Residential Battery Storage Operations in Rolling Blackouts: Can Customer Energy Storage Improve Grid Reliability?

Introduction

In electric power systems with rising renewable generation supply, variability and uncertainty is increased. As a result, utility and system operator resource adequacy (RA) practices must continue to evolve.[1] These RA assessment challenges were brought into focus in California in 2020 and Texas in early 2021. In California on August 14, 2020 the California Independent System Operator (CAISO) initiated rotating customer outages lasting up to several hours to reduce the risk of longer-duration widespread blackouts. This risk was brought on by a heat wave, increasing space cooling loads across the region. At the same time, solar generation was ramping down, causing lower-than-expected margins between net load and available supply resources. At 18:36 on August 14, CAISO was unable to maintain its load-plus-operating reserve obligation and issued Stage 3 Emergency notices to shed a total of 1000 MW of load; within two hours all load was ordered to be restored.

After widespread wildfires and the introduction of public safety power shutoffs (PSPS) in 2019, residential adoption of large storage plus solar photovoltaic (PV) systems in California—capable of providing backup power for days—increased significantly. Given this increased adoption, distributed energy resources (DER) may have mitigated a small portion of the risk facing CAISO. However, residential storage is primarily operated to maximize its owner's financial savings and personal backup power potential without consideration for the aggregate impacts on the energy system.

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If a few key steps are followed, customer-sited storage may contribute to resource adequacy and system reliability.

Depending on operating objectives and price signals, storage system operation may increase net load during system peak hours or fail to decrease net load. In an example from Twitter the following day,[2] a battery management system in California worked to maintain a high state-of-charge (SOC) to mitigate the risk of losing power in the rolling blackouts caused by the system capacity shortfall. Where the system normally would have discharged, the SOC was held constant as the gap narrowed between net load and supply until the system's owner intervened.

When bulk system reliability is at risk, there is an opportunity to leverage customer-sited storage systems as a distributed contribution to reserve margins. There will be trade-offs between the benefits to storage owners (reduced costs and backup capability) versus possible contributions to grid reliability, which may be weighed in planning studies.

This brief provides an illustrative analysis of how residential storage operates depending on owner incentives and price signals, and highlights the need for R&D to address the following key challenges:

1. Understanding how much energy supply residential storage systems could contribute to RA, and current limitations to accessing this potential.

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1 Electric Power Research Institute. *Program on Technology Innovation: Resource Adequacy Challenges: Issues Identified Through Recent Experience in California*. Palo Alto, CA: 2020. 3002019972.

2 Burgess, Ed (@edburgess). Twitter, August 16, 2020 6:07 PM. https://twitter.com/eburgess/status/1295119920808640512

2. Understanding how different approaches to procurement will impact participation in different owner groups, and how that impacts the diversity in supply across the system.
3. Understanding benefits and costs for stakeholders in various markets to structure products, tariffs, or customer programs to incentivize the needed level of residential storage participation.

Case Study: Analysis to Evaluate Residential Battery Storage Operations

This case study uses DER-VET™, an open source techno-economic optimization and simulation tool,[3] to simulate the operation of a residential battery plus PV system as it responds to various price or direct control signals. An illustrative modeled load shape for the home was used within DER-VET to size the battery and PV system.

The purpose of this case study is to provide insight into the following questions:

- If residential battery plus solar PV systems designed to provide backup power for several days becomes widespread, how might they behave with different operational objectives and price signals?
- How does modeled battery operation compare with CAISO's August 14 net load curve?

Household Load

This analysis used data from a publicly available modeled hourly load profile for a home that uses a central air conditioning system for space cooling.[4] The peak load for the day considered (August 14 in the modeled year) was 4 kW between 4–5 p.m. PDT. This represents an average home's load on an average summer day, based on a typical meteorological year (TMY3) weather data (averaged over 12+ of years of historical data) for Sacramento, CA.

Battery + PV System

- The PV system was sized at 4.51 kW to reduce the customer's yearly net energy charges to $0, generating 85% of the customer's annual energy consumption.
- The battery system has 10 kW power output capacity and can store 27 kWh of energy.
- Based on common battery SOC management strategies, the battery can provide up to 85% of full SOC (23 kWh) at rated output power for a duration of 2.3 hours.

The modeled home's electric demand (load) and the resulting net load (netting the output from the PV system from demand) are shown at the top of Figure 1.

Case Study Scenarios

The analysis considers battery plus solar PV systems that control the battery's charging and discharging based on a time-of-use (TOU) electricity rate, Federal Solar Tax Investment Credit (FITC) compliance, participation in a demand response (DR) program, and day-ahead (DA) CAISO nodal pricing. The modeled battery control strategies are shown below.

