Developing a Market-Driven Net Benefit Framework for Demand Flexibility

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ABSTRACT

Since 2020, California has introduced various regulations and funding programs targeting technology development, demonstration, and customer incentives for increased demand flexibility (DF) in the electricity sector. However, as an emerging concept, DF strategies and technologies continue to evolve, and policymakers need consistent performance metrics to set goals and track progress for these programs. By analyzing the relevant California programs and the growing scientific literature, this study proposes a market-driven net benefit framework for designing DF incentive programs, which can be more broadly applied to customer-side distributed energy resources (DER) and virtual power plants (VPPs). The proposed net-benefit framework can be applied to several distinct goals that DF may target. These goals are (1) increased renewable integration, (2) reduced cost of grid operations, and (3) improved reliability through emergency demand response (DR).

This study identifies various approaches for setting performance metrics and potential drivers for consumer engagement to support each goal. The proposed framework suggests a four-step approach for evaluating the outcomes of a new DF program. This framework will help stakeholders, especially policymakers, set specific goals for their DF programs and understand the cost-effectiveness and market readiness of a DF approach. Our analysis demonstrates that most customer programs, including real-time tariffs, are currently being piloted on a limited scale, and there is a lack of robust incentives for customers to participate in DF, especially to support renewable integration and reduce the cost of grid operations.

Introduction

Demand flexibility (DF) refers to comprehensive strategies or device-level features that allow event-based demand response (DR) or more frequent load shifting to align electricity consumption with dynamic grid conditions. Virtual power plants (VPPs) are portfolios of distributed energy resources (DER) such as smart thermostats, rooftop solar photovoltaics, electric vehicles (EVs), batteries, and smart water heaters that are actively controlled by software to benefit the power system, consumers, and the environment. In the context of this paper, only customer-owned DER and relevant VPPs are considered.

Since 2020, California has introduced various regulations and funding programs targeting technology development, demonstration, and customer incentives for increased DF in the electricity sector. However, DF is an emerging concept with continually evolving strategies and technologies, and policymakers need consistent performance metrics to set goals and track progress for these programs. This sector has experienced major challenges in determining the value proposition, key performance indicators, and a reasonable measurement and verification process, along with other technical issues such as data integration challenges between the utility and third-party implementers or software providers (CEC 2023b).

Several scientific studies and standardization approaches have attempted to quantify DF in various ways based on different objectives. These efforts, which are distinct but related, can be categorized into three groups.

1. Performance metrics for connectivity and technology readiness (such as Piette et al. (2022))
2. DF benchmarking for buildings (such as Carbonnier, Egolf, and Miller (2022), Li et al. (2022), and Liu et al. (2022))
3. Estimating grid system benefits for new DF or DER projects

This paper deals with studies related to estimating grid system benefits for new DF or DER projects. Some studies in this group primarily focused on electrical load impacts. For instance, Langevin et al. (2021) projected the technical potential of the U.S. regional system peak demand and electricity load impacts from commercial and residential building-level energy efficiency and DF measures for 2030 and 2050. The authors identified seven types of grid benefits, primarily focusing on generation-related savings in MW, such as load reductions during ramping periods. While understanding the electrical load impacts from a DF project may be the first step in evaluation, it does not provide enough insights into the cost-effectiveness and financial feasibility of such a project. The following section, Literature Review, analyzes two new studies that evaluate DF system benefits from a net benefit approach.

Literature Review on System Benefits from DF

Resource Adequacy Framework

Several recent frameworks have attempted to value distributed energy resources beyond the traditional energy savings metrics to more fully capture the system and policy benefits that DERs offer. One such framework was put forth by Hledik and Peters (2023a) from the Brattle Group. They conducted a recent study that values distributed energy resources that are aggregated to the level of VPPs based on the cost of meeting resource adequacy (RA) needs and societal benefits attributable to VPPs. The study compares the cost-effectiveness of three resource types: VPPs, utility-scale battery storage, and traditional natural gas peaker plants.

