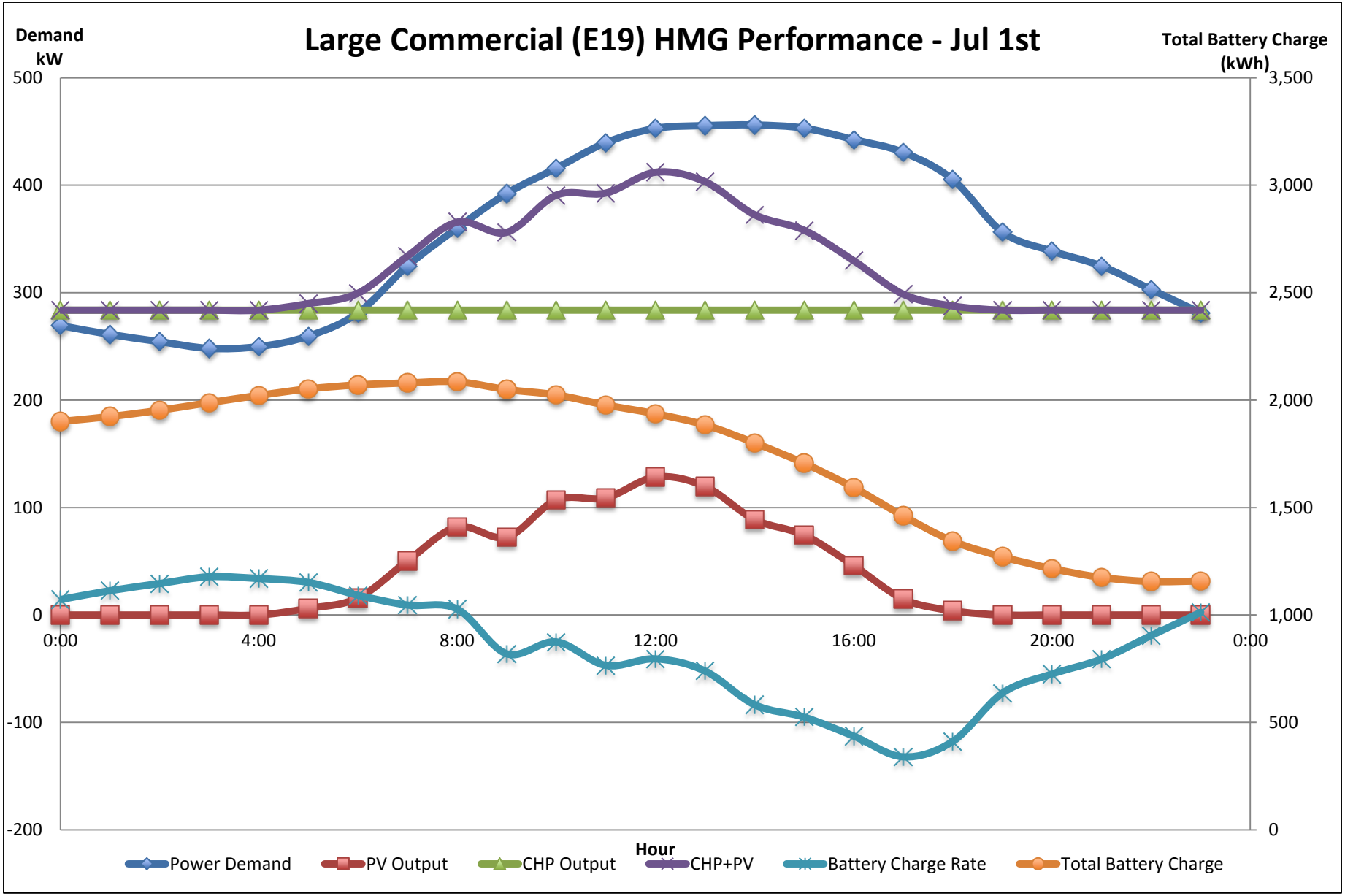
The following pages graphically display the HMG operation over a 24 hour period. Results for each facility include a summer and winter operation. Power demand (kW), solar PV output (kW), CHP output (kW), combined CHP+PV output (kW), battery charge rate (kW), and total battery charge (kWh) are all overlaid on the same plot. Positive batter charge rate values indicate the battery is charging, negative values indicate the battery is discharging.

