

Vehicle-Grid Integration in California: A Cost-Benefit Comparison Study

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Table of Contents

Executive Summary	6
1 Introduction	7
1.1 Vehicle-Grid Integration	7
1.2 California VGI Initiative	7
1.3 Purpose of Study	8
1.4 Structure of this Report	9
1.5 Affiliation to Columbia University	9
2 Methods	10
2.1 Tests	10
2.1.1 Total Resource Cost (TRC) Test	11
2.1.2 Program Administrator Cost (PAC) Test	11
2.1.3 Ratepayer Impact Measurement (RIM) Test	11
2.1.4 Participant Cost Test (PCT)	12
2.2 Data Sources and Assumptions	12
2.3 Impact on Environment	13
2.4 Impact on Resiliency	13
3 Cost-Benefit Analysis: Residential Peak Shaving	15
3.1 Residential V2G	15
3.1.1 Data and Assumptions	15
EV Stock and Features	15
Charging Infrastructure	16
Program Participation	17
Energy and Power Impacts	17
Administrative Costs	18
Net Bill Reductions and Incentives	19
3.1.2 Test Results and Sensitivity Analyses	20
3.1.3 Impact on the Environment	21
3.1.4 Impact on Resiliency	21
3.2 Residential Demand Response	22
3.2.1 Data and Assumptions	22
AC Cycling Program	22
Equipment Costs	22
Program Participation	22
Energy and Power Impacts	23
Administrative Costs	23

Net Bill Reductions and Incentives	23
Benefit Adjustments	24
3.2.2 Test Results and Sensitivity Analyses	24
3.2.3 Impact on Environment	24
3.2.4 Impact on Resiliency	25
3.3 Residential Storage	25
3.3.1 Data and Assumptions	25
Residential Storage Setup	25
Program Participation	26
Energy and Power Impacts	26
Administrative Costs	27
Net Bill Reductions and Incentives	27
3.3.2 Test Results and Sensitivity Analyses	27
3.3.3 Impact on Environment	28
3.3.4 Impact on Resiliency	28
3.4 Comparing Technologies for Residential Peak Shaving	28
4 Cost-Benefit Analysis: Utility-Scale Peak Shaving	30
4.1 School Bus Fleet V2G	30
4.1.1 Data and Assumptions	30
Electric School Bus Stock and Features	30
Charging Infrastructure	31
Energy and Power Impacts	31
Administrative Costs	32
Net Bill Reductions and Incentives	32
4.1.2 Test Results and Sensitivity Analyses	32
4.1.3 Impact on Environment	33
4.1.4 Impact on Resiliency	33
4.2 Commercial/Industrial Demand Response	33
4.2.1 Data and Assumptions	33
Base Interruptible Program	33
Energy and Power Impacts	34
Administrative Costs	34
Net Bill Reductions and Incentives	34
Benefit Adjustments	35
4.2.2 Test Results and Sensitivity Analyses	35
4.2.3 Impact on Environment	35
4.2.4 Impact on Resiliency	36
4.3 Utility-Scale Storage	36

4.3.1 Data and Assumptions	36
Utility-Scale Storage Setup	36
Energy and Power Impacts	37
Administrative Costs	37
Net Bill Reductions and Incentives	37
4.3.2 Test Results and Sensitivity Analyses	38
4.3.3 Impact on Environment	38
4.3.4 Impact on Resiliency	38
4.4 Comparing Technologies for Utility-Scale Peak Shaving	39
5 Cost-Benefit Analysis: Home Backup	40
5.1 Residential V2H	40
5.1.1 Data and Assumptions	40
Program Participation	40
Energy and Power Impacts	40
Net Bill Increases and Incentives	41
Equipment Costs	41
Administrative Costs	42
Benefits	42
5.1.2 Test Results and Sensitivities	42
5.1.3 Impact on Environment	43
5.1.4 Impact on Resiliency	43
5.2 Residential Storage	43
5.2.1 Data and Assumptions	43
Energy and Power Impacts, Participation	43
Net Bill Increases and Incentives	44
Equipment Costs	44
Administrative Costs	44
Benefits	44
5.2.2 Test Results and Sensitivities	44
5.2.3 Impact on Environment	45
5.2.4 Impact on Resiliency	45
5.3 V2H Emergency Backup Add-On	45
5.4 Storage Emergency Backup Add-On	46
5.5 Comparing Technologies for Home Backup	46
6 Interpretation and Conclusions	48
6.1 How does VGI compare with DER?	48
6.2 Assumptions and Sources of Error	49
6.3 Policy Considerations	50

