ECONOMIC ANALYSIS FOR RESIDENTIAL SOLAR PV SYSTEMS WITH BATTERY STORAGE IN PG&E TERRITORY

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ABSTRACT

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Electricity storage can be used as a tool to help with a variety of issues related to electric grid management. Declining costs and state incentives could allow fast penetration of battery storage. Distributed PV systems are now widely used, and battery storage has potential to address issues related to generation intermittency. This thesis assesses the financial potential of PV systems with behind-the-meter battery storage in two communities in Pacific Gas and Electric (PG&E) territory. An analysis is performed to calculate annual savings for four cases. The batteries are used to avoid peak period charges under a time-of-use (TOU) rate plan. A benefit cost analysis is performed to determine the feasibility of the investment.

Results show that most cases have positive net present value and payback periods less than 20 years when compared to households without PV or a battery. Systems in Fresno have better results than Arcata due to higher energy costs and a larger solar resource. Analysis also shows that the economics improve with the size of the system.

It is also notable that the positive benefit-cost results reported above are due primarily to the addition of PV rather than the inclusion of a battery. Under PG&E's current net energy metering (NEM) program, the marginal energy bill cost savings of adding a battery to a PV system are minimal. Meanwhile the costs of battery systems increase system costs by 33%-50%. This indicates that adding a battery to an existing PV system is not economically viable in most cases. A sensitivity analysis indicates that the financial performance of battery storage systems is more sensitive to TOU rates than to installed battery price. A higher price differential between peak and off-peak rates, a reduced NEM rate for exported energy, incentives and rebates could improve the economics of storage for residential use in the future.

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INTRODUCTION

With abundant resources, supportive legislations and incentives, renewable technologies have proliferated in California for the past decade. Wind and solar have the biggest share in non-hydro renewables market. As of 2016, almost 27% of retail electricity in California came from renewable sources, out of which wind was 39%, and solar was 23% of the total renewable generation (CEC, 2016). Meanwhile, solar photovoltaic (PV) has dominated the distributed generation sector, where 94% of all renewable distributed generation projects are PV (CEC, 2016). Prices for PV components continue to drop, which indicates that the price of energy from PV will be competitive with grid electricity even if the incentives for PV start to diminish (Fu et al., 2016).

However, changing tariff structures, mandatory time of use (TOU) pricing, and new net metering regulations might undermine residential sector interest in solar PV systems. Peak periods are shifting to later times in the evening when production from solar would be diminishing, and investor owned utilities (IOUs) in California are pushing for a lower export compensation rate for net metering customers (John, 2015a). Moreover, the increasing share of intermittent renewable energy systems has posed challenges in managing the grid (Denholm, O'Connell, Brinkman, & Jorgenson, 2015). Incorporation of storage systems in the growing and ever changing electric sector in California could alleviate and resolve a variety of issues with renewables. Storage can also raise the value of potential PV investment, help even out the load, enhance flexibility for consumers, and help with grid operations (Ardani et al., 2016).

Only a few years ago, the cost of integrating battery storage with grid tied PV systems was considered too expensive and counter intuitive (Hoppmann, Volland, Schmidt, & Hoffmann, 2014). In the past, battery storage was used with PV systems only under special conditions like for off grid locations. They usually had bulky lead acid batteries, which were difficult to maintain. For grid-tied systems, net metering has been the most important tool to generate savings through exporting excess PV energy back to the grid to offset the usage. Emerging battery technologies that have developed in recent years to compliment PV systems and have various benefits like deep cycling capabilities, light weight, high storage density, long life, and ease of installation / integration (Luo, Wang, Dooner, & Clarke, 2015). Lithium ion batteries have become one of the most popular battery types in recent years because of Tesla's launch of the Powerwall product and a subsequent decline in its costs (Clover, 2017).

This thesis explores the financial potential of residential PV systems with battery storage in Pacific Gas and Electric (PG&E) territory. The assessment includes calculation of savings generated by maximizing self-consumption of PV energy under the existing PG&E TOU rate structure. Annual savings are calculated for several typical residential arrangements, and a benefit cost analysis is performed to observe the economic feasibility of including storage in PV systems. This thesis evaluates the economic feasibility of such systems and discusses current and future prospects of storage with PV. Only lithium ion battery technologies are considered for this thesis. It is also assumed that the systems are customer owned and operated. Additionally, the economic analysis does not consider account the mortgage payments or third-party ownership arrangements.

The following literature review section includes information about the renewable energy market in California, intermittency and duck curve issues, the basics of net metering and the new successor tariff, PG&E rate plans and tariff information, inverter technologies for storage incorporation, and financial incentives for PV systems and electrical storage systems. The subsequent section, which covers data and methods, discusses the parameters and sources of data and discusses how they are used to determine power flows and battery charging and discharging protocols. It also lists the various input fields for different cases used in the analysis. This is followed by the results section, which shows the annual savings for each case and compares it to a business as usual (BAU) case. It also shows the payback period and other benefit cost analysis results to compare the financial viability of the system. The sensitivity analysis section includes an evaluation of how a variety of system parameters affect the economic feasibility of the system. It also compares the economics of the case to a system without storage. The final sections of the document consist of a discussion of the results, future prospects for the technology and market growth, and the scope for improvement.

LITERATURE REVIEW

The first step toward assessing the value of residential PV systems with storage would be to understand some background information related to the renewable energy goals of California and how these can affect the deployment of such systems.

Renewable energy goals

California has a long history of support for distributed generation and renewable energy. Encouraging renewable energy is an important part of California's efforts to achieve the goals set by the state's Global Warming Solutions Act of 2006, (also known as Senate Bill 32 (SB32)) of reducing greenhouse gas emissions 40 percent below 1990 levels by 2030 (Pavley, 2006). The efforts to support cleaner energy sources started back in 1970's after the energy crisis and during the first administration of Governor Jerry Brown (Galbraith, 2010). In 2002, a Renewable Portfolio Standard (RPS) was established for the state of California. Since then, California's electricity rates have increased modestly, while equipment and installation costs for renewable systems have fallen remarkably (EIA, 2015) (Fu et al., 2016). The RPS requires investor owned utilities (IOUs) to generate or procure a certain percentage of their electricity from renewable energy sources. The RPS is technology-neutral, which gives utilities the option to choose whatever mix of qualified renewables works best for their portfolio. As a result, a variety of renewable resources including solar photovoltaics (PV), solar thermal, wind, geothermal, biomass, and biogas have been widely implemented. The diversity of sources has made the grid more resilient as these various technologies generate power at different times, creating a smoother and more stable flow of electricity in the grid (Union of Concerned Scientists, 2016).

California initially started with a goal of 20% renewables by 2017, but in the later years the RPS kept getting more and more ambitious, requiring 20% by 2010 (set in 2006) and 33% by 2020 (set in 2011) (CEC, 2016). The state has always been ahead of schedule at meeting the RPS goals. The Clean Energy and Pollution Reduction Act of 2015 put into law a requirement to serve 50% of California's electricity use with renewable energy resources by 2030 (De León, 2015).

California Energy Commission's (CEC) published the latest update on progress towards renewable energy goals at the end of 2016. It discusses the growth of renewables due to declining costs of wind and solar and how renewable generation and capacity have grown in California. According to the report, in-state operating capacity of renewable resources was 26,300 MW as of October 31, 2016 (CEC, 2016). Out of the total in-state renewable capacity, almost half was solar PV, as shown in Figure 1 which shows the mix of in-state renewable resources by fuel type. The figure includes self-generation capacity, which refers to systems that generate energy that is consumed on-site, such as rooftop solar PV.

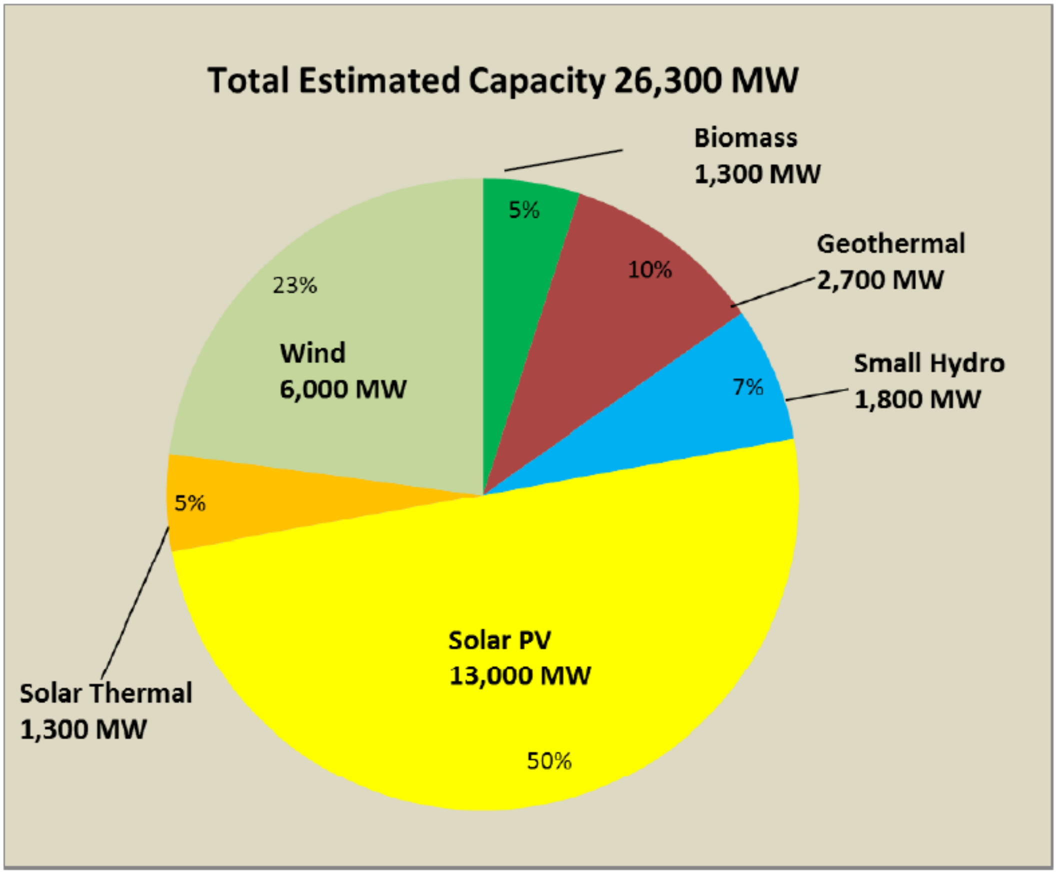

Figure 1: In-state Renewable Capacity by Resource Type for California (CEC, 2016).

While Figure 1 demonstrates the current capacity of renewables, Figure 2 shows how the renewable generation has grown in California over the years. It can be seen that solar production has increased at a higher rate in the last few years as number of utility scale solar systems came online (Munsell, 2017). The progress can be seen in relation to the RPS goals over the years.

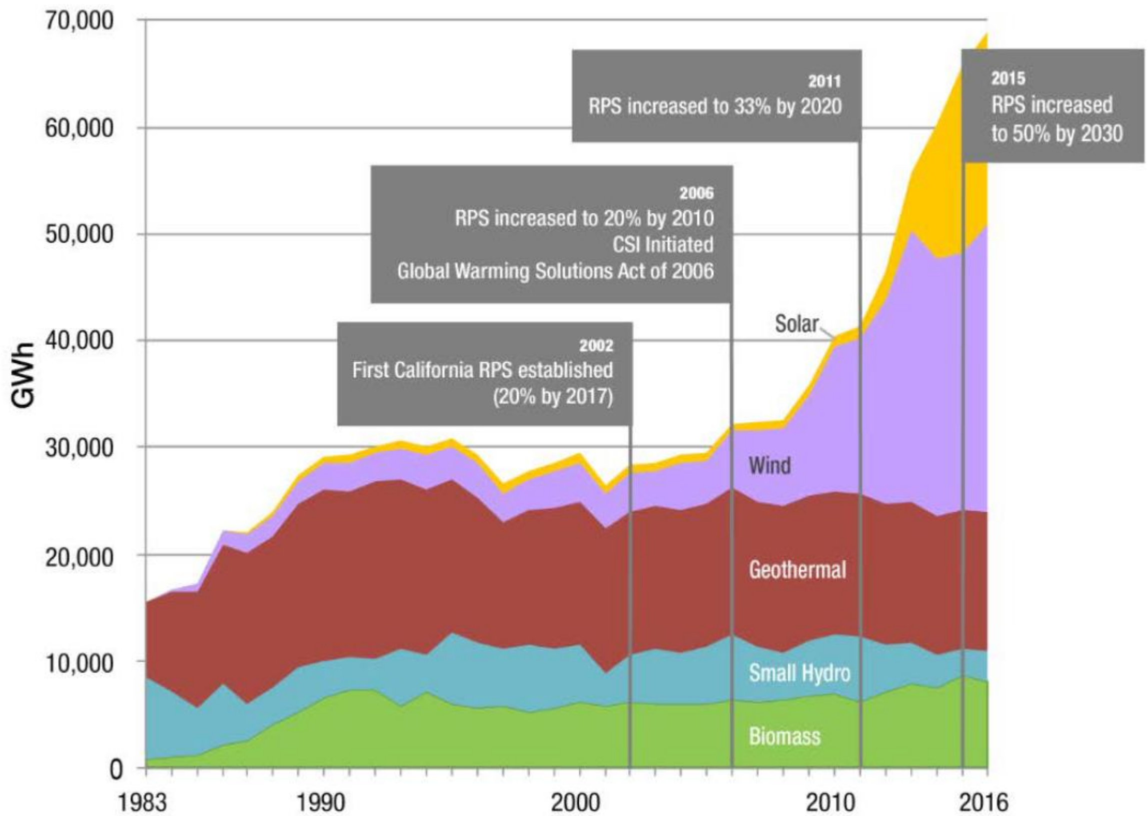

Figure 2: California Renewable Energy Generation by Resource Type (CEC, 2016).

The California Independent System Operator (California ISO) publishes daily reports under the renewables watch which provide information about the actual renewable energy in the grid. Figures 3 and 4 give an hourly breakdown of electricy according to resource type and type of renewable source respectively.The figures are for a sunny summer day, July 31st 2016 in this case.

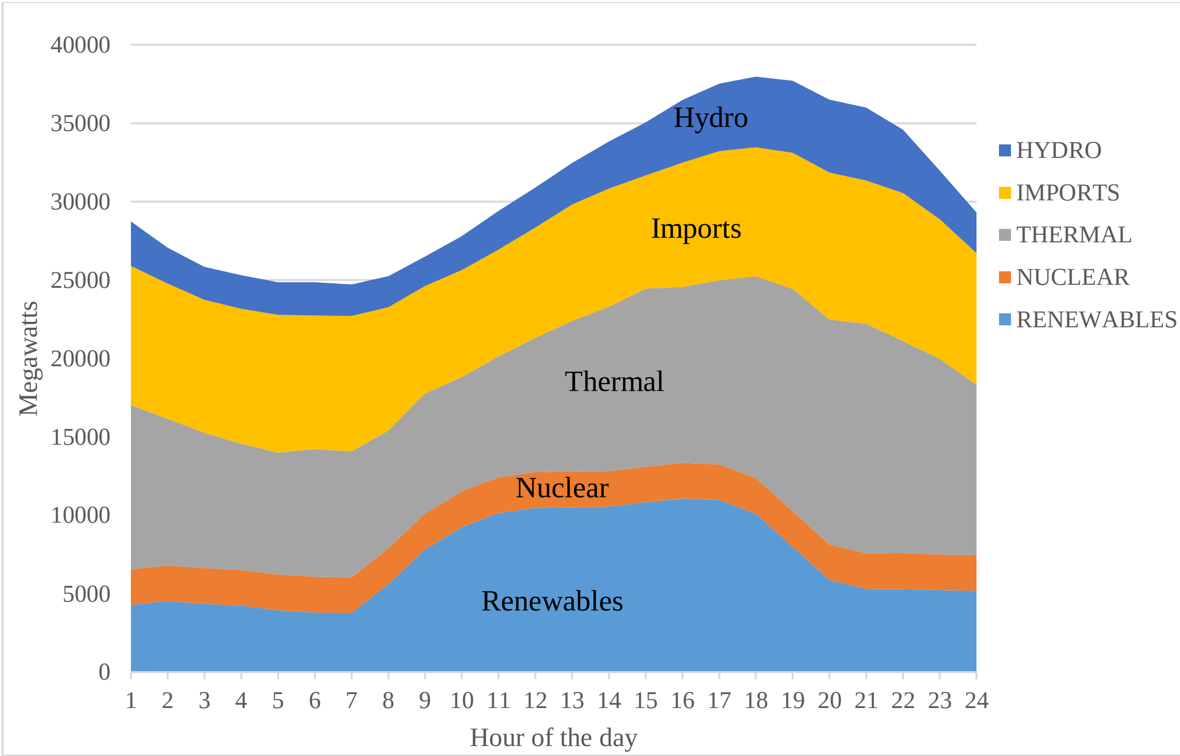

Figure 3: Hourly average breakdown of total production by resource type (CAISO, 2017).

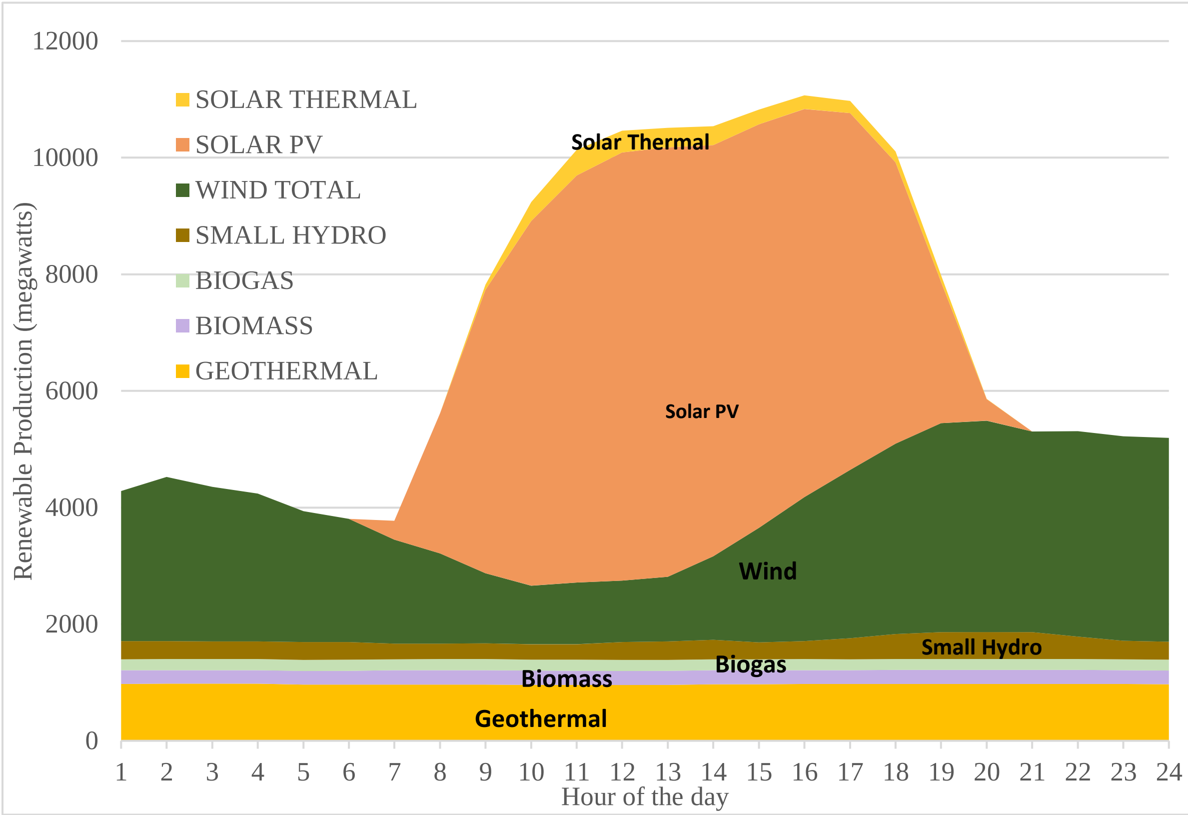

Figure 4: Hourly average breakdown of renewable resources (CAISO, 2017).

It can be observed in Figure 4 that renewable electricity generation steeply increases with the sunrise and peaks sometime around solar noon. This generation profile does not match with the load profile of most places. In Figure 3, a noticeable hump in renewable generation happens around the time with maximum solar insolation. This influences the whole grid profile as the share of renewables is significant at this point. Changes to the grid profile will only intensify in the future as more and more renewables are added to the grid. The following section addresses and discusses these aspects.

The Duck Curve and Intermittency

As discussed in the section above, the share of renewable electricity has steadily increased over the years and will continue to grow over the coming years. Using the data published by CAISO in its ‘Renewables Watch’ publication about hourly load and generation from different sources, Figure 5 was created to see how the share of renewables have grown over the years. Data for a typical spring day of April 30th was used for years 2010-2017. The figure shows the percentage of the load fulfilled from renewable sources.

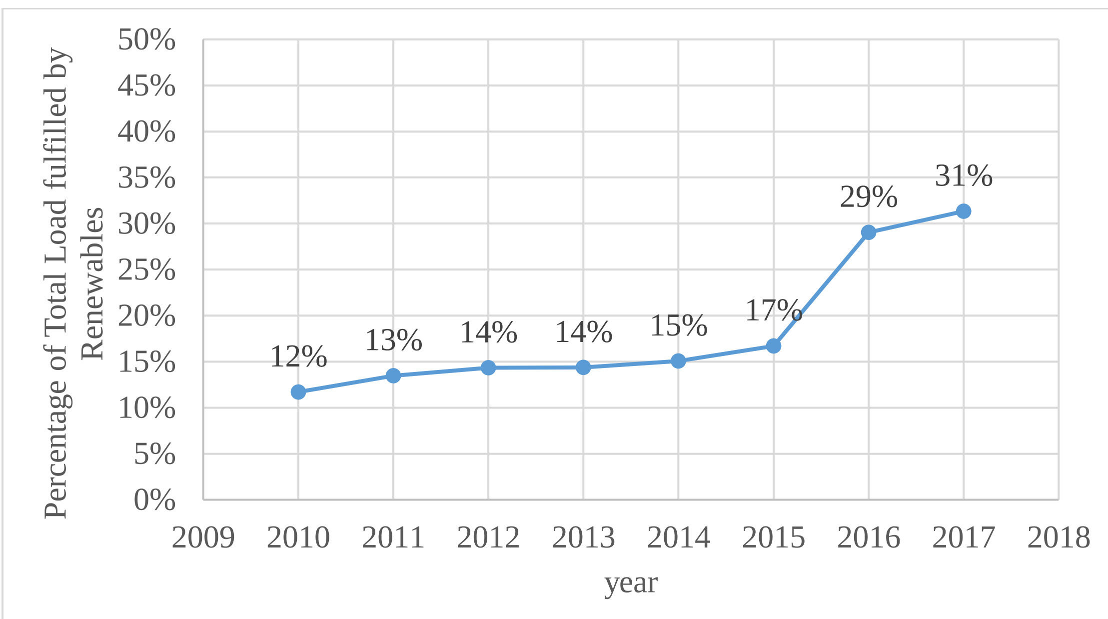

Figure 5: Growth of renewables from 2010-2017. Data from Renewables Watch for the day of April 30th 2010-2017 (CAISO, 2017).

