Behind-the-Meter Battery Market Study

DR19SDG0002 Report

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Prepared for:

Emerging Technology Program
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EXECUTIVE SUMMARY

This is a market study for behind-the-meter (BTM) battery energy storage systems (BESS) located at customer premises within San Diego Gas & Electric's (SDG&E's) service territory. Supporting data for this study were gathered through online and phone interviews with vendors, online customer surveys, and through secondary market research. Analysis and benchmarking of the gathered data was supported by in-depth dynamic systems modeling. Battery manufacturers, integrators, and installers participated in our survey and supplied details on their market activities today, as well as predictions for how they anticipate market activities will evolve through 2030.

PROJECT GOAL: Accurately characterize the distributed BESS market in San Diego, forecast future market growth, and anticipate economic and programmatic implications for SDG&E, as well as other regulated utilities operating in California.

TECHNOLOGY DESCRIPTION: We analyzed representative BESS operating behavior for residential and non-residential (commercial) BESS technology, with and without solar photovoltaics (PV), where time-of-use arbitrage, demand-charge management (DCM), and backup power represent the leading applications and customer value propositions.

PROJECT FINDINGS: Distributed BESS currently deployed are not being used to the full advantage nor benefit of customers, utilities, service providers, or society at large. While the total *potential* value of BESS technology is projected to be large, the total *observable* net economic benefits remain relatively small, in spite of significant growth potential (see Table 1). This appears to be due to many complicating factors, including:

- Insufficient or confusing market signals
- Incomplete knowledge and access to information
- Nonexistent supervisory communication and controls
- Misaligned customer-utility benefits and values
- Noncompetitive economically as backup-power solution

TABLE 1. BEHIND-THE-METER BESS SIMPLE PAYBACK AND MARKET-GROWTH FORECASTS OVER 10 YEARS

	SOLAR+STORAGE PAYBACK IN 2019 (YEARS)	SOLAR+STORAGE PAYBACK IN 2030 (YEARS)	TOTAL BESS CAPACITY IN 2019 (MW)	TOTAL BESS CAPACITY IN 2030 (MW)
Residential	7.9	5.1	14	288
Commercial	9.0	5.7	27	519

PROJECT RECOMMENDATION: Consider developing new market signals and services in partnership with vendors and other industry stakeholders.

ABBREVIATIONS AND ACRONYMS

BESS	Battery energy storage system
BTM	Behind-the-meter
DCM	Demand-charge management
DER	Distributed-energy resource
DR	Demand response
EV	Electric vehicle
FTM	Front-of-the-meter
PEA	Power Efficiency Agreement
PV	(Solar) Photovoltaic
RE	Renewable energy
RPS	Renewable portfolio standard
SGIP	Self-Generation Incentive Program
TOU	Time-of-use (rates)
VoV	Voice-of-vendor (survey)
VPP	Virtual power plant

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INTRODUCTION

Energy storage technologies – and battery energy storage systems (BESS) in particular – have become increasingly popular across global markets over the last five years. BESS technology is now commonly hailed as a panacea solution to help address numerous problems with legacy electric grids. In practical applications, unforeseen factors often limit the useful value that can be derived from BESS technology in the field. The intention of this study is to define and characterize the gap that exists between potential and actual benefits, estimate the future potential of the emerging behind-the-meter (BTM) BESS market, and identify promising opportunities for future products, services, and programs.

The potential benefits that BESS technology can theoretically deliver to support electric grid operations and utility customers are well-characterized and include:

- Increased utilization of renewable energy (RE)
- Lowered customer utility bills
- Lowered electricity carbon intensity
- Resilience in the form of distributed backup power
- Grid services like frequency regulation and peak-demand management
- Deferred upgrades or extensions to legacy electric grids

Electric utilities and other energy industry stakeholders have understood the potential of BESS technology to deliver both customer- and grid-side benefits for many years. However, it is only within the last five years that perceived benefits have been broadly accepted as worth serious consideration, relative to implementation cost and complexity. This change in perception is due in large part to improvements in technology performance, as well as rapidly declining battery and power electronics equipment costs, spurred by growth in the global electric vehicle (EV) market. This change is also being driven by a greater popular awareness and subsequent urgency around the need for action in response to climate change, including the adoption of policies and regulations aimed at curtailing negative impacts. As countries, states, cities, and large corporations move to adopt increasingly aggressive renewable portfolio standards and carbon-neutrality goals, viable energy storage solutions are needed to address RE intermittency, integration, and procurement challenges.

These three factors – *improved performance*, *lowered costs*, and *societal urgency* – are fueling what some have referred to as a global "battery arms race[1]," where dozens of battery manufacturers worldwide are now scaling up production to meet future demand. As a result, scaled battery cell production volumes are placing downward pressure on system costs. Just five years ago (in 2014) no battery manufacturer owned or operated a battery "megafactory," i.e. a factory capable of producing 1 gigawatt-hour (GWh) of battery cell

[1] Benchmark Mineral Intelligence (2019). EV Battery Arms Race Enters New Gear with 115 Megafactories, Europe Sees Most Rapid Growth. Mountain View, CA

energy storage capacity each year. Following Tesla's 2014 announcement that it would build Gigafactory 1 outside of Reno, NV beginning in 2015, every major (and some minor) battery manufacturer quickly took notice and followed suit. Today, there are roughly 100 battery megafactories worldwide, as well as plans to build several more and larger facilities over the coming decade. However, even though this race was instigated by an American company, Tesla remains the only major "battery arms race" competitor in North America.

The other major event that accelerated growth of the battery market in North America was the Aliso Canyon gas leak of 2015. With an estimated 97,000 tons of methane leaked into the atmosphere over a four-month period, insufficient delivery of natural gas to Southern California Edison's (SCE's) power plants placed strain on the local electric grid. In response, the California Public Utilities Commission (CPUC) mandated the procurement of several megawatts of battery storage, creating an immediate scaled demand for BESS technology that had not existed before the gas leak. This first round of scaled BESS procurement and deployment took the form of mostly large, centralized, utility-scale storage.

Today, many progressive utilities agree that centralized, front-of-the-meter (FTM) battery storage – like the BESS projects deployed in Southern California following the Aliso Canyon gas leak – represents a valuable new grid resource. At the same time, there is less agreement among utilities about the extent to which distributed BESS are necessary to the future of grid modernization. This lack of consensus is understandable when we consider the fact that BTM batteries are more expensive per unit of storage capacity deployed, and also much more difficult to monitor and control, as compared to centralized battery banks. At the same time, the primary value batteries deliver to utility customers – *resiliency in the form of backup power during a grid outage* – is not a benefit that large centralized batteries can easily deliver. As a result, the priorities of utility BESS deployment are often not aligned with those of utility customers. At the same time, a growing number of utility customers are deploying BESS units for their own reasons, irrespective of utility activities and priorities.

The incumbent technology used by customers for backup power is the engine-driven generator, typically powered by natural gas, gasoline, or diesel fuel to produce onsite electricity during grid outages or power-quality disturbances. High-end residential generators are 5-to-10 times less expensive than the current installed cost of a home battery system. Generators also don't need to be installed by a professional electrician, can be easily purchase at retail stores across North America, and are often portable, making them more versatile for use in numerous end-use applications. Conversely, generators are relatively noisy compared to batteries, produce hazardous localized emissions, pose a water contamination risk where fossil fuels are spilled, and may cost more to operate than a BESS unit. While the useful operating life is comparable, generators tend to be easier to operate, especially at high-power output over extended periods without interruption.

While residential generators are commonly used for backup power in rural and off-grid environments or at construction sites, they are less commonly used to power homes in urban and suburban environments. By contrast, grid-connected battery storage has recently become more common than off-grid batteries, and is being adopted in both urban and rural environments, though almost exclusively by mid-to-upper income customers. Until batteries reach cost parity with engine-driven generators – or until rate structures make energy arbitrage more attractive for residential customers – the demand for residential batteries may not expand far beyond the early-adopter market.

SCOPE OF MARKET STUDY

This study seeks to better understand both the residential and non-residential BTM battery market in SDG&E's territory. Our residential-focused research seeks to uncover the current and future state of the market in SDG&E's territory, understand key drivers for market uptake and expansion, and identify opportunities for SG&E to play a central role in this emerging market.

Specifically, this project seeks to understand the following market characteristics as they pertain to BTM battery storage in SDG&E's service territory:

- Number and size of BTM batteries
- Vendors active in the San Diego area
- Battery end-use applications and usage patterns
- Demographics of early commercial and residential adopters
- Impact of rates on customer benefits
- Battery charge-management behavior
- Rate of market growth through 2030

This market study draws from a number of new and preexisting information resources, including first-person interviews with numerous industry stakeholders (e.g. manufacturers, system integrators, contractors, installers, consultants, engineers, sales directors). This study also draws from numerous recent market studies, program evaluations, industry announcements, and program databases characterizing installed BTM batteries in California.

BASELINE MARKET CONDITIONS

Baseline market data indicates that commercial battery installations represent more overall capacity but far fewer projects relative to residential battery systems. At the same time, growth in commercial installations began to slow in 2016 and has yet to recover, while growth in residential system adoption picked up significantly in 2017 and continues on a steady growth trajectory. While we do not have perfect insight into why this is happening or if the available data accurately characterizes BTM battery market activity across all of California, insights gained from our market analysis point to a shift toward more-aggressive sales in the residential market and more-stringent safety requirements for commercial customers installing BESS. We elaborate on both of these factors – as well as the growth potential for both market sectors – throughout the body of this report.

INCENTIVES AND MARKET GROWTH

We anticipate that commercial BESS growth will continue to outpace residential BESS growth in total aggregate capacity through 2030. For residential BESS, we anticipate that Self-Generation Incentive Program (SGIP) incentive availability will not play a significant role in the continued growth of annual installations, but that the expiration of the Investment Tax Credit (ITC) in 2022 will significantly impact BESS adoption. On the commercial side, SGIP funding will play an important role in near-term adoption.

BACKGROUND

This section contains background information about key factors shaping today's BTM battery market, including a brief history of battery market maturation in North America, the emerging technology field study upon which we built our commercial battery analysis, and the questions that remained unanswered following the field study.

BATTERY MARKET MATURATION

Lithium-ion battery chemistries are leading growth in today's energy storage market. These battery chemistries have the advantage of high power- and energy-densities relative to alternative chemistries, making them popular for portable consumer electronics. However, for many years the relatively high cost of manufacturing these batteries, combined with safety concerns around chemical instability, stood in the way of expanding into large-format applications like transportation electrification or bulk energy storage for the grid.

Today, Lithium-ion batteries have become the favored storage technology with significant potential for nearly all applications in mobile and grid storage, as demonstrated by the market activities of dozens of manufacturers. More major battery manufacturers are now targeting development of this technology than any other. An entire family of battery chemistries fall under the umbrella of "lithium-ion," so no single company or group owns exclusive rights or patents—a situation that could otherwise slow market growth.

Historically, electrical fires caused by failures in thermal management have prompted significant safety concerns for lithium-based battery chemistries, especially for large storage systems. Advances in materials science, design, manufacturing, packaging, management, and monitoring have all combined to help reduce these fire risks and alleviate some safety concerns, though we are not entirely out of the woods yet on the issue of battery safety. More than a dozen large fires in South Korea in 2018 and a few high-profile fires in the U.S. have brought heightened concern and scrutiny to new lithium-ion battery projects.

Many battery market studies focus on the supply side: *how many batteries are being produced and at what cost?* These studies give us a sense of how healthy and robust the supply chain is, but tell us little about how those batteries are being used in the field. By contrast, our study aims to compliment what we think we know about the supply side of the battery market with greater insights about the *demand side* (i.e. utility customers).

While the market demand for batteries in transportation electrification applications has been closely tracked over the last decade, the business case for stationary applications, by comparison, is not very well defined. In general, non-residential customers install batteries at their facilities to save money on energy costs. By contrast, the primary driver for battery sales in the residential market is *resiliency* (i.e. backup power). While some residential customers would like to use time-of-use (TOU) arbitrage to save on their electric bills, it is not a viable option. Even for the relatively-cost residential BESS and high residential TOU rates, batteries do not reduce customer energy costs enough to warrant their high upfront cost. Other drivers of adoption include a desire to "be green," "be cool," "be prepared," and increase self-consumption of self-generated renewable electricity. In reality, this last benefit – particularly using more self-generated solar power – is currently the only compelling financial benefit of BESS technology to customers. Even then, this benefit is mostly only available to commercial customers at this time.

EMERGING TECHNOLOGY FIELD STUDY

This market study serves as a follow-on to a field study conducted by SDG&E from 2015 to 2019, implemented by Information & Energy Services (IES). The final report from that field study is available on the Emerging Technology Coordinating Council's (ETCC's) website and is titled Behind the Meter Battery Energy Storage System M&V Study[2]. At over 300 pages long, the study represents an extensive investigation into the demand response (DR) and demand-charge management (DCM) potential of BTM commercial BESS.

The pilot field study implemented by IES involved monitoring the operation of a total of 27 BESS units installed across two school districts in the San Diego area, representing a combined installed storage capacity of more than 5.3 MW. These battery systems were packaged in two module sizes (30 kW and 250 kW), which could then be combined in sets of two to effectively double the capacity of each module (i.e. 60 kW and 500 kW, respectively). All batteries had a discharge time of a little over 2 hours. The most common system size evaluated was 250 kW. For more details about the equipment and monitoring setup, please refer to the public report referenced and linked above.

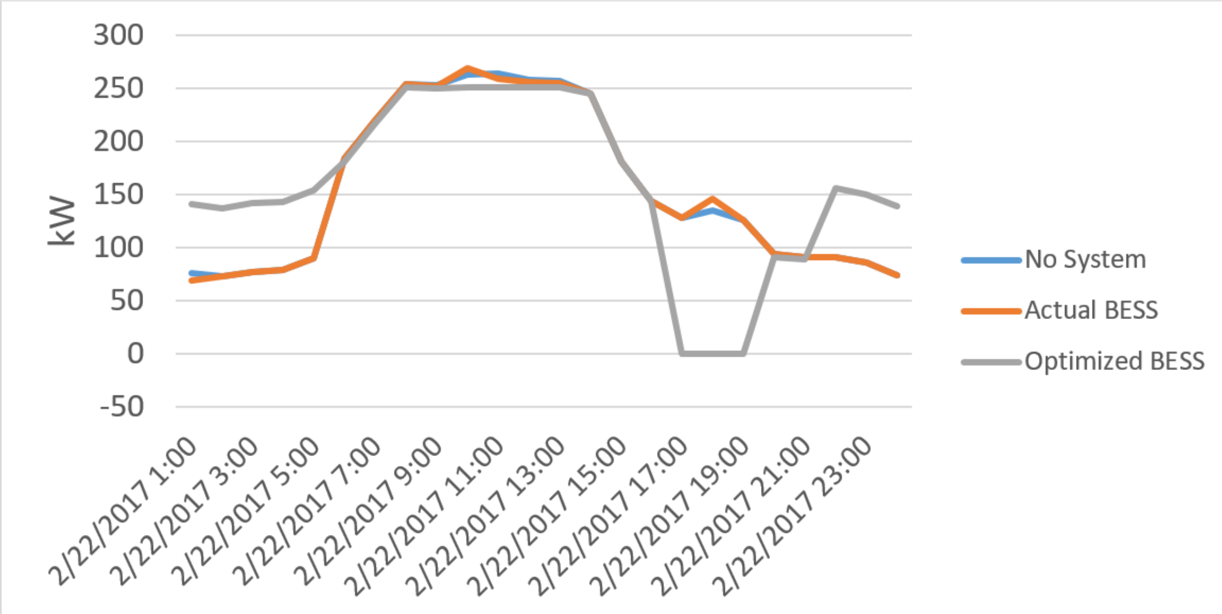
The 27 batteries monitored in the field study were all installed under Power Efficiency Agreements (PEAs), also referred to as "shared savings plans," between the school districts and the battery vendor. These agreements allowed the customer to pay nothing up front and immediately begin capturing savings over time as the batteries were used to shift demand away from peak-demand periods. This agreement structure takes the risk of installing BTM batteries off the shoulders of the customer and places the burden of ensured performance squarely on the solution provider. At the same time, depending on how these agreements are structured, the PEA may also significantly reduce the total lifetime value the customer is able to capture from battery operation over the contract period.

The overall fleet of batteries was evaluated by IES researchers in two phases; in Phase 1, researchers assessed the performance of 20 battery systems, while in Phase 2 they looked at the performance of the remaining 7 batteries. This phased approach was necessitated by a delay from the battery vendor, in response to the availability of SGIP funds. This serves as another indication of how important SGIP funds are to commercial BESS market adoption and continued growth in California. While the batteries in Phase 1 performed relatively well, collectively delivering over 90% of anticipated customer value, the batteries in Phase 2 performed relatively poorly, delivering only 20% of anticipated customer value.

Operation of the BESS appeared to generally follow a basic algorithm to limit facility peak demand. The BESS were used primarily to ensure that total facility demand did not exceed a predetermined fraction of anticipated facility peak demand (i.e. providing demand-charge management, or DCM). The result was a smoother overall facility demand curve that still generally followed the same patterns as the unassisted facility load, with demand increasing in the middle of the day and dropping off significantly in the evening. We compared this behavior to a BESS of the same size used optimally to reduce overall utility bills (Figure 1). The actual, observed BESS control algorithm functioned far from optimally, leading regularly to on-peak battery charging and only capturing about half of potential annual bills savings.