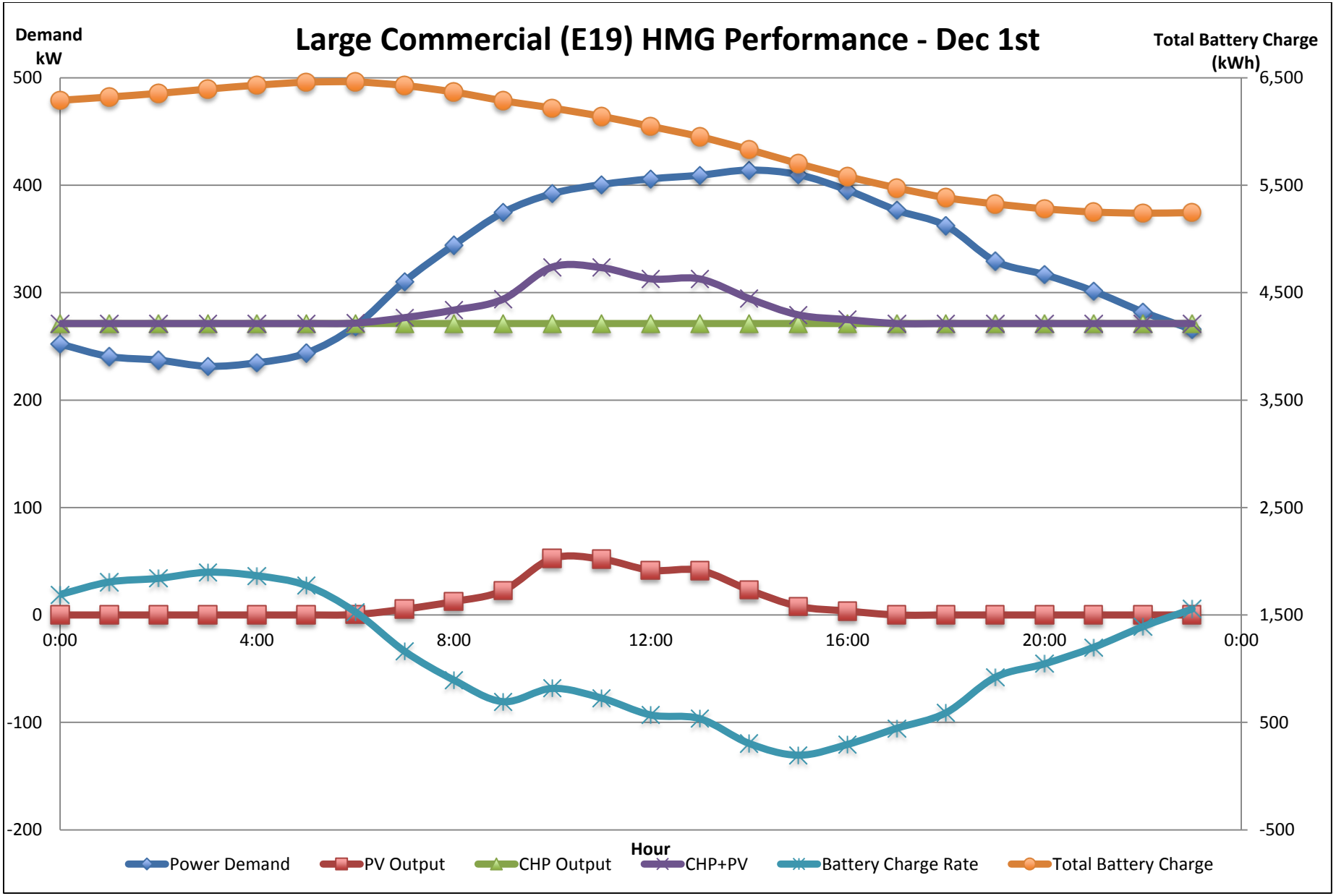

Commercial (A10) HMG Performance - July 1st
Demand (kW)
Total Battery Charge (kWh)
60
50
40
30
20
10
0
-10
-20
350
300
250
200
150
100
50
0
0:00
4:00
8:00
12:00
16:00
20:00
0:00
Hour
Power Demand
PV Output
CHP Output
CHP+PV
Battery Charge Rate
Total Battery Charge


Commercial (A10) HMG Performance - Dec 1st
Demand (kW)
Total Battery Charge (kWh)
50
40
30
20
10
0
-10
-20
700
600
500
400
300
200
100
0
0:00
4:00
8:00
12:00
16:00
20:00
0:00
Hour
Power Demand
PV Output
CHP Output
CHP+PV
Battery Charge Rate
Total Battery Charge


Multi-Residential (E6) HMG Performance - July 1st
Demand
kW
Total Battery Charge
(kWh)
350
300
250
200
150
100
50
0
-50
-100
-150
900
800
700
600
500
400
300
200
100
0
0:00
4:00
8:00
12:00
16:00
20:00
0:00
Hour
Power Demand
PV Output
CHP Output
CHP+PV
Battery Charge Rate
Total Battery Charge


Multi-Residential (E6) HMG Performance - Dec 1st
Demand kW
Total Battery Charge (kWh)
350
300
250
200
150
100
50
0
-50
-100
-150
3,000
2,500
2,000
1,500
1,000
500
0
0:00
4:00
8:00
12:00
16:00
20:00
0:00
Hour
Power Demand
PV Output
CHP Output
CHP+PV
Battery Charge Rate
Total Battery Charge