As the share of renewables have grown, wind and solar have been the biggest contributors to the renewables market. Wind and solar (including PV and thermal) are considered intermittent sources of energy (or variable generation systems), as they only generate energy whenever the resource is available. The availability of the resource is dependent on weather and thus it is hard to accurately predict the generation profile for any given day. As renewables have grown, the share of energy from intermittent sources has grown, too. Figure 6 shows how the share in generation from intermittent sources has grown over the years. This increase in generation from intermittent sources brings challenges associated with managing a power grid which was designed to deal with large controllable power plants (Fares, 2015). CAISO is required to constantly balance supply and demand of electricity in the state. It therefore needs to schedule the operations of power generators relative to their day ahead prediction of renewable generation.

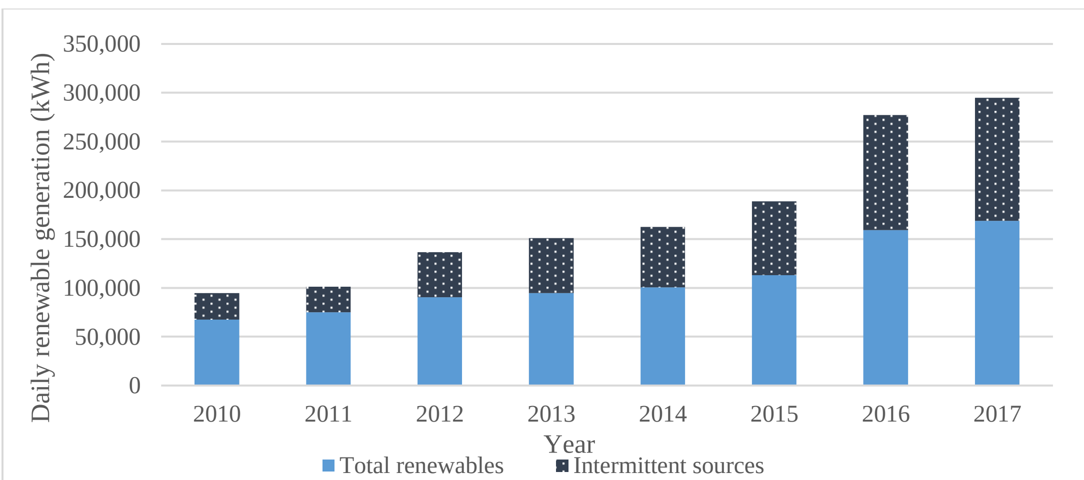

Figure 6: Growth of generation from intermittent sources. Data source *Renewables Watch*, April 30th 2010-2017 (CAISO, 2017).

It can be observed from Figures 1, 2, and 4 from the previous section that solar PV has the biggest share of renewables. This increased penetration of solar PV has raised concern about potential issues with managing the grid. In 2013, CAISO published a chart which is now known as the "duck chart", showing the potential for PV to provide more energy than can be used by the system, especially considering various constraints on power system operation (CAISO, 2013). The famous duck chart is shown in Figure 7 which plots a typical spring day net load. The net load is the difference between total demand and generation from variable sources (wind and solar).

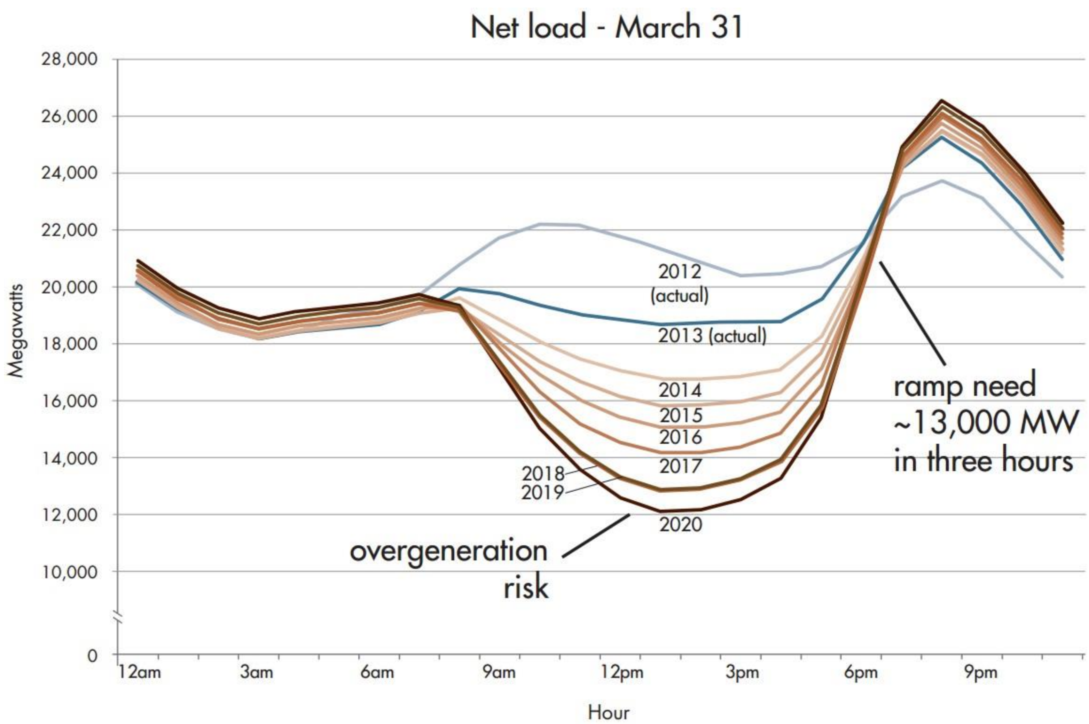

Figure 7: The Duck chart by CAISO shows the potential impact of overgeneration from PV on the net load (CAISO, 2013).

One of the biggest concerns relating to this chart is how this net load shape impacts successful integration of variable renewable energy technologies, mainly solar PV. One of the issues is curtailment of renewable energy during the times of over generation. Variable generation is relatively easier to curtail than shut down other generators. To meet the demand associated with the steep upward ramps in the later afternoon and early morning, the existing generators need to stay online during times the net load is low. The majority of the load is fulfilled by generation technologies that have longer start times, and they must produce energy at some minimum power output level in times when this electricity is not needed (Burnett, 2016). These generators, which are mainly hydro and thermal generators, cannot be switched on and off that easily and thus, during the times when net load is low, energy generated from variable sources has to be curtailed. As the penetration of intermittent renewable energy increases, the ramp is expected to get steeper as the “belly” of the “duck” fattens, and the grid would need to be increasingly flexible to be able to accommodate it. Generation from solar (PV and thermal) is the major cause for the afternoon ramp. As solar penetration increases every year, the curtailment would increase rapidly along with it, which would reduce its economic benefits and increase the cost of meeting renewable portfolio standards or carbon-reduction goals (Denholm et al., 2015). Thus, curtailments prove to be a key limiting factor for large-scale deployment of PV. According to NREL, to achieve as high as 50% solar PV penetration in California, energy storage would play a major role to alleviate some of the issues (Denholm & Margolis, 2016). There are several other ways of mitigating the challenges of increasing PV deployment, such as demand response, thermal storage, regional interchange, increased generation flexibility, and incorporating alternative renewable resources (Cochran, Denholm, Speer, & Miller, 2015). But research suggests that even a flexible power system would still need a significant amount of additional energy storage to enable high penetration of PV (Denholm & Margolis, 2016).

Most of the energy storage is likely to be utility scale, but distributed storage even at residential level could also have substantial impact with shifting load and reducing PV exports to the grid during the middle of the day. Moreover, according to a report from NREL, "…implementing new communications and control technologies that allow distributed resources to participate in grid functions could significantly increase PV potential" (Denholm et al., 2015). This quote refers to behind the meter technologies that are able to respond quickly to signals from a central operator to manage power flows to and from the grid and thereby contribute to effective grid management

In the future, distributed generation is likely to have a substantial and growing effect on the net load as the state works toward the goal of installing 12,000 MW of distributed generation systems (Trabish, 2012). Most grid-connected distributed generation facilities utilize net energy metering. The following section provides an overview of net metering, discusses the new net metering successor tariff, and outlines future prospects.

Net metering

Net metering is an arrangement between a consumer and utility under which the consumers who generate electricity can send excess energy back to the grid and get credit for it (PG&E, 2016d). It allows renewable energy producers to off-set energy consumption during periods when use exceeds generation with the excess energy generated when generation exceeds use. This arrangement generally involves a smart meter that keeps track of energy flow in both directions. Net metering arrangements are often tracked on a monthly basis. In a given month the customer may end up with a credit or a charge depending on the amount of energy generated and consumed respectively. At the end of the year the account is balanced for the remaining amount. For example, if, for a given month, the customer generates more energy than they consume, they would get a credit for that month according to the retail rates associated with the time that the net excess electricity was produced. And similarly, if more energy is consumed than the total energy produced, the customer gets a charge for that month at the corresponding rates. This means that the credit earned for excess generation in sunnier summer months can be used to pay off the charges during winter months when solar resource is scarce. Net metering also partially eliminates the need for having a storage system on site, as the customer could technically use the grid as a backup for the excess power generated. However, under a time of use plan (TOU) on peak hours, consuming electricity from the grid can be expensive. During those times, having storage on site could be helpful, as the system owner can utilize the storage to avoid being a net consumer during peak pricing periods. Net metering on a TOU plan can help save money for the customer if they can shift their loads and strategize their export and import. Exporting electricity at peak times could earn the customer more credits than on a regular rate. Due to TOU rates, there might be some months where the customer can have credit, even if they consumed more energy from the grid than they sent back. A hypothetical example to demonstrate this is shown in Table 1.

Table 1: Example showing the relationship between time of use (TOU) rates and energy costs (PG&E, 2016g).

	TOU rate ($/kWh)	**Energy Imported (kWh)**	**Energy Exported (kWh)**	**Net consumption (kWh)**	**Monthly bill ($)**
Peak	$0.39	50	350	-300	-$117
Off-peak	$0.32	420	100	320	$102
Total		470	450	20	-$15

In a net metering arrangement, the account is balanced every 12 months according to the net value of the electricity generated or consumed. If, at the end of the year, the monetary value of the net electricity generated is more than the value of the consumed amount, the excess is called net surplus generation and the utility compensates the customer in cash or extended credit. In California, under the legislation AB 920 (Huffman, 2009), “Every 12 months following the system’s interconnection to the grid, the customer would receive a True-Up Statement: a reconciliation of all electric usage charges and credits. If the customer has a credit balance at the annual True-Up, they may be eligible for payment through Net Surplus Compensation (NSC).”

For customers of PG&E, the credit for excess energy generated over the entire annual billing period is paid back at roughly $0.03 to $0.04 per kWh (PG&E, 2016d).

The monthly NSC rate is applied to all eligible customers with a true-up period in the following month. The NSC rate matches the 12-month period that a customer’s net surplus generation is calculated. The amount of compensation provided to eligible customers at the conclusion of the true up period is equal to the net surplus energy they generated in kilowatt hours (kWh) multiplied by the NSC rate (PG&E, 2016).

For PG&E, the old NEM program expired early 2017. Based on a state-mandated limit, a similar program called ‘net metering successor tariff,’ also known as NEM 2, is taking its place. On January 28th 2016, California Public Utilities Commission (CPUC) approved a decision to implement the new NEM successor tariff which, according to them, “continues the existing NEM structure while making adjustments to align the costs of NEM successor customers more closely with those of non-NEM customers” (CPUC, 2016). The changes under the new NEM 2 only apply to new customers who are applying to interconnect under NEM and do not apply to old NEM customers. The old NEM customers stay on the same program until the end of the 21st year after the time of interconnection. The old NEM program has a 20-year transition period, which means that all the customers enrolled are allowed to stay on the same program for 20 years. This is roughly the time during which the customer could get payback for their investment in a renewable energy system (Williard, 2016). The 20-year period remains the same under the NEM successor tariff, so the customer accounts enrolling under it are grandfathered for 20 years after the system’s first date of operation (CPUC, 2016).

When the NEM successor tariff was being developed, there were concerns around the compensation rate for the energy that is exported on a daily basis when generation exceeds demand (John, 2015b). Historically, the retail rate compensation under NEM has been a major driver of solar deployment in the state of California. With other state and federal incentives diminishing, the retail rate of compensation was essential to further encourage renewable energy adoption. In the proposal that IOUs submitted to the CPUC for consideration, the IOUs suggested a significantly lower compensation rate for exported electricity (Moore, 2015). The CPUC overruled the proposal and made sure that distributed generators and customers under the NEM successor tariff would get retail rate compensation for their exported electricity.

Despite changes, some aspects of the NEM policy are maintained in the NEM successor tariff. The policy still relies on the minimum bill amount to ensure that NEM customers pay for the benefit of having a grid connection, even if they generate as much energy as they use on an annual basis. The CPUC also declined to impose any demand charges, grid access charges, installed capacity fees, standby fees, or similar fixed charges on NEM residential customers in the near term (CPUC, 2016). The Commission is considering whether and how such fees should apply to residential customers in the future. The NEM successor tariff would treat an interconnecting customer who has a renewable energy generating system with additions or enhancements such as storage in the same manner as those systems interconnecting without them.

Some new aspects of the NEM Successor tariff, according to the CPUC approved Decision 16-01-044, are as follows (CPUC, 2016):

- New NEM customers with an on-site generation system under 1 MW will be required to pay a pre-approved onetime interconnection fee to the IOU. CPUC suggested that the fee should be somewhere around $75-$150. According to the PG&E, the fee for their customers will be approximately $145 (PG&E, 2016d).

- All new NEM residential customers are required to be on a time of use rate plan. Residential customers would choose a TOU plan available to them at the time of the interconnection. This approach is to be used until a default TOU is implemented in 2019; this topic is discussed below. The CPUC instructs IOUs to allow customers under the NEM successor tariff who take service on TOU rates before the default TOU rates start to remain on the TOU rate they have chosen for up to five years. However, the solar industry is skeptical about this requirement because the IOUs have not fully developed and implemented new TOU tariffs yet (Trabish, 2017). Utilities are implementing residential TOU plans on a pilot project basis, and these rate plans are relatively new. The uncertainty of rates might discourage investment in PV. Older TOU plans under PG&E were solar friendly (12pm-6pm peak period), while the newer plans have a later peak period which does not work very well with solar systems. Thus, the new TOU time periods could also affect the feasibility of PV projects. Old and new TOU rates under PG&E are discussed further in the next section about tariffs.

- Under the NEM successor tariff, customers would be required to pay a certain amount of non-bypassable charges (NBC) based on the quantity of energy they import from the utility in each metered time-period. In a given month, even if the amount of energy exported is larger than that imported, the extra kWh exported (after deducting energy imports) cannot be used to offset these NBC. These NBCs would be approximately 2-3 cents per kWh. All customers would be required to pay these charges except for customers on the current NEM, as they only pay for their net usage after deducting the energy that is exported to the grid. Under NEM 2.0, the monetary value of the energy exported to the grid would decrease by 2-3 cents per kWh. This would decrease the value of PV energy for the system owners, who export a significant amount of energy during surplus generation months (typically during the summer) to compensate for months when consumption is higher than production (typically during the winter).

  NBCs under the NEM successor tariff include the Public Purpose Program Charge, the Nuclear Decommissioning Charge, the Competition Transition Charge, and the Department of Water Resources Bond Charges (CPUC, 2016).

There are still numerous aspects that the NEM successor tariff has not addressed yet. The CPUC has set a future goal to revisit the NEM tariff in 2019. The NEM 2.0 or NEM successor tariff is only an interim solution, which keeps a lot of solar friendly aspects intact over the next two years. With the onset of default TOU rates in 2019, the CPUC would review the NEM successor tariff to adjust the tariff structure so that NEM customers have an export compensation rate that accounts for locational and time-differentiated values.

PG&E Tariffs

Pacific Gas and Electric (PG&E) is an investor owned utility servicing the northern regions of California. It serves 5.4 million electric customer accounts and 4.3 million natural gas customer accounts (PG&E, 2016a). Its service area stretches from Humboldt County in the north to Bakersfield in the south. PG&E services most residences in northern parts of California, with exceptions of places that have local municipal utilities.

There are various rate schedules available for residential customers under the PG&E tariff structure. Most tariff plans for residential customers have a tiered rate structure. The tiered tariff rates underwent changes as a result of the electric rate restructuring after the California energy crisis of 1998-2001 (Weare, 2003). California passed legislation that froze residential electric rates for low levels of consumption. This ensured that basic amounts of electricity would be protected from large price increases (Sweeney, 2002). Therefore, most of the cost of mitigating the electricity crisis fell on the customers that consumed energy at higher levels. As a result, there have been large differences between the electricity rates between the lowest and higher tiers.

The tiered rate structure used to consist of several tiers in the past, where electricity rates increased in step-wise fashion for the higher tiers. The amounts of energy associated with the tiers are based on the baseline usage quantity for each region. The baseline energy consumption quantities differ by region depending on the climate, season, geographical location, and the type of heating system that is used (PG&E, 2016b). The electricity rate remains the same for an individual tier over the entire service area, regardless on the size of the dwelling and the number of residents associated with a given service connection (PG&E, 2016b).

According to previous and current tier structures, the daily amount of consumption in Tier 1 is named the ‘baseline,’ which, according to PG&E, “represents the minimum level of usage needed to satisfy a substantial portion (50 to 60 percent) of the electricity needs of the average customer in a specific service area called a "baseline territory" (PG&E, 2016b).

PG&E’s service area is split in various geographical regions called “baseline territories.” Customers are given their baseline quantities in terms of the daily amount of energy (in kWh) which meets significant portion of all the basic needs of an average electric utility customer (PG&E, 2016b). Consumption equal to or lower than baseline is billed at the lowest rate in the tier structure, which encourages people to lower their usage and invest in energy efficiency measures. According to the California Public Utilities Commission (CPUC), “The baseline statute is meant to provide an energy allowance for basic energy needs at a lower rate and sets baseline amounts between 50-70% of average household consumption" (PG&E, 2016c).

The baseline quantities are largely affected by the location. Seasonal rates change according to the local climate, as the electricity requirements change with it. The PG&E service area is divided in 11 different territories. The baseline territory map is shown in Figure 8.

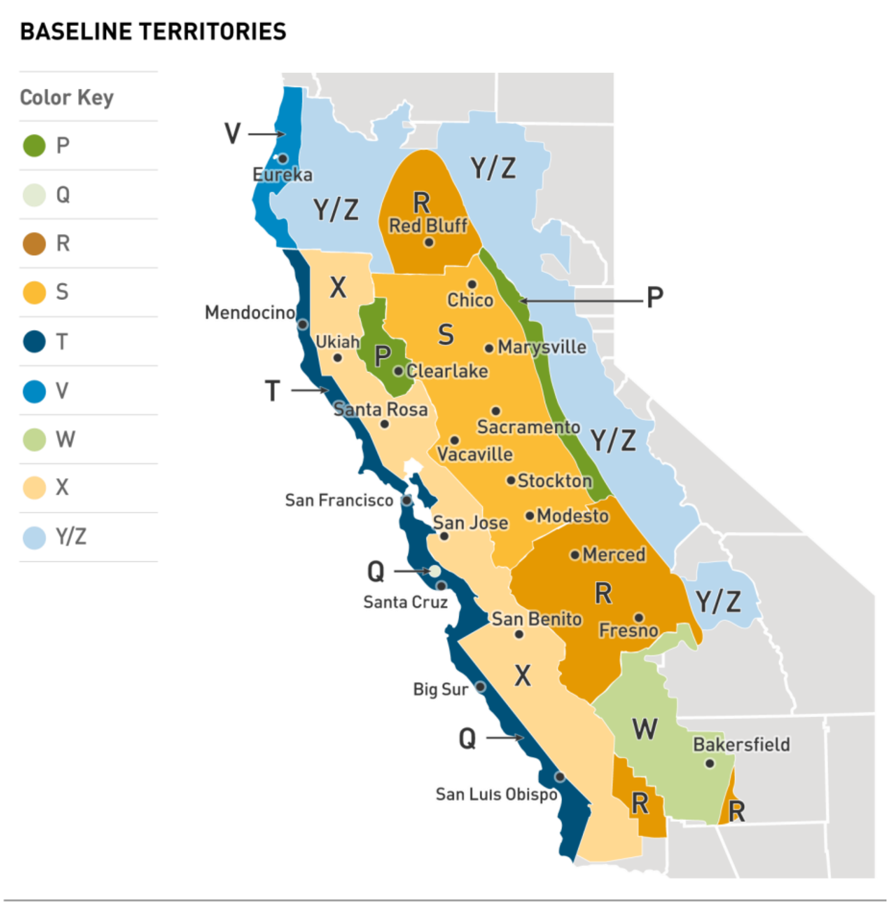

Figure 8: PG&E Baseline Territory Map (PG&E, 2016b).

In 2015, another residential rate reform was passed by CPUC to restructure the electricity tariff plans in California (John, 2015a). Under the previous rate structure, the customers in higher tiers ended up paying for most of the residential cost increases. According to the CPUC, the recent legislation passed aims to decrease such stark difference in electric rates and align the cost paid by the costumer with the actual cost of providing the service to them (CPUC, 2015).

There were various other reasons for implementing the new residential rate reform; the increasing penetration of renewables in the electric grid creates a need for new grid management strategies. In addition, California's newly increased renewable energy goals lead to a requirement for a new plan for tariff restructuring to deal with the associated high fraction of intermittent renewable energy. Replacement of all the older meters with smart meters, research and data that help us better to understand the demand and usage, and new energy efficiency technologies offer a great opportunity to develop tariffs that take advantage for these advancements.