[2] Michal Rogers, James Bottomley, Information & Energy Services, Inc. (2019). Behind the Meter Battery Energy Storage System M&V Study: Study Results Report with Addendum 1. San Diego, CA

FIGURE 1.DEMAND W/ BESS (ORANGE), WITHOUT BESS (BLUE), AND W/ OPTIMIZED BESS (GRAY)



UNANSWERED QUESTIONS

While the results of the BESS field study demonstrated that commercial batteries can be operated successfully to deliver customer benefit in the form of lower utility bills, a number of open questions remained at the end of the field evaluation, including:

- *How many customers are opting to install BESS?*
- *What types of customers are opting to install BESS?*
- *How do customers feel about BESS technology?*
- *How do vendors see the market growing and evolving?*
- *What are the economic impacts associated with BESS?*
- *How do rates affect the financial outlook for customers?*
- *How are financial benefits split between PV and BESS?*

The objective of this market study was to address these unknowns to the greatest extent possible. To do so, we created and fielded market surveys, modeled the impact customer rate structures have on the economic viability of BESS ownership for utility customers, and forecasted market growth in San Diego over a ten-year period.

MARKET STUDY OBJECTIVES

The primary objective of this study is to address unanswered questions that persisted following the commercial BESS field study. Specifically, we set out to quantitatively and qualitatively understand the size of the BESS market, its growth potential over the next 10 years, customer perceptions and behaviors, vendor and installer perspectives, and implications for the utility business model and future program opportunities.

SIZING THE MARKET

We estimate the size of the San Diego BTM battery market in terms of number of units installed, aggregate storage capacity (MW), aggregate energy stored (MWh), and likely future capacity growth for both the residential and commercial sectors in SDG&E's territory.

CHARACTERIZING CUSTOMER BEHAVIOR

Through prior market research, we found that customers report high levels of interest and satisfaction with BTM battery storage. In this study, we attempt to compare those self-assessments to other sources of market data, including vendor survey results and tracked BESS interconnections. This enables us to compare consumer perceptions and behaviors to vendor and utility perceptions of the market, and possibly to identify new opportunities for outreach, education, programs, and partnerships.

EXPLORING NEW BUSINESS OPPORTUNITIES

Though most BTM batteries are being sold directly to customers – either by solar installers or battery manufacturers – there may be new opportunities to deliver more overall market and grid value through different delivery channels and market mechanisms. These include, but are not limited to, utility customer-facing incentive programs (e.g. bring-your-own device, or BYOD), virtual power plant (VPP) aggregators, and new-construction housing development and community storage programs.

MARKET STUDY SCOPE

This section describes the scope of our market study, including how we engaged with industry stakeholders, assessed baseline market conditions, analyzed the influence of customer rate tariffs, forecasted future BESS market growth, and assessed the overall economic implications for the utility and its customers.

INDUSTRY STAKEHOLDER INTERVIEWS

With guidance from SDG&E staff, the market research team identified leading vendors operating in and around San Diego, including battery manufactures, integrators, installers, service providers, academics, consultants, and advocates. More than 200 individuals working at these companies were engaged directly by the research team to solicit participation in an online and/or phone interview. An additional 150 installers operating across California were contacted by representatives from Energy Sage to solicit additional input for this study. Participants were sent a link to an online survey, which on average required about 20 minutes to complete (Figure 2).

FIGURE 2. A SNAPSHOT OF THE WEB PORTAL FOR THE ONLINE VENDOR SURVEY

We at E Source, an independent research & advisory firm based in Boulder, CO are working with California utilities to characterize the state's grid-connected battery storage market as it exists today, as well as anticipate growth over the next 10 years.

A number of battery market studies already exist, but generally don't provide granular market information about things like:

1. The types of customers that have already installed batteries.
2. The types of customers that are likely to install batteries in the future.
3. The impact batteries are having on the California grid and economy.
4. The relative distribution of impacts by utility service territory.
5. How customers are really using batteries in their homes & facilities.
6. How utilities and the battery industry can partner to serve customers.

BASELINE MARKET CONDITIONS

Numerous prior battery market studies have been conducted over the last few years, and several utilize data provided either directly by utilities or from statewide incentive programs. Few of these studies utilize data collected directly from customers or vendors. In this study, we attempt to compare market adoption data from various sources to system interconnection data from the utility, as well as to vendor and customer survey data.

CUSTOMER RATE ANALYSIS

In order to understand how rate tariffs impact the financial attractiveness of BESS ownership, the research completed two rate analyses: one for *residential customers* and another for *commercial customers*. We compared common rate plans for both market sectors and evaluated the impacts that PV and storage operation have on customer energy use, costs, and savings over the course of one year. These analyses compared actual observed and optimized BESS operation, historical and current TOU rates, and the implication of restricting BTM batteries from feeding power back onto the electric grid.

MARKET GROWTH FORECAST

To better understand how the BTM battery market is likely to change over time, the research team created a 10-year market forecast model for BESS in SDG&E territory. We used best-in-class modeling methodologies and assumptions, as described in detail in the following section of this report (**Market Study Methodology**).

CUSTOMER AND UTILITY ECONOMICS

Utilizing the results of our rate analyses and market forecasting, we estimate the total economic impact to customers, vendors, and the utility. We estimate annualized cost of BESS ownership under different scenarios, as well as payback times and total potential energy cost savings. We also identify potential opportunities for maximizing total and shared value through strategic partnerships.

MARKET STUDY METHODOLOGY

This section describes the methodologies applied in this market study, including vendor and customer surveys were created and fielded, how baseline market conditions were established, how the influence of customer rate tariffs was analyzed, and how future market growth was forecasted.

SURVEY INSTRUMENTS

We created a “voice of vendor” (VOV) survey in an attempt to better understand how key market actors – including manufacturers, integrators, and installers – view the BTM battery market now and how they expect market conditions to change over time. We asked dozens of questions, divided into 8 distinct sections within the survey:

1. *Demographics*
2. *Battery capacity*
3. *Service territory*
4. *Rate tariffs*
5. *Solar + storage financials*
6. *Customer segmentation*
7. *Battery operation*
8. *Services & partnerships*

The survey instrument was first created in the format of a Microsoft Excel workbook before being converted into an online survey using Qualtrics (refer back to Figure 2). While a total of about 1,700 data points were collected via Qualtrics for a total of 20 completed responses, very few respondents provided answers to every question and many of these data points were left blank or are otherwise not useful. In a few cases, the person contacted was not the appropriate person to be answering this survey and/or they reported that they did not have useful information to share.

Since responses were slow and response rates were low, the research team supplemented direct email requests with phone calls, LinkedIn messaging, and in-person requests to complete the survey. Respondents had more than a month to complete the survey, and many were e-mailed 5 times with requests and reminders to participate. Data from Qualtrics indicates that several individuals began the survey but quickly dropped off, for unknown reasons.

We also reviewed the responses from a voice-of-customer (VoC) survey, fielded independently by E Source and its partners. While we cannot disclose all of the details from this survey, we share some high-level findings as they pertain to this study. That survey included a total of nearly 7,500 residential respondents, of which 200 customers were living in the state of California. Respondents were asked about their familiarity and satisfaction with many different end-use technologies, including home battery storage systems.

BASELINE MARKET CONDITIONS

The research team surveyed dozens of preexisting market studies, databases, and other references in establishing a snapshot of current BESS market conditions. Team members interviewed utility staff and program administrators and implementers, as well as vendors, consultants, and other market actors. There were significant discrepancies observed in the information gathered from various sources. The methodology for creating the baseline market analysis was simply to gather the most useful, defensible market information available, excluded questionable data or sources, and report back in an unbiased manner.

The Self-Generation Incentive Program's (SGIP's) was frequently referenced by those we interviewed as being the "de facto" database of BTM batteries installed in California. The program's online application database of distributed energy resource (DER) projects generally serves as a default repository of baseline market data for BTM battery installations in California. The SGIP program is also commonly credited with being the primary driver for exceptional market growth for BTM batteries in California, relative to other states. Below are a few select quotes that reflect these sentiments:

> *"…the California utilities [already] have a lot of good data through the SGIP program and its studies…"* – Sarah Van Cleve, Business Development & Policy, Tesla Inc., in response to a request for information

> *"The state's storage market is driven by favorable incentives within the Self-Generation Incentive Program (SGIP)"* – Smart Electric Power Alliance (SEPA), 2019 Utility Energy Storage Market Snapshot[3]

> *"…the vendor [waited] for SGIP funding prior to construction of each system."* – Information and Energy Services, Commercial Behind the Meter Battery Energy Storage System M&V Study

Two underlying assumptions being made by many of the people we talked to during this study are that:

1. The availability of SGIP funds are driving nearly all BTM battery market adoption in California; and,
2. The SGIP database of funded projects represents most of the installed systems in California.

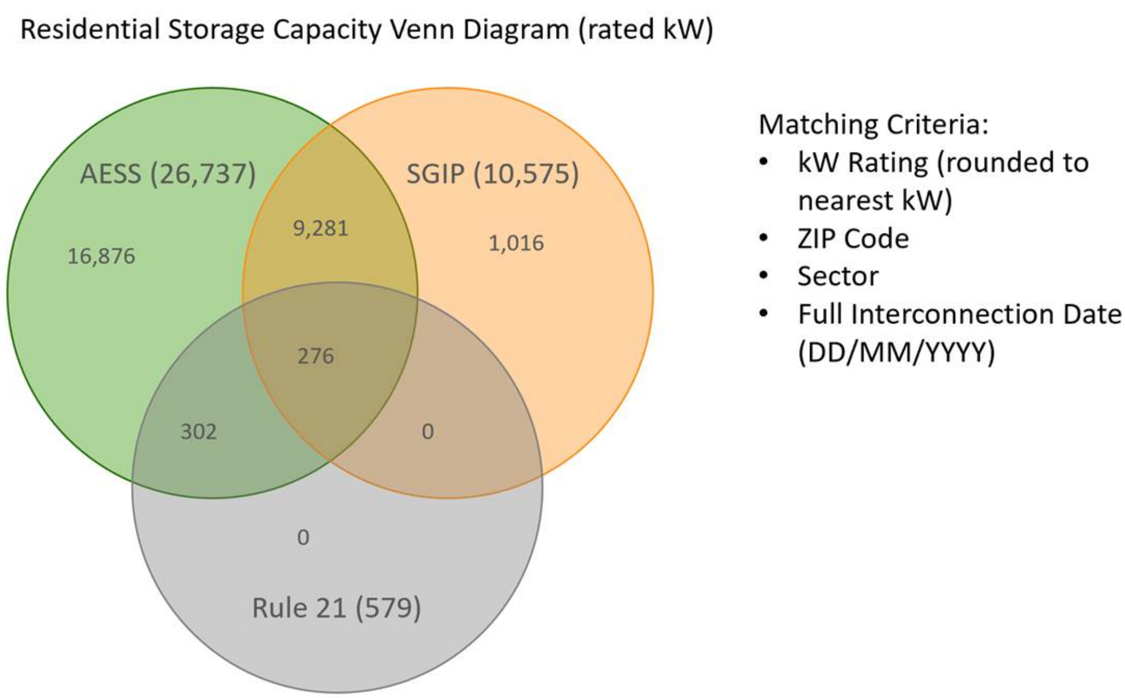
While this sentiment was supported by the available market evidence just a few years ago and still appears to generally hold true for commercial installations, it seems to no longer be true for residential systems. In 2018, the U.S. Energy Information Administration (EIA) asserted that 83% of small-scale battery projects in California had received SGIP funding as of Q4 2016, as described in its report titled U.S. Battery Storage Market Trends. However,

[3] Smart Electric Power Alliance (2019). 2019 Utility Energy Storage Market Snapshot

more recently, it seems that an increasing number of residential battery systems are being adopted without receiving SGIP funding.

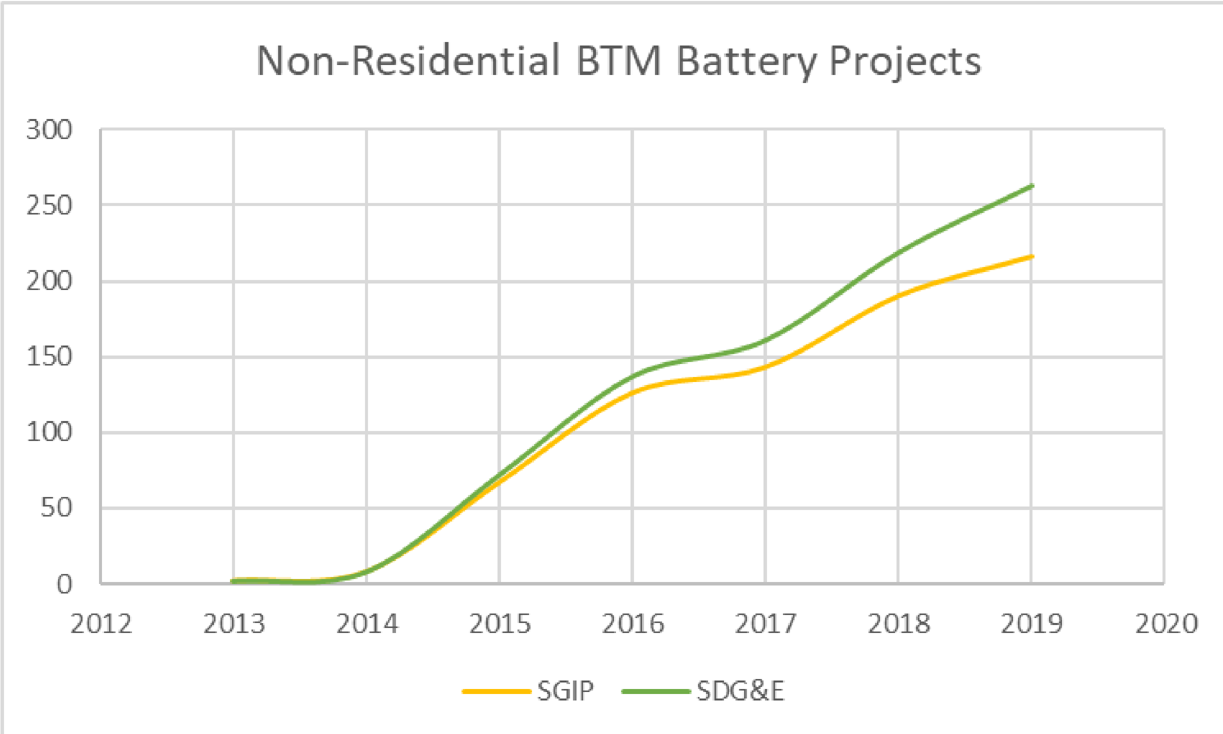
In theory, the Rule 21 database of DER interconnections should represent a more-complete list of all BTM battery systems in California, and SGIP projects should represent a sub-set of the Rule 21 interconnections. However, we have reason to believe that this is currently not the case. Following Rule 21 interconnection guidelines, the investor-owned utilities (IOUs) operating in California track and report DER system interconnections, and that data is made available publicly via the California Distributed Generation Statistics website. Presently, the total capacity reported for this Rule 21 data does not match with the data being reported by SGIP, nor with the interconnections tracked independently by SDG&E. As just one example, we compared the total capacity of residential battery systems reported by SGIP with those in the Rule 21 database and independently tracked by SDG&E, as of November 2019 (Figure 3). Note SDG&E is tracking 16 MW more residential BTM battery storage in its territory than reported by SGIP, which is reporting 10 MW more than Rule 21.

FIGURE 3. ATTEMPT TO MATCH SGIP, RULE 21, AND SDG&E RESIDENTIAL BTM BATTERY CAPACITY DATA



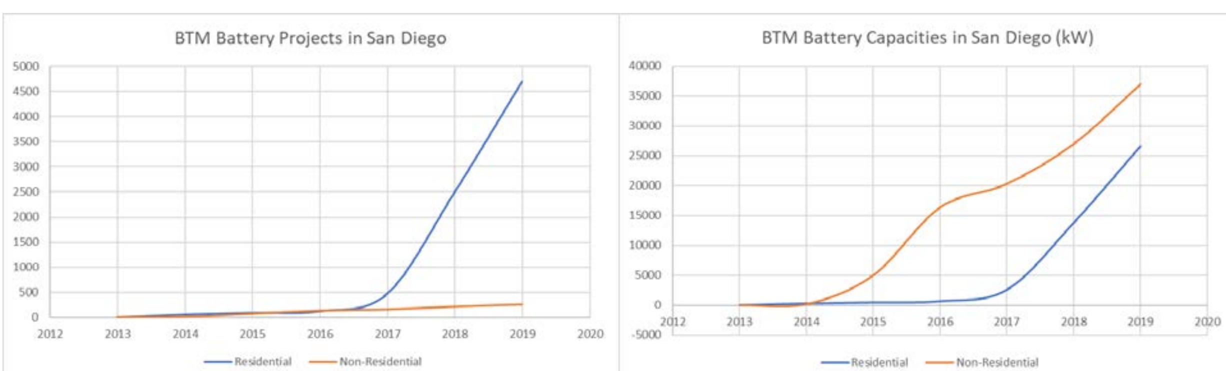
Since we have no way of explaining the discrepancies observed in the Rule 21 data (e.g. how many systems were mislabeled or capacities improperly recorded), we cannot easily make use of this dataset for market-benchmarking purposes. If we assume that both the SGIP and SDG&E datasets are relatively accurate, and that the SGIP data represents a subset of total systems in SDG&E's territory, then only about 40% of residential systems in SDG&E's territory are receiving SGIP funding, while more than 80% of commercial systems are funded by SGIP (Figure 4).

FIGURE 4. THE MAJORITY (> 80%) OF COMMERCIAL BTM BATTERIES IN SAN DIEGO RECEIVED SGIP INCENTIVE



As recently as 2016, there were roughly the same number of residential and commercial BTM battery systems in San Diego's territory. However, by the end of 2017, there were three times more residential systems than commercial systems in SDG&E's territory, and that difference has since grown six fold (Figure 5; *Left*). While the total capacity (kW) of commercial BTM battery storage in San Diego remains greater than the aggregate capacity of residential systems, that gap has been shrinking since 2017 (Figure 5; *Right*).