6.4 Next steps	50
Appendix A: Full Cost-Benefit Results	51
Acknowledgements	52

Executive Summary

In satisfaction of rulemaking by the CPUC, the VGI Working Group is currently in the process of answering the question, “How does the value of VGI use cases compare to other storage or DERs?” This study supports the Working Group’s efforts to answer this question by providing a quantitative cost-benefit analysis of three potential applications for VGI technology, which we then compare to a cost-benefit analysis of using storage and DERs for the same services. Based on guidance from the CPUC, we conduct four distinct cost-benefit tests for each application and each technology, yielding a benefit/cost ratio for each. Our results show that for peak shaving with residential customers, VGI is more cost-effective than home storage or demand response. For peak shaving using large municipal, commercial, or industrial consumers, VGI with a fleet of school buses is less cost-effective than demand response but more cost-effective than distributed storage. For home power backup, VGI is equally as beneficial as storage, though both are only cost-effective as add-ons to a pre-existing VGI or home storage program. Ultimately our model shows that VGI is most effective when it combines services into a single program. As the VGI Working Group answers the final question in its mandate, this model can serve as a quantitative benchmark for comparing VGI to DERs and storage.

1 Introduction

1.1 Vehicle-Grid Integration

With over 5.1 million electric vehicles (“EVs”) in use worldwide¹, each containing a battery capable of storing 16-90 kWh of electricity², EVs represent a significant distributed energy storage resource. Vehicle-Grid Integration (“VGI”) harnesses the potential of this underutilized energy resource to provide important grid services. Equipping EV charging infrastructure with bidirectional power flow or capability or remote operation capability allows EVs to serve a number of beneficial functions, including (a) peak shaving, (b) load shifting, (c) emergency home and building backup, (d) grid frequency regulation, (e) grid voltage regulation, (f) intermittent generation support, (g) grid upgrade deferral, and (h) spinning reserve³.

VGI encompasses several EV charging technologies⁴:

- Unidirectional charging with remote control (“V1G”) allows a utility to regulate power flow and time of use.
- Bidirectional charging with remote control (“Vehicle-to-grid,” or “V2G”) allows a utility to regulate power flow and time of use, as well as to draw energy from the plugged in EV as needed.
- Bidirectional charging to support home energy services (“Vehicle-to-home,” or “V2H”) allows EV owners to draw energy from the plugged in EV as needed.

As EV adoption accelerates, VGI is increasingly viewed as an avenue to improved grid function and sustainability. To date, over fifty pilot programs⁵ worldwide have shown the technology to be effective in providing these services, but the technology has never been implemented commercially due to the absence of commercial programs, resource aggregators, and buy-in from the system operators.

1.2 California VGI Initiative

At 600,000 EVs - 60% of the national total - California is the United States’ leading adopter⁶ ⁷. And with a statewide target of 5 million on the road by 2030⁸, EVs constitute a significant and growing grid storage resource for the state.

¹ *Global EV Outlook 2019*. IEA

² “Electric Vehicles,” *Battery University*

³ *California Vehicle-Grid Integration (VGI) Roadmap: Enabling vehicle-based grid services*. CAISO

⁴ *Evaluating California’s Vehicle-Grid Integration Opportunities A Framing Document*. GridWorks

⁵ *V2G Global Roadtrip: Around the World in 50 Projects*, Innovative UK

⁶ “California Continues to Lead in Electric Vehicle Adoption.” *Government Technology*

⁷ “EEI Celebrates 1 Million Electric Vehicles on U.S. Roads.” *Edison Electric Institute*

⁸ *ZEV Action Plan*. California Governor’s Office

In 2019, the California Public Utilities Commission (“CPUC”) delivered a [rule](#) (R. 18-12-006) establishing a “VGI Working Group” that would develop policies for harnessing the potential of VGI in California⁹. The Working Group includes representatives from several California state Agencies - including the CPUC, the California Air Resources Board (“CARB”), the California Energy Commission (“CEC”), and the California Independent System Operator (“CAISO”) - as well as from key stakeholders in a potential VGI program, including utilities, car manufacturers, environmental groups, and charging infrastructure manufacturers. The Working Group was directed to answer the following questions¹⁰:

1. What VGI use cases can provide value now, and how can that value be captured?
2. What policies need to be changed or adapted to allow additional use cases to be deployed in the future?
3. How does the value of VGI use cases compare to other storage or distributed energy resources (“DER”)?