Large Commercial (E19) HMG Performance - Jul 1st
Demand kW
Total Battery Charge (kWh)
500
400
300
200
100
0
-100
-200
3,500
3,000
2,500
2,000
1,500
1,000
500
0
0:00
4:00
8:00
12:00
16:00
20:00
0:00
Hour
Power Demand
PV Output
CHP Output
CHP+PV
Battery Charge Rate
Total Battery Charge


Large Commercial (E19) HMG Performance - Dec 1st
Demand kW
Total Battery Charge (kWh)
500
400
300
200
100
0
-100
-200
6,500
5,500
4,500
3,500
2,500
1,500
500
-500
0:00
4:00
8:00
12:00
16:00
20:00
0:00
Hour
Power Demand
PV Output
CHP Output
CHP+PV
Battery Charge Rate
Total Battery Charge

Appendix D

PG&E Rate Structure and Time-of-Use Periods

Pacific Gas and Electric Company
San Francisco, California
U 39

Revised	*Cal. P.U.C. Sheet No.*	35501-E
Cancelling Revised	*Cal. P.U.C. Sheet No.*	35122-E

ELECTRIC SCHEDULE A-10 Sheet 5
MEDIUM GENERAL DEMAND-METERED SERVICE

RATES: Time-of-Use Rates for Optional or Real-Time Metering Customers

Table B

TOTAL RATES

	Secondary Voltage	Primary Voltage	Transmission Voltage
Total Customer/Meter Charge Rates			
Customer Charge ($ per meter per day)	$4.59959	$4.59959	$4.59959
Optional Meter Data Access Charge ($ per meter per day)	$0.98563	$0.98563	$0.98563
Total Demand Rates ($ per kW)			
Summer	$15.54 (R)	$14.53 (R)	$10.16 (R)
Winter	$7.31 (R)	$7.51 (R)	$5.60 (R)
Total Energy Rates ($ per kWh)			
Peak Summer	$0.17891	$0.16420	$0.13481
Part-Peak Summer	$0.17087	$0.15846	$0.12958
Off-Peak Summer	$0.14642	$0.13650	$0.10973
Part-Peak Winter	$0.12750	$0.11949	$0.10392
Off-Peak Winter	$0.10654	$0.10231	$0.08816
PDP Rates (Consecutive Day and Four-Hour Event Option)*			
PDP Charges ($ per kWh)			
All Usage During PDP Event	$0.90	$0.90	$0.90
PDP Credits			
Demand ($ per kW)			
Maximum Summer	($2.89)	($2.74)	($3.04)
Energy ($ per kWh)			
Peak Summer	($0.00641)	($0.00608)	($0.00344)
Part-Peak Summer	($0.00641)	($0.00608)	($0.00344)
Off-Peak Summer	($0.00641)	($0.00608)	($0.00344)

*See PDP Details, section g, for corresponding reduction in PDP credits and charges if other option(s) elected.

Total bundled service charges shown on customers' bills are unbundled according to the component rates shown below. PDP charges and credits are all generation and are not included below.

(Continued)

Advice Letter No:	4689-E	*Issued by*	*Date Filed*	August 17, 2015
Decision No.	15-07-001	***Steven Malnight***	*Effective*	September 1, 2015
		Senior Vice President	*Resolution No.*	
5C9		*Regulatory Affairs*		

ELECTRIC SCHEDULE A-10
MEDIUM GENERAL DEMAND-METERED SERVICE

Sheet 11

DEFINITION OF TIME PERIODS:

Customers who have received new hourly interval meters under the real-time metering program funded by CEC, or who have voluntarily arranged for the installation of such meters, will pay TOU charges specified in this rate schedule. (L)

Times of the year and times of the day for the TOU rates are defined as follows:

SUMMER	Period A (Service from May 1 through October 31):	
Peak:	12:00 noon to 6:00 p.m.	Monday through Friday
Partial-Peak	8:30 a.m. to 12:00 noon AND 6:00 p.m. to 9:30 p.m.	Monday through Friday (except holidays)
Off- Peak:	9:30 p.m. to 8:30 a.m. All day	Monday through Friday Saturday, Sunday, and holidays
WINTER	Period B (service from November 1 through April 30):	
Partial-Peak	8:30 a.m. to 9:30 p.m.	Monday through Friday (except holidays)
Off-Peak	9:30 p.m. to 8:30 a.m. All day	Monday through Friday (except holidays) Saturday, Sunday, and holidays

HOLIDAYS: "Holidays" for the purposes of this rate schedule are New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed.

DAYLIGHT SAVING TIME ADJUSTMENT: The time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November. (L)

(Continued)

ELECTRIC SCHEDULE E-6
RESIDENTIAL TIME-OF-USE SERVICE

Sheet 2

RATES: Total bundled service charges are calculated using the total rates below. On-peak, part-peak, and off-peak usage is assigned to tiers on a pro-rated basis. For example, if twenty percent of a customer's usage is in the on-peak period, then twenty percent of the total usage in each tier will be treated as on-peak usage. Bundled service customers are billed the greater of the total minimum charge or the otherwise applicable total charge derived from total energy rates.