FIGURE 5. THERE ARE FAR MORE RESIDENTIAL PROJECTS (LEFT), BUT MORE NON-RES CAPACITY (RIGHT)



RESIDENTIAL UTILITY BILL ANALYSIS

To estimate residential customer utility bills and bill savings, the team derived prototypical residential building load shapes, simulated an optimal battery storage dispatch, and evaluated monthly bill charges for two residential electric tariffs.

RESIDENTIAL LOAD SHAPE ESTIMATION

Three 8760-hour shape profiles were available to derive pre-system building loads:

- Average residential customer hourly load, including solar and non-solar customers (10/9/2018-10/8/2019)[4]
- Average non-solar residential customer hourly load (year 2017)
- Simulated solar PV hourly generation (typical meteorological year)[5]

Since the most current (2018-2019) residential customer load data included both solar and non-solar customers, it was not suitable for use as a pre-system load shape (i.e. gross building load prior to PV or BESS). As such, a regression analysis was performed to develop an estimate of the average non-solar customer load shape with the best fit to 2018-2019 load data.

The first step in the regression analysis found an average daily profile (24-hours) by month for each of the three datasets. The second step found a best-fitting prediction of the average 2018-2019 customer load (including solar customers) by scaling the 2017 non-solar customer load shapes and simulated PV generation, per Equation 1.

EQUATION 1. RESIDENTIAL LOAD SHAPE REGRESSION PREDICTION

$$PredictedDailyAvgLoad_m = LoadScaling_m \times NonSolarDailyLoad_m + SolarScaling_m \times DailySolar_m$$

Where,

$PredictedDailyAvgLoad$: a prediction of the daily average customer load (solar and non-solar) by month meant to approximate the daily load shape of 2018-2019 average customer load [kW]
$LoadScaling$: a regressed monthly scaling factor applied to non-solar daily average load
$NonSolarDailyLoad$: the daily average load by month based on 2017 non-solar customer load [kW]
$SolarScaling$: a regressed monthly scaling factor applied to the simulated solar PV generation data
$DailySolar$: the daily average solar PV generation by month based on simulated typical meteorological year data [kW]
m : calendar month

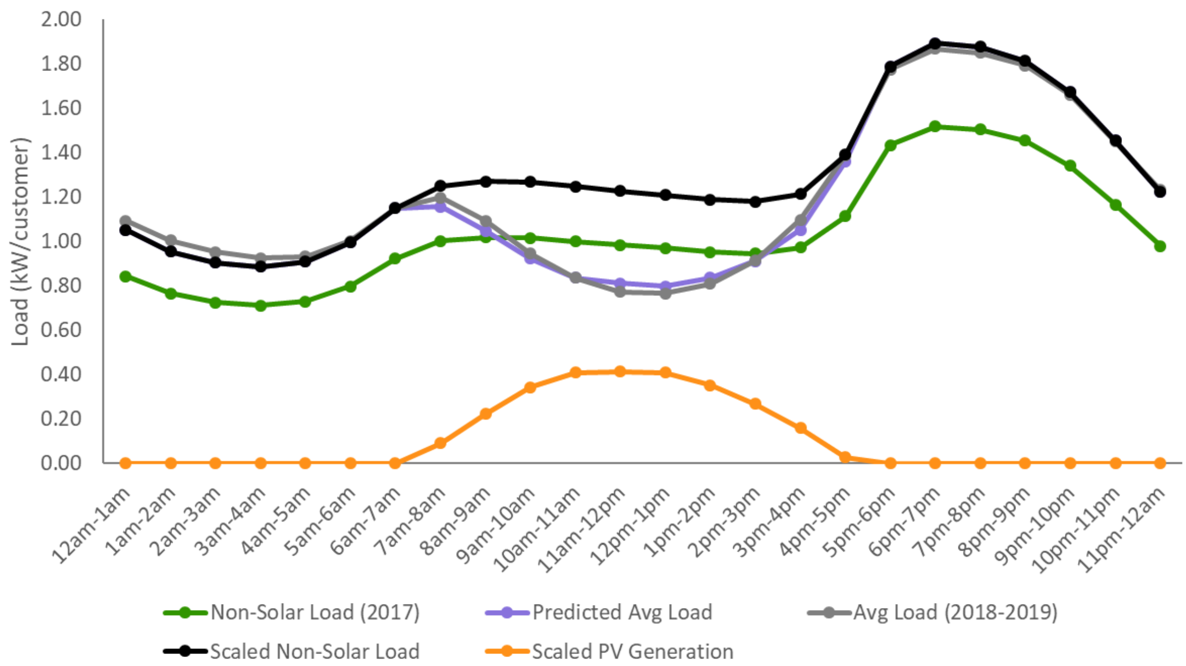
Figure 6 demonstrates the components considered in the regression analysis for the month of December. As the figure shows, the predicted average load (purple line) is a reasonable estimation of the historical 2018-2019 average load (gray line). Additionally, the scaled non-solar load (black line) provides an estimate of the daily average pre-system load, which

[4] SDG&E Dynamic Load Profiles, accessed on 10/10/2019 at http://www2.sdge.com/eic/dlp/dynamic.cfm

[5] Solar generation profile estimated for San Diego area using National Renewable Energy Laboratory's (NREL's) PVWatts Calculator, access on 10/10/2019 at https://pvwatts.nrel.gov/

represents the baseline condition upon which bill savings for various system types can be estimated.

FIGURE 6. ILLUSTRATION OF RESIDENTIAL LOAD ESTIMATION – DECEMBER AVERAGE DAY (KW/CUSTOMER)



Finally, the 8760-hour, non-solar residential customer load in 2017 was multiplied by the regressed *LoadScaling* coefficient associated with each month to produce an estimate of the 8760-hour, pre-system load shape for an average residential customer.

RESIDENTIAL LOAD SCALING FOR SOLAR CUSTOMERS

For this analysis, a 5 kW-DC PV system with a capacity factor of 19.0% was modeled. Following the California Energy Commission's (CEC's) assumption that, on average, a PV system offsets 90% of a residential customer's annual energy consumption, the team applied an additional scaling factor to the residential load shapes.[6] The implication of this scaling factor is that the pre-system annual energy consumption for residences installing a 5 kW-DC solar PV system was 9,237 kWh per year, or 14% lower than the regressed average customer's pre-system annual consumption.

RESIDENTIAL ELECTRIC RATES

Estimation of residential customer utility bills relied on TOU-DR1 and TOU-DR2 rates effective June 1, 2019.[7] Tier 1 charges are applied to monthly consumption up to 351 kWh

[6] See methodological descriptions in the California Energy Demand 2018-2030 Revised Forecast, accessed on 12/23/2019 at https://efiling.energy.ca.gov/getdocument.aspx?tn=223244

[7] Rate tariffs accessed on 10/01/2019 at http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_TOU-DR1.pdf and http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_TOU-DR2.pdf

per month during summer months and 359 kWh per month during winter months, per 130% of SDGE's baseline allowances for the Coastal climate region. Monthly energy consumption exceeding 130% of the baseline allowances incurs Tier 2 energy charges, which are an additional $0.10404 per kWh above summer Tier 1 charges and $0.09536 per kWh above winter Tier 1 charges. Lastly, the billing analysis included a monthly minimum bill of $0.338 per day.

Table 2 and Table 3 present the Tier 1 weekday and weekend energy charges for the TOU-DR1 rates.

TABLE 2. TOU-DR1 WEEKDAY TIER 1 TARIFFS ($/KWH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12am-1am	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
1am-2am	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
2am-3am	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
3am-4am	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
4am-5am	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
5am-6am	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
6am-7am	0.26	0.26	0.26	0.26	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26
7am-8am	0.26	0.26	0.26	0.26	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26
8am-9am	0.26	0.26	0.26	0.26	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26
9am-10am	0.26	0.26	0.26	0.26	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26
10am-11am	0.26	0.26	0.25	0.25	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26
11am-12pm	0.26	0.26	0.25	0.25	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26
12pm-1pm	0.26	0.26	0.25	0.25	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26
1pm-2pm	0.26	0.26	0.25	0.25	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26
2pm-3pm	0.26	0.26	0.26	0.26	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26
3pm-4pm	0.26	0.26	0.26	0.26	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26
4pm-5pm	0.27	0.27	0.27	0.27	0.27	0.46	0.46	0.46	0.46	0.46	0.27	0.27
5pm-6pm	0.27	0.27	0.27	0.27	0.27	0.46	0.46	0.46	0.46	0.46	0.27	0.27
6pm-7pm	0.27	0.27	0.27	0.27	0.27	0.46	0.46	0.46	0.46	0.46	0.27	0.27
7pm-8pm	0.27	0.27	0.27	0.27	0.27	0.46	0.46	0.46	0.46	0.46	0.27	0.27
8pm-9pm	0.27	0.27	0.27	0.27	0.27	0.46	0.46	0.46	0.46	0.46	0.27	0.27
9pm-10pm	0.26	0.26	0.26	0.26	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26
10pm-11pm	0.26	0.26	0.26	0.26	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26
11pm-12am	0.26	0.26	0.26	0.26	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26

Summer On-Peak · Summer Off-Peak · Summer Super Off-Peak

Winter On-Peak · Winter Off-Peak · Winter Super Off-Peak

TABLE 3. TOU-DR1 WEEKEND TIER 1 TARIFFS ($/KWH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12am-1am	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
1am-2am	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
2am-3am	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
3am-4am	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
4am-5am	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
5am-6am	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
6am-7am	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
7am-8am	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
8am-9am	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
9am-10am	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
10am-11am	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
11am-12pm	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
12pm-1pm	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
1pm-2pm	0.25	0.25	0.25	0.25	0.25	0.19	0.19	0.19	0.19	0.19	0.25	0.25
2pm-3pm	0.26	0.26	0.26	0.26	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26
3pm-4pm	0.26	0.26	0.26	0.26	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26
4pm-5pm	0.27	0.27	0.27	0.27	0.27	0.46	0.46	0.46	0.46	0.46	0.27	0.27
5pm-6pm	0.27	0.27	0.27	0.27	0.27	0.46	0.46	0.46	0.46	0.46	0.27	0.27
6pm-7pm	0.27	0.27	0.27	0.27	0.27	0.46	0.46	0.46	0.46	0.46	0.27	0.27
7pm-8pm	0.27	0.27	0.27	0.27	0.27	0.46	0.46	0.46	0.46	0.46	0.27	0.27
8pm-9pm	0.27	0.27	0.27	0.27	0.27	0.46	0.46	0.46	0.46	0.46	0.27	0.27
9pm-10pm	0.26	0.26	0.26	0.26	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26
10pm-11pm	0.26	0.26	0.26	0.26	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26
11pm-12am	0.26	0.26	0.26	0.26	0.26	0.24	0.24	0.24	0.24	0.24	0.26	0.26

Summer On-Peak | Summer Off-Peak | Summer Super Off-Peak

Winter On-Peak | Winter Off-Peak | Winter Super Off-Peak

Table 4 provides the Tier 1 energy charges for the TOU-DR2 rates.

TABLE 4. TOU-DR2 WEEKDAY AND WEEKEND TIER 1 TARIFFS ($/KWH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12am-1am	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
1am-2am	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
2am-3am	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
3am-4am	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
4am-5am	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
5am-6am	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
6am-7am	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
7am-8am	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
8am-9am	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
9am-10am	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
10am-11am	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
11am-12pm	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
12pm-1pm	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
1pm-2pm	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
2pm-3pm	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
3pm-4pm	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
4pm-5pm	0.27	0.27	0.27	0.27	0.27	0.43	0.43	0.43	0.43	0.43	0.27	0.27
5pm-6pm	0.27	0.27	0.27	0.27	0.27	0.43	0.43	0.43	0.43	0.43	0.27	0.27
6pm-7pm	0.27	0.27	0.27	0.27	0.27	0.43	0.43	0.43	0.43	0.43	0.27	0.27
7pm-8pm	0.27	0.27	0.27	0.27	0.27	0.43	0.43	0.43	0.43	0.43	0.27	0.27
8pm-9pm	0.27	0.27	0.27	0.27	0.27	0.43	0.43	0.43	0.43	0.43	0.27	0.27
9pm-10pm	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
10pm-11pm	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26
11pm-12am	0.26	0.26	0.26	0.26	0.26	0.23	0.23	0.23	0.23	0.23	0.26	0.26

Summer On-Peak | Summer Off-Peak

Winter On-Peak | Winter Off-Peak

RESIDENTIAL BESS DISPATCH OPTIMIZATION

A mixed-integer optimization model was used to determine the 8760-hour charging and discharging schedules for the BESS when configured as a solar-paired system and as a stand-alone system for each of the residential tariffs. The optimization model sought to minimize customer utility bills while respecting several constraints, as described below.

Key Optimization Constraints:

- Instantaneous charging and discharging rates cannot exceed the 5 kW power rating of the BESS
- The state of charge must stay between 5% and 95% of the maximum 10 kWh energy rating of the BESS
- The roundtrip efficiency of the storage system must equal 85.5%
- For solar-paired systems, at least 75% of stored energy must come from solar generation (for federal investment tax credit eligibility)
- The discharged energy cannot exceed the gross building load (i.e. battery discharge cannot be exported to the grid)

A sensitivity analysis allowing the BESS to export energy to the grid was also performed to observe the impact on customer utility bills and bill savings. Since the modeled residential electric tariffs had no demand charges, the optimization model tended to maximize the energy arbitrage potential. During winter months, the percentage difference between on-peak and off-peak TOU tariffs is lower than the modeled BESS roundtrip efficiency and does not provide an arbitrage opportunity. As such, the optimized dispatch schedules show no BESS charging or discharging during winter months.

RESIDENTIAL UTILITY BILL CALCULATIONS

This section provides the key equations the team used to estimate residential customer utility bills and bill savings. To calculate the utility bills for the modeled systems, net load (as seen at the meter) was found using the formulae in Equation 2.

EQUATION 2. RESIDENTIAL NET CUSTOMER LOAD BY SYSTEM TYPE

Parameter	Equation	System Type
$NetLoad =$	$GrossLoad$	"No System"
	$GrossLoad - PVGeneration$	"PV"
	$GrossLoad - NetBESSDischarge$	"BESS"
	$GrossLoad - PVGeneration - NetBESSDischarge$	"PV+BESS"

Where,

$NetLoad$: the hourly net customer load seen at the meter [kW]
$GrossLoad$: the hourly gross customer load prior to the impacts of the PV or BESS systems [kW]
$PVGeneration$: the hourly generation from the PV system [kW]
$NetBESSDischarge$: the hourly net discharge from the BESS, which is the discharging load less any charging load [kW]

For a given calendar month, the percentage of energy consumption billed at each tier's rates was calculated as shown in Equation 3.

EQUATION 3. RESIDENTIAL PERCENTAGE OF ENERGY CONSUMPTION BY TIER

$$Tier1Pct = \frac{Minimum(MonthlyConsumption,\ \ Allowance)}{MonthlyConsumption}$$

$$Tier2Pct = 100\% - Tier1Pct$$

Where,

Tier1Pct : the percentage of consumption billed at Tier 1 rates in a given month [%]
Tier2Pct : the percentage of consumption billed at Tier 2 rates in a given month [%]
MonthlyConsumption : the total consumption in a given month, which is the sum of the hourly net load for the month [kWh]
Allowance : 130% of the baseline allowance for a given month [kWh]

Having found the percentage of monthly consumption billed at each tier's rates, the energy charges by TOU period were calculated using Equation 4.

EQUATION 4. RESIDENTIAL MONTHLY ENERGY CHARGES BY TOU PERIOD

$$EnergyCharge_{m,p} = \left(Tier1Pct_m \times Tier1Rate_{m,p} + Tier2Pct_m \times Tier2Rate_{m,p}\right) \times Consumption_{m,p}$$

Where,

EnergyCharge : the billed energy charge by month and TOU period [$]
Tier1Rate : the Tier 1 electric rate by month and TOU period [$/kWh]
Tier2Rate : the Tier 2 electric rate by month and TOU period [$/kWh]
Consumption : the consumption by month and TOU period [kWh]
m : calendar month
p : TOU period

Equation 5 shows that total monthly energy charges are simply the sum of energy charges over TOU periods.

EQUATION 5. RESIDENTIAL TOTAL MONTHLY ENERGY CHARGES

$$TotalEnergyCharge_m = \sum_p EnergyCharges_{m,p}$$

Where,

TotalEnergyCharge : the total billed energy charges by month [$]

For months where total energy charges were less than the minimum monthly bill of approximately $10.28 per month (based on the minimum daily bill of $0.338), monthly minimum charges were assessed as shown in Equation 6.

EQUATION 6. RESIDENTIAL MINIMUM MONTHLY BILL

Parameter	Equation	Condition
	10.28	$TotalEnergyCharge_m \leq 0$
$MinimumCharge_m =$	$10.28 - TotalEnergyCharge_m$	$0 < TotalEnergyCharge_m < 10.28$
	0	$TotalEnergyCharge_m \geq 10.28$

Where,

$MinimumCharge$: the billed minimum charge to ensure the total monthly bill meets the minimum monthly bill [$]

Finally, the total monthly customer utility bill was calculated as shown in Equation 7.

EQUATION 7. RESIDENTIAL TOTAL MONTHLY UTILITY BILL

$$UtilityBill_m = MinimumCharge_m + TotalEnergyCharge_m$$

Where,

$UtilityBill$: the monthly utility bill including energy and minimum charges [$]

Once utility bills were estimated for all system types, energy and bill savings relative to a "No System" configuration were assessed for each residential tariff and system type.

NON-RESIDENTIAL UTILITY BILL ANALYSIS

To estimate non-residential utility bills and customer bill savings, the team relied on metered load data from a high school in San Diego. The metered data did not cover an entire year, so the team estimated gross building loads for missing months. Utility bills for various system types were estimated by considering impacts of PV and BESS systems under multiple non-residential electric tariffs.

NON-RESIDENTIAL LOAD SHAPE ESTIMATION

Historical metered net building load and BESS operation at 15-minute intervals was made available by IES for five billing months (22 February 2017 through 24 July 2017) for a high school in San Diego. Gross building load was calculated by removing the impacts of BESS operation from the metered net building load (i.e. subtracting charging loads from net building load and adding discharging loads).