The study modeled a prototypical, mid-sized, and aggressively decarbonizing utility's hourly load conditions using NREL's Cambium data set (Hledik and Peters 2023b). Cambium data sets are updated annually by NREL and contain hourly emission, cost, and operational data for a range of future scenarios of the nation's electricity sector (NREL 2023). The model includes several different scenarios with different underlying assumptions, including but not limited to the level of decarbonization achieved by 2050, which technologies are included, and policy drivers such as tax credits (Gagnon, Pham, and Cole 2024). The study used forecasted data for a region with a less "peaky" load profile, that would create a need for resource performance in many hours of the year and lead to a model that pushed the limits of the VPP resource. The VPP modeled in this study included a broad range of technologies, namely smart thermostats, smart water heaters, EV-managed charging, and behind-the-meter (BTM) battery demand response.

The required capacity of each of the three resource types to meet the modeled utility's resource adequacy need (400 MW) was determined, informing the total costs and benefits attributable to each resource type. The resource adequacy components, also known as the system cost impacts, quantified for the cost-effectiveness analysis included energy procurement costs, ancillary services, equipment and installation costs, and ongoing programmatic costs. The system cost impacts also included the avoided cost of transmission and distribution (T&D) investment. The avoided cost is a common way to assess the value of distributed energy resources and is calculated by quantifying the typical utility system cost to serve the amount of energy provided by a DER (E3 2022). The non-resource adequacy components, also referred to as the societal cost impacts, such as emissions and resilience value, were estimated and used to calculate the final net cost of each resource (Hledik and Peters 2023b). The additional streams of market value apart from resource adequacy were simulated using the Brattle Group's LoadFlex and bSTORE models to optimize the dispatch of the VPP portfolio and utility-scale storage resource, respectively.

The results indicated that VPPs provided most of the system-level benefit through T&D investment deferral, whereas neither other resource could. However, the energy benefits from the VPP were lower than the other two resources. Importantly, the VPP portfolio was the only resource that provided societal benefit in the form of both emissions and resilience, while utility-scale storage and gas peaker plants both came at a societal cost in the form of emissions. The study also conducted sensitivity analyses on multiple variables, which can be used to extrapolate how these results might change for different systems. One such sensitivity analysis was conducted for higher T&D costs than what was modeled in the base case. It is notable that the resulting benefits of the VPP portfolio modeled with higher T&D costs would far outweigh all other resource costs.

The authors of the study acknowledge that several benefits of VPPs remain unquantified. The major benefits that are not modeled in the study are increased integration of renewable generation due to load shifting, decreased load impacts of electrification measures, avoided interconnection delays, the flexibility to scale this resource over time without the risk of stranded assets, and improved intelligence behind the meter (Hledik and Peters 2023a). Additionally, the study does not quantify the potential impact of DERs on local transmission congestion when strategically deployed at congested local nodes.

Total System Benefit Framework

Chhabra (2022) of NRDC presents another framework for valuing distributed energy resources. This framework is based on the temporal and geographic variation in the value of energy while also accounting for the impact of integrating DERs on future system costs. Chhabra, therefore, introduces a more comprehensive metric called the Total System Benefit (TSB). The TSB values DERs by estimating the system costs avoided when a resource adds or reduces demand for a marginal unit of energy. The components of avoided system costs include energy, generation capacity, transmission and distribution capacity, ancillary services, losses, reduced RPS procurement, and environmental savings. The TSB builds on the Avoided Cost Calculator (ACC) in California, which has been used to comprehensively quantify these avoided system costs for every hour of the year for a given utility and climate zone (E3 2022). The ACC forecasts the levelized value of energy in $/MWh based on historical energy cost and transmission cost data, projected load growth and DER adoption rates, and legislative renewable energy goals.

The ACC has been used by the California Public Utilities Commission (CPUC) as the first step in cost-effectiveness calculations for various programs (E3 2022), but it has not allowed a consistent framework through which to value different DER technologies (Chhabra 2022). To do so, the TSB aggregates the ACC output of hourly avoided costs over the lifetime of the DER according to its load shape to determine the impact of energy efficiency and distributed energy technology over the entire time they are in use (Chhabra 2022). By extending the valuation of benefits to the lifetime of the DER with a more accurate temporal disaggregation, the TSB more fully captures the policy benefits offered by DERs and recognizes the impact of longer-life measures over the entire time they are installed and contributing to the grid. The TSB also presents a more comparable metric of dollars saved to break down silos between energy efficiency, demand flexibility, distributed generation, storage, and electrification measures.