Customers receiving a medical baseline allowance shall pay for all usage in excess of 130 percent of baseline at rates applicable to usage from 131 percent through 200 percent of baseline. No portion of the rates paid by customers that receive a Medical Baseline allowance shall be used to pay the DWR Bond charge. For these customers, the Conservation Incentive Adjustment is calculated residually based on the total rate less the sum of: Transmission, Transmission Rate Adjustments, Reliability Services, Distribution, Generation, Public Purpose Programs, Nuclear Decommissioning, New System Generation Charges[1], Competition Transition Charges (CTC), and Energy Cost Recovery Amount.

Direct Access (DA) and Community Choice Aggregation (CCA) charges shall be calculated in accordance with the paragraph in this rate schedule titled Billing.

TOTAL RATES

Total Energy Rates $ per kWh)	PEAK		PART-PEAK		OFF-PEAK	
Summer						
Baseline Usage	$0.32654	(I)	$0.21127	(I)	$0.13449	(I)
101% - 130% of Baseline	$0.35778	(I)	$0.24251	(I)	$0.16574	(I)
131% - 200% of Baseline	$0.41064	(R)	$0.29537	(R)	$0.21859	(R)
201% - 300% of Baseline	$0.47952	(R)	$0.36425	(R)	$0.28747	(R)
Over 300% of Baseline	$0.47952	(R)	$0.36425	(R)	$0.28747	(R)
Winter						
Baseline Usage	–		$0.15566	(I)	$0.13883	(I)
101% - 130% of Baseline	–		$0.18690	(I)	$0.17007	(I)
131% - 200% of Baseline	–		$0.23976	(R)	$0.22293	(R)
201% - 300% of Baseline	–		$0.30864	(R)	$0.29181	(R)
Over 300% of Baseline	–		$0.30864	(R)	$0.29181	(R)

Total Meter Charge Rate ($ per meter per day)	$0.25298
Total Minimum Charge Rate ($ per meter per day)	$0.32854 (I)
California Climate Credit (per household, per semi-annual payment occurring in the April and October bill cycles)	($24.76)

Total bundled service charges shown on customer's bills are unbundled according to the component rates shown below. Where the minimum charge applies with no usage, generation is calculated residually based on the total minimum charge less the sum of: Distribution, Transmission, Reliability Services, Public Purpose Programs, and Nuclear Decommissioning. Where the minimum charge applies with usage, the generation charge is calculated residually based on the total charge less the sum of: Transmission, Transmission Rate Adjustments, Reliability Services, Distribution, Public Purpose Programs, Nuclear Decommissioning, New System Generation Charges[1], CTC, Energy Cost Recovery Amount, and DWR Bond.

[1] Per Decision 11-12-031, New System Generation Charges are effective 1/1/2012.

(Continued)

ELECTRIC SCHEDULE E-6
RESIDENTIAL TIME-OF-USE SERVICE

Sheet 4

SPECIAL CONDITIONS:

1. BASELINE RATES: PG&E may require the customer to file with it a Declaration of Eligibility for Baseline Quantities for Residential Rates.

2. BASELINE (TIER 1) QUANTITIES: The following quantities of electricity are to be billed at the rates for baseline use (also see Rule 19 for additional allowances for medical needs):

BASELINE QUANTITIES (kWh PER DAY)

Baseline Territory*	Code B - Basic Quantities				Code H - All-Electric Quantities			
	Summer Tier I		Winter Tier I		Summer Tier I		Winter Tier I	
P	13.8	(C)	12.3	(C)	16.4	(C)	29.6	(C)
Q	7.0	I	12.3	I	8.3	I	29.6	I
R	15.6	I	11.0	I	18.8	I	29.8	I
S	13.8	I	11.2	I	16.4	I	27.1	I
T	7.0	I	8.5	I	8.3	I	14.9	I
V	8.7	I	10.6	I	13.6	I	26.6	I
W	16.8	I	10.1	I	20.8	I	20.6	I
X	10.1	I	10.9	I	9.3	I	16.7	I
Y	10.6	I	12.6	I	13.0	I	27.1	I
Z	6.2	(C)	9.0	(C)	7.7	(C)	18.7	(C)

3. TIME PERIODS: Times of the year and times of the day are defined as follows:

Summer (service from May 1 through October 31):

Peak: 1:00 p.m. to 7:00 p.m. Monday through Friday

Partial-Peak: 10:00 a.m. to 1:00 p.m.
AND 7:00 p.m. to 9:00 p.m. Monday through Friday
Plus 5:00 p.m. to 8:00 p.m. Saturday and Sunday

Off-Peak: All other times including Holidays.

Winter (service from November 1 through April 30):

Partial-Peak: 5:00 p.m. to 8:00 p.m. Monday through Friday

Off-Peak: All other times including Holidays.

Holidays: "Holidays" for the purposes of this rate schedule are New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed.