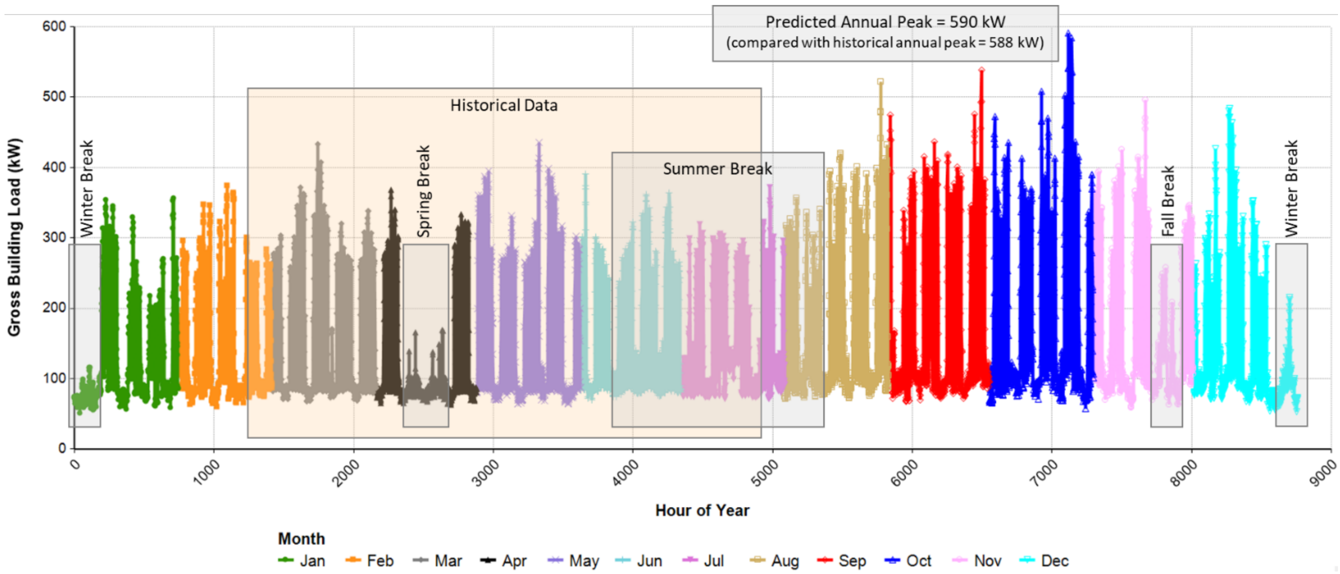
To estimate the gross building loads for the 2017 dates outside of the known billing months, the team performed the following data manipulations:

1. Condensed the 15-minute gross load data to average hourly loads, while preserving on-peak and non-coincident peaks.
2. Found the average load and load factor (the ratio of average load to peak load) for each day of available data.
3. Regressed daily average load and load factors on several explanatory variables (see further description below).
4. Predicted daily average load and load factors for days outside of the known billing months using the regression model.

5. Matched known days of gross loads having similar daily load factors to the predicted load factors for days outside of the known billing months.
6. Scaled the matched days of known gross loads to result in the average load predicted for days outside of the known billing months (note that this scaling does not change the daily load factor).

The combination of historical hourly gross loads and predicted gross loads, following the process described above, are shown in Figure 7. Figure 7 highlights the known "historical" data, and all other dates result from the regression prediction. The figure also highlights several breaks included in the school year, which the regression model treated specially.

FIGURE 7. ACTUAL AND PREDICTED NON-RESIDENTIAL GROSS BUILDING LOAD



The regression model described in Step 3 (above) categorized calendar days into four unique classes:

- Weekends and federal holidays
- School-year weekdays
- Summer-break weekdays
- Winter-, spring-, and fall-break weekdays

For each class, historical daily average loads and load factors were regressed on daily net heating-degree days (i.e. heating-degree days less cooling-degree days, assuming a base temperature of 65 degrees Fahrenheit), daily hours of sunlight, a constant term, and a random error term, as shown in Equation 8.

EQUATION 8. NON-RESIDENTIAL LOAD METRIC REGRESSION MODELS

$$AverageLoad_c = HDDSensitivity_c \times NetHDD_c + DaylightSensitivity_c \times Daylight_c + Constant_c + RandomError_c$$

$$LoadFactor_c = HDDSensitivity_c \times NetHDD_c + DaylightSensitivity_c \times Daylight_c + Constant_c + RandomError_c$$

Where,

AverageLoad : the average gross building load in a given day [kW]
LoadFactor : the load factor in a given day [average kW/peak kW]
HDDSensitivity : the regressed coefficient representing the sensitivity to net heating-degree days [kW/degree-day]
NetHDD : the net heating-degree days in a given day [degree-days]
DaylightSensitivity : the regressed coefficient representing the sensitivity to hours of daylight [kW/hour]
Daylight : the number of hours of daylight in a given day [hours]
Constant : a regressed constant term [kW]
RandomError : a random error term [kW]
c : class of calendar days

The predictions of daily average load and load factors generated by these regression models had R^2 correlation coefficients of 0.83 and 0.92, respectively, to the known average loads and load factors.

NON-RESIDENTIAL MODELED PV SYSTEM

The solar PV system considered in the non-residential bill analysis consisted of a 400 kW-DC system with a capacity factor of 18.9%. The hourly PV generation profile was simulated based on weather from a typical meteorological year. The annual generation from the modeled PV system was 662.2 MWh or 53.1% of the gross annual building consumption. Solar PV systems were analyzed solely for current electric rates (i.e. 2019 AL-TOU Secondary and DG-R Secondary).

NON-RESIDENTIAL ELECTRIC RATES

Estimation of non-residential customer utility bills relied on AL-TOU Primary (March 2017 vintage), AL-TOU Secondary (effective January 2019) and DG-R Secondary (effective January 2019) rates. The March 2017 vintage of the AL-TOU Primary rates, with electric energy commodity costs (EECC) effective March 2017, were evaluated for consistency with historical billing data and BESS implementer invoices to the customer.[8] The team also evaluated the January 2019 vintages of the AL-TOU Secondary and DG-R Secondary tariffs, with EECC effective June 2019, to better understand utility bills for a generic non-residential customer on these rates.[9]

The AL-TOU Primary (March 2017) rates included a $37.68 per month basic service fee. Non-coincident demand charges, which were applicable every hour of the year, were $23.89 per kW on this tariff. Table 5, Table 6 and Table 7 provide this tariff's weekday energy, weekend energy and weekday on-peak demand charges, respectively.

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[8] Accessed on 12/26/2019, the March 2017 AL-TOU Primary tariffs and EECC are available at http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_AL-TOU_2017.pdf and http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_EECC_2017.pdf.

[9] Accessed on 12/26/2019, the January 2017 AL-TOU Secondary and DG-R Secondary tariffs are available at http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_AL-TOU.pdf and http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_DG-R.pdf. Similarly, the June 2019 EECC are available at http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_EECC.pdf.

TABLE 5. AL-TOU PRIMARY (MARCH 2017 VINTAGE[10]) WEEKDAY ENERGY TARIFFS ($/KWH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12am-1am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
1am-2am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
2am-3am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
3am-4am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
4am-5am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
5am-6am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
6am-7am	0.09	0.09	0.09	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09
7am-8am	0.09	0.09	0.09	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09
8am-9am	0.09	0.09	0.09	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09
9am-10am	0.09	0.09	0.09	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09
10am-11am	0.09	0.09	0.09	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09
11am-12pm	0.09	0.09	0.09	0.09	0.12	0.12	0.12	0.12	0.12	0.12	0.09	0.09
12pm-1pm	0.09	0.09	0.09	0.09	0.12	0.12	0.12	0.12	0.12	0.12	0.09	0.09
1pm-2pm	0.09	0.09	0.09	0.09	0.12	0.12	0.12	0.12	0.12	0.12	0.09	0.09
2pm-3pm	0.09	0.09	0.09	0.09	0.12	0.12	0.12	0.12	0.12	0.12	0.09	0.09
3pm-4pm	0.09	0.09	0.09	0.09	0.12	0.12	0.12	0.12	0.12	0.12	0.09	0.09
4pm-5pm	0.09	0.09	0.09	0.09	0.12	0.12	0.12	0.12	0.12	0.12	0.09	0.09
5pm-6pm	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.11	0.11
6pm-7pm	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
7pm-8pm	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
8pm-9pm	0.09	0.09	0.09	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09
9pm-10pm	0.09	0.09	0.09	0.09	0.11	0.11	0.11	0.11	0.11	0.11	0.09	0.09
10pm-11pm	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
11pm-12am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07

Summer On-Peak | Summer Semi-Peak | Summer Off-Peak

Winter On-Peak | Winter Semi-Peak | Winter Off-Peak

TABLE 6. AL-TOU PRIMARY (MARCH 2017 VINTAGE[11]) WEEKEND ENERGY TARIFFS ($/KWH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12am-1am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
1am-2am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
2am-3am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
3am-4am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
4am-5am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
5am-6am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
6am-7am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
7am-8am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
8am-9am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
9am-10am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
10am-11am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
11am-12pm	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
12pm-1pm	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
1pm-2pm	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
2pm-3pm	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
3pm-4pm	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
4pm-5pm	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
5pm-6pm	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
6pm-7pm	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
7pm-8pm	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
8pm-9pm	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
9pm-10pm	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
10pm-11pm	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07
11pm-12am	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.07	0.07

Summer Off-Peak

Winter Off-Peak

[10] Includes March 2017 vintage of EECC.

[11] Includes March 2017 vintage of EECC.

TABLE 7. AL-TOU PRIMARY (MARCH 2017 VINTAGE[12]) WEEKDAY ON-PEAK DEMAND TARIFFS ($/KW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12am-1am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1am-2am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2am-3am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3am-4am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4am-5am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5am-6am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6am-7am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7am-8am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8am-9am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9am-10am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10am-11am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11am-12pm	0.00	0.00	0.00	0.00	20.76	20.76	20.76	20.76	20.76	20.76	0.00	0.00
12pm-1pm	0.00	0.00	0.00	0.00	20.76	20.76	20.76	20.76	20.76	20.76	0.00	0.00
1pm-2pm	0.00	0.00	0.00	0.00	20.76	20.76	20.76	20.76	20.76	20.76	0.00	0.00
2pm-3pm	0.00	0.00	0.00	0.00	20.76	20.76	20.76	20.76	20.76	20.76	0.00	0.00
3pm-4pm	0.00	0.00	0.00	0.00	20.76	20.76	20.76	20.76	20.76	20.76	0.00	0.00
4pm-5pm	0.00	0.00	0.00	0.00	20.76	20.76	20.76	20.76	20.76	20.76	0.00	0.00
5pm-6pm	7.52	7.52	7.52	7.52	20.76	20.76	20.76	20.76	20.76	20.76	7.52	7.52
6pm-7pm	7.52	7.52	7.52	7.52	0.00	0.00	0.00	0.00	0.00	0.00	7.52	7.52
7pm-8pm	7.52	7.52	7.52	7.52	0.00	0.00	0.00	0.00	0.00	0.00	7.52	7.52
8pm-9pm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9pm-10pm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10pm-11pm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11pm-12am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Summer On-Peak Summer Off-Peak
Winter On-Peak Winter Off-Peak

The AL-TOU Secondary (January 2019) rates included a $186.30 per month basic service fee. Non-coincident demand charges, which were applicable every hour of the year, were $24.23 per kW on this tariff. Table 8, Table 9 and Table 10 provide this tariff's weekday energy, weekend energy, and on-peak demand charges, respectively.

12 Includes March 2017 vintage of EECC.

Table 8. AL-TOU Secondary (January 2019 Vintage[13]) Weekday Energy Tariffs ($/kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12am-1am	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
1am-2am	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
2am-3am	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
3am-4am	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
4am-5am	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
5am-6am	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
6am-7am	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
7am-8am	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
8am-9am	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
9am-10am	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
10am-11am	0.11	0.11	0.10	0.10	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
11am-12pm	0.11	0.11	0.10	0.10	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
12pm-1pm	0.11	0.11	0.10	0.10	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
1pm-2pm	0.11	0.11	0.10	0.10	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
2pm-3pm	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
3pm-4pm	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
4pm-5pm	0.13	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.13	0.13
5pm-6pm	0.13	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.13	0.13
6pm-7pm	0.13	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.13	0.13
7pm-8pm	0.13	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.13	0.13
8pm-9pm	0.13	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.13	0.13
9pm-10pm	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
10pm-11pm	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
11pm-12am	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11

Summer On-Peak | Summer Off-Peak | Summer Super Off-Peak

Winter On-Peak | Winter Off-Peak | Winter Super Off-Peak

Table 9. AL-TOU Secondary (January 2019 Vintage[14]) Weekend Energy Tariffs ($/kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12am-1am	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
1am-2am	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
2am-3am	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
3am-4am	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
4am-5am	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
5am-6am	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
6am-7am	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
7am-8am	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
8am-9am	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
9am-10am	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
10am-11am	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
11am-12pm	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
12pm-1pm	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
1pm-2pm	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
2pm-3pm	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
3pm-4pm	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
4pm-5pm	0.13	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.13	0.13
5pm-6pm	0.13	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.13	0.13
6pm-7pm	0.13	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.13	0.13
7pm-8pm	0.13	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.13	0.13
8pm-9pm	0.13	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.13	0.13
9pm-10pm	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
10pm-11pm	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11
11pm-12am	0.11	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.11	0.11

Summer On-Peak | Summer Off-Peak | Summer Super Off-Peak

Winter On-Peak | Winter Off-Peak | Winter Super Off-Peak

[13] Includes June 2019 vintage of EECC.

[14] Includes June 2019 vintage of EECC.

TABLE 10. AL-TOU SECONDARY (JANUARY 2019 VINTAGE[15]) ON-PEAK DEMAND TARIFFS ($/KW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12am-1am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1am-2am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2am-3am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3am-4am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4am-5am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5am-6am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6am-7am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7am-8am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8am-9am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9am-10am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10am-11am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11am-12pm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12pm-1pm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1pm-2pm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2pm-3pm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3pm-4pm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4pm-5pm	17.07	17.07	17.07	17.07	17.07	27.65	27.65	27.65	27.65	27.65	17.07	17.07
5pm-6pm	17.07	17.07	17.07	17.07	17.07	27.65	27.65	27.65	27.65	27.65	17.07	17.07
6pm-7pm	17.07	17.07	17.07	17.07	17.07	27.65	27.65	27.65	27.65	27.65	17.07	17.07
7pm-8pm	17.07	17.07	17.07	17.07	17.07	27.65	27.65	27.65	27.65	27.65	17.07	17.07
8pm-9pm	17.07	17.07	17.07	17.07	17.07	27.65	27.65	27.65	27.65	27.65	17.07	17.07
9pm-10pm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10pm-11pm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11pm-12am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Summer On-Peak Summer Off-Peak

Winter On-Peak Winter Off-Peak

The DG-R Secondary (January 2019) rates included a $186.30 per month basic service fee. Non-coincident demand charges, which were applicable every hour of the year, were $15.12 per kW on this tariff. Table 11, Table 12 and Table 13 provide this tariff's weekday energy, weekend energy, and on-peak demand charges, respectively.

[15] Includes June 2019 vintage of EECC.

TABLE 11. DG-R SECONDARY (JANUARY 2019 VINTAGE[16]) WEEKDAY ENERGY TARIFFS ($/KWH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12am-1am	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
1am-2am	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
2am-3am	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
3am-4am	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
4am-5am	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
5am-6am	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
6am-7am	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14
7am-8am	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14
8am-9am	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14
9am-10am	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14
10am-11am	0.14	0.14	0.13	0.13	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14
11am-12pm	0.14	0.14	0.13	0.13	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14
12pm-1pm	0.14	0.14	0.13	0.13	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14
1pm-2pm	0.14	0.14	0.13	0.13	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14
2pm-3pm	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14
3pm-4pm	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14
4pm-5pm	0.33	0.33	0.33	0.33	0.33	0.32	0.32	0.32	0.32	0.32	0.33	0.33
5pm-6pm	0.33	0.33	0.33	0.33	0.33	0.32	0.32	0.32	0.32	0.32	0.33	0.33
6pm-7pm	0.33	0.33	0.33	0.33	0.33	0.32	0.32	0.32	0.32	0.32	0.33	0.33
7pm-8pm	0.33	0.33	0.33	0.33	0.33	0.32	0.32	0.32	0.32	0.32	0.33	0.33
8pm-9pm	0.33	0.33	0.33	0.33	0.33	0.32	0.32	0.32	0.32	0.32	0.33	0.33
9pm-10pm	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14
10pm-11pm	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14
11pm-12am	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14

Summer On-Peak | Summer Off-Peak | Summer Super Off-Peak

Winter On-Peak | Winter Off-Peak | Winter Super Off-Peak

TABLE 12. DG-R SECONDARY (JANUARY 2019 VINTAGE[17]) WEEKEND ENERGY TARIFFS ($/KWH)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12am-1am	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
1am-2am	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
2am-3am	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
3am-4am	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
4am-5am	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
5am-6am	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
6am-7am	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
7am-8am	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
8am-9am	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
9am-10am	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
10am-11am	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
11am-12pm	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
12pm-1pm	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
1pm-2pm	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.13	0.13
2pm-3pm	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14
3pm-4pm	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14
4pm-5pm	0.33	0.33	0.33	0.33	0.33	0.32	0.32	0.32	0.32	0.32	0.33	0.33
5pm-6pm	0.33	0.33	0.33	0.33	0.33	0.32	0.32	0.32	0.32	0.32	0.33	0.33
6pm-7pm	0.33	0.33	0.33	0.33	0.33	0.32	0.32	0.32	0.32	0.32	0.33	0.33
7pm-8pm	0.33	0.33	0.33	0.33	0.33	0.32	0.32	0.32	0.32	0.32	0.33	0.33
8pm-9pm	0.33	0.33	0.33	0.33	0.33	0.32	0.32	0.32	0.32	0.32	0.33	0.33
9pm-10pm	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14
10pm-11pm	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14
11pm-12am	0.14	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14

Summer On-Peak | Summer Off-Peak | Summer Super Off-Peak

Winter On-Peak | Winter Off-Peak | Winter Super Off-Peak

[16] Includes June 2019 vintage of EECC.