While the TSB is a step in the right direction to comprehensively measure the value of DERs, it is not exactly reflective of present grid conditions since it is based on historical data. This becomes pertinent when considering the impact of a changing climate on future grid conditions. For example, historical data in California suggests that the average hourly value of energy is highest in September, driven primarily by the cost of generation to meet peak hours (Chhabra 2022). In 2022, this pattern held true due to the heat waves that caused the highest reliability-need hours to occur in September. In 2023, the system net peak hours in 2023 occurred in August. This meant the actual value of energy was highest in August, even though the ACC did not reflect this, thereby undervaluing DERs during the peakiest hours of that year.

Gaps Remain in Existing Frameworks

Both frameworks and methodologies incorporate the many energy and non-energy benefits provided by DERs and VPPs, yet are not sufficient in practice. The framework used by the Brattle Group to value VPPs is modeling-intensive and is likely unable to be applied easily for the valuation of demand flexibility through utility-scale programs. In contrast, the TSB is a practical metric that intends to capture the costs and benefits associated with energy efficiency and DERs. However, the current implementation of TSB in California still leaves some of the so-called DER value stack on the table. For example, the CPUC's Cost-Effectiveness tool considers sector average load shapes as the baseline instead of individual, site-specific load shapes. One leading industrial energy management service provider, Cascade Energy, indicated that this approach often undervalues the contribution of an energy efficiency measure to the grid (S. Sethuraman and S. Skidmore, Senior Director of Business Development and Director of West Programs, Cascade Energy, pers. Comm., October 23, 2023).

While modeling studies discussed here provide important insights on quantification and monetary value assessment for DF programs, there is a gap in the literature about whether the existing utility or third-party programs in a certain market can engage customers and realize the intended benefits to the grid. The following section provides detailed information about California's electricity market and the statewide programs designed to incentivize and create value for DF and VPPs.

The Context of Demand Flexibility in California's Electricity Market

The Need for Demand Flexibility in California

California has experienced recent periods of extreme grid stress prompted by extreme weather conditions and changing resource adequacy needs due to increasing renewable penetration. In 2020, a historic heat wave caused excess demand from what was forecasted and induced rotating outages (CAISO 2021). On September 6, 2022, the California Independent

System Operator (CAISO) experienced a record peak load of 52GW during a heat wave, through which CAISO instituted Grid Emergency Alerts (CAISO 2024a). Data from recent years indicates that California will continue to need DR to improve grid reliability and prevent rolling blackouts. Figure 1 below shows the Top 100 net load hours in California compared to energy emergency alerts issued by CAISO based on grid stress. The Top 100 Hours are defined by the 100 highest net peak hours of the year, which are typically concentrated in the late summer months. CAISO uses multiple levels of Energy Emergency Alerts (EEA) when the system may be energy deficient, each triggering different actions. The alerts span from EEA Watch, triggered when the Day-Ahead Analysis is forecasting that one or more hours may be energy deficient, to EEA3, triggered when all resources and emergency load management programs are in use, yet potential electricity interruptions may be required (CAISO 2023).