DAYLIGHT SAVING TIME ADJUSTMENT: The time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

* The applicable baseline territory is described in Part A of the Preliminary Statement.

(Continued)

ELECTRIC SCHEDULE E-19
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

Sheet 4

3. Rates: (Cont'd.)

TOTAL RATES

	Secondary Voltage	Primary Voltage	Transmission Voltage
Total Customer/Meter Charge Rates			
Customer Charge Mandatory E-19 ($ per meter per day)	$19.71253	$32.85421	$59.13758
Customer Charge Voluntary E-19:			
Customer Charge with SmartMeter™ ($ per meter per day)	$4.59959	$4.59959	$4.59959
Customer Charge without SmartMeter™			
Customer Charge Rate V ($ per meter per day)	$4.77700	$4.77700	$4.77700
Customer Charge Rate W ($ per meter per day)	$4.63507	$4.63507	$4.63507
Customer Charge Rate X ($ per meter per day)	$4.77700	$4.77700	$4.77700
Optional Meter Data Access Charge ($ per meter per day)	$0.98563	$0.98563	$0.98563
Total Demand Rates ($ per kW)			
Maximum Peak Demand Summer	$19.04	$18.91	$17.03
Maximum Part-Peak Demand Summer	$4.42	$4.06	$3.78
Maximum Demand Summer	$14.38 (R)	$11.39 (R)	$7.18 (R)
Maximum Part-Peak Demand Winter	$0.24	$0.46	$0.00
Maximum Demand Winter	$14.38 (R)	$11.39 (R)	$7.18 (R)
Total Energy Rates ($ per kWh)			
Peak Summer	$0.16233	$0.14861	$0.09129
Part-Peak Summer	$0.10893	$0.10219	$0.08665
Off-Peak Summer	$0.07397	$0.07456	$0.07043
Part-Peak Winter	$0.10185	$0.09696	$0.08500
Off-Peak Winter	$0.07797	$0.07787	$0.07214
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005
PDP Rates			
PDP Charges ($ per kWh)			
All Usage During PDP Event	$1.20	$1.20	$1.20
PDP Credits			
Demand ($ per kW)			
Peak Summer	($6.19)	($5.99)	($5.51)
Part-Peak Summer	($1.34)	($1.16)	($1.22)
Energy ($ per kWh)			
Peak Summer	$0.00000	$0.00000	$0.00000
Part-Peak Summer	$0.00000	$0.00000	$0.00000

Total bundled service charges shown on customers' bills are unbundled according to the component rates shown below. PDP charges and credits are all generation and are not included below.

(Continued)

ELECTRIC SCHEDULE E-19
MEDIUM GENERAL DEMAND-METERED TOU SERVICE

Sheet 12

6. DEFINITION OF TIME PERIODS: Times of the year and times of the day are defined as follows: (L)

SUMMER	Period A (Service from May 1 through October 31):	
Peak:	12:00 noon to 6:00 p.m.	Monday through Friday (except holidays)
Partial-peak:	8:30 a.m. to 12:00 noon AND 6:00 p.m. to 9:30 p.m.	Monday through Friday (except holidays)
Off-peak:	9:30 p.m. to 8:30 a.m. All day	Monday through Friday Saturday, Sunday, and holidays
WINTER	Period B (service from November 1 through April 30):	
Partial-Peak:	8:30 a.m. to 9:30 p.m.	Monday through Friday (except holidays)
Off-Peak:	9:30 p.m. to 8:30 a.m. All day	Monday through Friday (except holidays) Saturday, Sunday, and holidays

HOLIDAYS: "Holidays" for the purposes of this rate schedule are New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed.

DAYLIGHT SAVING TIME ADJUSTMENT: The time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

CHANGE FROM SUMMER TO WINTER OR WINTER TO SUMMER: When a billing month includes both summer and winter days, PG&E will calculate demand charges as follows. It will consider the applicable maximum demands for the summer and winter portions of the billing month separately, calculate a demand charge for each, and then apply the two according to the number of billing days each represents.

7. POWER FACTOR ADJUST-MENTS: Bills will be adjusted based on the power factor for all customers except those selecting voluntary E-19 service. The power factor is computed from the ratio of lagging reactive kilovolt-ampere-hours to the kilowatt-hours consumed in the month. Power factors are rounded to the nearest whole percent.

The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill will be reduced by the product of the power factor rate and the kilowatt-hour usage for each percentage point above 85 percent. If the average power factor is below 85 percent, the total monthly bill will be increased by the product of the power factor rate and the kilowatt-hour usage for each percentage point below 85 percent.

Power factor adjustments will be assigned to distribution for billing purposes. (L)

(Continued)

Appendix E

PG&E Standby Schedule

ELECTRIC SCHEDULE S
STANDBY SERVICE

Sheet 3

RATES: (Cont'd.)