[17] Includes June 2019 vintage of EECC.

TABLE 13. DG-R SECONDARY (JANUARY 2019 VINTAGE[18]) ON-PEAK DEMAND TARIFFS ($/KW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12am-1am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1am-2am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2am-3am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3am-4am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4am-5am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5am-6am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6am-7am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7am-8am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8am-9am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9am-10am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10am-11am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11am-12pm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12pm-1pm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1pm-2pm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2pm-3pm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3pm-4pm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4pm-5pm	0.65	0.65	0.65	0.65	0.65	13.38	13.38	13.38	13.38	13.38	0.65	0.65
5pm-6pm	0.65	0.65	0.65	0.65	0.65	13.38	13.38	13.38	13.38	13.38	0.65	0.65
6pm-7pm	0.65	0.65	0.65	0.65	0.65	13.38	13.38	13.38	13.38	13.38	0.65	0.65
7pm-8pm	0.65	0.65	0.65	0.65	0.65	13.38	13.38	13.38	13.38	13.38	0.65	0.65
8pm-9pm	0.65	0.65	0.65	0.65	0.65	13.38	13.38	13.38	13.38	13.38	0.65	0.65
9pm-10pm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10pm-11pm	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11pm-12am	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Summer On-Peak | Summer Off-Peak
Winter On-Peak | Winter Off-Peak

NON-RESIDENTIAL BESS DISPATCH OPTIMIZATION

A mixed-integer optimization model was utilized to determine the 8760-hour charging and discharging schedules for the BESS when configured as a stand-alone system for each non-residential tariff and as a solar-paired system for the AL-TOU Secondary and DG-R Secondary tariffs. The BESS charge-management algorithm of the optimization model seeks to minimize customer utility bills while respecting several constraints, as described below.

Key Optimization Constraints:

- Instantaneous charging and discharging rates cannot exceed the 250 kW power rating of the BESS
- The state of charge must stay between 5% and 95% of the maximum 572 kWh energy rating of the BESS
- The roundtrip efficiency of the storage system must equal 86%
- For solar-paired systems, at least 75% of stored energy must come from solar generation (for federal investment tax credit eligibility)
- The discharged energy cannot exceed the gross building load (i.e. battery discharge cannot be exported to the grid)

A sensitivity analysis – allowing the BESS to export energy to the electric grid – was also performed, to assess the impact on customer utility bills and bill savings. The results of this analysis showed that the impact of allowing the BESS to export energy to the grid had a negligible effect (i.e. less than 1% difference) on the non-residential customer's utility bills.

The non-residential optimized BESS dispatch prioritized reducing demand charges, both on-peak and non-coincident, over energy arbitrage. However, when excess stored energy was

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[18] Includes June 2019 vintage of EECC.

available in the BESS after reducing demand charges, that energy was often used to reduce on-peak energy charges using low-cost grid electricity stored during late night hours or solar generation stored during mid-day.

NON-RESIDENTIAL UTILITY BILL CALCULATIONS

This section describes the key equations the team used to estimate non-residential customer utility bills and bill savings. It should be noted that the analysis evaluating the AL-TOU Primary (March 2017 vintage) tariff used billing months when estimating customer bills for comparison with the 2017 historical billing data available, while the analysis of the current non-residential rates relied on calendar months.

To calculate the utility bills for the modeled systems, net load (as seen at the meter) was found using the same formulae as used for the residential analysis, per Equation 2. For each electric tariff's energy TOU periods, the total monthly consumption was tallied and multiplied by the energy rate for that TOU period, as shown in Equation 9.

EQUATION 9. NON-RESIDENTIAL MONTHLY ENERGY CHARGES BY TOU PERIOD

$$EnergyCharge_{m,p} = EnergyRate_{m,p} \times Consumption_{m,p}$$

Where,

$EnergyCharge$: the billed energy charge by month and TOU period [$]
$EnergyRate$: the energy rate by month and TOU period [$/kWh]
$Consumption$: the consumption by month and TOU period [kWh]
m : calendar month (for AL-TOU Secondary and DG-Secondary) or billing month (for AL-TOU Primary)
p : TOU period

Equation 10 shows that total monthly energy charges are simply the sum of energy charges over TOU periods.

EQUATION 10. NON-RESIDENTIAL TOTAL MONTHLY ENERGY CHARGES

$$TotalEnergyCharge_m = \sum_p EnergyCharges_{m,p}$$

Where,

$TotalEnergyCharge$: the total billed energy charges by month [$]

The maximum demand in each electric tariff's on-peak and non-coincident TOU periods was found for each month. Monthly non-coincident demand was compared against 50% of the annual maximum demand, and the larger of the two was selected as the non-coincident demand considered in the utility bill calculations, as shown in Equation 11.

EQUATION 11. NON-RESIDENTIAL BILLED NON-COINCIDENT DEMAND

$$BilledNCDemand_m = Maximum(ActualNCDemand_m, 50\% \times AnnualNCDemand)$$

Where,

$BilledNCDemand$: the maximum non-coincident demand used in billing calculations [kW]
$ActualNCDemand$: the maximum non-coincident demand measured for the month [kW]
$AnnualNCDemand$: the maximum annual demand [kW]

The non-coincident demand charges were calculated by multiplying the billed non-coincident demand by each tariff's non-coincident demand rate, as shown in Equation 12.

EQUATION 12. NON-RESIDENTIAL NON-COINCIDENT DEMAND CHARGES

$$NCDemandCharges_m = NCDemandRate \times BilledNCDemand_m$$

Where,

$NCDemandCharges$: the monthly charges for non-coincident demand [$]
$NCDemandRate$: the rate for non-coincident demand [$/kW]

Similarly, each month's on-peak demand charges are the product of maximum on-peak demand and on-peak demand rates, as illustrated in Equation 13.

EQUATION 13. NON-RESIDENTIAL ON-PEAK DEMAND CHARGES

$$OnPeakDemandCharges_m = OnPeakDemandRate_m \times OnPeakDemand_m$$

Where,

$OnPeakDemandCharges$: the monthly charges for on-peak demand [$]
$OnPeakDemandRate$: the rate for on-peak demand [$/kW]
$OnPeakDemand$: the maximum monthly on-peak demand [kW]

Finally, the total monthly non-residential customer utility bill was calculated as shown in Equation 14.

EQUATION 14. RESIDENTIAL TOTAL MONTHLY UTILITY BILL

$$UtilityBill_m = ServiceFee + TotalEnergyCharge_m + NCDemandCharges_m + OnPeakDemandCharges_m$$

Where,

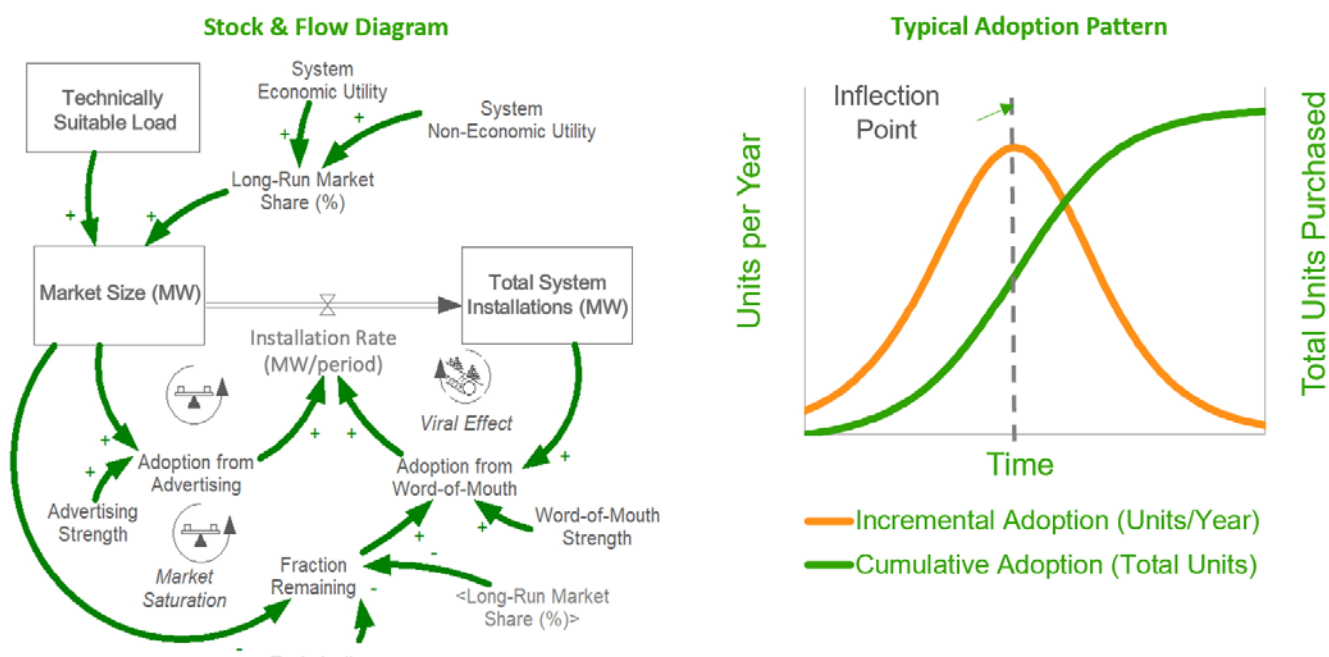
$UtilityBill$: the monthly utility bill including energy and demand charges and basic service fees [$]

Once utility bills were estimated for all system types, energy and bill savings relative to a "No System" configuration were assessed for each non-residential tariff and system type.

ADOPTION FORECAST METHODOLOGY

Lumidyne researchers forecasted BESS adoption beginning in the fourth quarter of 2019 through the end of 2030 by simulating customer uptake using a Bass Diffusion approach implemented in a Systems Dynamics framework, as portrayed in Figure 8. The Bass Diffusion model generates an S-shaped adoption curve seen routinely in new product uptake, while the System Dynamics construct permits robust response to dynamic market conditions like changing population, technology costs, and electricity rates, among others.[19,20] The BESS adoption model's forecasts were differentiated by residential versus non-residential customers, by stand-alone versus solar-paired storage systems, and by ZIP Code within SDG&E's service territory.

FIGURE 8. ADOPTION MODEL STOCK-FLOW DIAGRAM



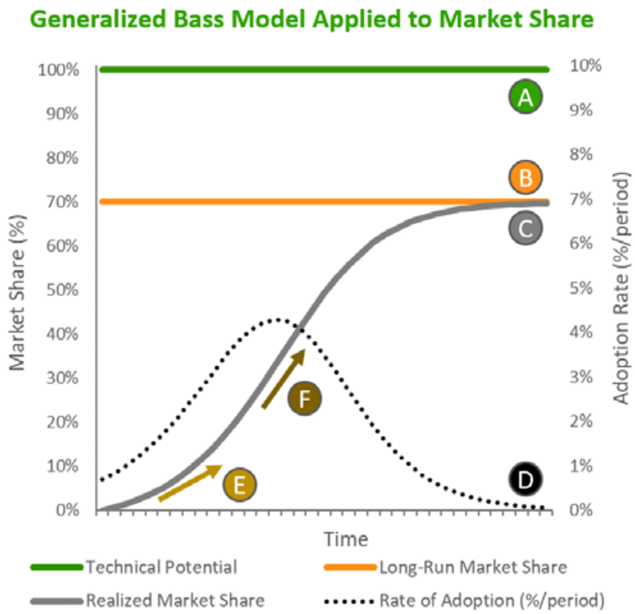
Source: Lumidyne

Figure 9 demonstrates the theoretical dynamics of the adoption model in terms of BESS market share. Of importance is the concept of long-run market share, which is the theoretical percentage of suitable customers that would be willing to purchase a BESS based on its economic attractiveness. This study relied on payback acceptance curves to determine the long-run market share at each point in time.

[19] Bass, Frank M. (1969). A New Product Growth Model for Consumer Durables, Management Science, 15: 215-27

[20] Sterman, John D. (2000). Business Dynamics: Systems Thinking and Modeling for a Complex World, Irwin/McGraw-Hill. Boston, MA

FIGURE 9. ILLUSTRATIVE MARKET SHARE DYNAMICS



Source: Lumidyne

A **Technical Potential:** the total technically feasible market size (e.g. the quantity of building load or PV systems that can host a BESS system)

B **Long-Run Market Share:** the theoretical percentage of the technical potential that would be willing to adopt a technology based on current technology characteristics (e.g., cost, performance, etc.)

C **Realized Market Share:** the percentage of the market that actually adopts the technology after accounting for barriers to adoption (e.g., consumer awareness, financing options, trust in product, etc.). With sufficient time, this asymptotes to the long-run market share

D **Rate of Adoption:** the incremental percentage of the market that adopts each period

E **Marketing Effectiveness:** the effectiveness of marketing dictates the initial slope of the S-shaped curve and represents marketing's influence on innovators and early adopters

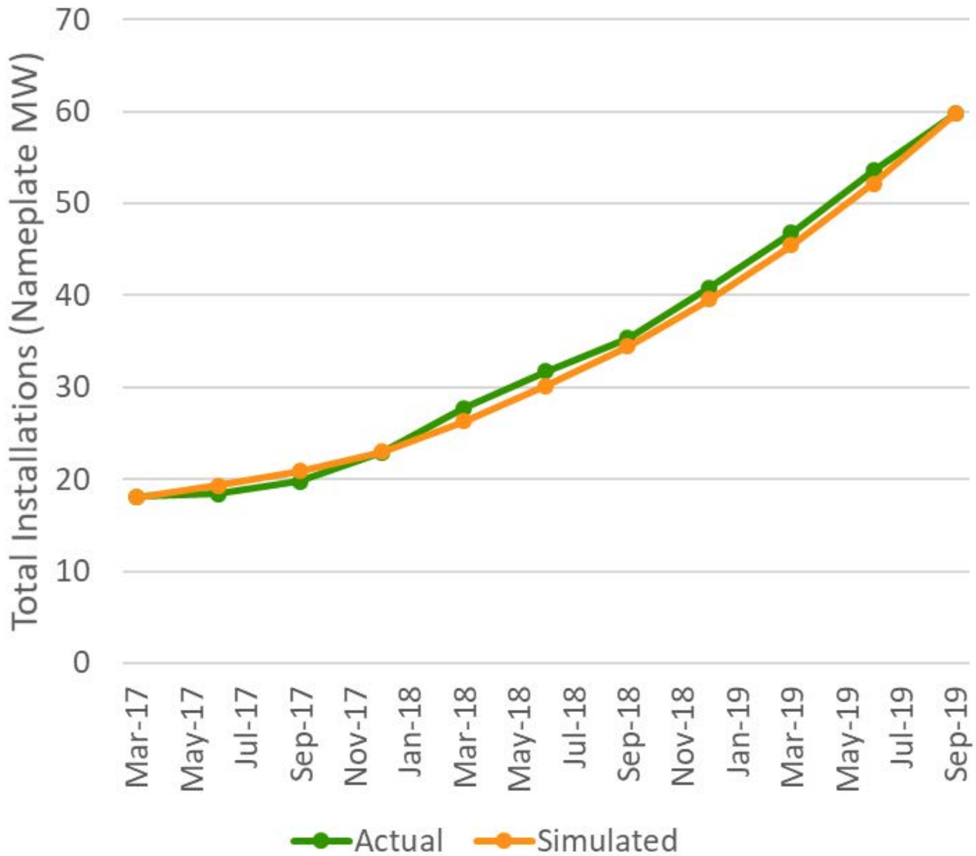
F **Word-of-Mouth Strength:** the strength of peer-to-peer influence dictates the slope of the growth phase of the S-shaped curve

Two other important model parameters addressed in Figure 9 are the "marketing effectiveness" (analogous to the "p" coefficient in the original Bass formulation) and the "word-of-mouth strength" (analogous to the "q" coefficient in the original Bass formulation). These Bass Diffusion parameters, which influence the shape and speed at which the long-run market share is realized, were calibrated such that a backcast simulation of adoption was well-fitted to historical BESS adoption data for SDG&E, as shown in Figure 10.[21,22]

[21] SDG&E's Advanced Energy Storage Systems database was the source for historical BESS adoption.