Customer-Centric Scenarios

1. TOU-Based Shifting:[5] Residential retail rate,[6] peak rate is about 2.8 times the off-peak rate, and the partial peak rate is about 2.2 times the off-peak rate.
2. FITC Compliant Shifting: TOU-based shifting, battery is *only* able to charge from PV output.
3. FITC Shifting with Backup Power: FITC Compliant Shifting, with advance notice of a potential blackout battery charges to 100% SOC; the battery will not discharge until the risk has passed.

Grid-Centric Scenarios

4. Demand Response: TOU Tariff-based Shifting plus DR program participation; when signaled the battery discharges at full output power for two hours.
5. CAISO DA Price-based Shifting:[7] Shifts based on the August DA locational marginal prices for PG&E's default aggregation point.

For the first three customer-centric scenarios, battery discharge (power output) is not allowed to exceed customer demand, and no energy from the battery is exported to the grid. For the grid-centric DR program and CAISO DA pricing scenarios this

3 Electric Power Research Institute. (2020). Distributed Energy Resources Value Estimation Tool (DER-VET™). https://www.der-vet.com/
4 Annual hourly electricity and gas use for a customer in Sacramento, CA, with energy broken out by major end-use category, available: https://openei.org/datasets/files/961/pub/RESIDENTIAL_LOAD_DATA_E_PLUS_OUTPUT/HIGH/USA_CA_Sacramento.Exec.AP.724830_TMY3_HIGH.csv
5 The entire month of August was simulated for the first four cases.
6 Pacific Gas and Electric (PG&E) EV-A rate schedule was used. https://www.pge.com/en_US/residential/rate-plans/rate-plan-options/electric-vehicle-base-plan/electric-vehicle-base-plan.page
7 The wholesale energy time shift case was simulated for August 1–18.