For PG&E, this reform would mean that, starting in 2017, the tier structure would collapse to only two tiers and a high electric rate for a "super user" customer whose consumption is more than 400% of baseline quantity. See Figure 9.

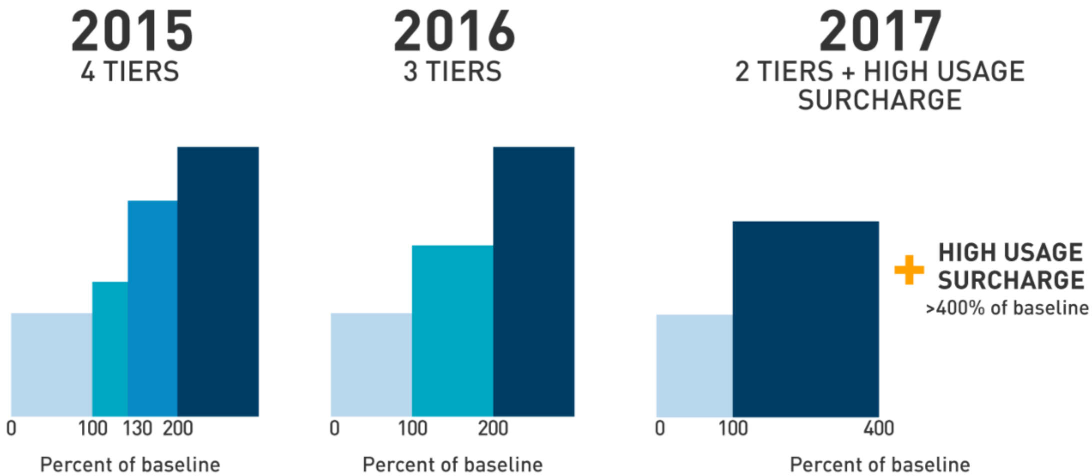

Figure 9: Changes to PG&E's rate tier structure for residential electricity rates from 2015 to 2017 (PG&E, 2016e).

A basic residential tariff plan under PG&E, like the E1 tariff, has a flat rate for electricity for a given tier irrespective of the time of consumption (PG&E, 2017). However, the actual demand, and production of electricity to fulfill that demand, is far from stable. The periods of high demand show up as peaks when consumption is plotted against time. The load profile also changes with season, as load is dependent on weather conditions. Refer to Appendix A for figures that show load profiles for two locations in PG&E territory: Arcata and Fresno. These load profiles are made using data sets from the U.S. Department of Energy's Office of Energy Efficiency & Renewable Energy (EERE), retrieved from OPENEI which has information and datasets related to energy (Office of Energy Efficiency & Renewable Energy (EERE), 2013). This data set contains hourly load profile data for residential buildings based on the Building America House Simulation Protocols and Residential Energy Consumption Survey (RECS). The sources and analysis for these data are further discussed in the chapter titled, “Data and Methods,” in the subsection titled “Consumption Data.”

Tiered rate structures do not accurately reflect the cost of producing the electricity. The marginal cost of electricity generation changes according to the instantaneous demand, while customer retail rates remain fixed according to the pre-determined rate schedule. Peak use periods occur when there is a surge in the electricity demand. Conventionally, this surge in demand would be met through the use of peaking power plants that are turned on and operated for the duration of the surge (Hall, 2010). These “peaker” power plants are more expensive to operate than baseload power plants, which supply a stable and consistent amount of electricity. Thus, the electricity produced is more expensive during peak times. Time of use rates can be more effective for reflecting the cost of producing the electricity than standard flat rates. TOU rate designs are considered beneficial because they can be designed to allow customers to respond to high peak period prices by reducing their load. Shaving the peak demand could reduce the need for additional infrastructure and could potentially reduce overall GHG emissions by reducing the need to run less efficient fossil fuel plants during peak load periods. TOU rates could also improve grid reliability. However, for TOU rates to be effective, customers must understand their electricity rate structure and usage and have the ability to move their usage. Within PG&E’s customer base, almost all commercial and industrial consumers are already on a mandatory time of use rates (CPUC, 2015).

Under the 2015 Residential rate reform, the IOUs are required to design residential rates by January 1, 2018 that propose a default TOU rate structure to begin in 2019. That means that all residential electric customers of the three major IOUs in California will be defaulted to a time of use rate plan unless they choose to opt-out of the arrangement. This would be a very significant change from the current situation where only a fraction of residential customers has opted for TOU rates (CPUC, 2015).

Currently, for PG&E residential customers, time of use rate schedules are offered on a voluntary basis. The older time of use tariff plans, like E-6 and E-7, have been discontinued for all new customers. Existing customers on the E-6 plan, which have peak hour of 1 pm -7 pm, would be allowed to stay on the plan till 2022, with peak hours gradually transitioning to 4 pm - 9 pm. Customers under the residential E-7 rate plan who had a smart meter were automatically transferred to a E-TOU-A, unless they changed their rate plan otherwise. The customers without smart meters were transferred to a E-1 rate plan (PG&E, 2016e).

These older tariff plans had different time periods for “peak”, “partial-peak” and “off-peak,” and the rates were tiered. The time periods changed over the year, but usually the peak period was from 12 pm – 6 pm. These rate plans were beneficial for solar PV owners, as the peak overlapped with the peak solar resource for the PV system. But CPUC thought these older plans were confusing and resulted in counter-intuitive rates. For example, under the older E-6 plan, the summer months alone had three different time periods and 12 different rates. These tariff plans were replaced by the ETOU plan, which offers two options, ETOU-A, and ETOU-B, that are described below.

ETOU-A:

For ETOU-A, the peak hours only exist for weekdays and they start at 3 pm and end at 8 pm. All other times are considered as off-peak. This rate plan additionally eliminates partial peak rates. The winter and summer seasons for this rate plan are different than previous rate plans. The ETOU summer season is from June 1st to September 30th, whereas the summer season for other rate plans are from May 1st to October 31st. The winter season for ETOU-A is from October 1st to May 31st, while the winter for older and other rate plans is from November 1st to April 30th (PG&E, 2016g). The peak hours remain the same during both seasons while the baseline amount changes. The difference between the peak and off-peak rates is more significant in the summer months. Currently the difference is around 8¢/kWh (23%) for summer months and 1¢/ kWh (5%) for winter months. This rate plan has a baseline credit in terms of $/kWh, which means customers will receive a credit per kWh for all usage up to the amount of their baseline allowance for the billing period. The current rates are as presented in Table 2 and a graphical representation is shown in Figures 10 & 11.

Table 2:Residential electric rates under plan ETOU-A (PG&E, 2016g).

Season	**Total Energy Rates ($ per kWh)**	**Peak**	**Off-Peak**
Summer	Total usage	$0.39	$0.32
	Baseline credit	-$0.09	-$0.09
Winter	Total usage	$0.28	$0.26
	Baseline credit	-$0.09	-$0.09

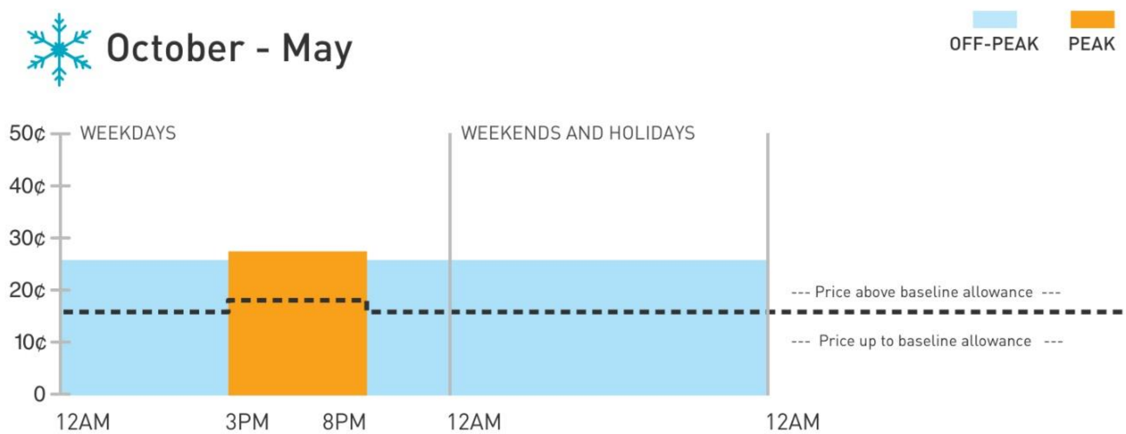

Figure 10: Representation of how rates work in winter months (October-May) (PG&E, 2016g).

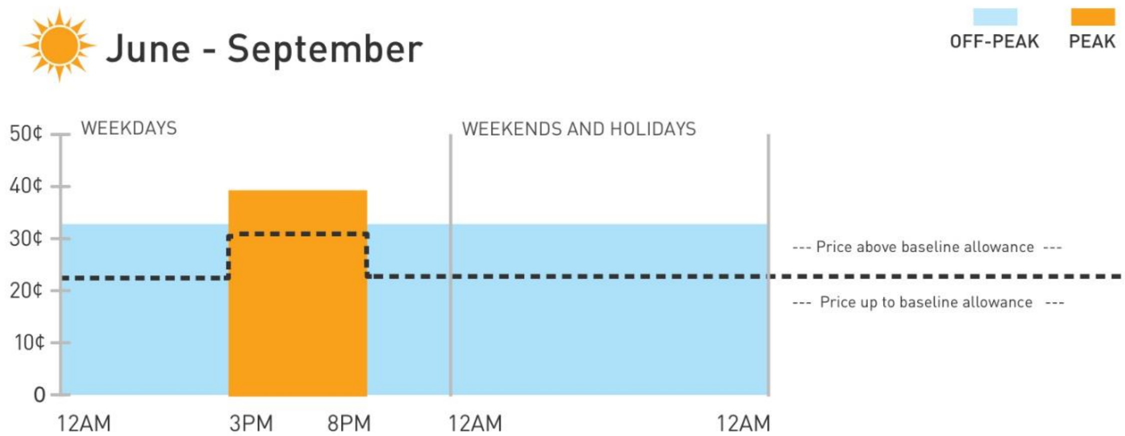

Figure 11:Representation of how rates work in summer months (June-September) (PG&E, 2016g)

ETOU-B:

ETOU-B rate plan has its peak hours during 4 pm - 9 pm on weekdays, and all other times are off-peak. The summer and winter seasons are the same as the ETOU-A. The major difference between two rates is the time for the peak hours. Another difference is that ETOU-B does not have a baseline credit. The rates would be the same for every household irrespective of the total consumption. The rates are also lower than the ETOU-A rates. Thus, this rate might not work well for customers that have a very low consumption (under baseline), as it does not provide any incentive for low usage. Whereas this rate plan can prove lucrative for customers with high consumption who can be flexible with their usage. ETOU-B is only available to a limited number of customers and might be discontinued or amended after the cap has been reached. The rates for TOU-B is shown in Table 3

Table 3: Residential electric rates for ETOU-B (PG&E, 2016g).

Total Energy Rates ($ per kWh)	**Peak**	**Off-Peak**
Summer	$0.36	$0.26
Winter	$0.22	$0.20

Minimum bill charge

The minimum bill charge replaced a previously existing fixed charge which was an addition to the bill. This mechanism is designed to recover a minimum amount of revenue, acknowledging that some costs should be paid to maintain service even in the event that a customer does not use energy (PG&E, 2016). Those customers pay the minimum bill amount, which acts like a charge to stay connected to the grid, and have the choice and ability to use electricity from the grid. It also would cover a portion of the fixed costs that the utility bears for the upkeep of the grid and keeping the customer connected. Moderate and high usage customers do not pay for the minimum bill amount because they cover the cost of connection through the purchase of energy ($/kWh) (CPUC, 2015).

According to PG&E (PG&E, 2016):

> The charges for the Minimum Bill include components for the generation of electricity and the delivery of energy. The generation portion of the bill is used to pay for the electricity itself, while the delivery portion is used to pay for the transportation of the electricity over PG&E's grid.

Since March 2016, the minimum bill has only been applied as a delivery charge. It was renamed as minimum delivery charge in the tariff plans and customer bills. For renewable energy customers on net metering, this charge is applied every month and credited back at the end of the year in their respective true-up statements. For other customers, the minimum delivery charge would apply if their usage is below the minimum amount. Additionally, there would be an energy charge applied for the small amount of electricity that they did use.

In the residential rate reform, the CPUC authorized an increase in the minimum bill amount for all residential customers. The monthly minimum bill increased on September 2015 from $4.50 to approximately $10 (PG&E, 2016f).

The minimum bill charge is an important issue to discuss for net metering customers. For net metering customers, there might be times when they use little to no amount of energy from the grid, yet they still must pay $120/year to stay connected.

To maximize savings under the TOU plan, it is important to strategize energy management for each customer's system. The following section discusses the technology that could help manage such systems.

Hybrid Inverters and Multi flow technology.

Due to the falling costs of PV electricity and opportunities for an expansion in the use of battery integrated PV systems, a lot of inverter manufacturing companies are moving towards storage compatible inverters and supporting components. Hybrid inverters and AC-coupled inverters are very suitable for existing and prospective residential PV customers with storage. To maximize self-consumption and be financially viable, these PV storage systems require inverters that have more complex control systems. These new intelligent inverters and technologies offer a variety of functions which are favorable to battery owners.

The Tesla energy press kit mentions Fronius and SolarEdge inverters as seamless solutions for PV and storage systems (Tesla Energy, 2016). These companies are the leading, early innovators of load flow management and various charge and discharge profiles. Fronius Symo Hybrid inverters are an easily integrated solution for existing and new system owners. Moreover, the Symo Hybrid inverter offers an AC charging function, which can prove to be beneficial for various reasons as noted below.

During periods when the solar resource is limited, the AC charging function enables electricity from other sources to be stored temporarily in the PV storage system and then discharged later(Fronius, 2015). It is also useful when little to no solar resource is available for a prolonged period and the battery is deeply discharged. Charging the battery through AC charging could prevent early degradation of the battery (Battery

University, 2016). It could also maintain a minimum amount of charge for emergency situations.

The AC charging function can also be beneficial to utility customers who are on a TOU plan. Even customers who do not own a PV system could find it beneficial. Under TOU, electricity can be imported and stored when it's cheaper during off peak times and can provide power during peak hours when prices are high.

The most attractive feature incorporated in the analysis for this thesis is a multi-flow technology incorporated in Fronius inverters which allows for various parallel flows of energy (Fronius, 2015). These inverters are programmable to allow custom flow patterns according to user preferences and to ensure the optimum operation of PV and storage systems.

Financial incentives

Over the years, to accelerate deployment of renewable energy technologies, states and the federal government have implemented a variety of policy options. The following sections discuss two import incentives for the system under consideration.

Investment Tax Credit (ITC)

The investment tax credit (ITC) is a federal incentive mechanism designed for residential and commercial renewable energy systems and energy efficiency. It is one of the most important programs introduced to encourage solar deployment. According to the Database of State Incentives for Renewables & Efficiency, under this policy, “A taxpayer may claim a credit of 30% of qualified expenditures for a system that serves a dwelling unit located in the United States that is owned and used as a residence by the taxpayer” (DSIRE, 2017).

Ever since it started in 2006, the ITC has helped the solar energy industry grow rapidly, and it also supported speedy deployment of other types of renewable energy systems (NARC, 2016). The ITC helped cut down the higher up-front costs of solar systems and encouraged more people to invest in solar (SEIA, 2016). It has been repeatedly extended, with the most recent extension occurring in December 2015. Congress passed the Consolidated Appropriations Act just before the end of 2015, which provided ITC extensions for PV and solar thermal technologies and introduced a gradual step down in the credit value in the later years (Dent, 2015).

The ITC will remain at 30% for all systems till the end of 2019, after which it would start to phase out. ITC would reduce to 26 percent in 2020 and 22 percent in 2021. After 2021, the residential credit will drop to zero while the commercial and utility credit will drop to a permanent 10 percent(SEIA, 2016).The phasing out is depicted in Figure 12. This analysis assumes a tax rebate of 30% of the total upfront costs for the systems.

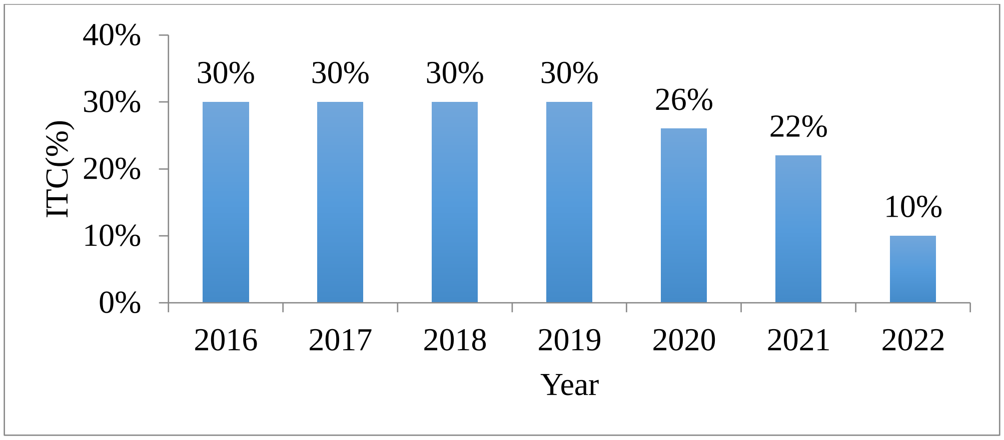

Figure 12: Phasing out of ITC (SEIA, 2016).

Self-Generation Incentive Program (SGIP)

The Self-Generation Incentive Program (SGIP) is a CPUC program which provides rebates to encourage distributed energy sources installed on the customer's side of the utility meter within California. According to a recent update from CPUC regarding residential customers:

> The planned reopening of SGIP to energy storage applicants is due to occur in late March or April 2017. Once reopened, SGIP will reserve 75% of its incentives for energy storage projects. 15% of the reservation will be reserved for residential energy storage projects less than or equal to 10kW in size. On the day the program reopens, the incentive level for residential energy storage systems 10kW or smaller will be set at 50 cents/watt-hour (Matasci, 2016).

The incentive value gradually decreases once demand for the incentive exceeds a predetermined funding amount, after which the rebate goes down a “step” to a lower incentive level (Matasci, 2016). A certain amount of money is reserved for each step. The applications started in spring 2017, and the incentive amount for a given project depends on the size of the system and the time of application. As the incentive value is variable, the amount per system cannot be currently predicted precisely.

The following section consists of the methodology used for the analysis.

DATA AND METHODS

The methodology for this thesis follows several steps to assess the feasibility of residential PV system with storage under a TOU rate. This approach involves estimating the energy savings for PV systems that involve storage for several different consumption scenarios at two locations in California (Fresno and Arcata). First, all the data used in the analysis are collected and computed to give hourly load profiles and hourly PV generation. These data are used to strategize how the energy flows in a typical system and how the residential load is fulfilled. All this information is used to calculate annual savings in term of avoided energy costs compared to a business as usual (BAU) scenario, where the customer is under a TOU rate, and they buy all their energy from the utility. The last step is to do a benefit cost analysis for each version of the model to see the viability of these systems. The chapter begins with a few sections describing the sources of data used in this analysis, explaining the logic of the model built and justifying the assumptions made in the model.

Solar Resource

The solar resource data are from the National Solar Radiation Database (NSRDB), published by the National Renewable Energy Lab (NREL). This analysis uses the Typical Meteorological Year, version 3 (TMY3) data sets for hourly values of solar radiation and relevant weather data for a typical year. These data sets are an update to, and expansion of, the TMY2 data released by the National Renewable Energy Laboratory (NREL) in

1994. These data sets are derived from the 1961-1990 and 1991-2005 NSRDB archives (NREL, 2016b). Generally, TMY3 datasets are used instead of TMY2 because they are updated and more recent. Moreover, the TMY3 data set contains information for 1020 locations in USA. The TMY2 data set was produced using weather and solar data from the 30-year window spanning 1961–1990 for 239 locations. During 1991-2005, weather and solar data were collected for more than 1400 locations. According to the user manual for the TMY3 data sets, “At sites where data are available for 30 years, the base time period for the TMY algorithm spans 1976-2005. For the remaining sites, the base time period spans 1991-2005”(National Renewable Energy Laboratory, 2016)

Figure 13 is a map of TMY3 stations. As shown in the figure, the stations are divided into classes. Class I sites are those with the lowest uncertainty data, Class II sites have higher uncertainty data, and Class III sites have an incomplete period of record (Wilcox & Marion, 2008). In the analysis presented in this thesis, two locations that fall under PG&E territory are considered. These two locations are, Arcata, CA (40.9° N, 124.1° W) and Fresno, CA (26.7° N, 119.8° W). They are both Class I sites.

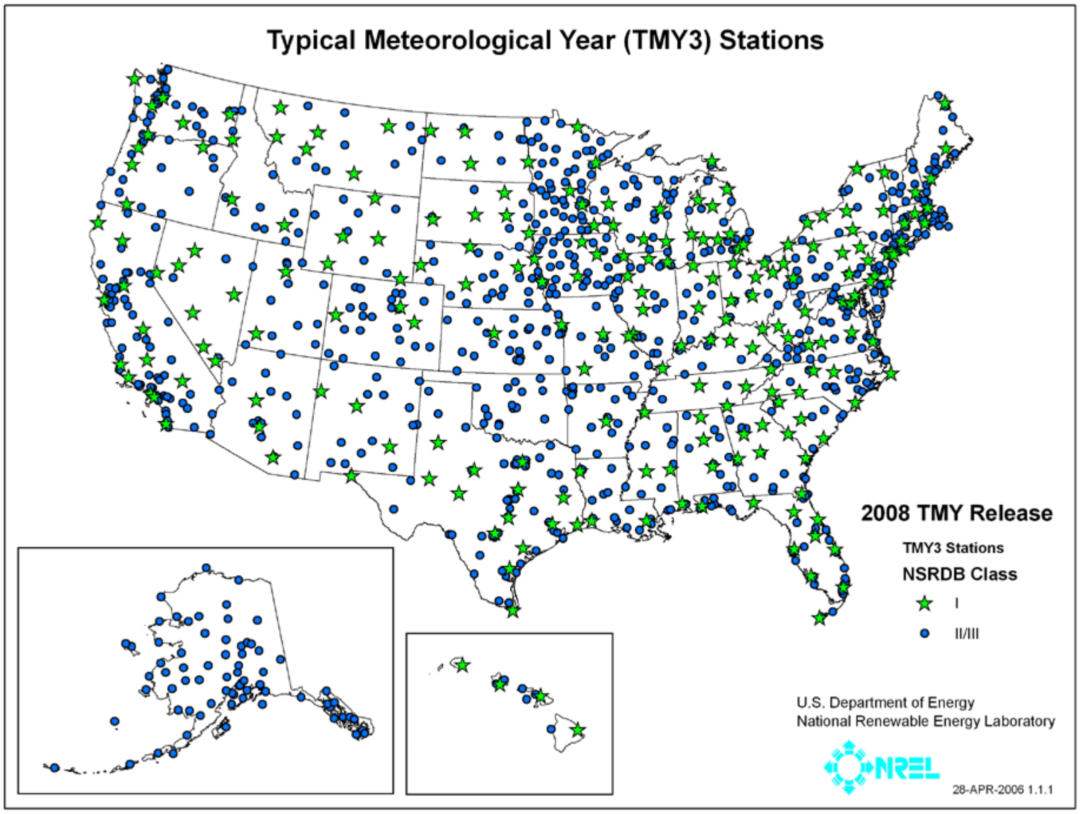

Figure 13: Map of geographical distribution of TMY3 stations (NREL, 2016b).