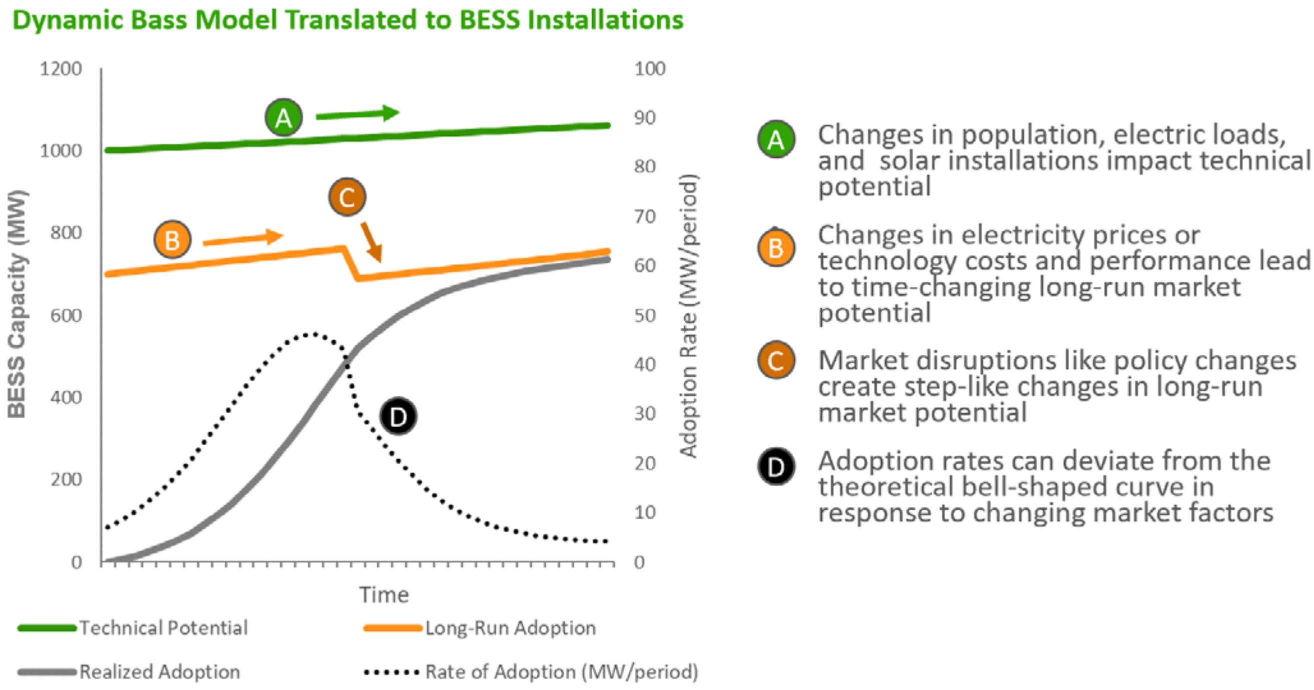
[22] Due to the limited number of historical residential stand-alone BESS installations, the calibrated Bass Diffusion parameters for solar-paired residential systems were also used for stand-alone residential systems. In contrast, adequate historical information was available to uniquely calibrate non-residential Bass Diffusion parameters for both stand-alone and solar-paired systems.

FIGURE 10. BACKCAST OF TOTAL HISTORICAL BESS ADOPTION FOR MODEL CALIBRATION (NAMEPLATE MW)



The model was used to estimate technical, long-run market potential, and realizable or achievable BESS adoption potential, similar to Figure 11. The technical potential, representing the upper bound on technically feasible BESS adoption, was a function of forecasted building loads and installed PV systems. PV adoption were based on a ZIP-Code level forecast that Lumidyne produced for SDG&E's Distribution Planning Group in 2019.

FIGURE 11. ILLUSTRATIVE BESS ADOPTION POTENTIAL



Source: Lumidyne

For solar-paired BESS, the technical potential was estimated by multiplying the ZIP-Code level solar PV forecasts by the ratio of BESS size to kW-DC of solar applied in the economic analysis (see further discussion in the **BESS Economic Assessment** section). As such, technical potential for solar-paired BESS included potential from both BESS retrofits on existing solar PV systems and bundled solar PV plus storage installations.

For stand-alone BESS, the following steps were taken to generate estimates of technical potential:

1. Using meter count data from SDG&E, we forecasted future meter counts using building growth rates calculated from historical census data by ZIP Code and forecasted building counts from the CEC for all of SDG&E's territory.
2. Using average residential and non-residential load shapes per meter from SDG&E, we scaled the load shapes by meter counts to represent total forecasted load for residential versus non-residential customers.
3. We reduced the total forecasted load by the percentage of buildings anticipated to have solar PV systems.
4. We then multiplied the forecasted non-solar peak building loads by the ratio of BESS size per kW of peak load, while ensuring consistency with the ratio applied in the economic assessment of the BESS.

Notably, this modeling approach ensured consistency between the solar PV and BESS adoption forecasts for each sector and ZIP Code.

BESS Economic Assessment

The team performed economic assessments – from a customer's point-of-view – of BESS systems and a "no system" scenario for each sector and BESS type (e.g. stand-alone, bundled solar PV plus storage, and storage added to existing PV). The following sections detail the key assumptions made in those economic assessments.

System Characteristics

The BESS sizes and operating parameters considered in these economic assessments are provided in Table 14. Residential system sizes were similar to the Tesla Powerwall, which has been one of the most commonly installed systems historically. Non-residential systems were sized to be near the average non-residential system size in SDG&E's Advanced Energy Storage System database.

Table 14. BESS System Characteristics

	Residential	Non-Residential
Energy (kWh/system)	13.2	100
Power (kW/system)	5	50
Storage Duration (hours)	2.64	2
Roundtrip Efficiency (%)	90%	90%
Minimum Charge Level (%)	5%	5%
Maximum Charge Level (%)	95%	95%
Expected Lifetime (years)	10	10

For solar-paired systems, the modeled PV system characteristics are shown in Table 15. The system sizes reflect average installed sizes since 2018 derived from the California Distributed Generation Statistics' (DG Stats) database.[23] The PV capacity factors reflect variation in solar irradiance profiles provided by SDG&E.

Table 15. Solar PV System Characteristics

	Residential			Non-Residential		
Climate Zone	Size (kW-DC)	Capacity Factor (%)	Consumption Met by Solar (%/premise)	Size (kW-DC)	Capacity Factor (%)	Consumption Met by Solar (%/premise)
Coastal	6.2	19%	90%	110.5	19%	38%
Desert	8.2	22%	90%	87.1	22%	34%
Inland	6.7	19%	90%	58.8	19%	20%
Mountain	7.4	18%	90%	87.0	18%	27%

[23] The NEM Currently Interconnected Data Set, last updated 10/31/2019, was accessed at https://www.californiadgstats.ca.gov/download/interconnection_nem_pv_projects/.

Table 16 shows the characteristics of the gross building load (i.e. prior to load modification from BESS and solar PV systems). Average load shapes per residential versus non-residential meter were provided by SDG&E and scaled for this analysis. The analysis scaled residential load shapes to ensure that 90% of the annual building consumption would be met by the modeled PV system size. Non-residential load shapes were scaled by meter-per-premise counts provided by SDG&E to account for premises having more than one meter.

TABLE 16. GROSS BUILDING LOAD CHARACTERISTICS

	Residential		Non-Residential	
Climate Zone	Annual Consumption (kWh/premise)	Peak Load (kW/premise)	Annual Consumption (kWh/premise)	Peak Load (kW/premise)
Coastal	11,275	2.3	478,346	83.6
Desert	17,980	3.7	496,004	86.7
Inland	12,415	2.5	484,569	84.7
Mountain	13,349	2.7	512,524	89.6

As part of the economic assessments, the team condensed hourly load shapes into an average week per month by finding average loads for each day of the week and hour of the day in each month. As such, the peak loads shown in Table 16 provide a conservative estimate of maximum load, which in turn leads to conservative estimates of non-residential demand charge savings when calculating utility bills.

BESS DISPATCH OPTIMIZATION

Similar to the BESS dispatch optimization routines described in the **Utility Bill Analysis** sections of this report, a mixed-integer optimization model was used to simulate the optimal charging and discharging strategy for the stand-alone and solar-paired systems considered in the adoption forecast. However, instead of optimizing all 8,760 hours of the year, these optimization routines relied on an average week (i.e. 168 hours per month) for the sake of computational tractability.

UTILITY BILL SAVINGS

The forecast was initiated using June 2019 TOU-DR1 (see Table 2 and Table 3) and January 2019 AL-TOU Secondary (see Table 8 through Table 10) electric rates for residential and non-residential sectors, respectively. These rates were escalated at 2.1 percent per year over the forecast period.

The optimal BESS dispatch strategy – and the associated net building load seen at the meter – for an average week was extrapolated to every week in each month. Then the model calculated all applicable bill charges for each system type for each month following the same equations described in the previous **Utility Bill Analysis** sections of this report.

The baseline systems for determining bill savings are shown in Table 17. For this analysis, the team estimated bill savings for solar-paired systems using two methods: 1) accounting for bill savings resulting from both solar PV and BESS; and, 2) accounting for the incremental increase in bill savings solely from the addition of the BESS.

TABLE 17. BASELINE SYSTEM FOR BILL SAVINGS

BESS System Type	Baseline System
Solar PV plus Storage	No System
Stand-Alone Storage	No System
Storage Added to Existing PV	Solar PV

INSTALLED SYSTEM COSTS

Table 18 shows the assumed BESS installed costs over the forecast period. Statistics from the Self-Generation Incentive Program (SGIP) were the source of the 2019 costs.[24] The forecast assumes that BESS costs decline at a rate of 7% per year.[25] These costs are lower than the costs reported by installers participating in our vendor survey.

TABLE 18. BESS UPFRONT INSTALLED COSTS ($/KWH)

Year	Residential	Non-Residential
2019	767	948
2020	713	882
2021	663	820
2022	617	763
2023	574	709
2024	534	660
2025	496	613
2026	462	570
2027	429	530
2028	399	493
2029	371	459
2030	345	427

When estimating the payback time for bundled solar PV plus storage systems, it was necessary to consider solar PV installed costs, as shown in Table 19. DG Stats was the source of the 2019 costs, and rates declined at 4.2% per year.

[24] Accessed on 26 December 2019, the SGIP statistics are available at https://sites.energycenter.org/sgip/statistics.

[25] Per an analysis performed by Greentech Media, referenced at https://www.utilitydive.com/news/not-so-fast-battery-prices-will-continue-to-decrease-but-at-a-slower-pace/518776/.

TABLE 19. SOLAR PV UPFRONT INSTALLED COSTS ($/KW-DC)

Year	Residential	Non-Residential
2019	3,813	3,028
2020	3,653	2,900
2021	3,500	2,779
2022	3,353	2,662
2023	3,212	2,550
2024	3,077	2,443
2025	2,948	2,340
2026	2,824	2,242
2027	2,705	2,148
2028	2,592	2,058
2029	2,483	1,971
2030	2,379	1,889

In addition to incorporating the federal ITC for solar PV and solar plus storage systems, the analysis included SGIP incentives for BESS.[26] Since new residential SGIP non-equity incentives have not been issued since April 2018, the forecast assumed no further incentives would be issued for residential systems (though it's possible that funding could be continued).[27] A quick sensitivity analysis, where SGIP funding was assumed to be reinstated, led to a residential BESS adoption growth difference of less than 1 percent.

For non-residential BESS, it's uncertain how long funding will last and at which dates the remaining incentive steps will be triggered. For this forecast, it was assumed that Steps 3 through 5 incentive levels will each last roughly 2.5 years and will persist through the end of 2025, as shown in Table 20. It was also assumed that modeled solar-paired BESS claimed the federal ITC, which in turn reduced the SGIP incentive level. System interconnection fees of $132 per interconnection were also assessed as part of this economic evaluation.

TABLE 20. MODELED NON-RESIDENTIAL AVERAGE SGIP INCENTIVES ($/KWH)

Year	Stand-Alone	Solar-Paired
2019	350	250
2020	350	250
2021	300	220
2022	300	220
2023	275	200
2024	250	180
2025	250	180
2026	0	0
2027	0	0
2028	0	0
2029	0	0
2030	0	0

[26] Federal investment tax credits (ITCs) are described at https://programs.dsireusa.org/system/program/detail/1235 and https://programs.dsireusa.org/system/program/detail/658.

[27] Residential SGIP incentive applicants applying through the Center of Sustainable Energy (i.e., SDG&E customers) have been waitlisted since April 30, 2018, per https://www.selfgenca.com/home/about/.

Payback Time

Simple payback time was the key economic metric influencing the BESS adoption forecasts. Equation 15 provides the equation for simple payback time.

Equation 15. Simple Payback Time

$$PaybackTime = \frac{UpfrontInstallCost - TaxCredit - Incentives + InterconnectFee}{FirstYearBillSavings - O\&MCosts}$$

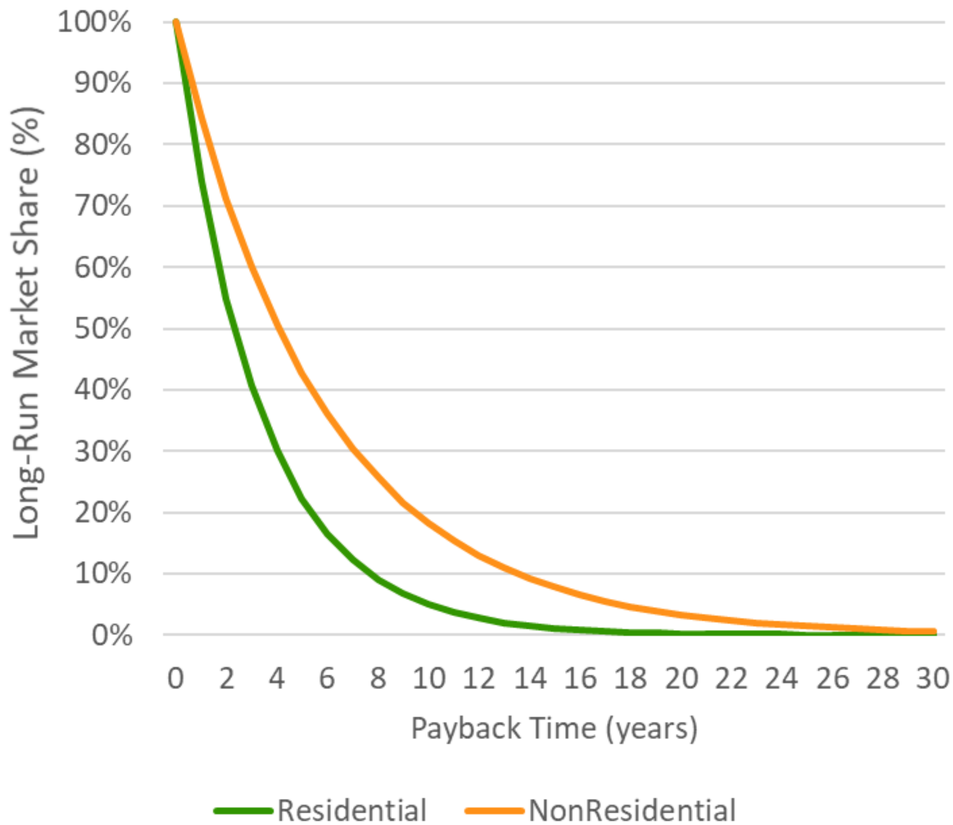
Where,

$PaybackTime$: the simple payback time [years]
$UpfrontInstallCost$: the upfront BESS and, if applicable, solar PV system installed costs, which also includes the present value of BESS replacement costs incurred after 10 years of operation [$]
$TaxCredit$: the federal investment tax credit [$]
$Incentives$: the SGIP incentive [$]
$InterconnectFee$: the system interconnection fee [$]
$FirstYearBillSavings$: the first-year bill savings [$/year]
$O\&MCosts$: the BESS and, if applicable, solar PV system operation and maintenance costs [$/year]

Depending on the sector, the model considered solar plus storage payback times for different economic conditions. For example, residential solar-paired systems relied on the bundled solar plus storage payback time, which included PV and BESS equipment costs and the combined bill savings from these equipment types. This approach was meant to reflect the most likely information that residential customers would have available, since it was deemed unlikely that BESS implementers would advertise the incremental economics of adding storage to a residential solar PV system. However, for non-residential customers likely to demand a more sophisticated economic analysis of solar-paired systems, the model applied payback times associated with an incremental addition of a BESS to an existing solar PV system. In this situation, only the BESS equipment costs and incremental bill savings were included in the payback times.

For each BESS configuration and sector, the analysis used the simple payback times in combination with a sector-specific payback acceptance curve to estimate the long-run market share (as described in the section on **Adoption Forecast Methodology**). The customer sensitivity to payback times, which influences the shape of the payback acceptance curves, relied on values derived from adoption of solar PV systems. The team took this approach because BESS adoption is still in its early stages and available PV adoption data has greater history and richness to permit a reliable calibration of customer sensitivity. Figure 12 depicts the payback acceptance curves used in the BESS adoption forecasts.

FIGURE 12. BESS PAYBACK ACCEPTANCE CURVE (MARKET SHARE %)



ANNUALIZED COSTS

Though not directly used in this adoption forecasting model, the team also calculated the levelized annual cost of meeting building load. The intent of this metric was to capture the net present value (NPV) of all cash flows related to purchasing grid electricity and installing BESS and solar PV equipment. The NPVs were then levelized into representative annual costs to compare against the annual cost of solely meeting building load with grid electricity.

Equation 16 gives the formula for the total net present value (NPV) of all cash flows over the modeled 20-year economic horizon.

EQUATION 16. TOTAL NET PRESENT VALUE OF MEETING BUILDING LOAD

$$TotalNPV = UtilityBill\_NPV + LoanPmt\_NPV + O\&M\_NPV + InterconnectFee - Deductions\_NPV$$

Where,

TotalNPV: the sum of the NPVs of all cash flows [$]
UtilityBill_NPV: the NPV of utility bills [$]
LoanPmt_NPV: the NPV of loan payments on BESS and, if applicable, solar equipment after subtracting investment tax credits and incentives [$]
O&M_NPV: the NPV of operation and maintenance costs on BESS and, if applicable, solar equipment [$]
InterconnectFee: the interconnection fee [$]

$Deductions\_NPV$: the NPV of interest, equipment depreciation and operating expense tax deductions (for non-residential customers only) [$]

Using Microsoft Excel's syntax, the equation for levelizing the total NPV for all cash flows, based on a 20-year economic horizon, is shown in Equation 17.

EQUATION 17. LEVELIZED ANNUAL COST

$$LevAnnualCost = PMT(DiscountRate, 20, TotalNPV)$$

Where,

$LevAnnualCost$: the levelized annual cost of meeting building load [$/year]
PMT: the loan payment function in Microsoft Excel, which converts a lump sum into uniform annual payments based on an assumed interest rate
$DiscountRate$: the consumer discount rate [%/year]

RESULTS

This section describes the results from this market study, including survey results, utility bill analysis results, market forecast results, and economic assessment results.