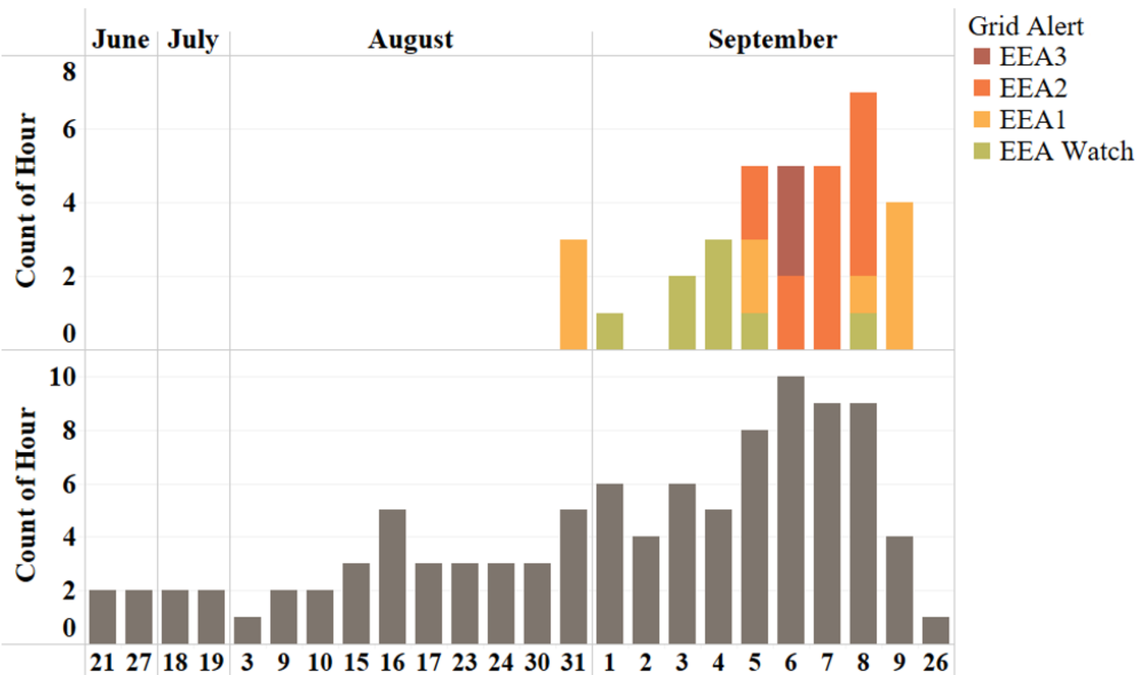

Figure 1. The comparison of the timing and duration of the CAISO-issued emergency alerts and the Top 100 net peak hours occurred in 2022. The extreme heat event between August 31 and September 9 resulted in several emergency events, each lasting up to seven hours.

This analysis was conducted using CAISO's Production and Curtailments data from 2022 (CAISO 2024b). California's grid experienced five consecutive days of extremely high grid stress as indicated by the EEA1-3 alerts. CAISO had seven consecutive hours of active emergency alerts on a single day surpassing the typical five-hour DR window. Notably, every day of the September 2022 heat wave contributed 8 to 10 hours to the Top 100, occurring between 2PM-10PM, as shown in Figure 2 below. The RMO refers to the Restricted Maintenance Operations notification from CAISO, and Flex Alert refers to the voluntary conservation public announcement (CAISO 2023). Still, almost all the highest energy emergency alerts occurred during the 4PM-9PM window, which is also when electricity prices are highest. The severity of the 2022 summer season is likely an indicator of a worsening climate. California's Fourth Climate Change Assessment finds that annual temperatures are expected to rise 4.4°F-5.8°F by 2050, and the heat-related health events will worsen throughout the state

(California Climate Adaption Strategy 2024). The California electricity system must prepare for a widening range of severity.