Any standard TMY3 data set for a location has 68 data fields, which contains information about solar radiation, precipitation, illuminance, wind and much more. Only a handful of those data fields were used for this analysis. The insolation data in the data set are for solar radiation on a horizontal surface. These data are used to calculate insolation on a tilted surface using solar geometry calculations.

Most residential systems are rooftop mounted due to lack of space and to minimize shading. Residential roofs have different pitches depending on the type of the house and roof. The residential photovoltaic array can be a fixed tilt, 1-axis tracking or 2-axis tracking depending on the importance of maximizing production. Fixed tilt is the most commonly used mounting type for rooftop systems.

The Liu and Jordan model (1963) is used to calculated the total insolation on a tilted surface. In this model, the solar radiation on a tilted surface is considered to be composed of three parts, including the beam, diffuse, and reflected from ground fractions. It was assumed that the diffuse radiation is isotropic only.

According to the isotropic diffuse model by Liu and Jordan (1963), total solar radiation available on a tiled surface is a combination of the following three components:

- Beam radiation, which is the portion of the solar radiation which comes in form of parallel beams straight from the sun to the surface of the earth in a single direction.

- Diffuse radiation is the part of the solar radiation that has been scattered by the particles in the atmosphere and arrives on the surface after undergoing various changes in direction. Diffuse radiation depends on sky conditions and it is highly variable.

- Ground reflected radiation is a small portion of the diffused radiation and can be described as the radiation which bounces off the surface of the earth or other surfaces near the tilted plane. It depends on the reflectance (ρ_g) of the surrounding surfaces.

An hourly estimate of available radiation (or irradiance) on the tilted surface needs to be calculated from the available TMY3 data for the desired locations. The data set already contains values for the diffuse horizontal irradiance and global horizontal irradiance, which are the total amount of beam and diffuse solar radiation received on a horizontal surface during the given hour. Beam radiation is calculated by subtracting the diffuse radiation value from the global horizontal irradiance.

$$I_{Beam} = I_{Global\ horizontal} - I_{diffuse}$$

According to (Duffie & Beckman, 2013), for a surface tilted at an angle β from the horizontal, total solar irradiance on a tilted surface for an hour can be given by (p. 89):

$$I_T = I_b R_b + I_d\left(\frac{1+\ \cos\beta}{2}\right) + I\ \rho_g\left(\frac{1-\ \cos\beta}{2}\right)$$

Where, I_T = Hourly solar irradiance on a tilted surface (Wh/m^2)

I_b = Hourly beam horizontal solar irradiance (Wh/m^2)

I_d = Hourly diffuse horizontal solar irradiance (Wh/m^2)

I = Hourly global horizontal solar irradiance (Wh/m^2)

ρ_g= Ground reflectivity (assumed to be 0.2 for normal conditions)

R_b= ratio of beam radiation on a tilted surface to radiation on a horizontal surface.

The units for all radiation data in TMY3 datasets are in Watt-hour per square meter (Wh/m^2). The factor R_b is calculated for every given hour of the year to determine the hourly solar resource. For this analysis, the tilt angle β is assumed to be equal to the latitude. The tilt angle remains the same throughout the year.

From the solar resource data, hourly production of DC electricity is calculated by multiplying the hourly irradiance on the tilted surface with the system size of the photovoltaic system (in Watts).

$$P_{DC} = I_T * PV\ array\ size\ (W)$$

Where, I_T = Hourly solar irradiance on a tilted surface (Wh/m^2)

P_{DC}= DC power generated from the PV array.

The AC electricity produced is calculated by multiplying the DC amount by the inverter efficiency and deducting system losses. The total system loss is calculated by multiplying the reduction due to each loss. According the NREL PVWatts version 5 calculator, the current default value is 14%, and losses represented by this number include the impacts of soiling, shading, snow cover, mismatch, wiring, connections, light induced degradation, nameplate rating, system age, and operational availability (Dobos, 2014).

That means that the derate factor for DC energy production would be 0.86. This does not include the inverter losses, as each type of inverter has a different efficiency value. To get a DC-to-AC derate factor, it is necessary to multiply 0.86 by the nominal efficiency of the chosen inverter. The inverter model used for this analysis is Fronius Symo Hybrid series whose capacity changes depending on the size of the system. Their efficiencies are reported to average around 96.5% (Fronius, 2015). Thus, the DC-to-AC derate factor for this analysis would be: 0.86 * 0.965 = 0.83. Refer Appendix B for more technical specifications.

When trying to predict the net worth of an investment in a PV system, it is important to accurately account for the predicted decrease in power output over the lifetime of the project. Solar modules undergo degradation over the years and generate less power as they degrade. Following the NREL estimates, the degradation rate is assumed to be 0.5%/ year (Jordan & Kurtz, 2013).

After figuring out the insolation available, the next step is to determine the residential load that need to be fulfilled. The next section shows how the consumption data were computed.

Consumption Data

U.S. electricity consumption varies widely depending on the place and its climate. The load profile of an average residence, for any given place, can be charted from the hourly residential electric consumption data. The data set used for analysis in this thesis is from the U.S. Department of Energy. The dataset, available on OPEN EI, consists of hourly load profiles from the Residential Energy Consumption Survey (RECS). The dataset consists of modeled hourly consumption for typical low and high load households. As mentioned above, the data for two chosen locations in PG&E territory are used in this analysis. The data set is used to map the load profile over the period of 24 hours for winter and summer seasons, and the load profiles are assumed to be stable over the duration of the respective seasons. These load profiles are then used to simulate the hourly consumption depending on different types of residence energy consumption scenarios. The consumption scenarios cases are set based on the baseline quantities, which are established by the Public Utilities Commission (PUC). The analysis in this thesis focused exclusively on systems with a TOU rate. The corresponding daily baseline quantities for the two locations considered, Arcata and Fresno, are displayed in Table 4. These baseline quantities, as discussed previously, “represent the minimum level of usage needed to satisfy a substantial portion (50 to 60 percent) of the electricity needs of the average customer in a specific service area” (PG&E, 2016b). The quantities reported in Table 4 are relative to the rate plan under consideration, which is ETOU-A. These are for Code B ‘basic quantities,’ which are for customers that do not have a permanently installed electric heating system. Those customers who do have permanently installed electric heating system fall under Code H- for ‘All-electric quantities’.

Table 4: PG&E seasonal baseline quantities for Arcata and Fresno under ETOU-A (PG&E, 2016b).

Season	**Arcata (kWh)**	**Fresno (kWh)**
Summer	8.6	17.6
Winter	10.3	11.1

There are four cases for residential energy consumption considered for this analysis, which are as follows:

- Baseline: The lowest assumption made is for baseline consumption quantities, which means that daily consumption by the household is equal to the baseline quantity for the given region in PG&E territories. Consumption that is lower than the baseline amount is billed at a lower rate than consumption over the baseline.

- Typical: The second assumption is for a typical residence in the given region. The daily consumption in this scenario is assumed to be 50% higher than the baseline quantity. Energy consumed up to baseline is charges at a lower rate or is discounted. All the energy consumed over and above baseline level is charged a higher rate.

- High: The third assumption is made for a larger household that consumes double the amount of the baseline quantity.

- Higher: The fourth assumption is for a particularly large household where daily consumption is four times the baseline quantity. If this household was under E1 rate schedule, it would be charged a super user surcharge. Under TOU, the rates (in $/kWh) would be the same as for the High use scenario, but energy costs would be the higher due to high level of consumption.

Power Flows

With programmable systems, a variety of energy management strategies are possible. The aim is to maximize self-consumption (i.e. consumption of self-generated electricity) and to avoid energy use from the grid during peak use periods under a TOU rate. Doing so can expand the economic benefits of having a PV system with storage. In the future, the electricity exported to the grid might not be compensated at the retail rate, which would diminish the value of PV energy generated by the system owner. Under the current TOU plans, the difference in peak and off-peak period charges is not big enough at present to generate significant revenue from exporting battery energy to the grid during peak hours. Thus, this analysis focuses only on minimizing exports and imports from the grid. The system components, and possible energy flows, can be seen in Figure 14.

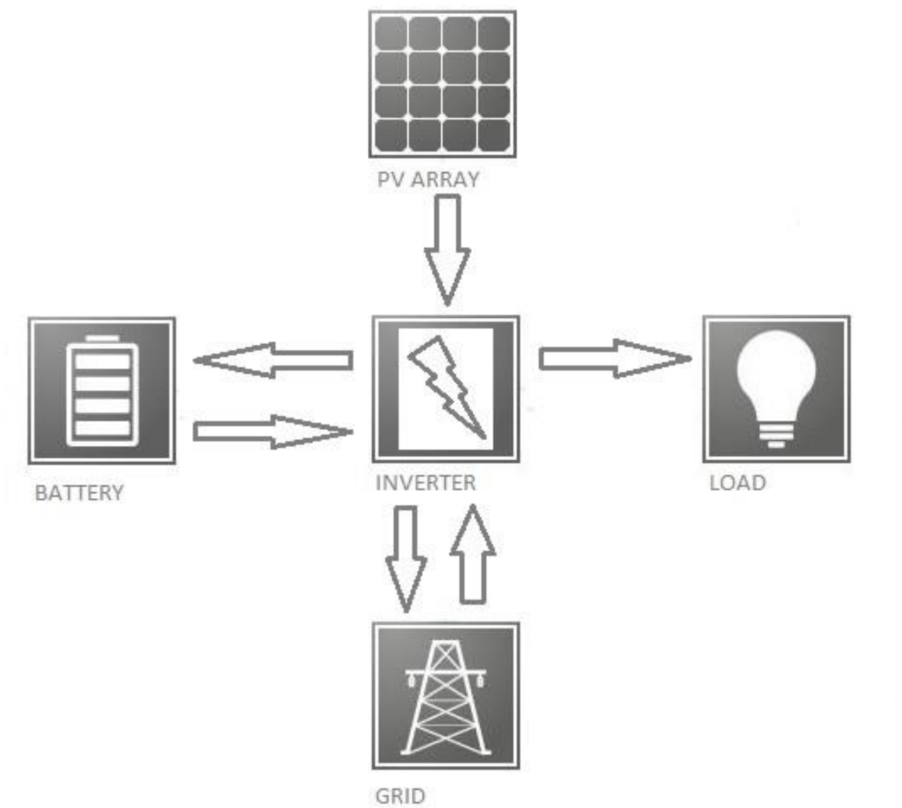

Figure 14: Components for a typical PV+ storage system and the possible power flows among them.

As discussed above, this system intends to maximize self-consumption and avoid energy consumption during peak rate periods. The energy management logic for modeling a typical system is described in the following section.

- Battery Charging: By default, the battery would only charge from the PV-generated electricity. The batteries would only charge when all the conditions listed below are satisfied:

1. Batteries would charge only when PV energy generated exceeds the energy needed to supply the load at the time of generation.

2. Charging would only occur if the battery is not full already. If enough PV energy is available, the batteries would keep charging until it is full.

3. Battery charging would take place exclusively during off-peak hours.

Most new inverters and charge controllers allow users to customize their preferences and change the charging whenever they want. The inverter and battery can be programmed to import grid electricity to charge the battery whenever an outage or peak period in predicted for the near future.

- Battery Discharging: The energy from the batteries would only be discharged to fulfill load requirements (which could be changed later as per needed). The batteries would discharge when all the conditions listed below are satisfied:

  1. The battery would supply energy to the load when energy generated by the PV array is not enough to fulfill the load. During this time, the load might be met with a mix of power from the battery and PV.

  2. The battery would supply energy to the load if it has enough charge to supply the load. In this case, the battery need to have at least 10% of its maximum capacity.

3. The battery would supply energy to the load primarily during peak rate periods to avoid paying the corresponding high rates.

Moreover, once the discharging starts, the batteries would keep discharging to meet the residential load until the battery capacity is below 10%. This would mean that if the battery still had charge left after the end of peak hours, it would keep supplying the load till it's under 10%. If a battery is oversized compared to the load, it can also export energy to the grid during peak hours to get more credit for the exported energy. However, this analysis does not account for the latter scenario.

- PV Energy: The energy generated from the Rooftop PV array can be used in one of three ways: (i) to supply the load, (ii) to charge the battery, and (iii) to export energy to the grid. The logic to route this energy is as follows:

    1. The first priority for the PV energy is to supply the load.

    2. When the PV production exceeds the load, the excess is redirected towards storage to charge the batteries.

    3. When the batteries are full and PV energy exceeds load, the excess energy is redirected and is exported to the grid at the retail rate.

- Grid energy imports: The logic for this model is designed to minimize grid imports, so grid energy is only imported when the following is true:

  - When battery level is lower than 10% of its maximum capacity and cannot supply the load.

  - When PV generated energy is not sufficient to supply the load; this occurs frequently at night and early in the morning. Sometimes energy may need to be imported if there are extended low insolation periods.

- Energy exports to the grid: Under this model, only excess PV energy is exported to the grid. The export to the grid would only take place under following conditions:

  - When battery is fully charged, and the load is completely fulfilled, the extra energy generated by the PV system would be exported to the grid.

Annual Savings Calculations

To determine the economic feasibility of PV systems with storage, the most important factor is to calculate the savings from avoided energy costs. Most of the economic benefit of owning a residential solar PV system is in form of the avoided cost on electricity bills. For this calculation, the following steps were taken:

- The first step involves calculating average consumption values for each hour over the 24-hour day for the summer and winter seasons because the TOU rates are categorized according to the season; thus, the consumption and production data were averaged for the same months. Consumption was averaged in terms of percentages of the daily load to figure out the load profile for the day. These averaged percentages were multiplied by the assumed daily load to get the respective hourly loads.

*Hourly load (kWh) = Percentage of the daily load * Assumed daily consumption (kWh)*

As discussed in the consumption data section, the various scenarios in this analysis and their corresponding daily consumption assumptions are shown in Table 5.

Table 5: Assumptions for daily consumptions for Arcata and Fresno for 4 different cases (PG&E, 2016b) .

Case	Factor	Arcata Summer (kWh)	Arcata Winter (kWh)	Fresno Summer (kWh)	Fresno Winter (kWh)
Baseline	x1	8.6	10.3	17.6	11.1
Typical	x1.5	12.9	15.45	26.4	16.65
High	x2	17.2	20.6	35.2	22.2
Higher	x4	34.4	41.2	70.4	44.4

- The second step is to estimate the generation from the array. Averaging values for solar energy production differs a little. The AC and DC production values are calculated for every hour of the year. After that, they are averaged over the months for summer and winter TOU seasons to give values for each hour of a typical day in those respective seasons. The PV production values are dependent on the array size. For the various cases considered, the array size is an important parameter. Array sizes are determined according to the assumed size of the household and consumption. The array is sized to offset approximately 90% of the annual usage for Arcata and 95% for Fresno. The PV array size is slightly smaller than the size that would be required to meet the full load in order to allow the net energy consumption costs to be more than minimum bill amount. Even if 100% of the demand were fulfilled by PV generation, the customer would still be required to pay $120 a year which is the minimum bill requirement. Thus, the PV arrays are downsized to avoid paying the minimum bill requirement without getting any energy from the grid in exchange. The system sizes for Arcata and Fresno are described in Table 6.

Table 6: PV array sizes for four residential scenarios for Arcata and Fresno

	Baseline	**Typical**	**High**	**Higher**
Arcata	2 kW	3.75 kW	5 kW	10 kW
Fresno	2.75 kW	4.2 kW	5.5 kW	11 kW

After determining the energy flows for every hour of the day for winter and summer months, the next step is to calculate the annual energy costs. These amounts can be determined by tracking daily export and import of electricity. The costs incurred on a given day depend on the amount of energy exported or imported (in kWh) and the rate of electricity at the time of export or import (TOU rates in $/kWh). The daily dollar amount is then multiplied with number of days in the respective baseline season to give total net cost for that period.

Energy cost for winter = {(Net peak usage Winter peak rate) + (Net off-peak usage* Winter off-peak rate) – (usage up to baseline * baseline credit) + (NBC)} * 243 (days in winter season)*

Energy cost for Summer = {(Net peak usage Summer peak rate) + (Net off-peak usage* Summer off-peak rate) – (usage up to baseline * baseline credit) + (NBC)} * 122 (days in summer season)*

Annual energy costs = Summer Cost + Winter Costs

The annual energy costs are then compared to the business as usual (BAU) cost, which is calculated by multiplying hourly load data in the to the TOU rate.

Annual savings = BAU costs – Energy costs (PV + storage)

Solar costs

Solar costs have been steadily declining over the years. According to NREL, recent cost reductions were driven by lower module and inverter prices, increased competition, lower installer and developer overheads, improved labor productivity, and optimized system configurations (Fu et al., 2016).

The assumed cost per installed watt for this analysis is $3.10, which is higher than the national average rate for residential systems in 2016 as seen in Figure 15. This is to allow for the range of solar PV array sizes assumed for this analysis, which spans from 2 kW to 9 kW. It is also to allow for changes in costs, additional profit margin, and added fees.

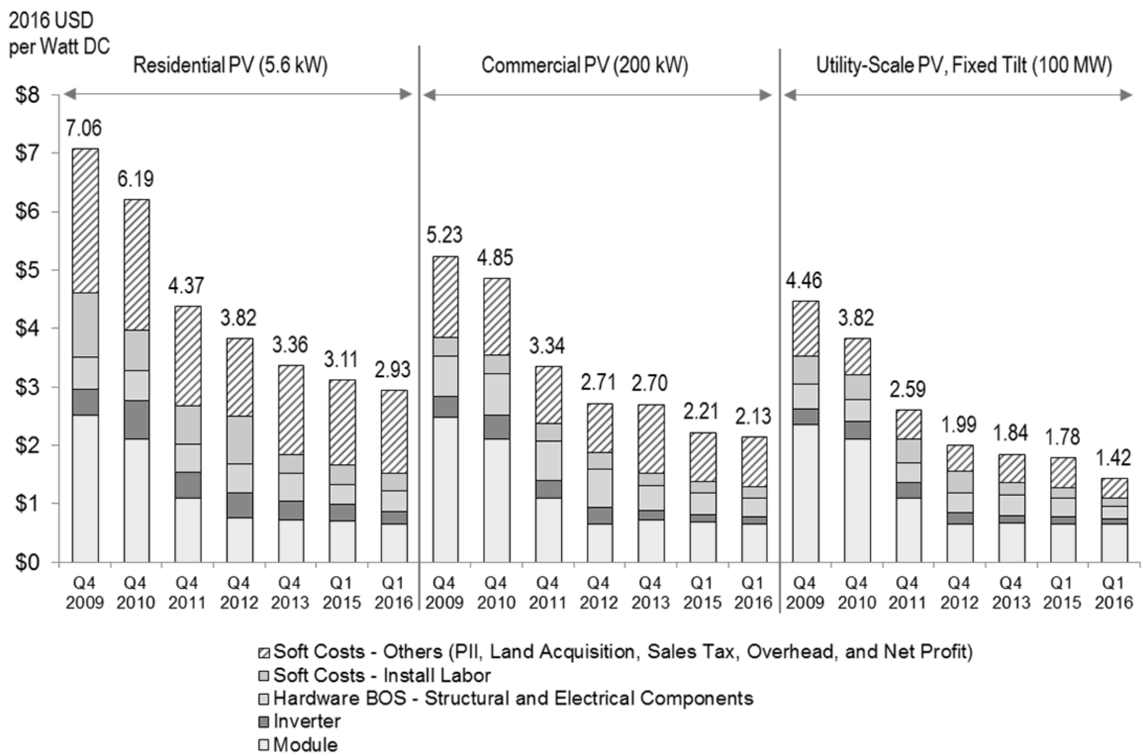

Figure 15: NREL PV system cost benchmark summary (Q4 2009- Q1 2016), (Fu et al., 2016)

California has had higher costs for residential PV systems compared to the rest of the country, even though the average cost for systems in the state have been steadily falling in the last decade. The trajectory of installed cost per watt for residential solar systems under PG&E territories can be seen in Figure 16. The chart shows the steady decline of prices during the period California solar initiative was in effect, which ended in 2014 (Lacey, 2014). The costs have fallen further in the last 3 years with the latest average of $3.89/watt(Richardson, 2017). A lower estimate is assumed for this analysis according to recent quotes for Arcata and Fresno. Moreover, labor costs and softs costs depend heavily on the place of installation. Regional solar contracters charge different prices depending on their rates.