SURVEY RESULTS

While we were not able to engage all of the key vendors identified during the scoping of this study, we gathered survey responses from a range stakeholders that offer unique insights into this emerging market. In general, we found that industry stakeholders are excited and optimistic about the potential for BTM batteries, though many lack the information needed to help guide their business planning and market activities going forward.

Some factors are nearly universally understood by vendors while others are not. For example, many of the vendors we surveyed provided an accurate estimate of the ratio of summer peak-to-off-peak rates for residential customers in San Diego (i.e. about 2-to-1). Vendor survey respondents also generally had a clear understanding of how BTM batteries can potentially save customers money (i.e. by increasing self-consumption of on-site solar generation and avoiding on-peak grid energy consumption). Vendors also generally provided consistent estimates of both BESS installed costs and per-unit costs (e.g. $/kWh).

However, when asked to address the value of storage independently from the value of solar, vendors either ignored the question or refused to break out these two value streams. Examples of the types of responses we received from vendors on this question included:

> *"Breaking out savings provided by a battery without solar is not reasonable. The savings is derived from self-generation (solar), not from the ability to store energy on site"*

> *"We typically are installing solar with the battery so that is reducing the bill. Also many of our clients already have solar and are adding a battery"*

Vendor survey respondents generally seemed comfortable estimating solar + storage utility bill savings, but were considerably less comfortable with attempting to estimate the economic benefits of storage-only systems. In some cases, this may be due to the fact that the respondents do not know what portion of utility bill savings are associated with solar and what portion should be attributed to the addition of storage. However, this may also be a case vendors preferring to "*bundle*" the benefits of solar and storage in order to avoid admitting that the economic benefits of BESS alone are relatively small. We will discuss this further in the **Bill Analysis Results** section, below.

We were only able to validate the installed BESS capacity estimates of two vendors against capacity estimates from SGIP, both for vendors installing exclusively residential systems. For one vendor, the installed capacity reported by SGIP was about 82% of the capacity reported in our survey. For the second vendor, the installed capacity reported by SGIP was about 60% of the capacity reported in our survey. A third vendor simply told us to refer to SGIP capacity numbers, implying that 100% of systems were accounted for in the SGIP dataset. However, in comparing AES data to SGIP data, we find that only about 40% of residential BESS interconnected in SDG&E's territory are reported in the SGIP database.

While a few of the utility industry stakeholders we surveyed told us that installed BESS costs reported by SGIP are inflated, we found that the costs reported by vendors in our survey were consistently higher. We used SGIP-reported installed BESS costs in our adoption forecasts (see Table 18), but the average per-unit costs reported in our VoV survey was over $1,200 per kWh.

In general, our VoV survey responses were skewed toward small, residential solar + storage installers. This was an artifact of partnering with Energy Sage to field our vendor survey, as their memberships is largely comprised of residential solar and solar + storage installers. Smaller vendors may also be more inclined to participate in this type of study as they perceive less risk in the sharing of information. In general, these respondents were working solely in the residential sector, though most anticipated moving into the commercial sector within the next decade. To read all of their survey responses, refer to **Appendix A**.

Of the residential customers in our VoC survey that live in California, about 6% said they currently own a whole-home BESS, while 22% said they are likely to purchase a BESS within the next 3 years. Both the level of self-reported BESS ownership and likelihood to purchase are much higher than the levels of adoption estimated by our team. We estimate that only about 0.3 percent of SDG&E's residential customers currently own a BESS, and that market share isn't likely to reach 6% until 2023 (i.e. in three years). While it is certainly possible that our forecast greatly underestimates the market adoption growth potential in San Diego, we think it is more likely that residential customers greatly overestimate their likelihood to purchase new technologies (and in some cases, customers don't understand what these new technologies are or if they do in fact own them).

BILL ANALYSIS RESULTS

Our team's rigorous analysis of customer utility bills provides supporting evidence for the following assertions (for all bill analysis data, see **Appendix A**):

1. <u>Poor economic performance in Phase 2 of the commercial BESS field study may not have been due to differences in customer rates or the presence of solar</u>. In their discussion of the field study results, researchers assumed that having customers in Phase 2 of the study on the DG-R rate led to poor economic performance of systems in that phase of the study. In our analysis, we found that utility bills (and bill savings) are fairly similar for customers on both DG-R and AL-TOU rates, and if anything, being on the DG-R rate should deliver greater utility bill savings, not lower. Researchers in that study also observed that solar was present on facilities in Phase 2 of the study, and that this may have contributed to the poor economic performance of those systems. However, again, in our analysis we can clearly see that systems paired with PV always out-perform those without PV.
2. <u>The majority of bill savings for both residential and commercial customers is delivered by solar PV, while a relatively smaller fraction comes from the BESS</u>. For residential systems, we found that the customer's annual utility bill can be reduced by about 85% with the addition of solar, while adding the BESS only delivers an additional 6% savings relative to a solar-only system. Similarly, for commercial systems, we found that a customer's annual utility bill can be reduced by 36% with the addition of solar, while adding a BESS only lowers the customer's bill by 17%. Without solar pairing, a residential BESS is not at all economically viable, while a commercial BESS is significantly less attractive and will take longer to pay back.
3. <u>Restricting the ability of a customer's BESS to export electricity to the grid does not significantly impact the economic viability of the BESS</u>. While some vendors reported that the financial viability of a BESS was artificially limited by restrictions that

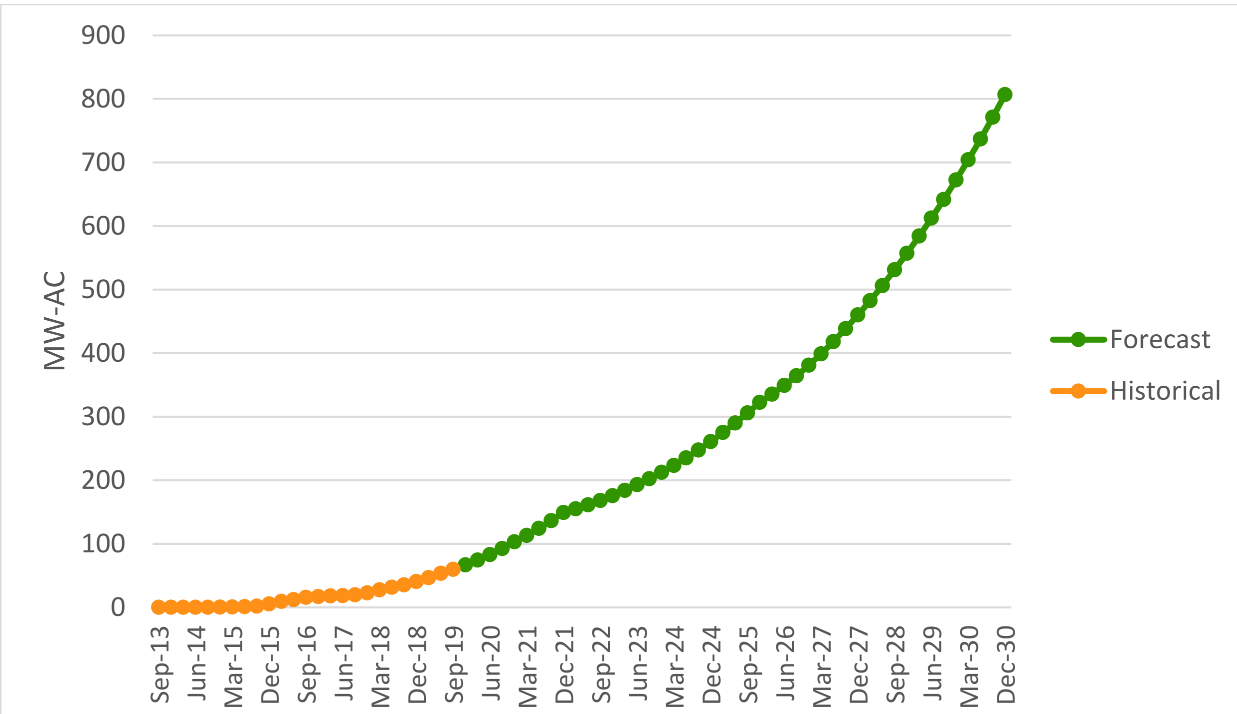
currently prohibit them from feeding power back onto the electric grid, we found that this restriction does not have a significant impact on customer bill savings.

4. Accounting for differences in seasonal TOU rates and BESS efficiency losses, it is only economically viable to operate a residential BESS in San Diego for 4 months during the year. In the winter season, the difference between peak and off-peak rates is too small to represent meaningful TOU arbitrage savings, and does not justify the added electricity consumption of the BESS associated with its round-trip efficiency losses.

Market Forecast Results

The research team anticipates steady market growth for both the residential and non-residential BESS markets in San Diego through 2030. The only anticipated barrier to steady growth is the expiration of the federal ITC in 2022. We anticipate that combined aggregate BTM storage capacity will grow on average 130% annually, from around 60 MW in 2019 to over 800 MW in 2030. We anticipate that about two-thirds of total capacity growth will be in the commercial sector, while the remaining one-third will come from the residential sector. Figure 13 illustrates our combined BTM battery capacity forecast through 2030.

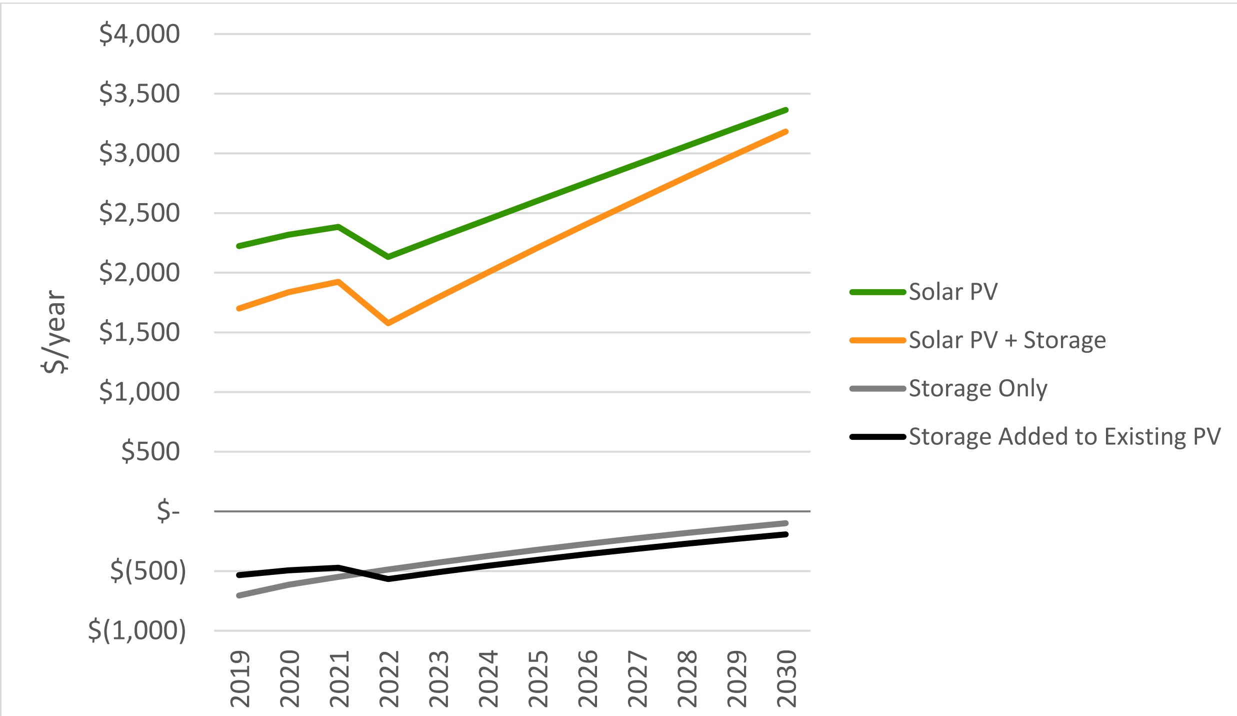
Figure 13. Total BTM Battery Capacity Forecast for SDG&E Through 2030



Economic Assessment Results

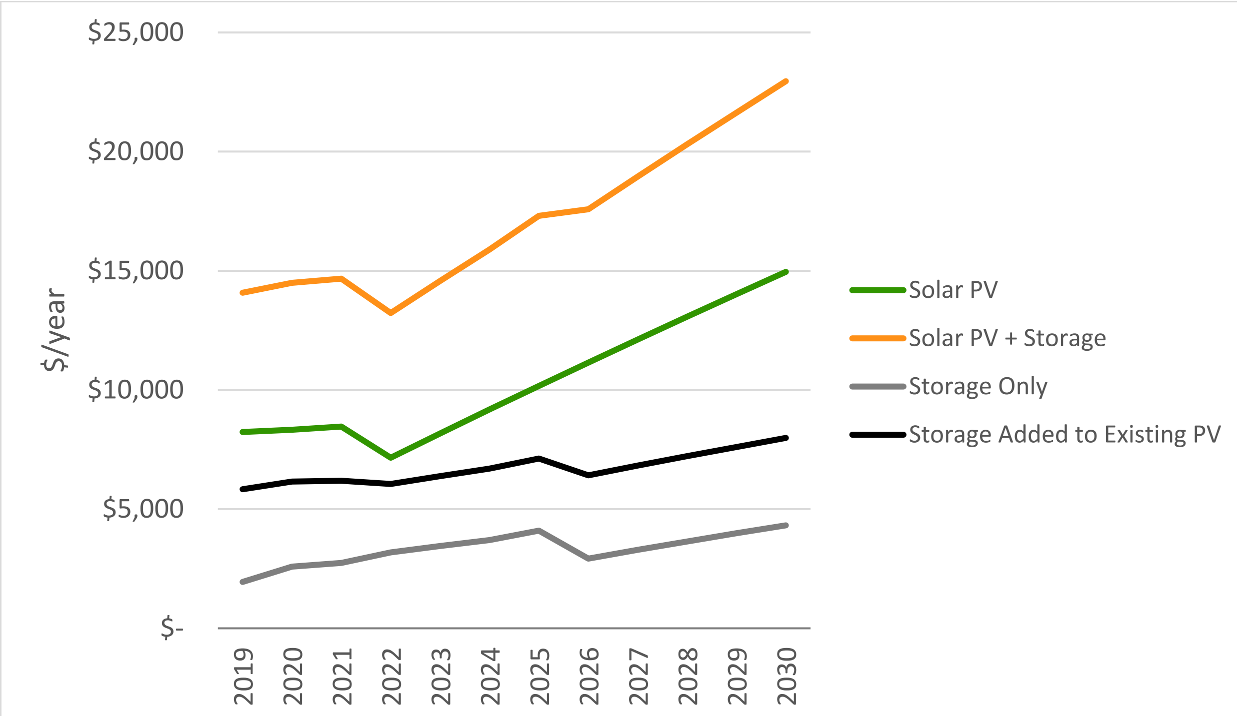
Based on the assumptions outlined in the **Methodology** section of this report and the results of our economic assessment, we compared the cost of BESS and BESS+PV ownership to annually utility costs for residential and non-residential customers. For residential customers, we found that the levelized annual cost savings associated with installing a BESS alone, or in addition to an existing PV system, is negative and remains negative over the forecast period. In contrast, the levelized annual cost savings associated with PV and solar + storage is positive and increasing over the forecast period (Figure 14).

Figure 14. Levelized Annual Energy Cost Savings for Residential Customers



For non-residential systems, we observed similar trends, though all cases deliver positive annual cost savings and the solar + storage case looks much more attractive (Figure 15).

FIGURE 15. LEVELIZED ANNUAL ENERGY COST SAVINGS FOR NON-RESIDENTIAL CUSTOMERS



The research team also estimated simple payback times for each system type in both residential and non-residential applications. For residential customers, PV has the fastest payback in any year, while solar + storage has a similar but consistently longer payback time across the board. Storage added to an existing PV system had by far the longest simple payback time (Figure 16). By contrast, for non-residential customers, we found that storage added to an existing PV system actually had the shortest payback time, while storage-only systems tended to have the longest payback time (Figure 17).