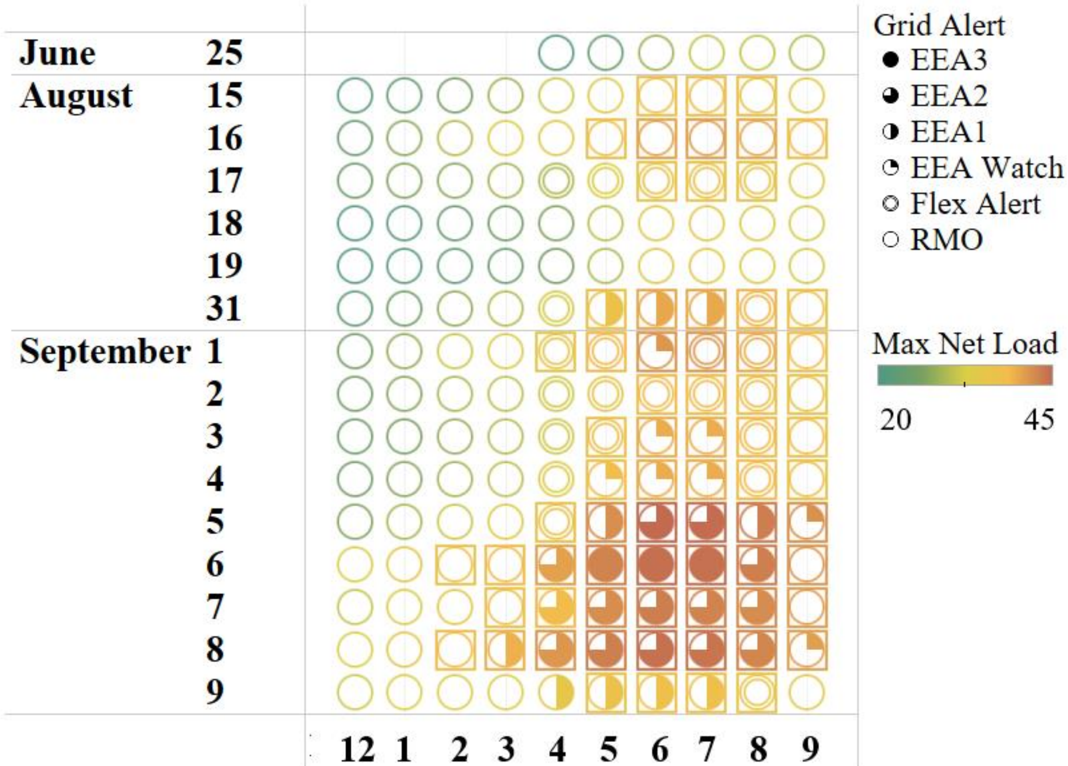

Figure 2. The occurrence and temporal comparison of the emergency grid events in 2022. Emergency events occurred between 3PM and 10PM, which is beyond California's standard 4PM-9PM peak rate window. The highest system net peak hours bleed into the 2PM-10PM window (marked in square).

While the outcomes of the 2022 summer season highlight California's need for emergency demand response, the ever-increasing rates of renewable curtailment indicate the need for general load shifting. The California grid has been facing the growing problem of solar overgeneration, which has led to curtailment, or the limiting of generation due to oversupply.. As seen in Figure 3, the monthly curtailment during the mild spring months has more than doubled from 300 GWh in 2020 to 700 GWh in 2023 in just three years (CAISO 2024a). The average daily solar curtailment in April 2023 was enough to fuel over 1.4 million electric vehicles every day based on the average California mileage of 34.8 miles (Hardesty 2023)[1]. Demand flexibility can be a key tool in better integrating renewables in the future and reducing inefficiencies due to overgeneration.

[1] This estimate assumes a vehicle drive efficiency of 400 Watt-hour/mile and a charging efficiency of 85 percent.

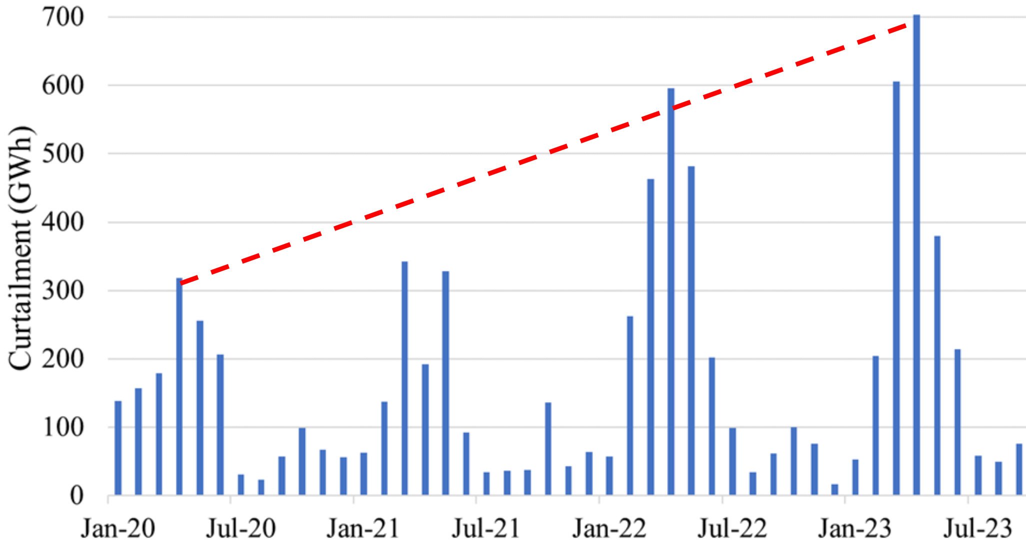

Figure 3. California's monthly solar curtailment doubled from 2020 to 2023, indicating a greater need for DF to shift flexible loads and better utilize these resources.

Market Programs Related to DF and DER Integration

Since 2021, California has introduced several market programs that have impacted the value proposition of DF and VPPs for both customers and third-party implementers. These programs are primarily designed to improve summer reliability and to ease resource concerns following the grid events during the summer of 2020 (CPUC 2021). Some of these programs encourage event-based DR, while others encourage more frequent seasonal or daily load shifting. Most market programs discussed below apply to California's investor-owned utilities only, which serve about 78 percent of the state's population (California Publicly Owned Utilities 2021). Most programs described below are newly introduced and in the pilot phase. There is very limited information available about their actual performance in the field.