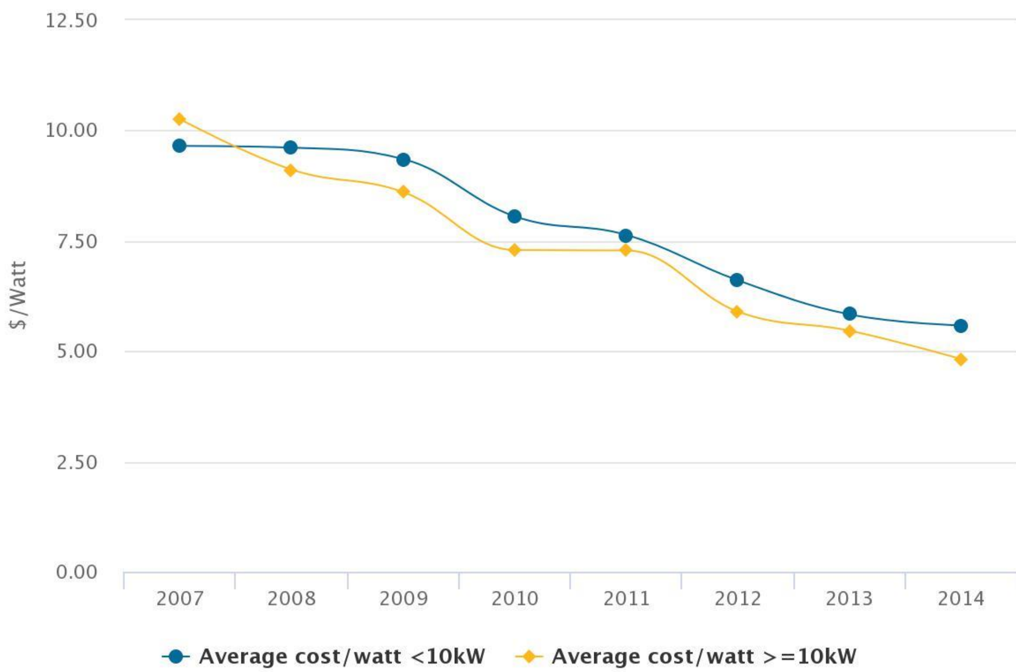

Figure 16: Installed Cost per watt over the years 2007-2014 for residential systems in PG&E territory. 2016 (“CaliforniaDGStats,” 2016

Battery assumptions

For selecting a battery to be used in a solar PV system, several things need to be considered. These include battery cost, cycle life, depth of discharge, ease of installation, and maintenance requirements. Batteries in connection with PV systems have to meet the demands of unstable grid energy, heavy cycling (charging and discharging), and irregular full recharging (Zipp, 2015). For the past years, lead acid batteries have been used in combination with PV for off-grid applications. They are cheaper than most other types of batteries, but are bulky and unsafe for indoor use. They also have high maintenance costs and require proper handling and delivery to a waste disposal facility that is equipped to handle them.

Only Lithium-ion batteries are considered for this analysis. They are costlier than lead acid batteries, but they are more suitable for solar applications. Lithium-ion batteries typically have better lifetime cycling properties, potentially reducing the number of battery replacements over a system lifetime (DiOrio, Dobos, & Janzou, 2015). Lithium-ion nickel manganese cobalt oxide (NMC) batteries similar to the Tesla Powerwall batteries were considered for this analysis, as they are deep cycle batteries which could sustain thousands of discharge cycles before experiencing considerable degradation (Liu, Xiong, & He, 2014). This analysis assumes that the battery can be cycled once daily within 0%-100% of its total capacity. It also assumes that the batteries would hold their charge for at least five extra years after their 10-year warranty period before the battery capacity degrades significantly. Fifteen years of daily cycles would mean approximately 5500 total cycles.

For this analysis, the cost assumption for the battery is $500/kWh. This assumption is supported by Deutsche Bank analysts estimates for lithium-ion batteries costs (Shah & Booream-Phelps, 2015). Cost estimates for lithium-ion batteries used for EVs are generally lower than batteries used for other electric storage purposes. Various studies show that the costs are declining faster than predicted (Evans, 2015). According to the (Nykvist & Nilsson, 2015), “Industry-wide cost estimates declined by approximately 14% annually between 2007 and 2014, from above US$1,000 per kWh to around US$410 per kWh.” Moreover, in the last 6 years, costs of batteries used in EV’s have dropped 80%, with an estimate of $227/kWh at the end of 2016(Lambert, 2017). In spite of the fast-dropping battery cost, the assumed battery cost is kept conservative at 500$/kWh. The actual cost of the entire battery storage system would be higher because there are added costs like balance of system costs, supporting hardware and software needed to manage the energy, permitting and interconnection fees, sales tax, shipping and installation. Battery system cost assumptions are shown in Table 7. Installed cost for different sizes is shown in Table 8.

Table 7: Battery system cost assumptions.

Type of cost	Value	Sources
Battery cost ($/kWh)	$500/kWh	Standard assumption in NREL studies (DiOrio et al., 2015) (Ardani et al., 2016)
Permitting fees	$500	Industry quote from Gogreensolar.com (Martin, 2017)
Interconnection fees	$250	Industry quote from Gogreensolar.com (Martin, 2017)
Balance of system costs	$500	Industry quote from Gogreensolar.com (Martin, 2017)
Installation cost	$1700	Industry quote from Gogreensolar.com (Martin, 2017) and NREL estimate(Ardani et al., 2016)
Sales tax (% of the total cost)	Arcata (8.5%) Fresno (8.25%)	(California state board of equalization, 2017)
Shipping cost (% of the battery cost)	5%	Industry quote from Gogreensolar.com (Martin, 2017)

$$Installed\ battery\ system\ cost = \Big[\Big\{\$500\left(Battery\ cost\ in\ \frac{\$}{kwh}\right) * battery\ size(kWh)\Big\} * 1.05\ (Shipping\ cost\ 5\%\ of\ total\ battery\ cost) + \$500(Permitting\ fees) + \$250\ (Interconnection\ fees) + \$500\ (Balance\ of\ System\ costs)\Big] * \{1 + sales\ tax(\%)\} + \$1700\ (Installation\ costs)$$

Table 8: Assumptions for battery capacities and prices for each case in Arcata (Ardani et al., 2016).

Case	Battery Nameplate Capacity	Price assumption
Baseline	3 kWh	$4,765
Typical	5 kWh	$5,904
High	7 kWh	$7,044
Higher	14 kWh	$11,031

Benefit cost analysis:

A benefit cost analysis (BCA) (also called cost benefit analysis or CBA) is a method of assessment which helps determine the economic feasibility of an investment or project. It is a systematic process, which involves evaluating all the possible costs related to the project and also assessing the benefits in the form of revenue or avoided costs. The two main purposes of BCA in this case are to see if the benefits of owning a PV system with storage outweighs the costs associated with installation and operation of the same and to compare the value of different sizes of systems under different scenarios.

The following was used as a basis to compare and assess the economic feasibility of the system:

The costs incurred by the system can be broadly categorized into four parts:

- Capital costs or upfront costs: These are fixed, onetime costs, which involve purchasing and installing the system. For this analysis, this is the upfront costs of the system are calculating following the steps below.

  Installed cost of the system (before tax) =

  *{Installed cost per watt ($/W) * Size of the system (W)}*

  *+ {Price of the Battery per kwh ($/kWh) * Maximum battery capacity (kWh)}*

The tax incurred on the system is dependent on local sales tax rate. The rate is multiplied with the costs to figure out the tax in its $ value.

It is assumed that the system qualifies for the ITC credit for residential renewable energy systems. It is assumed that the homeowner has sufficient tax liability to take advantage of the full rebate. Thus, the final amount is reduced by 30%, as the rebate would cover that cost.

$$Total\ cost\ without\ the\ ITC\ rebate$$
$$= \{Installed\ cost\ of\ the\ sytem(before\ tax) * (1 + Sales\ Tax\ in\ the\ region(in\ \%)\ \}$$

$$Total\ upfront\ cost$$
$$= Total\ cost\ without\ the\ ITC\ rebate - 30\%\ federal\ tax\ rebate$$

- Operational and Maintenance (O&M) costs: After installation, PV systems keep producing electricity with no operational costs, although occasional maintenance and up keep is need to maximize production. According to NREL’s estimates, for fixed (without tracking) PV systems under 10 kW, estimated annual O&M costs are about $21/kW installed(NREL, 2016a).

- Energy costs: For cases in Arcata, the PV system is sized to cover approximately 90% of the electric consumption. For Fresno, the PV system is sized to offset approximately 95% of the consumption. Which means, under most circumstances, there would still be an annual bill for energy costs. Even if energy export credits completely offset for the energy charges, the customer is still responsible to pay for the minimum bill amount and NBC. As the PV system degrades over time, the difference between production and consumption would widen and thus more electricity would be needed to be purchased from the grid every year. This value keeps increasing every year. The energy costs would also be dependent on the electricity price escalation and the rate of degradation.

- Replacement costs: Inverters and batteries have a minimum of 10 years of warranty. For this analysis, they are assumed to last an extra five years. Inverter and battery replacement costs are incurred on year 15 of the system. Battery replacement cost is assumed to be $200/kwh in the future, sometime around 2032. Inverter costs are assumed to fall by 33% over the next decade (Taylor, Ralon, & Ilas, 2016). The current price of inverters considered for this analysis is approximately $500/kW, so the cost of inverter replacement 15 years from now is assumed to be $300/kW. Replacement costs for battery and inverter are calculated separately, as there is no literature for future prices of battery systems that come with an inbuilt inverter.

The economic benefits of the system are in form of energy costs that are avoided because of having a PV system and on site storage to maximize self-consumption. There are also other benefits to owning a battery system such as reducing carbon emissions, avoided peak charges, and increasing independence from the grid. However, the latter benefits are difficult to quantify as a direct financial benefit, and, therefore, they are not considered for the analysis.

The avoided energy costs are dependent on the total electric consumption of the household and energy prices. The annual savings for each year keeps increasing with rising electricity prices. The avoided energy costs are calculated relative to a BAU case, which would be an absence of PV system where total load is fulfilled from grid electricity under the ETOU-A rate. All the assumptions for the BCA are listed below in Table 9.

Table 9: Assumptions for BCA analysis

Parameter	**Assumed value**
Life of the system	30 years
Installed cost per watt for PV systems	$3.10/W
Cost of lithium ion battery pack per kwh	$500/kWh
Sales tax: Arcata	8.50%
Sales tax: Fresno	8.23%
ITC Rebate	30%
Maintenance costs	$21/kW-yr
Discount rate or interest rate	3%
Annual degradation in PV performance	0.5%/yr
Electricity price escalation rate (above inflation)	2.6%
Price of electricity (varies according to TOU rates)	ETOU-A rates

There are several methods to assess the economic feasibility of a project. This analysis uses the following methods to evaluate the value of a potential project.

Net Present Value (NPV):

NPV is generally the best economic method for assessing economic feasibility and is most consistent with value maximization. NPV is measured by taking a difference between the total present value of all the benefits and costs. The present value is the value of a future cash stream discounted at the appropriate market interest rate, which is called the discount rate (Chen, 1996). Homeowners with no debt or only a mortgage have a much lower discount rate than the national average (Coughlin & Cory, 2009). The discount rate is assumed to be 3% for this analysis, which is also the default value in NREL's Levelized Cost of Energy Calculator (NREL, 2016a).

Payback Period:

The payback period is defined as the time it takes for an investment or project to generate an amount of benefits that are equal to the initial cost of investment. A simple payback period does not account for the time value of money and thus does not accurately depict if the project is economically feasible. Thus a discounted payback period is used to demonstrate the results, as it accounts for the time value of money and the calculation is based on the discounted cash flows.

The following section displays annual cost savings for various scenarios and the results of the BCA.

RESULTS

First, before examining the results for the systems that include battery storage, it is important to establish what would be the costs under a business as usual (BAU) scenario.

Business as Usual Costs

BAU is where the customer purchases all their electricity from the grid under a ETOU-A rate structure. As discussed above, the consumption for each case varies. Table 10 shows values for the electricity costs incurred for each case.

Table 10: Energy costs under Business as usual scenario for Arcata.

Cases	**Arcata**	**Fresno**
Baseline	$705	$1,046
Typical	$1,215	$1,782
High	$1,724	$2,519
Higher	$3,762	$5,466

If we observe the composition of these charges incurred under the TOU rate structure, it is evident that charges during peak demand periods are a major part of the cost. Peak charges are approximately 30% of the total for Arcata and 37% for Fresno. Peak hours are 3 PM - 8 PM which is only 5 hours out of the 24 hours, but almost a third of the daily cost occurs during peak hours. Figures 16 and 17 show the share of the bill that is associated with energy use during peak and off-peak rate periods.

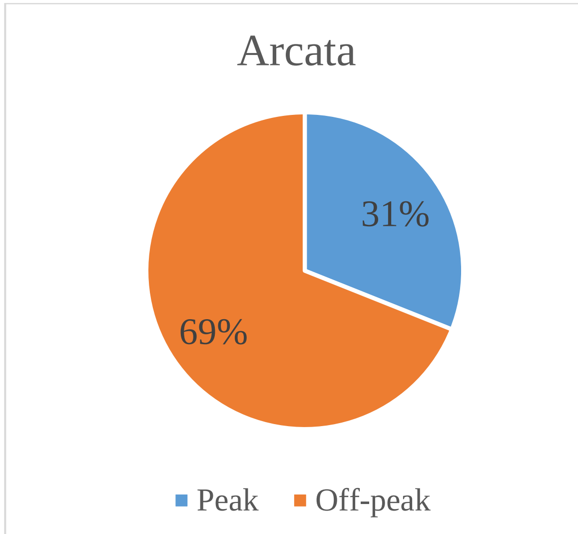

Figure 17: Composition of BAU cost for Arcata.

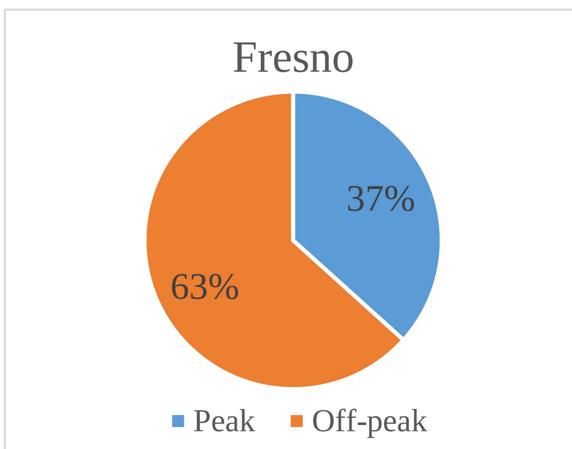

Figure 18: Composition of BAU cost for Fresno.

The next few analysis scenarios use battery storage to eliminate or minimize the peak charges and maximize self-consumption.

Annual Savings from Avoided Energy Costs

Results for Arcata:

This section includes results for annual savings calculations for all cases for Arcata. The system parameters and assumptions which were previously mentioned in Tables 4, 5, 6, and 7 are synthesized below in Table 11 for reference. The PV systems are sized to offset electricity consumption by 90%, and battery storage is sized to offset the peak period usage.

Table 11: System parameters and assumptions for Arcata

	PV array size (kW)	**Battery size**	**Consumption**
Baseline	2.5	3	1x baseline
Typical	3.75	5	1.5x baseline
High	5	7	2x baseline
Higher	10	14	4x baseline

The energy costs and savings for each case can be seen in Table 12. In cases where the energy costs are less than the minimum bill, the annual cost incurred would be the minimum bill amount ($120). Refer to Appendix C for load fulfillment graphs for all the residential systems scenarios for Arcata.

Table 12: Annual energy costs and savings

	BAU Energy Costs	**PV and Battery System Energy Costs**	**Savings**	**Energy produced (kWh)**
Baseline	$705	$122	$584	3,217
Typical	$1,215	$144	$1,071	4,825
High	$1,724	$192	$1,532	6,434
Higher	$3,762	$414	$3,349	12,868

Results for Fresno

A similar analysis was performed for the location of Fresno; the cases are similar to Arcata, but the system parameters differ. The assumptions for consumption levels are the same as discussed before for Arcata, and the values for baseline quantities and assumption values can be verified from Tables 4 and 5. The PV array is sized so that the production offsets consumption by approximately 95%. The battery is sized so that it could get charged from extra PV energy and could supply enough energy during the peak hours. Table 13 shows the system parameters for reference.

Table 13: System parameters and assumptions for Fresno

	PV array size (W)	**Battery size**	**Consumption**
Baseline	2.75	4	1x baseline
Typical	4.2	6	1.5x baseline
High	5.5	7.5	2x baseline
Higher	11	15	4x baseline

The annual savings were calculated for the location of Fresno in the same way as for Arcata. As it can be seen in Table 14, the savings for Fresno are higher than those of Arcata. This is due to the higher consumption levels for Fresno. Moreover, the savings are directly proportional to the BAU cost. Energy production is higher for Fresno compared to Arcata for similar system sizes. This is because Fresno receives more solar insolation due to better weather conditions and clearer skies.

Table 14: Annual Energy costs and savings for Fresno

	BAU Energy Costs	PV and Battery System Energy Costs	Savings	Energy produced (kWh)
Baseline	$1,046	$157	$889	4,599
Typical	$1,782	$156	$1,626	7,024
High	$2,519	$246	$2,273	9,198
Higher	$5,466	$492	$4,974	18,395

Benefit Cost Analysis Results for Arcata

The benefit cost analysis for all four cases for Arcata are presented in Table 15. All the NPVs are positive at the discount rate of 3% except for the baseline case. The LCOE for all cases ranges from $0.11/kWh to $0.13/kWh, which is lower than the cost of grid electricity under every tariff plan.

Table 15: Net present value, internal rate of return (IRR) and payback periods for all the cases in Arcata

Case	NPV	IRR	Simple Payback Period (yrs)	Discounted Payback Period (yrs)	LCOE
Baseline	-$1,516	2%	24.7	30+	$0.13
Typical	$5,185	6%	17.0	21.0	$0.12
High	$10,885	7%	12.3	17.7	$0.12
Higher	$31,908	9%	10.5	12.6	$0.11

The baseline case has the highest payback period because the BAU costs are not that big to begin with. Thus, the savings are low and cannot justify the up-front cost for the system. For all other cases the payback period is under eight years, which shows that the systems could be economically feasible.

A similar benefit cost analysis was performed for systems in Fresno. Results for the BCA for Fresno are shown in Table 16.

Table 16: Net present value, internal rate of return (IRR) and payback periods for all the cases in Fresno

Case	NPV	IRR	Simple Payback Period (yrs)	Discounted Payback Period (yrs)	LCOE
Baseline	$3,689	5%	17.0	21.3	$0.10
Typical	$16,737	10%	9.7	11.5	$0.09
High	$25,780	11%	8.8	10.3	$0.09
Higher	$67,126.73	14%	7.5	8.6	$0.08

When we compare the BCA results for the two sites, we see that the economics are better in Fresno than in Arcata. Figure 19 compares the discounted payback periods for all four cases for the two locations of Fresno and Arcata. The payback periods for Fresno are shorter than those for Arcata. This shows that the system would be more economically feasible at locations like Fresno, which generally has higher levels of electricity consumption and an abundant solar resource. A similar assumption can be made while looking at the NPV for the systems in Figure 20, which shows that systems in Fresno have a higher NPV even though upfront costs would be higher due to bigger PV arrays and higher battery storage sizes.

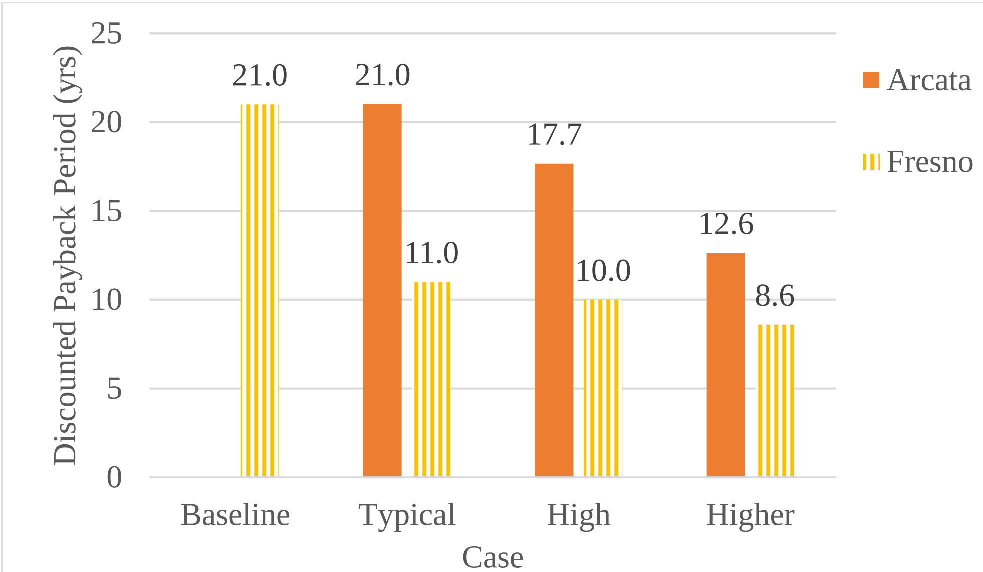

Figure 19: Comparison of the discounted payback period for Arcata and Fresno in years.

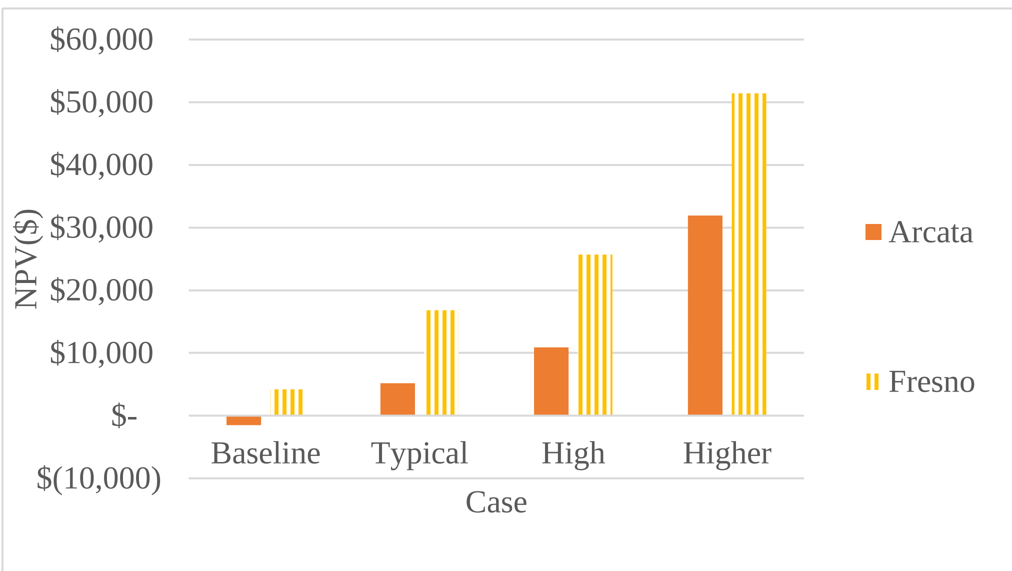

Figure 20: Comparing NPV for Arcata and Fresno.

The LCOE values displayed in Figure 21 for Fresno range from \$0.08/kWh to \$0.10/kWh, while the LCOE value for Arcata range from \$0.11/kWh to \$0.13/kWh. A lower LCOE amount shows that the PV energy from this project will be that much less expensive.