The VGI Working Group concluded its work on Question 1 on December 8, 2019, having generated 1,060 unique use cases, of which 278 were deemed ready for implementation on a short-term timeframe. On April 9, 2020, the Working Group concluded Question 2, having formulated 126 policy recommendations for VGI implementation. As of the submission of this report, the Working Group is in the process of comparing VGI use cases to storage or DER use cases in satisfaction of the CPUC’s third question.

1.3 Purpose of Study

The purpose of this study is to aid the VGI Working Group in answering the question, “How does the value of VGI use cases compare to other storage or DERs?” This study addresses three promising applications of VGI technology and uses a standardized cost-benefit analysis to judge the relative benefit of VGI versus comparable storage or DER technologies for each. The applications are described below:

1. **Residential Peak Shaving:** Using V2G, utilities draw energy from plugged in EVs to diminish the severity of daily peak demand. For this application, we compare V2G to home storage and behind-the-meter demand response (“DR”) programs.
2. **Utility-Scale Peak Shaving:** Using V2G, utilities draw energy from a plugged in electric school bus fleet to diminish the severity of daily peak demand. For this application, we compare V2G to commercial/industrial storage programs and commercial/industrial DR programs.
3. **Home Backup:** Using V2H, homeowners draw energy from plugged in EVs to provide electricity to their homes in the event of a power outage. For this application, we compare V2H to home battery storage.

⁹ “VGI Communication Protocol Working Group: Energy Division Staff Report.” *CPUC*

¹⁰ “Vehicle Grid Integration Working Group.” *GridWorks*

The study is intended as a supplement to the VGI Working Group's planned activity for Question 3 and is designed to provide a numerical basis for evaluating the relative value of VGI for various applications.

The results of this study are highly input- and assumption-dependent and thus are not intended as definitive judgements on the programs addressed. For this reason, we also provide the model we used to generate these results, so that the Working Group may adjust the inputs as members see fit. Additionally, members of the Working Group may use the model to tailor various VGI policy proposals so that these policies provide maximum value.

1.4 Structure of this Report

This report is intended as a supplement to the "VGI Cost-Benefit Comparison Tool" presented to the VGI Working Group. So as to best aid the work of the Working Group, the report is structured in a way that allows readers to understand the assumptions undergirding the test scores for each application and thus to adjust the model as they see fit.

Section 2 of this report explains the basis and the methodology for the cost-benefit analysis presented here. It explains each of the cost-benefit tests conducted and how to interpret the scores, and it gives a broad overview of the sources for the inputs.

Sections 3, 4, and 5 present the cost-benefit analysis performed for residential peak shaving, municipal peak shaving, and home backup, respectively. Each of these sections is subdivided by technology (e.g. VGI, DR, or storage). For each technology, we first present all the data sources and assumptions that form the basis for our analysis. Then we present the results of the analysis in numerical form. We also include a qualitative analysis of the impact each technology might have on the environmental and on system resiliency.

In Section 6 we present our conclusions. Namely, we explore the overall value of VGI versus other storage and DER technologies. We also address any shortcomings of the model and the possible implications our results may have for VGI policies. We conclude by exploring next steps, including how this analysis can inform the Working Group's activities in the future.

1.5 Affiliation to Columbia University

The authors of this study are students at the Columbia University School of International and Public Affairs, and this study is completed as a group research project or "practicum" for the Energy and Environment Department. Funding for this study comes from the Energy and Environment Department and the Center for Global Energy Policy.

2 Methods

2.1 Tests

Energy from EVs is designated as a distributed energy resource by California's Public Utilities Code¹¹. As such, cost-benefit analysis in this study is conducted in accordance with CPUC Rulemaking (R. 14-10-003): "Decision Adopting Cost-Effectiveness Analysis Framework Policies for All Distributed Energy Resources." The decision declares that all cost-benefit analyses on DERs conducted for a CPUC program should be conducted using four tests described in the "California Standard Practice Manual: Economic-Analysis of Demand-Side Programs and Projects." The Standard Practice Manual - first published in 1983 and most recently revised in 2001 - describes factors to be considered as costs and benefits when ascertaining the value of a program from various perspectives.

For each application, costs and benefits are projected five years into the future, beginning in 2021 and ending in 2025. The test results for each application include a net present value ("NPV") consisting of the total costs subtracted from the total benefits, an NPV per kWh consisting of the total costs subtracted from the total benefits divided by the total energy savings the program offers, and a benefit/cost ratio consisting of the total benefits divided by the total costs. In keeping with the guidance from the CPUC Decision, analysis in this study is based on each test's benefit cost-ratio. A benefit-cost ratio greater than 1 indicates that the program provides a net benefit to the perspective addressed by that test, while a benefit-cost ratio below one indicates that the program is a net negative for the perspective addressed¹².