California Flexible Unified Signal for Energy (CalFUSE). California is currently developing dynamic rates for the mainstream market as a unified economic signal to incentivize customers to manage their load and use cheaper, cleaner electricity. The CPUC initiated the Demand Flexibility Rulemaking on July 14, 2022, to advance demand flexibility through electric rates (CPUC 2024a). This proceeding requires California's investor-owned utilities to pilot and demonstrate real-time communication and control technologies to enable customers to respond to price signals. The first phase of these pilot projects, covering a range of end-uses, such as residential water heaters and electric vehicle charging, was completed in 2024. As of January 2024, the Commission expanded pilots through the end of 2027 (CPUC 2024c). CPUC's proceeding is complementary to implementing the CEC's Load Management Standards, requiring large utilities and customer choice aggregators to offer an optional dynamic rate by 2027 (CEC 2023a). CEC's Load Management Standards also maintains a price server called Market Informed Demand Automation System (MIDAS) which has a machine-readable API and is becoming a central repository for utilities to upload and broadcast their dynamic tariffs (CEC 2021).

Emergency Load Reduction Program (ELRP). ELRP is designed to pay electricity consumers for reducing energy consumption or increasing electricity supply during periods of electrical grid emergencies (CPUC 2024b). The program is managed by investor-owned utilities, which incentivizes customers of all types to voluntarily reduce energy consumption during emergency events triggered by the CAISO's grid emergency declarations. Consumers receive a prefixed compensation of $2/kWh for the actual reduction in energy compared to the typical energy use as measured by the existing smart metering infrastructure. This program has been rolled out as a five-year pilot, and the first residential participation was allowed in the summer of 2022. While this program does not require a commitment and is only triggered if there is a grid emergency, it has expanded the type of customers that would normally participate in DR. The CEC has expanded this approach to publicly-owned utilities under the Demand Side Grid Support (DSGS) program (CEC 2024a).

Market Access Program. On July 30, 2021, Governor Newsom issued an Emergency Proclamation directing state agencies to address a statewide electricity shortage (CPUC 2024d). In response, CPUC authorized the Market Access Program (MAP) as a strategy to reduce peak demand. MAP expands on an earlier iteration of the Peak FlexMarket program implemented by MCE and Recurve Analytics. Through MAP, third-party implementers of energy efficiency and load shifting measures are incentivized to benefit the grid by generating revenues based on the cost of avoided energy use, which is then validated by customers' smart meter data. This program was created as a two-year pilot from 2022 to 2023 with a budget of up to $150 million. As of February 2024, there is a pending CPUC decision on whether MAP should be allowed to continue. Although the hourly MAP signals are based on historical dollar value estimates from the ACC, this program has been a major incentive for third parties to engage with load shifting outside the existing demand response programs.

Self-Generation Incentive Program (SGIP). SGIP was introduced by the CPUC to expand customer DER and assist with upfront costs of equipment (SGIP 2024). As of 2024, the program is active and supporting both small-residential and large-scale energy storage projects, wind projects, and equity resiliency projects. While this program does not incentivize smart device installations, it supports the installation of energy storage systems, which increase the load-shifting potential of a building.

Distributed Energy Backup Assets (DEBA). The DEBA program incentivizes the deployment of cleaner and more efficient distributed energy assets that would serve as on-call emergency supplies or load reduction for the state's electrical grid during extreme events (CEC 2024b). The CEC, the administrator for DEBA, released program guidelines on August 15, 2023, highlighting potential financial incentives for various technologies and strategies, including DF and VPPs. Once fully established, DEBA can potentially reduce the cost of DF or VPP projects by assisting with upfront costs and/or providing performance-based milestone payments. The following section will discuss how the programs introduced here are relevant to a distinct set of grid benefit goals from DF.

A Market-Driven Net Benefit Assessment

Based on our review of the DF modeling studies and the DF-related market programs in California, we identified the following primary grid benefits that may be targeted by DF programs.