TOTAL RATES

	Secondary Voltage	Primary Voltage	Transmission Voltage
Total Maximum Reactive Demand Charge ($ per kVAR)	$0.35	$0.35	$0.35
Total Reservation Charge Rate ($/kW)			
Reservation Charge (per KW per month applied to 85 percent of the Reservation Capacity)	$3.76 (R)	$3.66 (R)	$1.26 (R)
Total Energy Rates ($ per kWh)			
Peak Summer	$0.53786 (R)	$0.52611 (R)	$0.11207 (R)
Part-Peak Summer	$0.28851 (R)	$0.28486 (R)	$0.10716 (R)
Off-Peak Summer	$0.18415 (R)	$0.18331 (R)	$0.08851 (R)
Part-Peak Winter	$0.15360 (R)	$0.15184 (R)	$0.10527 (R)
Off-Peak Winter	$0.12405 (R)	$0.12489 (R)	$0.09048 (R)
Power Factor Adjustment Rate ($/kWh/%)	$0.00005	$0.00005	$0.00005

Total bundled service charges shown on customers' bills are unbundled according to the component rates shown below

UNBUNDLING OF TOTAL RATES

	Secondary Voltage	Primary Voltage	Transmission Voltage
Reservation Charges Rate by Components ($/kW)			
Generation	$0.50	$0.44	$0.36
Distribution**	$2.64	$2.60	$0.28
Transmission*	$0.61 (R)	$0.61 (R)	$0.61 (R)
Reliability Services*	$0.01	$0.01	$0.01
Energy Rate by Components ($ per kWh)			
Generation:			
Peak Summer	$0.10042	$0.09815	$0.08149
Part-Peak Summer	$0.09256	$0.09211	$0.07658
Off-Peak Summer	$0.06869	$0.06898	$0.05793
Part-Peak Winter	$0.09146	$0.08943	$0.07469
Off-Peak Winter	$0.07098	$0.07130	$0.05990
Distribution**:			
Peak Summer	$0.40249	$0.39204	$0.00000
Part-Peak Summer	$0.16100	$0.15683	$0.00000
Off-Peak Summer	$0.08051	$0.07841	$0.00000
Part-Peak Winter	$0.02719	$0.02649	$0.00000
Off-Peak Winter	$0.01812	$0.01767	$0.00000
Transmission* (all usage)	$0.01304 (R)	$0.01304 (R)	$0.01304 (R)
Transmission Rate Adjustments* (all usage)	$0.00052	$0.00052	$0.00052
Reliability Services* (all usage)	$0.00011	$0.00011	$0.00011
Public Purpose Programs (all usage)	$0.01522	$0.01619	$0.01085
Nuclear Decommissioning (all usage)	$0.00097	$0.00097	$0.00097
Competition Transition Charges	$0.00029	$0.00029	$0.00029
Energy Cost Recovery Amount (all usage)	($0.00504)	($0.00504)	($0.00504)
DWR Bond (all usage)	$0.00526	$0.00526	$0.00526
New System Generation Charge(all usage)**	$0.00458	$0.00458	$0.00458
California Climate Credit (all usage)***	($0.00320)	($0.00382)	($0.00347)

* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.
** Distribution and New System Generation Charges are combined for presentation on customer bills.
*** Only customers that qualify as Small Businesses – California Climate Credit under Rule 1 are eligible for the California Climate Credit.

(Continued)

ELECTRIC SCHEDULE S
STANDBY SERVICE

Sheet 4

RATES (Cont'd.)

Meter and Customer Charges:*
($/meter/day)

Customer Class	Customer Charge	TOU or Load Profile Meter Charge
Residential	$0.16427	$0.12813
Agricultural	$0.52567	$0.19713
Small Light and Power (Reservation Capacity ≤ 50 kW)		
Single Phase Service	$0.32854	$0.20107
PolyPhase Service	$0.65708	$0.20107
Medium Light and Power (Reservation Capacity > 50 kW and < 500 kW)	$4.59959	$0.17741
Medium Light and Power (Reservation Capacity ≥ 500 kW and < 1000 kW)		
Transmission	$59.13758	–
Primary	$32.85421	–
Secondary	$19.71253	–
Large Light and Power (Reservation Capacity ≥ 1000 kW)		
Transmission	$65.70842	–
Primary	$49.28131	–
Secondary	$32.85421	–
Supplemental Standby Service Meter Charge	–	$6.11088

* All Meter and Customer charges are assigned to distribution.

(Continued)

ELECTRIC SCHEDULE S
STANDBY SERVICE

RATES:
(Cont'd.)