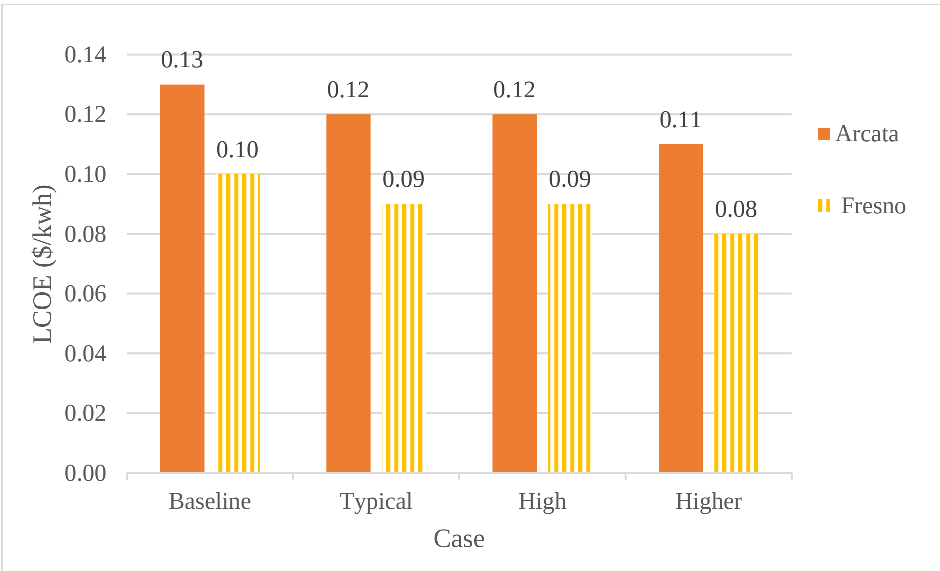

Figure 21: LCOE Comparison between Arcata and Fresno.

SENSITIVITY ANALYSIS

This section shows how some of the parameters and metrics influence the feasibility of the project. Battery costs and cost of solar PV are dropping every year. Moreover, the tariff plans and net metering structures are expected to change significantly over the next few years. The following sections try to estimate how these factors would affect the value of the system. The sensitivity analysis is performed only for two out of the four cases for the sake of simplicity. Most of the results vary almost linearly with system size.

Monthly Analysis

The scope of the analysis can be expanded further to better understand how storage could help save money. Currently consumption and production are both averaged over the period of TOU summer and winter months. Thus, the values are highly generalized and may not accurately represent daily values. For example, the TOU winter period is from October 1st to May 31st, which means the values were averaged over 8 months. During these 8 months, weather conditions and load profile changes significantly, which is ignored in this analysis. Variations in the monthly load profile for Arcata (high consumption case) are shown in Figures 22 and 23, below. The analysis is only used to show how the values change among months and, thus, it is only performed for Arcata. Accounting for these variations could improve the resolution of the results and give a better sense of the savings associated with the use of a PV system with (or without) a storage battery.

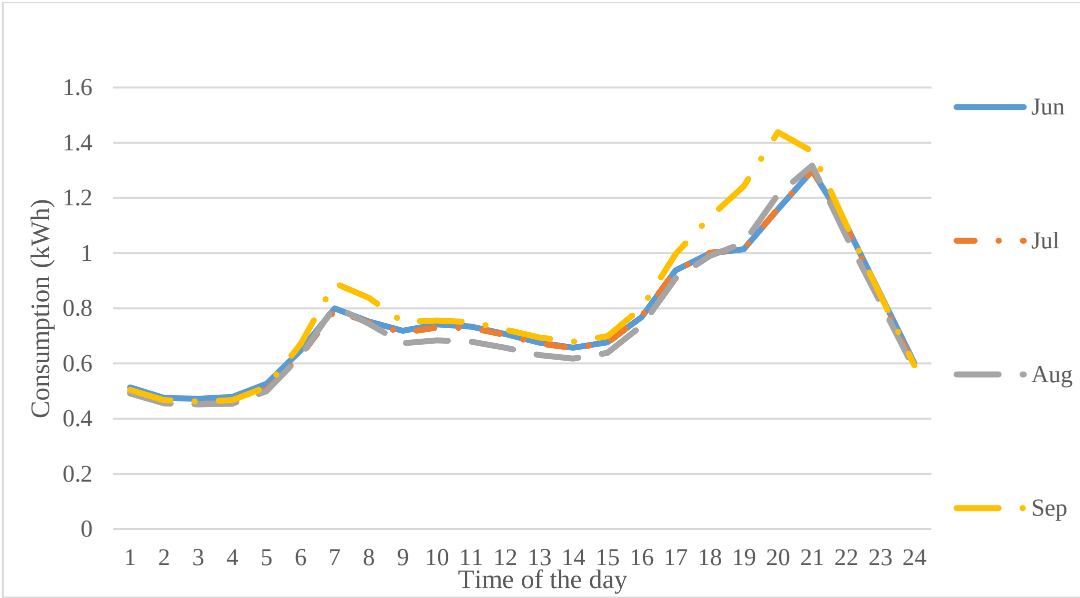

Figure 22:Arcata electricity load profile for summer months in Arcata for a typical load.

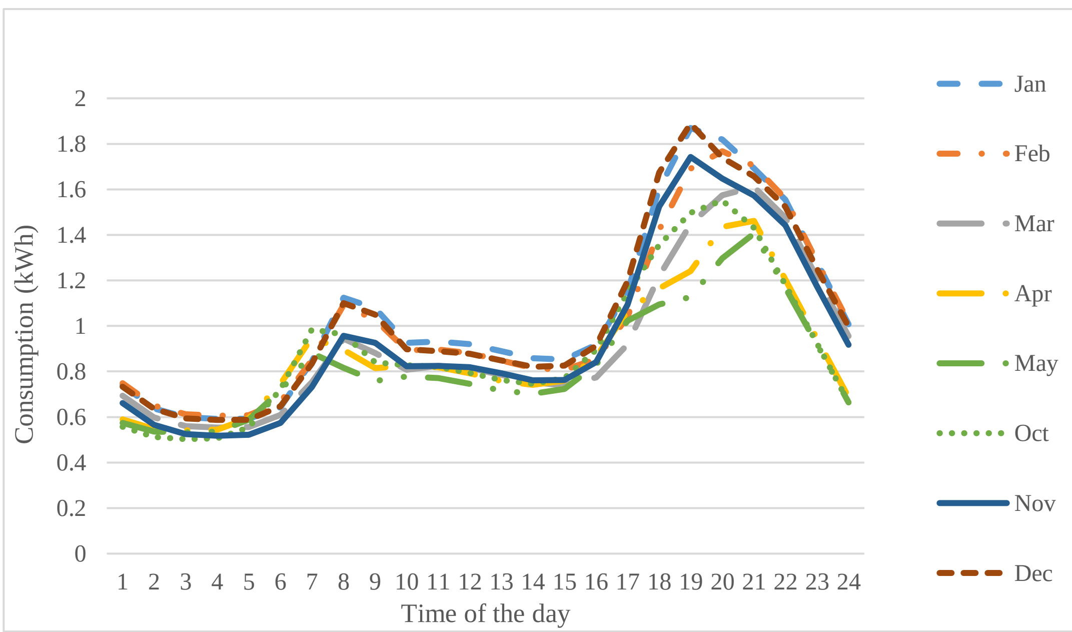

Figure 23: Arcata load profile for winter months in Arcata for a typical load.

Generation of energy from the PV system would also vary with seasonal changes, and availability of the solar resource is highly dependent on the time of the year. Figures 24 and 25 show how PV generation changes for one of the cases in Arcata

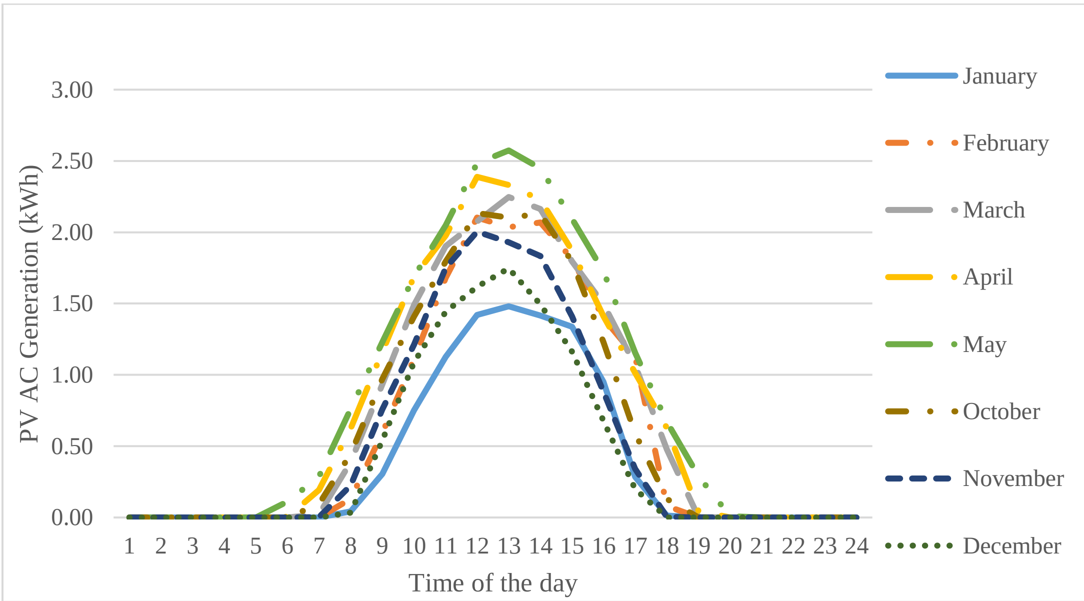

Figure 24: Representation of Hourly PV generation for each month of the TOU winter period in Arcata for the typical load case.

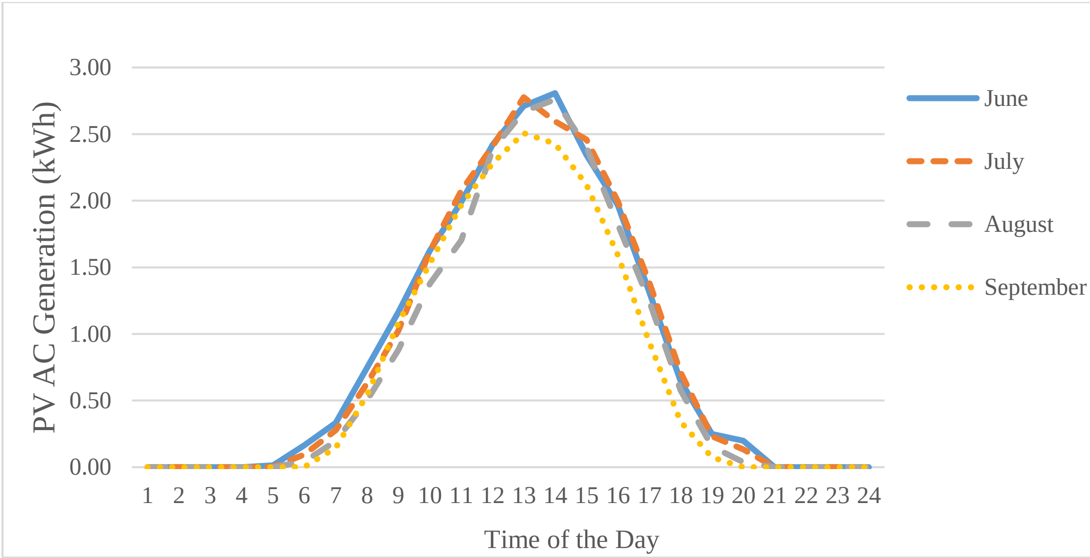

Figure 25: Representation of Hourly PV generation for each month of TOU summer period in Arcata for the typical load case.

The seasonal analyses to calculate annual energy costs and savings are done based on TOU periods. It is assumed that all months in the given period (June-September or October-May) have the same consumption, PV generation, and energy management strategies. A similar analysis is performed on a monthly basis to see how the results would change. The monthly analysis should better reflect the effects of monthly changes in available solar insolation and consumption. The data for load profile and PV generation are averaged for each month of the year. The energy management strategy is not changed so the results could be compared with the seasonal analysis. The annual energy cost comparison is shown in Table 17, and it can be seen that the energy costs are almost the same for both cases. Due to the energy costs and saving being almost equal, the BCA was not performed for the monthly analysis results.

Table 17: Comparison of energy costs results for a monthly analysis and seasonal analysis for two cases in Arcata

	PV array size (kW)	Annual BAU Energy Cost	Annual PV and Battery System Energy Costs (monthly analysis)	Annual PV and Battery System Energy Costs (seasonal analysis)
Typical	3.75	$1,215	$143	$144
High	5	$1,724	$195	$192

Varying Battery Price

As discussed in the section on battery assumptions, the cost of lithium-based batteries is declining quickly. However, for systems in places where lithium batteries are not widely used, and shipping or overhead costs are high and battery costs might still be higher than the assumed values used in this analysis. In the case of the systems under consideration (battery costs at $500/kWh), batteries constitute approximately 20% of the total PV and battery system cost. As the battery cost is varied from $200/kwh to $1000/kwh, that share fluctuates from 8% to 30% of the total costs. Figures 26 to 29 show how NPV and discounted payback period changes with battery prices for Arcata and Fresno. The analysis is done for battery prices of $200/kwh, $350/kwh, $500/kwh, $750/kwh and $1000/kwh. The results are displayed for Arcata first and then Fresno.

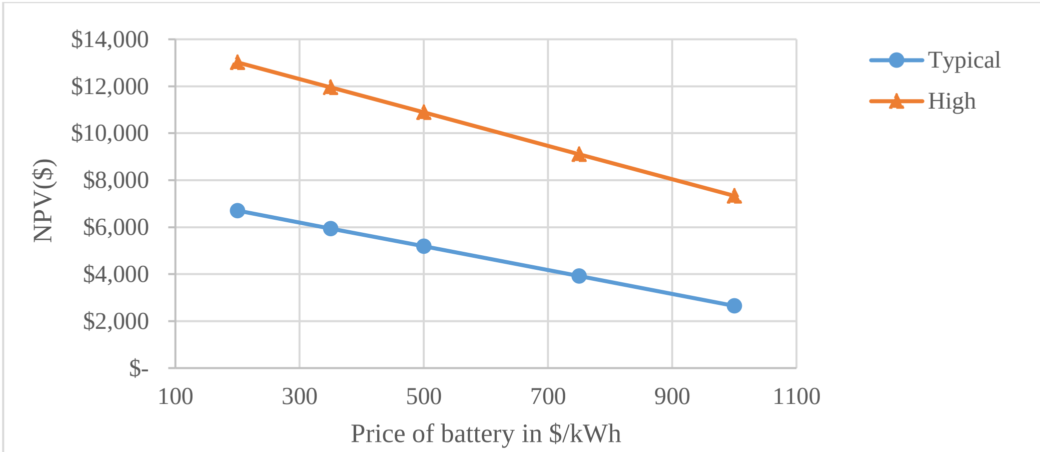

Figure 26: Net present values for varying battery prices for Arcata.

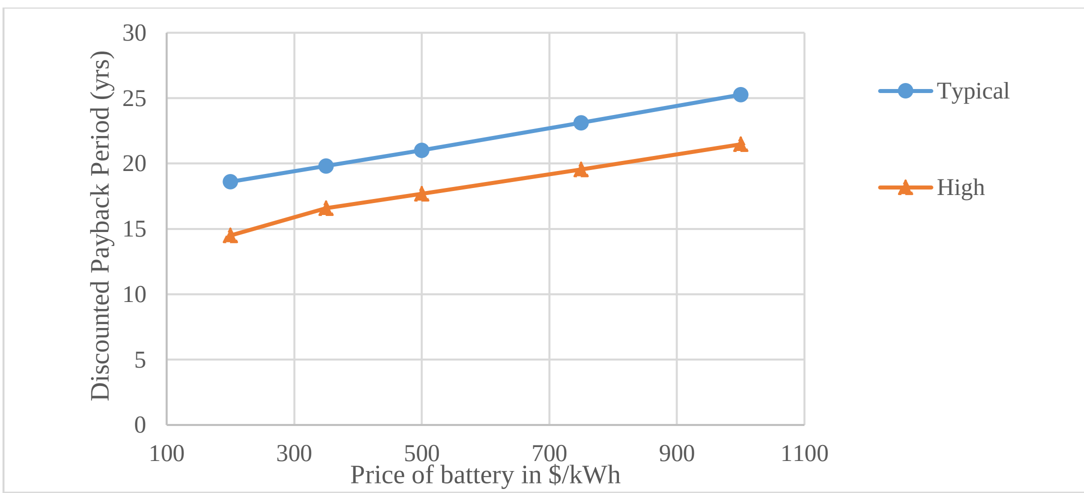

Figure 27: Discounted payback period for varying battery prices in Arcata.

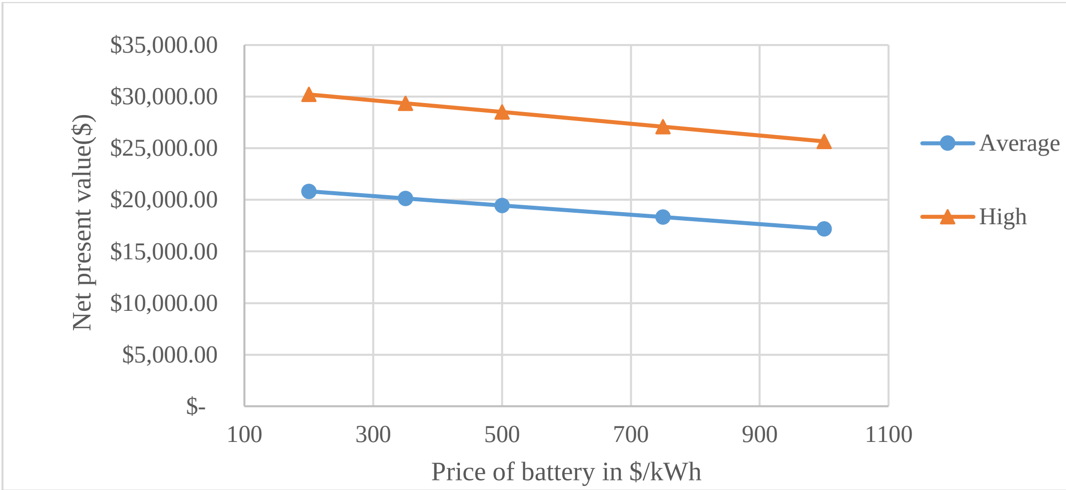

Figure 28: Net present value for varying battery prices for systems in Fresno

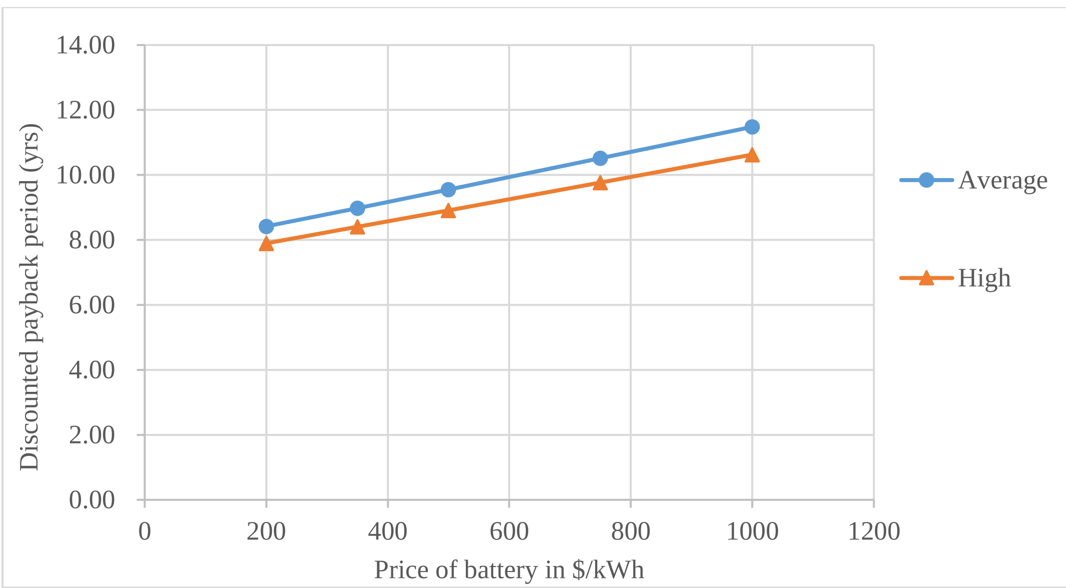

Figure 29: Discounted payback period for varying battery prices for systems in Fresno

For both locations, NPV and payback period does not change very rapidly with battery price. NPV approximately increases by $3-4 for a $1/kwh decrease in battery price.

Meanwhile the payback periods increase by approximately two years with ever step increase of the battery prices.

Varying Discount Rates

The net present value of any project depends highly on the assumed discount rate. Figures 30 and 31 show how NPV changes with changes discount rate.