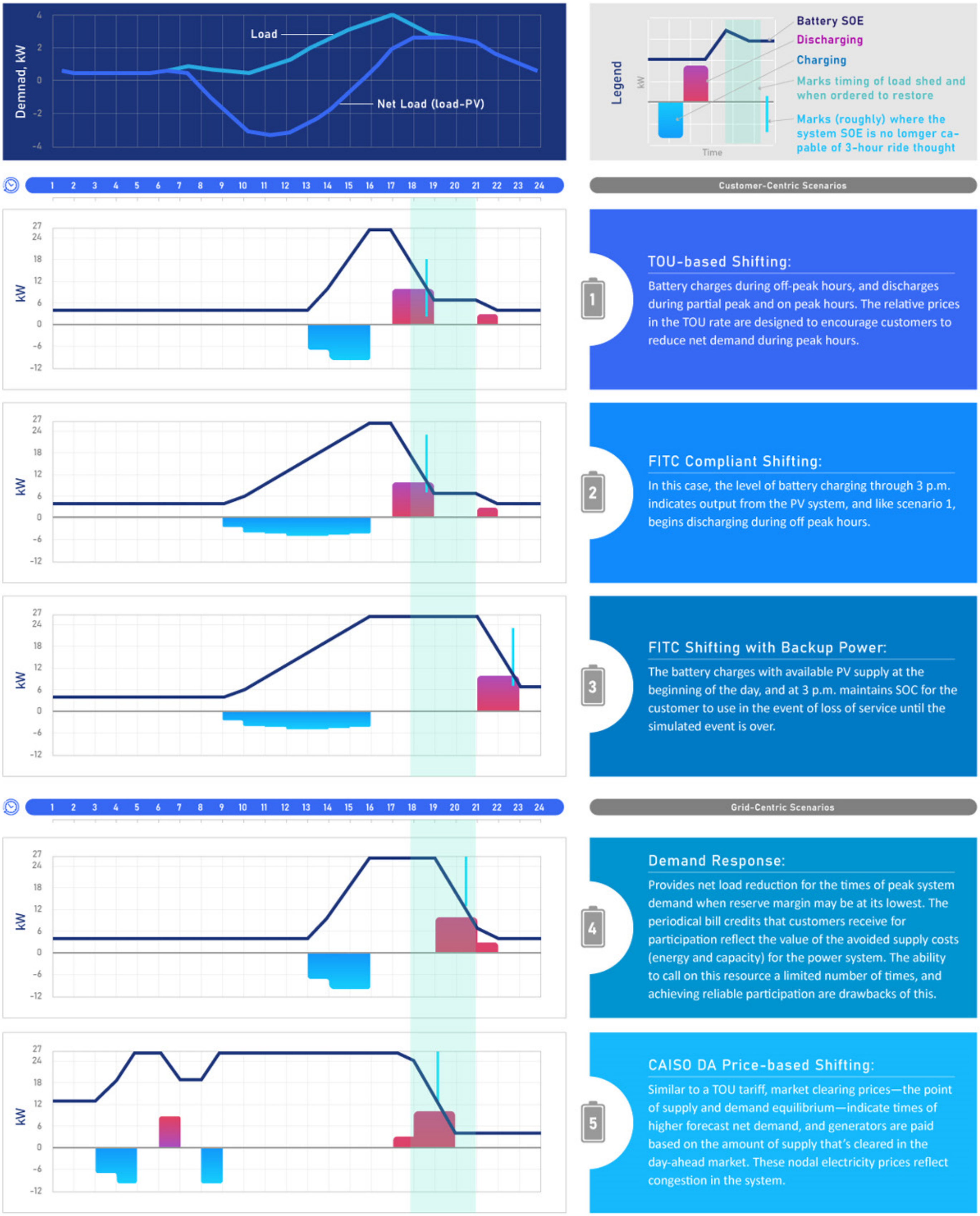

Figure 1. Modeling results of battery charge behavior and SOE shown with the household demand and net demand profiles

limitation was removed, allowing the battery to discharge at its full output power capacity, regardless of the customer's load.

Key Results and Insights

Most of the scenarios in the case study call for the battery to be discharging or have discharged fully by the time the home's net load peaks between 6 and 7 p.m. (hours 18 and 19 in Figure 1), leaving little to no energy stored to back up the home's load if an outage occurs. This represents the trade-off between responding to relative prices or direct load control signals (DR), versus reserving some battery energy for possible self-backup. Battery plus PV systems of this size may provide backup power for critical customer load for longer durations, such as PSPS shutoffs. The three-hour rolling blackouts of August 2020 did not require as much energy, so the system could reserve ample stored energy for backup and still have enough left over to support the grid in some capacity.

To look more closely at the ability of this battery plus PV system to supply the next three hours of demand (per the modeled shape), battery state of energy (SOE) throughout the day can be compared to the amount of energy needed to cover the next three hours of demand. The vertical bars on the charts in Figure 1 indicate roughly where the SOE has discharged to the point it may not cover the next three hours of demand in the home.

Only in the backup power case does the storage system retain enough stored energy to cover any three-hour outage throughout the entire day modeled here. In all other cases, including the wholesale and residential energy time shift cases, the afternoon discharge reduces the amount of energy stored in the battery enough that a three-hour outage would more than deplete the stored energy. If only 12 kWh of the 23 usable kWh in the battery system were made available for demand response or energy shifting on this day, the battery could ride through any three-hour rolling blackout while still supporting the grid via (slightly diminished) DR and achieving its financial objectives (energy time shift and demand response).

Battery SOE throughout the day, and charge and discharge periods are shown in Figure 1, with the 24-hour load and net load profiles provided at the top. A three-hour window between 6 and 9 p.m. is shaded in the charts to indicate the timing of load shed and restoration orders.

Gaps to Making Residential Energy Storage a Grid Resource

While residential energy storage is currently relatively rare, it is likely to become more common in the near future. Appropriate research may allow system operators to use this resource to mitigate, and perhaps prevent, rolling outages or blackouts in the future without compromising customer convenience and comfort. In particular, there will be a need for least-cost approaches to:

1. Understand customer behavior to inform modeling of DER adoption and operation.
2. Integrate customer DER with the ability to track assets and maintain the data needed to support settlements.
3. Invest in the communications and hierarchical control systems to carry out high-value use cases.
4. Procure customer flexibility.
5. Coordinate decision making and building capabilities to assess the benefits and costs of various approaches.

Utilities and system operators may consider specialized tariffs, incentives, direct control programs, shared ownership, or market services to incentivize beneficial adoption and operation of energy storage, balancing customer, grid, and societal needs. Each of these pathways will impact the level of customer participation, resource response, and the ability for customers to opt out.

Key research questions include:

- How could current operational strategies and expected customer adoption of DER impact grid reliability?
- What operational strategies could contribute to increased grid reliability, mitigating the need for rolling blackouts? What strategies contribute to increased grid resilience? Which strategies can support the ability of energy systems to mitigate, adapt to, and quickly restore power from widespread long-duration outages?
- How can RA models be adapted to better represent customers' resources and their actions?
- How much participation, and what level of certainty of resource response is needed for DER to provide grid services?

- How will customer choices and behavior change if they are offered several options: specialized tariffs, incentives, bill credits (as in DR programs), or the ability to provide services through a market?
- What is needed in evaluation, measurement, and verification (EM&V) plans to gauge effectiveness of these procurement pathways, to inform how energy services may evolve over time?

Continue the Conversation/EPRI Resources

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