1. Renewable integration
2. Grid reliability and resiliency
3. Reduced cost of generation (energy and capacity procurements)
4. Reduced cost of distribution

In implementation, these goals are all related and interact with each other. For instance, aligning load with renewable generation would also reduce solar curtailment (discussed in the previous section) and reduce the cost of generation, especially during the spring and fall seasons. On the other hand, these grid benefit goals require different performance metrics and types of engagement from customers.

For renewable integration, energy planners can measure the performance of a DF program by evaluating the marginal greenhouse gas (GHG) impacts from changed load shapes (hourly or shorter duration). However, to achieve this goal, they must engage customers with dynamic tariff structures (seasonal time-of use rates or real-time price signals) or incentivize customer-side energy storage. It is also possible to engage customers by incentivizing third parties, such as companies that manage building HVAC loads, by using MAP incentives. Finally, energy planners must also determine the tools and procedures to be used for evaluating success. In the case of renewable integration, NREL's Cambium tool can be a valuable resource for estimating long-run marginal emissions, as the GHG mix of the grid is highly dynamic and can change based on various factors, such as utilities' progress on RPS targets or the availability of hydropower resources dependent on weather.

Figure 4 below describes the proposed approach for a net benefit assessment of a proposed DF program or project. This framework could guide DF efforts of state energy offices, public utilities commissions, and loads serving entities. The proposed approach emphasizes the need to specify the grid benefit objectives as grouped under the four categories above. In California, summer reliability due to extreme weather events and renewable integration due to growing solar curtailment have been the major drivers for seeking DF. However, reducing the cost of distribution upgrades is also becoming another major policy driver, which is largely driven by the growing utility spending to support electrification (Balaraman 2023).

The proposed framework also emphasizes the importance of identifying market programs and drivers for consumer engagement before estimating the program's impacts. Finally, a data-driven impact analysis is critical to estimate the outcome from a proposed DF measure. This analysis should ideally use metered loads to evaluate the electrical load patterns for specific end uses and sectors. Once the impact of a DF project is determined, program implementers should estimate the program costs, including the cost of DER management software, customer outreach, project administration, customer incentives, or smart device installations.

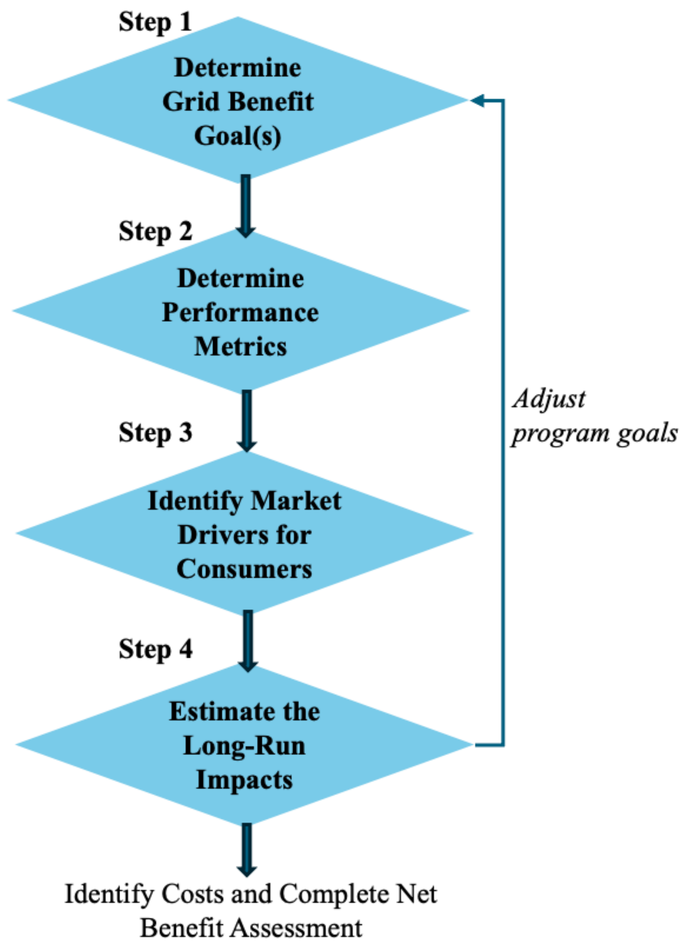

Figure 4. The proposed framework for setting specific targets and evaluating outcomes for new DF programs suggests a four-step process.