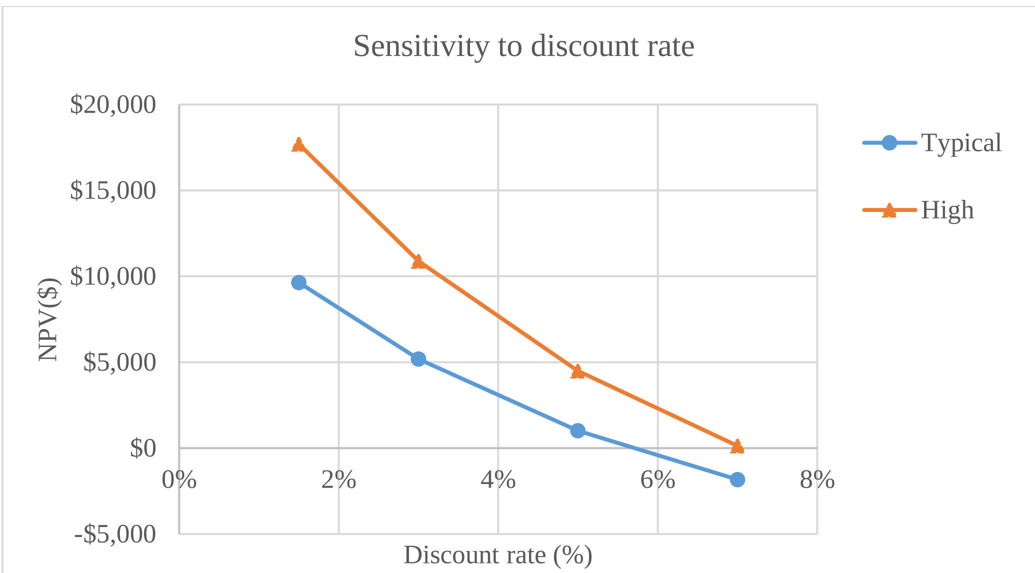

Figure 30: Net present values (NPV) for varying discount rates for Arcata

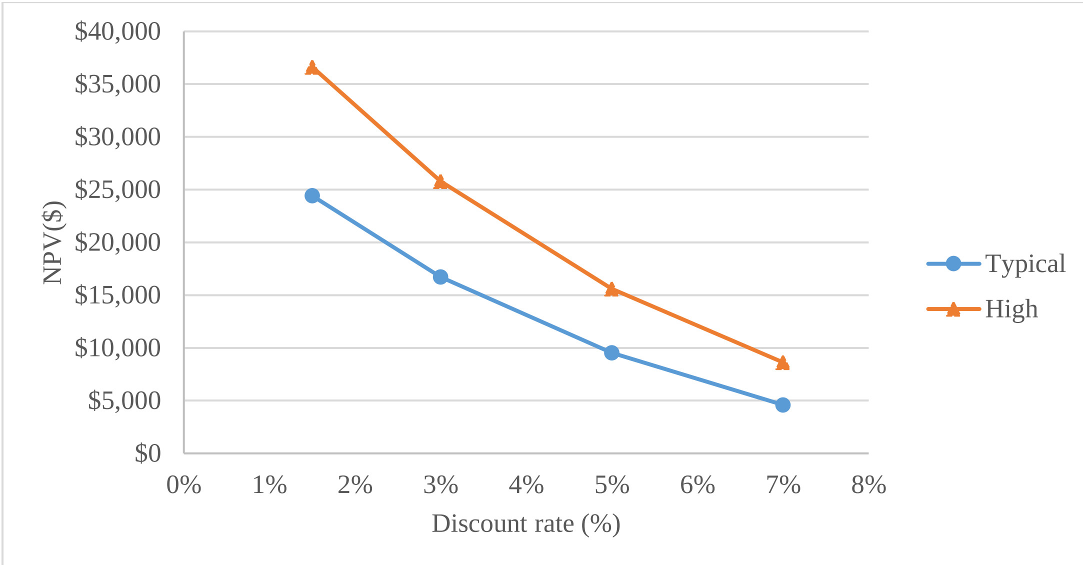

Figure 31: NPV values for varying discount rates for Fresno

Varying Installed Cost per Watt for PV Systems

The installed cost per watt for solar PV systems keeps changing, but it broadly follows a downward trend. The main analysis presented in this document assumed a conservative rate of $3.10/watt for an installed PV system, although some places might have a higher or lower cost depending on a variety of factors. This is the most important parameter that dictates the cost effectiveness of a PV and battery system. Figures 32 and 33 show how NPV and payback period changes with changes in installed cost per watt.

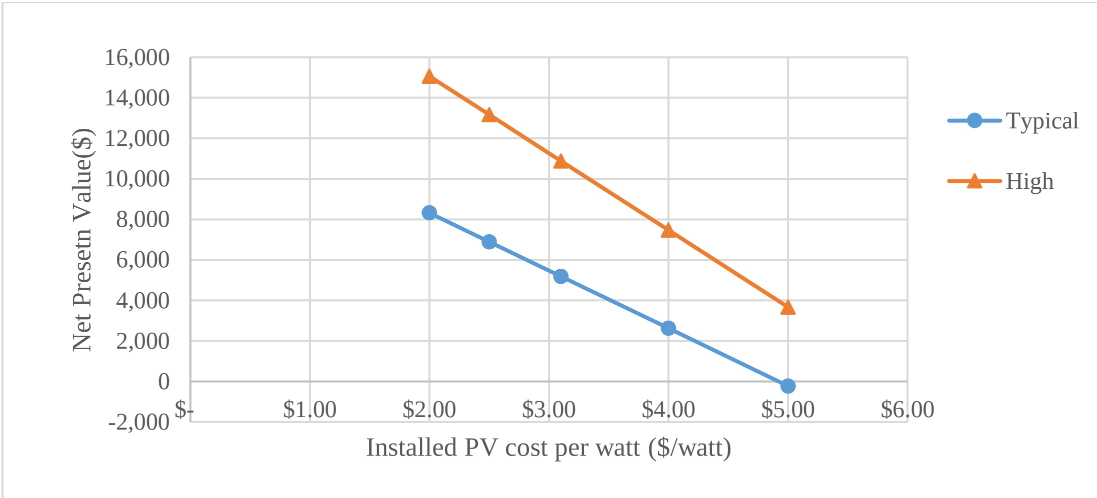

Figure 32: Net present value for varying installed cost per watt of PV for Arcata.

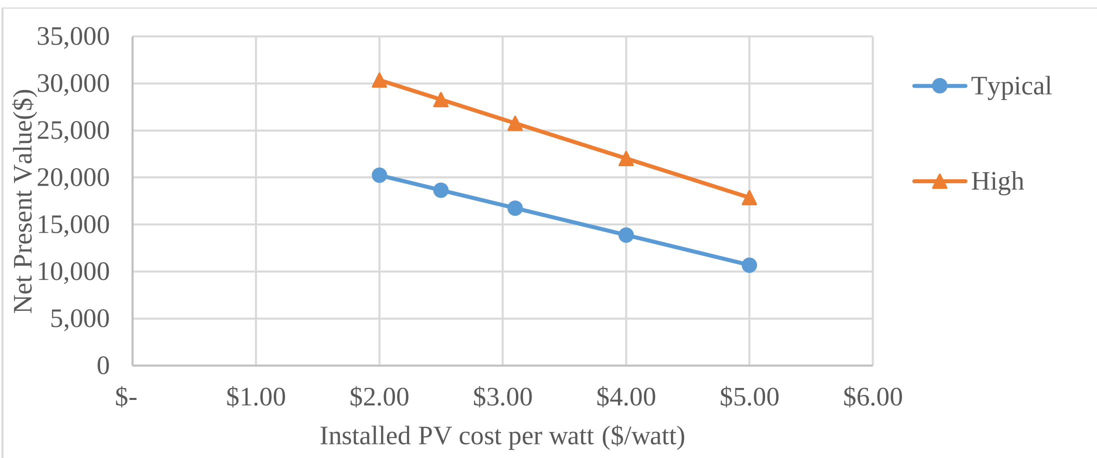

Figure 33:Net present value for varying installed cost per watt of PV for Fresno

Varying Time of Use Plan

The energy cost savings depend heavily on how the TOU rates are designed. Currently the price differential between peak and off-peak rates is not very substantial to generate an incentive to shift load through a battery. The peak period is also shifting to later time periods. This section shows results for two different scenarios relating to TOU rates:

1. Increased price differential: In this scenario, peak rates are 30% higher than the off peak rates. The comparison between current TOU rates and the higher peak rates are shown in Table 18.

Table 18: Comparison of current TOU rates with a hypothetical TOU rate that involves a higher price differential between peak and off-peak rates.

Time period	**Current TOU**	**Hypothetical TOU Rate with an Increased Price Differential**
Summer Peak rate	$0.39	$0.51
Summer Off-peak rate	$0.32	$0.32
Winter Peak Rate	$0.28	$0.36
Winter Off-Peak Rate	$0.26	$0.26

2. Peak period of 4pm-9pm: Current assumed plan ETOU-A has a peak period of 3pm-8pm. Under this plan, an early portion of the peak period coincides with the time when PV generation is sufficient to fulfill the load. However, the peak periods are estimated to shift to lower times, so the analysis was repeated for a peak period of 4pm-9pm.

The results for BCA and the comparison can be seen in Tables 19 and 20 for Arcata and Tables 21 and 22 for Fresno. As discussed previosly, the anaylis is only repeated for the cases of typical and high loads.

Table 19: Comparison between different TOU scenarios for typical case in Arcata

	NPV	IRR	Discounted Payback (years)
Current TOU	$5,185	6%	21.1
TOU with increased price differential	$12,157	8%	14.4
Peak hours 4pm-9pm	$4,988	6%	21.3

Table 20: Comparison between different TOU scenarios for high case in Arcata

	NPV	IRR	Discounted Payback (years)
Current TOU	$10,885	7%	17.7
TOU with increased price differential	$18,400	9%	12.1
Peak hours 4pm-9pm	$10,623	7%	17.8

Table 21: Comparison between different TOU scenarios for Typical case in Fresno

	NPV	IRR	Discounted Payback (years)
Current TOU	$16,737	10%	11.5
TOU with increased price differential	$24,635	12%	9.3
Peak hours 4pm-9pm	$15,890	10%	11.8

Table 22: Comparison between different TOU scenarios for high case in Fresno

	NPV	IRR	Discounted Payback (years)
Current TOU	$25,780	11%	10.3
TOU with increased price differential	$35,588	14%	8.5
Peak hours 4pm-9pm	$24,635	12%	9.3

It can be seen from comparisons that NPV increases by almost 50% when the price differential is wider and peak rates are higher than the current TOU. Even the payback period decreases by 2 years, so the systems would pay off for themselves faster. However, shifting the time period by an hour does not change the results much. It does have NPV slightly lower than the current TOU and the payback period increases. However, the price differential has a larger effect on the outcome than and small shift in the timing of the peak period.

Comparison Between PV Systems With and Without Storage.

Most existing residential PV systems do not include a battery or any other storage systems. The majority of those systems use the electric grid as storage. As a result, all the extra PV energy which is not consumed internally is exported to the grid. Likewise, energy is drawn from the grid during times when the solar generation is smaller than the load. An analysis presented below indicates that systems with battery storage generate only minimal savings compared to the PV systems without storage. The net savings and energy bills for cases that involve PV systems with and without storage are very similar while the installed cost of the system increases by 33% - 50% when storage is included. Tables 23 and 24 contains values for energy costs for PV systems with and without storage on a TOU rate. These values assume that customers are compensated for energy exported to the grid at the retail rate, which is consistent with the PG&E’s current NEM 2.0 policy.

Table 23 Comparison of savings between PV systems with and without storage on the ETOU-A rate for Arcata.

	PV Array Size	Annual BAU Energy Cost	Annual PV System Bill w/o Storage	Annual PV System Bill with Storage
Typical	3.75	$1,215	$146	$144
High	5	$1,724	$194	$192

Table 24: Comparison of savings between PV systems with and without storage on the ETOU-A rate for Fresno

	PV Array Size	Annual BAU Energy Cost	Annual PV System Bill w/o Storage	Annual PV System Bill with Storage
Typical	4.2	$1,782	$219	$170
High	5.5	$2,519	$322	$263

The energy costs reported in Table 23 assumes that the customer receives retail rate compensation for the electricity they export. According to proposals submitted to CPUC, IOUs wants to lower the NEM compensation rate significantly. PG&E suggested a compensation rate of approximately $0.097/kWh for exported energy (CPUC, 2016). As the NEM arrangement is up for reconsideration in 2019, a lower compensation rate is expected for exported energy. The results of an analysis to estimate energy costs if the exported energy is compensated at $0.097/kWh and the PV system does not have battery storage are presented in Tables 25 and 26. In this analysis, NBCs are neglected because the exported energy is charged at a much lower rate. It is also assumed that the plan would still offer a baseline credit. The savings for systems with storage increase under a reduced compensation rate scenario, but they are still very small compared to the added costs of a battery system.

Table 25:Comparison of energy costs at a reduced export compensation rate for Arcata.

	PV Array Size	Annual BAU Energy Cost	Annual PV System Bill w/o Storage	Annual PV System Bill with Storage
Typical	3.5kW	$1,215	$601	$343
High	5kW	$1,724	$802	$457

Table 26: Comparison of energy costs at a reduced export compensation rate for Fresno.

	PV Array Size	Annual BAU Energy Cost	Annual PV System Bill w/o Storage	Annual PV System Bill with Storage
Typical	4.2 kW	$1,782	$855	$514
High	5.5 kW	$2,519	$1,147	$712

After looking at all the results and sensitivity analyses, there are some major trends that can be observed which are discussed in detail in the next chapter.

DISCUSSION

Following are some main takeaways and key findings from this analysis.

- There is not much incentive to oversize the PV array. As discussed before, NEM customers have a minimum bill amount to pay. Thus, even if the system owner completely offsets their usage, they still have to pay the minimum bill amount. Moreover, there is not much economic benefit to over-generate. If a customer has credit left at the end of the year they are compensated at the wholesale rate, which is a fraction of the retail rate. Oversizing the system might make sense for large commercial scale generation system, but residential customers do not benefit from it.

- There are still several challenges for deployment of battery storage for residential use. The economics of storage depend highly on the utility tariffs and NEM arrangement. NEM 2.0 is still very favorable to PV, but it does not have any special incentives for storage. The successor tariff preserved the retail rates for exported energy, which means it is more lucrative to export energy than self-consume. In addition, it is notable that CPUC has declined to allow the IOUs to impose demand charges on NEM 2.0 customers. Adding storage to the system could have reduced the demand charges if they were imposed.

  The price differential under the current TOU rate plans is not large enough to make storage a viable investment to avoid energy consumption during periods with peak rates. A storage-specific tariff plan that has large price difference between peak and off-peak rates would encourage customers to shift their loads, as they have the ability to do so with a battery on site and it could save them money. According to the NEM arrangement for PG&E, standalone battery storage does not qualify and has to be paired with an energy generation system.

- Going forward, distributed generation system owners may prioritize self-consumption due to following reasons.
    - Utilities want to reduce the compensation rate for exported electricity. CPUC's decision on NEM2.0 is up for reconsideration in 2019. A revised policy could introduce lower rates which would reduce the value of PV energy.
    - System owners might want to use more of their own clean solar energy instead of grid electricity. Even though the PG&E grid mix is comparatively cleaner than most utilities, a significant portion of it comes from fossil fuel sources. If the customer prefers to not buy any electricity from the grid and still stay connected, they have an option to do so with a larger PV system and a bigger battery.
    - The gradually shifting peak periods (currently 3PM-8PM) does not completely coincide with PV production. PV production starts declining in the

evening when electricity rates are the highest. Energy stored in batteries could help avoid electricity purchases during peak rate periods.

- The comparison between the cost savings for PV systems with and without storage shows that adding a battery to an existing system under the current NEM structure and TOU would not generate any significant savings for the owner. The investment might make more sense if NEM customers were to get a lower rate for their exported energy, but that change may not happen for a few years. So under the current tariffs, the benefits of avoiding energy use during peak rate periods will not generate measurable financial gains and will not justify the up-front cost of the batteries.

  Adding a battery to an existing system can make better financial sense if the Self-Generation Incentive Program (SGIP) can be utilized. The incentive structure is complex and tiered, and the exact amount for SGIP cannot be predicted due to how those funds are allocated. Thus the rebate is not considered for this analysis. It could be useful to perform an analysis under several different incentive value scenarios, which could make battery systems much more attractive than paying full costs for them.

- The comparative analysis between the results for Arcata and Fresno demonstrates that the economic feasibility of PV systems with storage vary significantly with location. The solar resource, baseline use levels, load profile, amount of consumption, and tax rates all can be influenced by the location of the installed system.

There are several factors that affect the results for the two locations considered in this study. Arcata is coastal town with relatively higher rainy and cloudy days. It also has lower daily consumption than most places. Electric consumption is higher is the winter compared to the summer. It mostly remains cool through the summer, and, thus, most customers do not use air conditioning. Winter has heating loads due to lower temperatures during a few months. Due to these factors, the baseline quantities are higher in the winter than in the summer for Arcata. Due to weather conditions, the solar electricity generation is the lowest during a few winter months. During those times, the peak use periods occur when there is little or no PV energy generated, which increases the energy bill.

In contrast, Fresno is a flatland area which is more than a hundred miles inland from the coast. It has an abundant solar resource, and customers in the region also have a higher level of electricity consumption. Due to its weather conditions, customers have a higher level of consumption during summer months because of cooling loads and lower consumption in the winter months. In general, PV systems are more favorable in Fresno because, during the summer months, their highest load period and highest production period coincide. As a result, net electricity use during peak periods can be reduced with a solar PV system.

CONCLUSION

Solar technologies have flourished in the past few decades, especially in California. For years, the intermittency of solar and a lack of viable storage options have been hindrances for their expansion. Recently developments in storage technologies and market investment in storage options create a potential solution for these issues.

The purpose of this analysis was to gauge the economic viability of integrating batteries into residential PV systems. Currently lithium ion batteries have the best potential to be paired with residential PV systems. The Tesla Giga factory, when completed, could mass produce lithium batteries at affordable prices and generate completion in the market which could drive the prices down. Even with falling prices for battery storage, the analysis presented in this thesis indicates that there is not much motivation to add a battery to an existing PV system. However, California has incentives and regulations in place to encourage adoption of storage systems, but it might need more targeted efforts to make distributed storage more viable.

Because of the changing electric rates and net metering regulations, in the near future it could make more sense to incorporate battery from the start, although significant changes to the tariff structure would be needed to make batteries more attractive.

Under current TOU rates and NEM, there are not a lot of short-term financial benefits to adding storage to PV compared to systems without storage. The battery system costs are still high and generate no additional savings making them a poor financial investment.

Battery storage could still help with resiliency, maximize self-consumption and give backup power, but these additional benefits are not considered in the financial analysis conducted in this thesis. So, to conclude, unless there are any major changes to TOU price differential and NEM compensation rate, adding battery storage is not be a significant cost saving tool for customers who already have PV systems and are under the current NEM.

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APPENDIX A- Load profiles

The following are typical load profiles for the locations of Arcata and Fresno during the TOU seasons of winter (October-May) and summer (June-September).

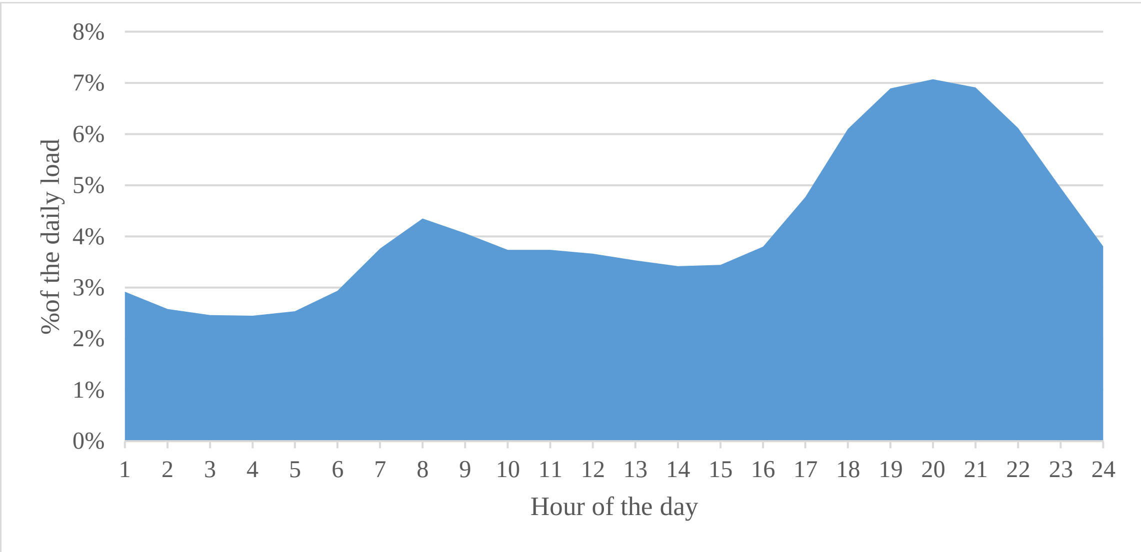

Figure A1: Arcata load profile for winter months (October to May)(Office of Energy Efficiency & Renewable Energy (EERE), 2013)

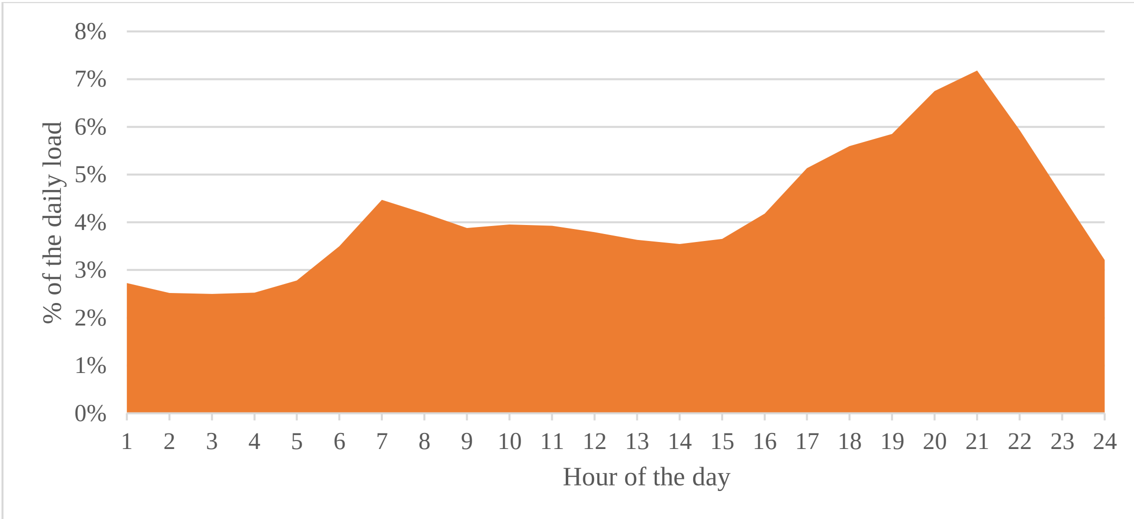

Figure A2: Arcata load profile for summer months (June to September) (Office of Energy Efficiency & Renewable Energy (EERE), 2013)