TYPES OF CHARGES: (T)

The customer's monthly charge for service under Schedule S is the sum of the Reservation, Energy, Customer, and TOU Meter Charges.

a. The **Reservation Charge**, in dollars per kilowatt (kW), applies to the customer's Reservation Capacity, as defined in Special Condition 1. (T)

b. The **Energy Charge** is the sum of Energy Charges from the peak, partial-peak and off-peak periods. The customer pays for energy by the kilowatt-hour (kWh), and rates are differentiated to times of day and time of year. (T)

c. The **Customer Charge** will be paid monthly by all nonresidential customers. Residential customers will pay a Customer Charge only in months when the Customer Charge exceeds the customer's bill under Schedule S. (T)

d. The Customer Charge varies by class of service, Reservation Capacity, and Voltage Level (for customers with Reservation Capacity greater than 499 kW). (T)

e. The **TOU Meter Charge** applies to Residential, Agricultural, and Small and Medium Light and Power customers, with Reservation Capacity less than 500 kW. This charge will be paid in addition to the monthly Customer Charge. (T)

f. The **Load Profile Meter Charge** applies to customers electing to receive the back-up and maintenance portions of their total service requirements under the provisions of Special Condition 7. This charge will be paid in addition to the regular Schedule E-19, Schedule E-20, or Schedule E-37 monthly customer charge. (T)

(Continued)

ELECTRIC SCHEDULE S
STANDBY SERVICE

Sheet 6

RATES:
(Cont'd.)

(D)

DEFINITION OF TIME PERIODS: (L)

Times of the year and times of the day are defined as follows:

SUMMER Period A (service from May 1 through October 31):

Peak:	12:00 noon to 6:00 p.m.	Monday through Friday (except holidays)
Partial-Peak:	8:30 a.m. to 12:00 noon AND 6:00 p.m. to 9:30 p.m.	Monday through Friday (except holidays)
Off-Peak:	9:30 p.m. to 8:30 a.m.	Monday through Friday
		All Day Saturday, Sunday, and holidays

WINTER Period B (Service from November 1 through April 30):

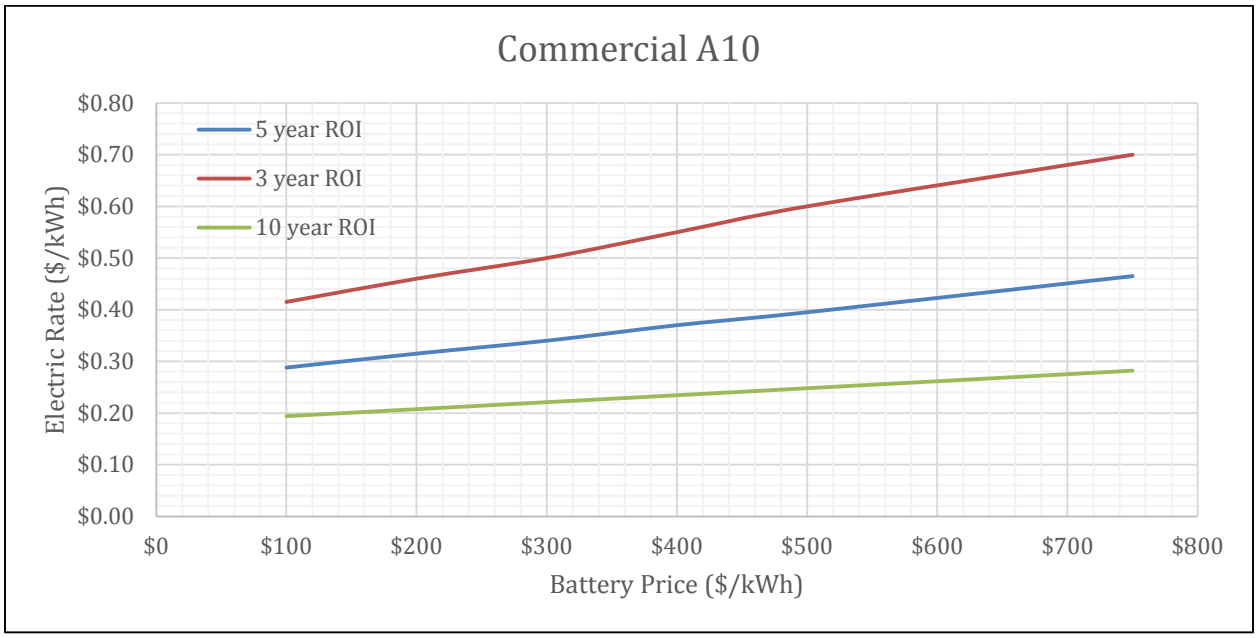
Partial-Peak:	8:30 a.m. to 9:30 p.m.	Monday through Friday (except holidays)
Off-Peak:	9:30 p.m. to 8:30 a.m.	Monday through Friday (except holidays)
		All Day Saturday, Sunday and holidays