Table 1 below is a summary of how the tools and market programs discussed in this paper are related to the four grid benefit objectives. The performance metrics, consumer drivers, and tools for estimating the performance vary based on the grid benefits being targeted. The results demonstrate that there is a need for more established and long-term market programs that can generate dynamic signals and incentivize customers and third parties to engage with DF. Most customer programs, including real-time tariffs, are currently being piloted at a limited scale and do not provide robust incentives for customers to engage with DF. The default time-of-use rates (which have a single peak period of 4PM-9PM) offered by California utilities and customer solar are the only drivers for customers to support these goals. Also, note that the “tools and resources for estimating performance” in Table 1 below only focus on ex-ante estimates. In the design phase, building energy models can be used to estimate site-level load shapes. Some popular building energy modeling tools include E-Plus, E-Pro, and E-Quest (Office of Energy Efficiency & Renewable Energy 2024). For ex-post measurement and verification, metered load shapes are the most reliable way to evaluate the overall success of a project.

It is crucial for implementers to begin with identifying all the performance metrics, consumer incentives, and tools and data collection needed to track a program’s performance. Traditional cost-effectiveness tests are based on consumer enrollment projections and load shifting estimates made at a single point in time. This approach does not utilize an ongoing data collection and validation process, which may leave the implementers uninformed about any potential adjustments needed to the program.

Table 1: Summary of Demand Flexibility Objectives, Performance Metrics, Customer Drivers, and Tools for Measurement &Verification

Goals	**Performance metrics**	**Consumer Driver Factors (California)**	**Tools and Resources for Estimating Performance**
Integrate Renewables	Marginal GHG impacts (reduced annual GHG)	Dynamic rates, MAP, customer solar & storage	Cambium (NREL); ACC & TDV (/kW estimates)
Grid Reliability & Resiliency	Load reduction during CAISO emergency events	DR programs, ELRP & DSGS, critical peak pricing	CAISO quarterly testing events and CPUC Load Impact Protocol reports (DR); ELRP/DSGS program reports.
Reduced Cost (Generation)	CAISO net-peak (Top 100 Hours) and utility RA requirement impacts	Dynamic rates, MAP, customer solar & storage	CAISO and CEC's RA determinations for utilities; ACC and TDV.
Reduced Cost (Distribution)	Load reduction during circuit-level peak hours	Demand charges, dynamic rates, MAP, customer storage.	Utility hosting capacity datasets; ACC & TDV

The proposed framework can be demonstrated on a hypothetical utility pilot program authorized under CalFUSE. As discussed previously, the CPUC initiated the Demand Flexibility Rulemaking on July 14, 2022, to advance demand flexibility through highly dynamic rates (CPUC 2024a). In a scenario where a utility company is implementing a new CalFUSE pilot targeting residential EV charging, the utility first would identify the existing EV load in their territory along with projections for the future year to capture the expected load growth. Then, the utility would set one or more primary objectives for this program. As seen in Table 1, the primary goals of a program could be the reduced cost of generation and distribution upgrades. These goals must be quantified by using the relevant performance metrics such as the expected utility RA benefits and substation transformer and feeder protection benefits. In the example above, the driver for consumer engagement would be utility bill savings. Once the utility identifies the cost of implementation and the cost-effectiveness of the proposed pilot, it will set the protocols for data collection and performance validation before the implementation of a new pilot.

Discussion

This study introduces a market-driven net benefit assessment for DF programs. Instead of hypothetical values from complex modeling, it identifies potential sources of revenues and savings available in California's existing market structure for all parties, including customers, utilities, and third parties[2]. The analysis identified four main goals from DF programs and relevant performance metrics. These goals are renewable integration, grid reliability, reduced cost of generation, and reduced cost of distribution.

The proposed framework suggests a four-step approach for evaluating the outcomes of a new DF program. This framework can guide decision making for energy planners and implementers of DF programs such as state energy officers, public utility commissions, and load serving entities. The results demonstrate that most customer programs, including real-time tariffs, are currently being piloted on a limited scale and do not provide robust incentives for customers to engage with DF. The default time-of-use rates offered by California utilities (which have a single peak period of 4PM-9PM) and customer solar & storage are currently the only drivers for customers to support DF goals. There is a need for more established and long-term market programs incorporating dynamic grid signals to engage customers and third parties and take full advantage of DF.

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[2] Third parties can include DR aggregators, DER management software (DERMS) developers, or certain energy efficiency implementers such as the ones participate in the Market Access Program.

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