FIGURE 16. SIMPLE PAYBACK TIMES FOR RESIDENTIAL CUSTOMERS

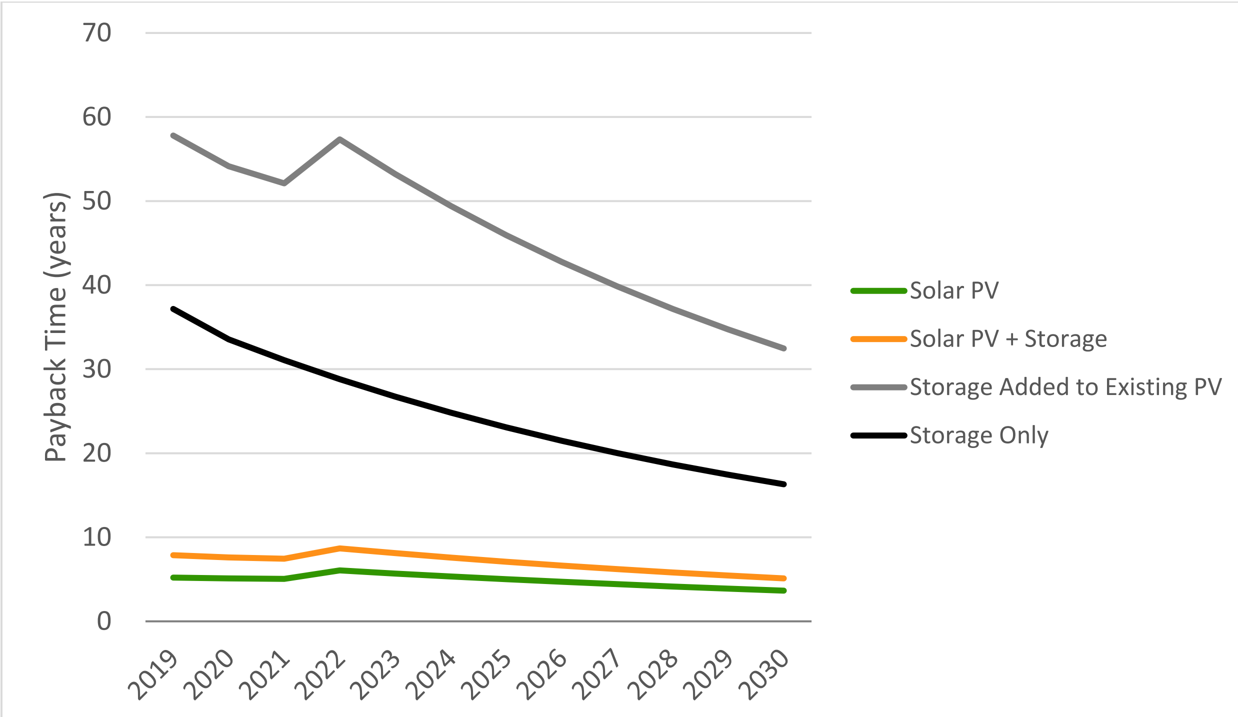
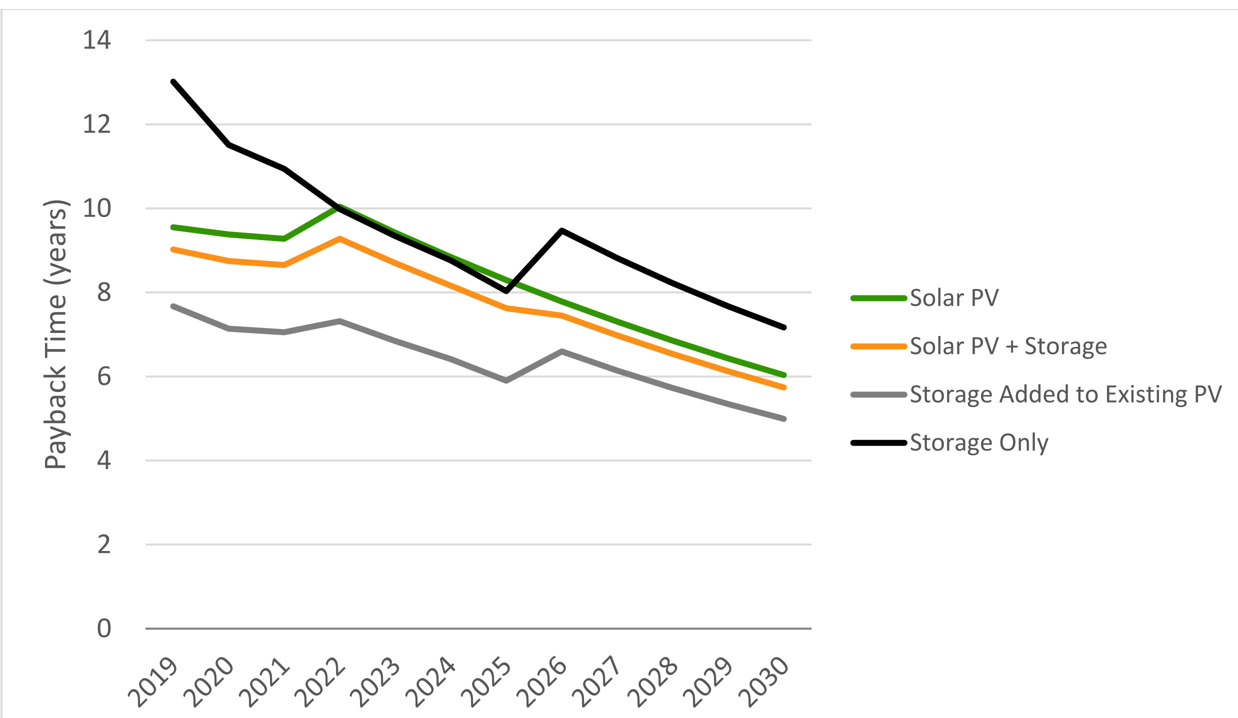


FIGURE 17. SIMPLE PAYBACK TIMES FOR NON-RESIDENTIAL CUSTOMERS



DISCUSSION

Our survey results indicate that both customers and vendors are generally bullish on BESS technology and its market potential, but our detailed market and economic analyses suggest that their enthusiasm is not entirely justified. While commercial BESS installations represent the more attractive financial option relative to residential systems, they are also the most reliant on incentive availability for continued market growth. By comparison, while we have observed that residential BESS installations are significantly less sensitive to the availability of financial incentives, they are also significantly less attractive in terms of economic benefit to the customer.

While vendors reported that BESS are often sold to residential customers primarily as a backup-power solution, this remains a relatively expensive option for such applications. Also, by reserving storage capacity to be used in the event of an outage, customers are precluded from using the BESS to store self-generated solar power and reduce their utility bills. To cost-effectively deliver backup power during a grid outage, engine-driven generators represent a more rational economic choice. However, in light of electrification and decarbonization goals, we do not anticipate that fossil-fueled generators will be promoted broadly to customers as a resiliency alternative. In order for BESS technology to reach price parity with backup generators, both the cost of the systems and the cost to install them will need to drop significantly.

The ability of BESS to reduce customer utility bills depends largely on its capacity to store self-generated solar power. Where batteries are installed without solar PV, in general, it becomes much more difficult to make the case financially for adoption of the BESS. For residential customers, adding a BESS to an existing PV system poses the longest payback time of the cases we considered. For commercial customers, the opposite is true; adding a BESS to an existing PV system can deliver a faster payback relative to other scenarios, largely because the PV system has already been paid for.

Unless new programs or services can be used to influence how customers use their BESS, there will be approximately 740 MW of new uncontrolled battery load connecting to the electric grid in San Diego over the next decade. Judging from what we've seen so far, the charge-discharge behavior of these batteries will soak up some over-generation of distributed solar, but will generally not coincide with overall grid needs and system peaks. For these assets to deliver more overall value, they will need to be connected to some form of supervisory control network, such as a distributed energy resource management system (DERMS). Without a functioning DERMS in place, much of the potential value of distributed battery storage is unlikely to be realized.

CONCLUSIONS

By 2030, we estimate that a cumulative $575 million in annual utility bills savings could be achievable by residential and non-residential customers. However, if non-residential systems behave similarly to what was observed in the field study (i.e. sub-optimally), the total savings potential drops to about $390 million. However, non-residential customers will capture more overall cost-savings, while the overall economic benefit to residential customers will be marginal or negative. At the same time, the SDG&E could lose more than half a million dollars in operational revenue.

To ensure that more value is derived from BTM batteries and that the net societal impacts are positive, systems should be monitored and controlled collectively to optimize beneficial outcomes. Presently, we are relying on individual customers and vendors to make the right decision about how and when BESS should be managed, and we have little reason to be confident that the best decisions are being made.

Residential customers who want whole-home battery storage may be more inclined to purchase a new home built with a BESS included. Rolling the cost of the BESS into new-home financing adds relatively little to the overall home price, while the real estate developers can market the homes based on this feature and potentially sell them at a premium in target markets. Utilities should consider working with real-estate developers to established shared control or automatic enrollment of BESS into custom rate plans or other programs.

This approach – working with housing developers to aggregate BESS capacity – is already being taken or considered by multiple leading battery vendors. By incorporating BESS monitoring and management into the design of a new community, in aggregate they can be treated as a virtual power plant (VPP) and more value can be delivered to both the customers and the local utilities.

APPENDIX A – UTILITY BILL ANALYSIS

Residential Customer Utility Bill (TOU-DR1)

Row Labels	Minimum Charges	Summer Off-Peak Energy	Summer On-Peak Energy	Summer Super-Off Peak Energy	Winter Off-Peak Energy	Winter On-Peak Energy	Winter Super-Off Peak Energy	Grand Total
No System		$ 560	$ 600	$ 274	$ 668	$ 452	$ 482	$ 3,037
BESS		$ 528	$ 51	$ 622	$ 668	$ 452	$ 482	$ 2,805
PV	$ 10	$ (230)	$ 425	$ 41	$ (163)	$ 348	$ 22	$ 453
PV + BESS	$ 31	$ (28)	$ (61)	$ 117	$ (163)	$ 348	$ 22	$ 266

Residential Customer Utility Bill (TOU-DR2)

Row Labels	Minimum Charges	Summer Off-Peak Energy	Summer On-Peak Energy	Winter Off-Peak Energy	Winter On-Peak Energy	Grand Total
No System		$ 867	$ 565	$ 1,150	$ 452	$ 3,035
BESS		$ 1,239	$ 48	$ 1,150	$ 452	$ 2,890
PV	$ 10	$ (173)	$ 397	$ (137)	$ 348	$ 446
PV + BESS	$ 31	$ 116	$ (57)	$ (137)	$ 348	$ 300

Residential Customer Utility Bill Savings (TOU-DR1)

Row Labels	Minimum Charges	Summer Off-Peak Energy	Summer On-Peak Energy	Summer Super-Off Peak Energy	Winter Off-Peak Energy	Winter On-Peak Energy	Winter Super-Off Peak Energy	Grand Total
BESS		$ 32	$ 549	$ (349)				$ 232
PV	$ (10)	$ 790	$ 175	$ 233	$ 832	$ 104	$ 460	$ 2,584
PV + BESS	$ (31)	$ 589	$ 661	$ 157	$ 832	$ 104	$ 460	$ 2,771

Residential Customer Utility Bills Savings (TOU-DR2)

Row Labels	Minimum Charges	Summer Off-Peak Energy	Summer On-Peak Energy	Winter Off-Peak Energy	Winter On-Peak Energy	Grand Total
BESS		$ (372)	$ 517			$ 145
PV	$ (10)	$ 1,040	$ 168	$ 1,287	$ 104	$ 2,589
PV + BESS	$ (31)	$ 751	$ 623	$ 1,287	$ 104	$ 2,734

Residential Customer Annual Consumption, kWh (TOU-DR1)

Row Labels	Summer Off-Peak Energy	Summer On-Peak Energy	Summer Super-Off Peak Energy	Winter Off-Peak Energy	Winter On-Peak Energy	Winter Super-Off Peak Energy	Grand Total
No System	1,863	1,154	1,095	2,132	1,398	1,595	9,237
BESS	1,742	97	2,472	2,132	1,398	1,595	9,437
PV	-953	923	214	-616	1,268	88	924
PV + BESS	-117	-133	616	-616	1,268	88	1,106

Residential Customer Annual Consumption, kWh (TOU-DR2)

Row Labels	Summer Off-Peak Energy	Summer On-Peak Energy	Winter Off-Peak Energy	Winter On-Peak Energy	Grand Total
No System	2,958	1,154	3,727	1,398	9,237
BESS	4,202	97	3,727	1,398	9,424
PV	-739	923	-528	1,268	924
PV + BESS	496	-133	-528	1,268	1,103

Non-Residential Customer Annual Consumption, kWh (2017)

Row Labels	Summer Off-Peak Energy	Summer Semi-Peak Energy	Summer On-Peak Energy	Winter Off-Peak Energy	Winter Semi-Peak Energy	Winter On-Peak Energy	Grand Total
No System	97,878	93,687	93,138	72,262	122,738	18,114	497,816
Actual BESS	98,578	93,832	94,325	74,885	123,537	15,620	500,777
Optimized BESS	128,169	90,096	70,610	94,790	115,362	6,836	505,863

Non-Residential Customer Utility Bill (2017)

Row Labels	Non-Coincident Demand	Summer On-Peak Demand	Winter On-Peak Demand	Summer Off-Peak Energy	Summer Semi-Peak Energy	Summer On-Peak Energy	Winter Off-Peak Energy	Winter Semi-Peak Energy	Winter On-Peak Energy	Basic Service Fees	Grand Total
No System	$ 47,580	$ 24,704	$ 5,039	$ 7,948	$ 10,477	$ 11,313	$ 5,274	$ 11,567	$ 1,987	$ 188	$ 126,076
Actual BESS	$ 41,406	$ 21,507	$ 4,001	$ 8,005	$ 10,493	$ 11,457	$ 5,466	$ 11,642	$ 1,713	$ 188	$ 115,878
Optimized BESS	$ 35,768	$ 18,186	$ 3,400	$ 10,407	$ 10,075	$ 8,576	$ 6,919	$ 10,872	$ 750	$ 188	$ 105,142

Non-Residential Customer Annual Consumption, kWh (2019; AL-TOU Secondary)

Row Labels	Summer Off-Peak Energy	Summer On-Peak Energy	Winter Off-Peak Energy	Winter On-Peak Energy	Summer Super-Off Peak Energy	Winter Super-Off Peak Energy	Grand Total
No System	353,000	86,048	374,101	116,652	120,958	195,630	1,246,389
BESS	350,322	21,811	368,516	39,721	199,723	293,204	1,273,296
PV	126,428	66,575	156,555	106,790	48,625	79,122	584,095
PV + BESS	170,336	9,585	170,818	58,716	72,075	122,889	604,420

Non-Residential Customer Annual Consumption, kWh (2019; DG-R Secondary)

Row Labels	Summer Off-Peak Energy	Summer On-Peak Energy	Winter Off-Peak Energy	Winter On-Peak Energy	Summer Super-Off Peak Energy	Winter Super-Off Peak Energy	Grand Total
No System	353,000	86,048	374,101	116,652	120,958	195,630	1,246,389
BESS	351,057	21,176	371,804	37,444	199,723	292,896	1,274,098
PV	126,428	66,575	156,555	106,790	48,625	79,122	584,095
PV + BESS	175,377	4,878	198,669	33,651	72,107	124,147	608,829

Non-Residential Customer Utility Bill (2019; AL-TOU Secondary)

Row Labels	Non-Coincident Demand	Summer On-Peak Demand	Winter On-Peak Demand	Summer Off-Peak Energy	Summer On-Peak Energy	Winter Off-Peak Energy	Winter On-Peak Energy	Basic Service Fees	Summer Super-Off Peak Energy	Winter Super-Off Peak Energy	Grand Total
No System	$ 129,902	$ 29,380	$ 26,587	$ 42,522	$ 12,179	$ 42,561	$ 14,724	$ 2,236	$ 11,949	$ 19,557	$ 331,598
BESS	$ 104,621	$ 10,647	$ 15,322	$ 42,200	$ 3,087	$ 41,926	$ 5,014	$ 2,236	$ 19,731	$ 29,312	$ 274,095
PV	$ 86,681	$ 27,674	$ 26,129	$ 15,229	$ 9,423	$ 17,811	$ 13,479	$ 2,236	$ 4,804	$ 7,910	$ 211,376
PV + BESS	$ 62,632	$ 8,846	$ 14,361	$ 20,519	$ 1,357	$ 19,434	$ 7,411	$ 2,236	$ 7,120	$ 12,285	$ 156,200

Non-Residential Customer Utility Bill (2019; DG-R Secondary)

Row Labels	Non-Coincident Demand	Summer On-Peak Demand	Winter On-Peak Demand	Summer Off-Peak Energy	Summer On-Peak Energy	Winter Off-Peak Energy	Winter On-Peak Energy	Basic Service Fees	Summer Super-Off Peak Energy	Winter Super-Off Peak Energy	Grand Total
No System	$ 81,061	$ 14,217	$ 1,012	$ 51,404	$ 27,503	$ 51,974	$ 38,219	$ 2,236	$ 14,993	$ 24,479	$ 307,098
BESS	$ 64,474	$ 5,152	$ 633	$ 51,121	$ 6,768	$ 51,655	$ 12,268	$ 2,236	$ 24,756	$ 36,650	$ 255,712
PV	$ 54,091	$ 13,392	$ 995	$ 18,410	$ 21,279	$ 21,750	$ 34,988	$ 2,236	$ 6,027	$ 9,900	$ 183,068
PV + BESS	$ 38,408	$ 3,942	$ 570	$ 25,538	$ 1,559	$ 27,601	$ 11,025	$ 2,236	$ 8,938	$ 15,535	$ 135,352

Non-Residential Customer Bill Savings (2019; AL-TOU Secondary)

Row Labels	Non-Coincident Demand	Summer On-Peak Demand	Winter On-Peak Demand	Summer Off-Peak Energy	Summer On-Peak Energy	Winter Off-Peak Energy	Winter On-Peak Energy	Summer Super-Off Peak Energy	Winter Super-Off Peak Energy	Grand Total
BESS	$ 25,281	$ 18,733	$ 11,265	$ 323	$ 9,092	$ 635	$ 9,710	$ (7,781)	$ (9,755)	$ 57,504
PV	$ 43,221	$ 1,706	$ 458	$ 27,293	$ 2,756	$ 24,750	$ 1,245	$ 7,146	$ 11,647	$ 120,222
PV + BESS	$ 67,270	$ 20,534	$ 12,226	$ 22,004	$ 10,822	$ 23,127	$ 7,313	$ 4,829	$ 7,272	$ 175,398

Non-Residential Customer Bill Savings (2019; DG-R Secondary)

Row Labels	Non-Coincident Demand	Summer On-Peak Demand	Winter On-Peak Demand	Summer Off-Peak Energy	Summer On-Peak Energy	Winter Off-Peak Energy	Winter On-Peak Energy	Summer Super-Off Peak Energy	Winter Super-Off Peak Energy	Grand Total
BESS	$ 16,588	$ 9,065	$ 379	$ 283	$ 20,734	$ 319	$ 25,951	$ (9,763)	$ (12,171)	$ 51,386
PV	$ 26,971	$ 825	$ 17	$ 32,993	$ 6,224	$ 30,224	$ 3,231	$ 8,966	$ 14,579	$ 124,030
PV + BESS	$ 42,653	$ 10,276	$ 442	$ 25,866	$ 25,943	$ 24,373	$ 27,194	$ 6,055	$ 8,945	$ 171,746