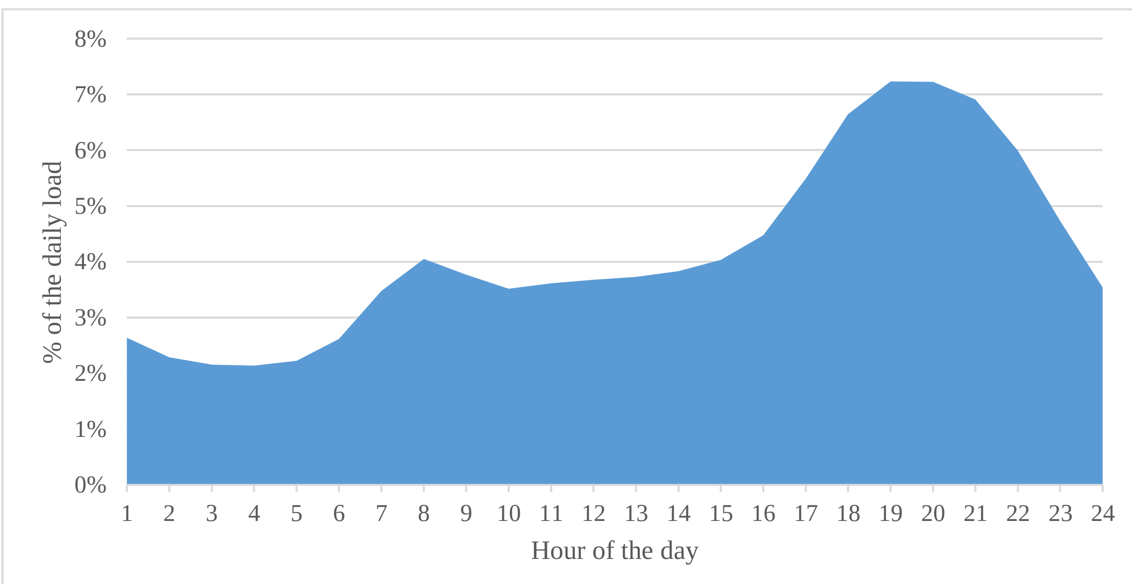

Figure A3: Fresno load profile for winter months (October to May) (Office of Energy Efficiency & Renewable Energy (EERE), 2013)

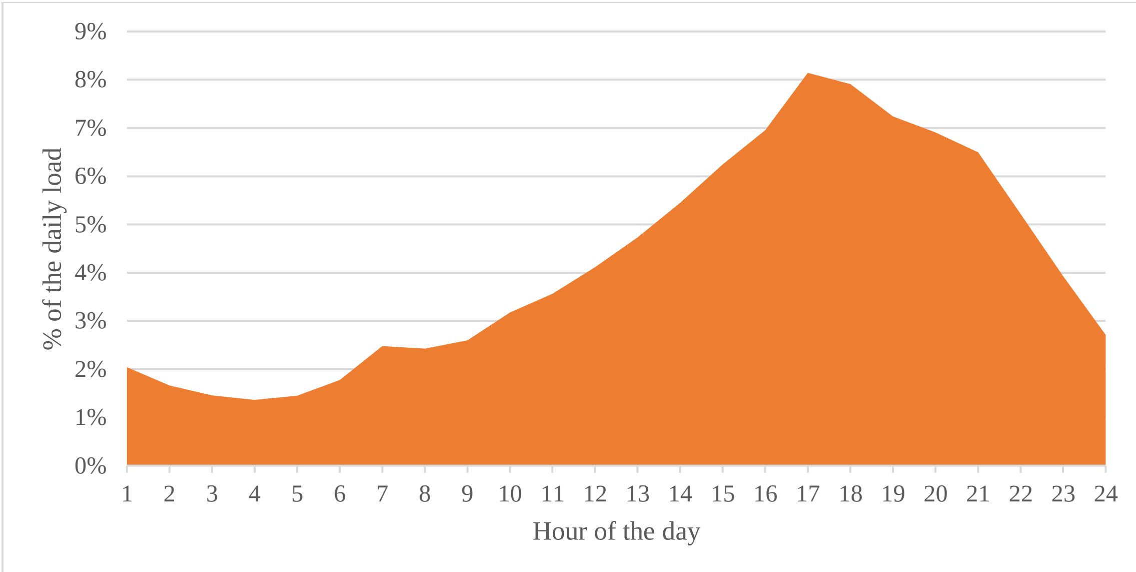

Figure A4: Fresno load profile for summer months (June to September) (Office of Energy Efficiency & Renewable Energy (EERE), 2013)

APPENDIX B-Technical Specifications

Below are some technical specifications for the assumed components for the system.

Table B1: Technical Specifications for Fronius Symo Hybrid (Fronius, 2015)

TECHNICAL DATA	**FRONIUS SYMO HYBRID**
Power classes	5.0, 6.5, 8 kW AC
Number of DC connections (PV)	2
Max. efficiency (PV - grid)	97.8%
Max. efficiency (PV - battery - grid)	>90%
DC input voltage range	150 V - 1000 V
Grid connection	400 V / 230 V or 380 V / 220 V and 45 - 65 Hz
Degree of protection	IP 65
Dimensions (width x height x depth)	645 x 431 x 204 mm
Weight	19.9 kg.
Inverter design	Transformerless
Cooling	Regulated air cooling
Installation	Indoor and outdoor installation
Ambient temperature range	-25 - +60°C
Max. input current	1 x 16 A
Max. short circuit current, module array	24 A
Feed-in start voltage	200 V
Max. AC output current	8.3 A
Usable MPP voltage range	150 - 800 V

Table B2: Technical Specifications for Tesla Powerwall 2 (Tesla Energy, 2016)

Technical data	**Tesla Powerwall**
Usable Capacity	13.5 kWh
Depth of Discharge	100%
Efficiency	90% round-trip
Power	7kW peak / 5kW continuous
Supported Applications	Solar self-consumption, Time of use load shifting, Backup Off grid
Warranty	10 years
Scalable	Up to 10 Powerwalls
Operating Temperature-	4° to 122°F / -20°C to 50°C
Dimensions	L x W x D: 44" x 29" x 5.5"(1150mm x 755mm x 155mm)
Weight	264.4 lb / 120 kg
Installation	Floor or wall mounted Indoor or outdoor
Certification	North American and International Standards Grid code compliant

APPENDIX C- Load Fulfillment Graphs

This appendix shows load fulfillment graphs for each case in Arcata. The load is fulfilled by a combination of energy from the PV array, battery system and the grid. The following figures show how the load is fulfilled.

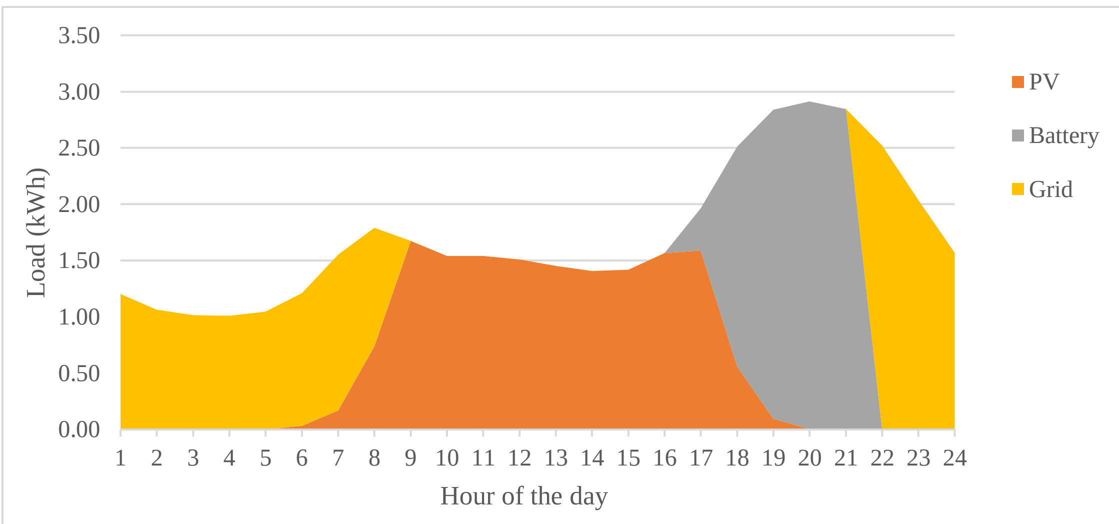

Figure C1: Arcata Winter Load Baseline Case

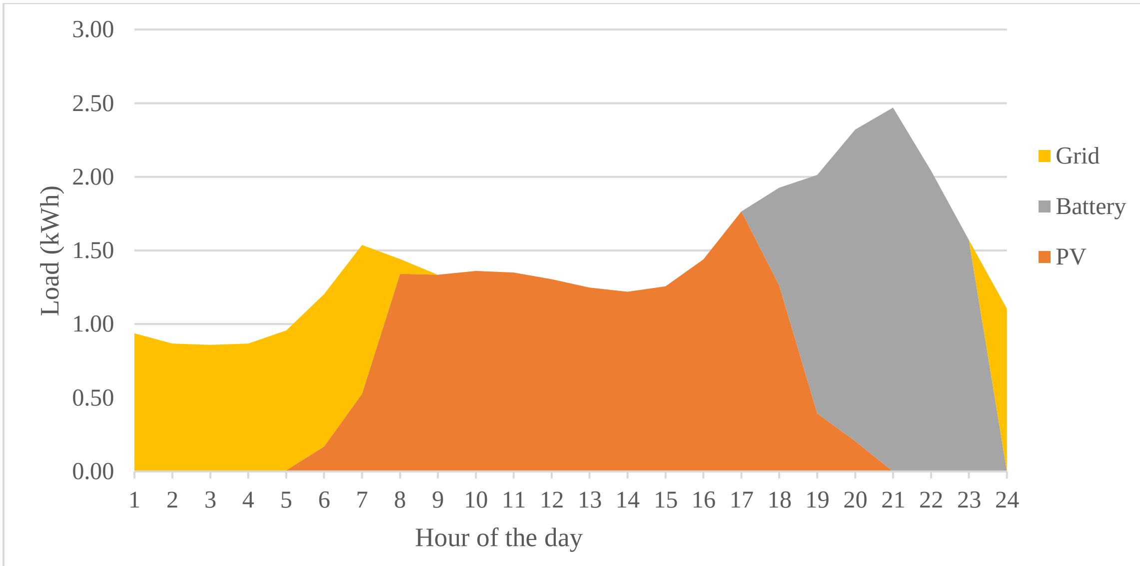

Figure C2: Arcata Summer Load Baseline Case

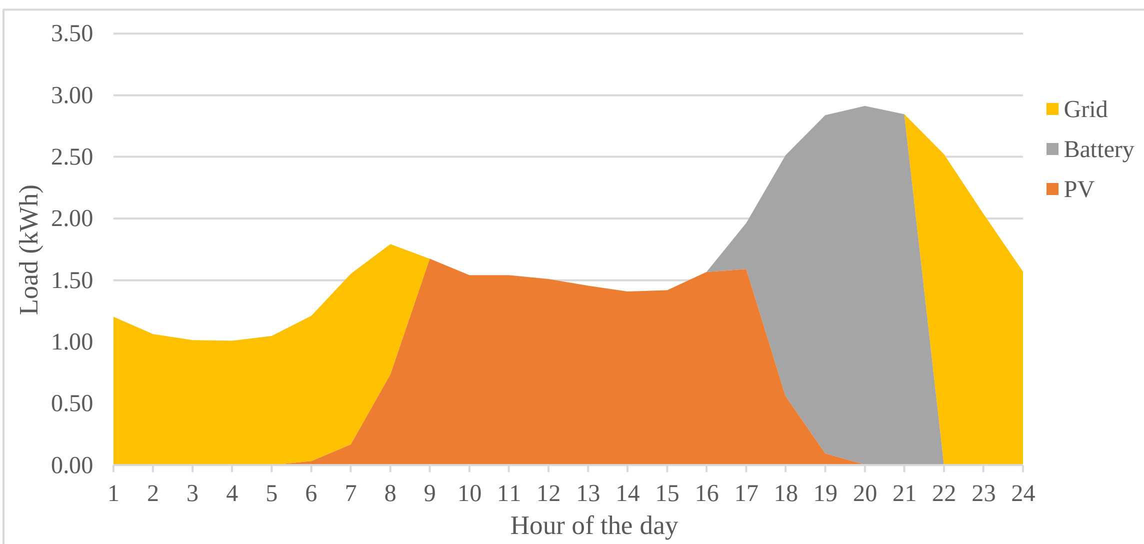

Figure C3: Winter Load Typical Case

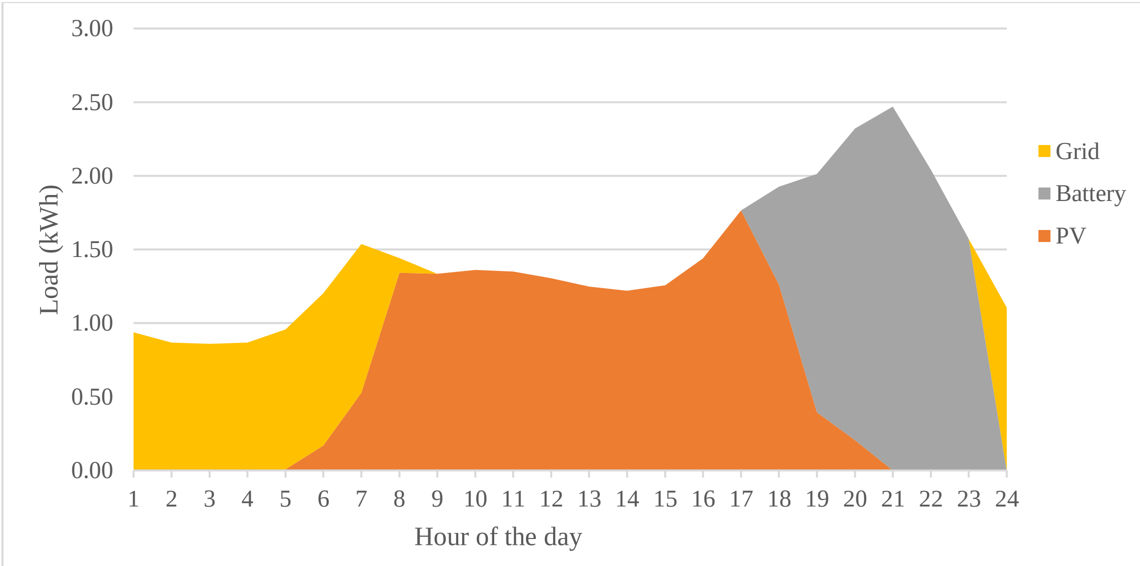

Figure C4: Arcata Summer Load Typical Case

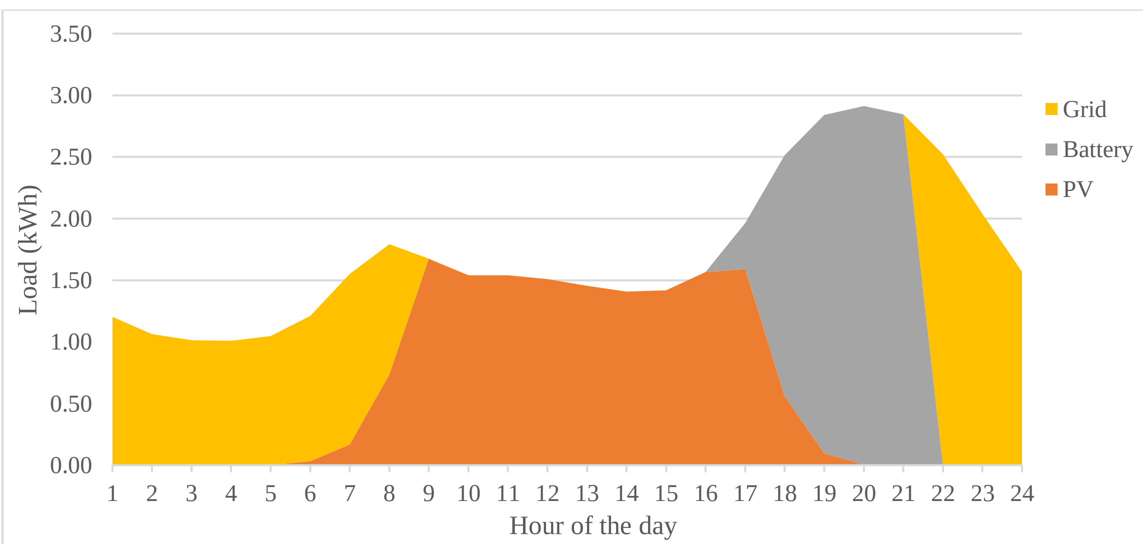

Figure C5: Arcata Winter Load High Case

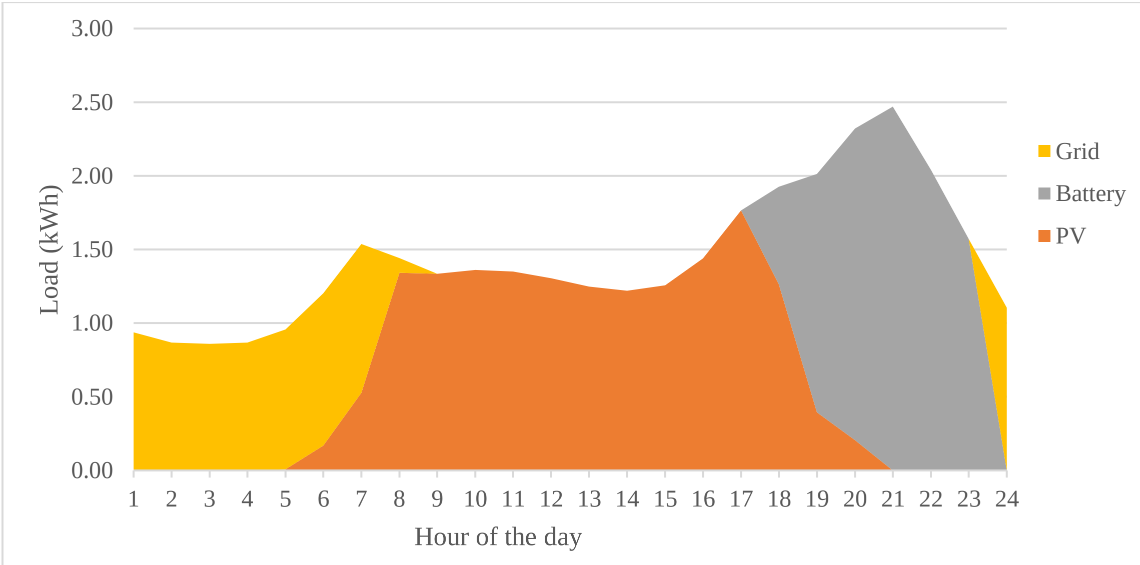

Figure C6: Arcata Summer Load High Case

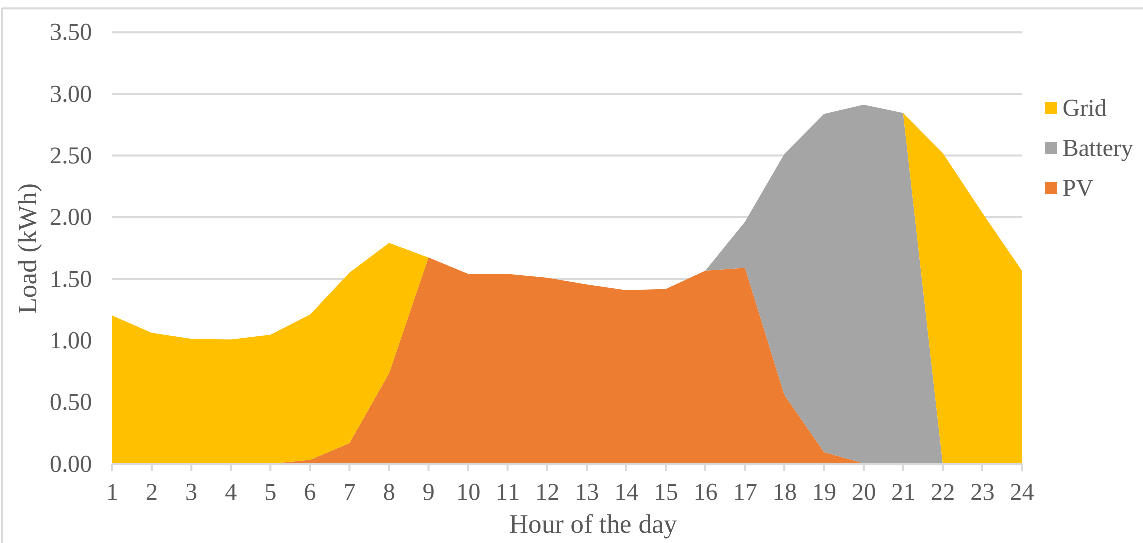

Figure C7: Arcata Winter Load Higher Case

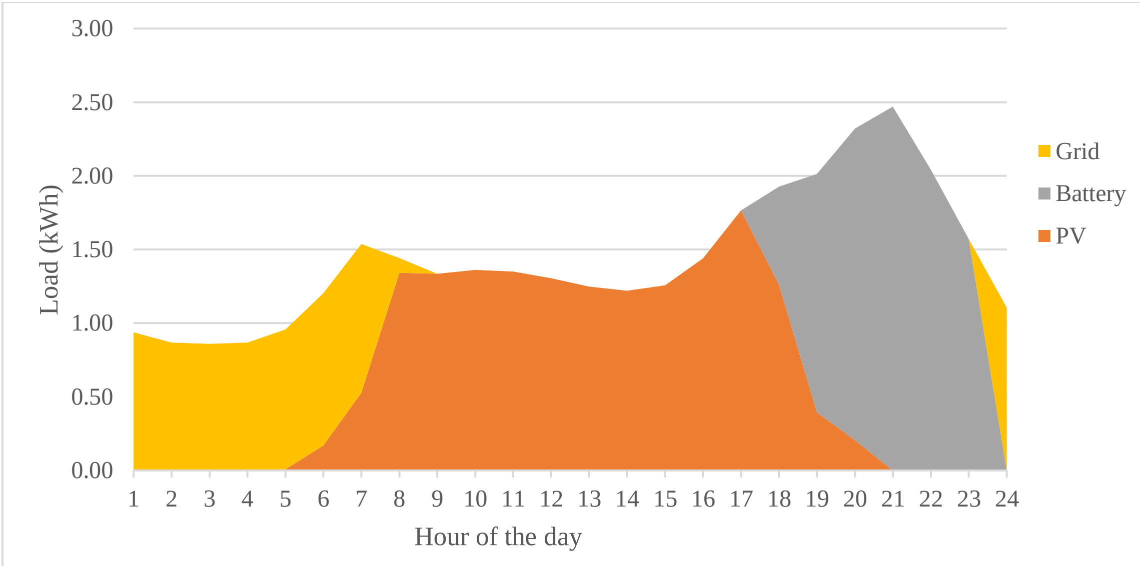

Figure C8: Arcata Summer Load Higher Case