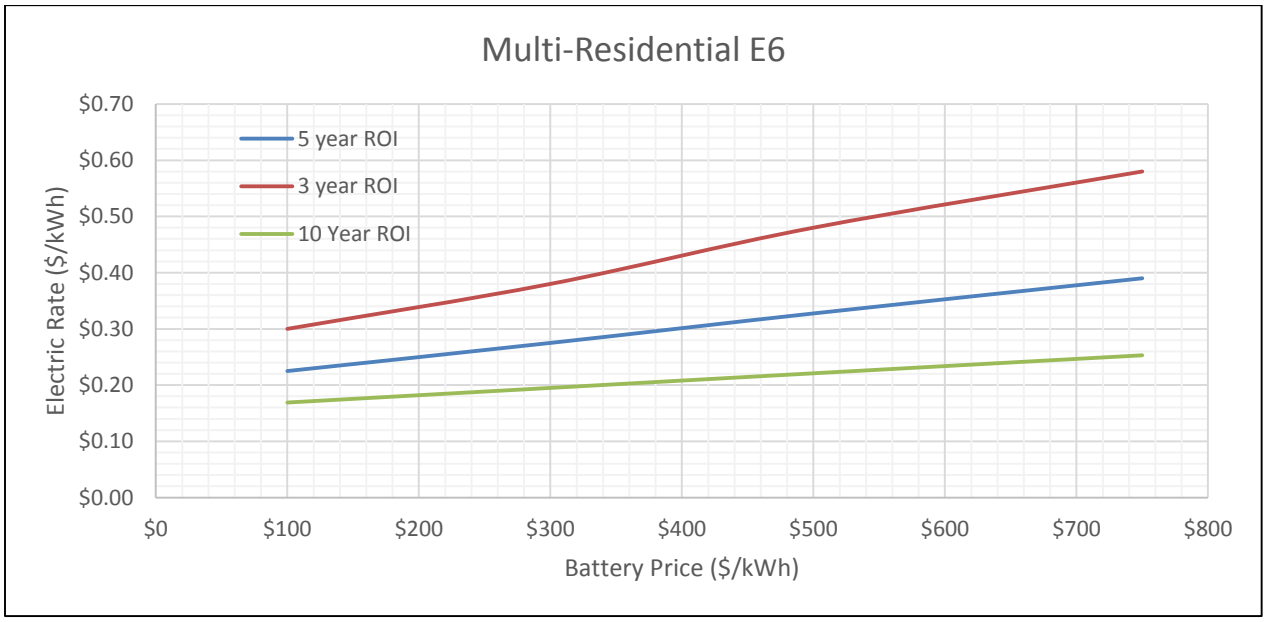
HOLIDAYS: "Holidays" for the purposes of this rate schedule are New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed. (L)

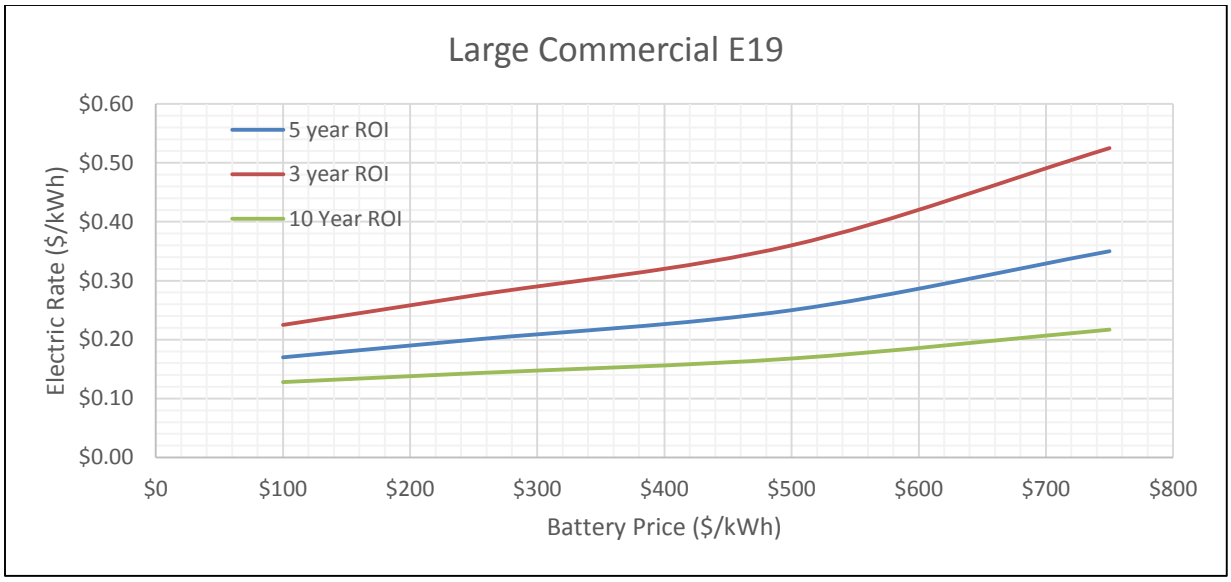
(Continued)

Appendix F

ROI Thresholds for Individual Facilities






Large Commercial E19
5 year ROI
3 year ROI
10 Year ROI
Electric Rate ($/kWh)
$0.60
$0.50
$0.40
$0.30
$0.20
$0.10
$0.00
$0
$100
$200
$300
$400
$500
$600
$700
$800
Battery Price ($/kWh)