The tests were conducted using tools provided by the CPUC. Specifically, CPUC's "Avoided Cost Calculator," most recently updated in June 2019, provides all inputs related to the energy and cost savings generated by DER programs. The calculator uses production, consumption, ancillary service, transmission, capacity, distribution, greenhouse gas, and renewable portfolio standard data from California's three major utilities, CAISO, and California government agencies; these data are updated annually. Output from this calculator is then fed into the CPUC's "DR Reporting Template," which uses the avoided cost results to calculate the test results described herein. The "VGI Cost-Benefit Comparison Tool" used as the basis for this report is a variation on the "DR Reporting Template"; we have updated and expanded the tool to suit the technologies addressed by our analysis.

In the sections below, we describe the four tests used in this study to measure program value.

¹¹ Regulation of Public Utilities: Div. 1, Part 1, Ch. 3, Art. 3, §796(a)

¹² "Standard Practice Manual." CPUC

2.1.1 Total Resource Cost (TRC) Test

The TRC test measures the value to society of a particular DER program. “Society” here is defined as all utilities, program participants, and non-participating customers in the region addressed by the program. Benefits in the TRC Test include avoided supply costs; reduced transmission, generation, and distribution costs; reduced greenhouse gas emissions; reduced air pollutants; and other miscellaneous benefits. Costs include equipment costs, maintenance costs, administrative costs, and other miscellaneous costs. Tax credits are considered a reduction in costs. For the purposes of the TRC test, incentives paid by the utility to participants are considered a transfer and are thus not counted as either a cost or a benefit.

The CPUC Decision states that “the Total Resource Cost test shall be considered the primary test of cost-effectiveness for all distributed energy resources.”¹³ The TRC test is the most comprehensive test used in this study and thus serves as the primary indicator of the overall effectiveness of a program.

2.1.2 Program Administrator Cost (PAC) Test

The PAC test measures the net benefit of a program from the perspective of the entity administering it¹⁴. For all of the applications addressed in this study, the “program administrator” refers to an investor-owned utility (“IOU”). Data and assumptions for the tests are drawn from California’s three major IOUs: Pacific Gas and Electric (“PG&E”), Southern California Edison (“SCE”), and San Diego Gas and Electric (“SDG&E”), which together serve 88% of Californians

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Benefits in the PAC test are similar to the TRC test, but costs only address those incurred by the program administrator, namely incentives, equipment costs, administrative costs, and any increased production costs. A benefit/cost ratio greater than 1 indicates that the program is net beneficial to the IOU, while a ratio below 1 indicates that it is net unfavorable. The PAC test is intended as a supplement to the TRC test as it only presents the favorability of a program from one perspective. Nevertheless, it provides a valuable projection regarding how a certain program might affect the IOU administering it.

2.1.3 Ratepayer Impact Measurement (RIM) Test

The RIM test projects what will happen to the electric bills paid by IOU customers in the region addressed by a program, and thus whether the program will be beneficial or detrimental to

¹³ “Decision Adopting Cost-Effectiveness Analysis Framework Policies for All Distributed Energy Resources.” *CPUC*

¹⁴ *Ibid.*

¹⁵ “Company Profile.” *PG&E*

¹⁶ “About SCE.” *SCE*

¹⁷ “About Us.” *SDG&E*

¹⁸ “California.” *U.S. Census Bureau*

ratepayers in general¹⁹. IOUs in California set retail rates using “cost of service recovery,” meaning any change in company revenues will translate to a change in retail rates²⁰. Thus, if a program reduces the administrator’s revenues (through avoided electricity payments), customers will see their rates increase and if a program increases the administrator’s revenues, customers will see their rates decrease.

The RIM test takes as its benefits all avoided costs the program incurs. In the model, this includes any generation, transmission, distribution, and capacity costs that might be eliminated by the program. RIM test costs include incentives paid, revenue lost (due to demand reduction), equipment costs, and admin costs. A benefit/cost ratio greater than 1 indicates that the IOU’s customers will see their electricity bills go down as a consequence of implementing the program, whereas a ratio less than 1 indicates that customers will see their electricity bills increase.

The RIM test is also intended as a supplement to the TRC test as it presents an incomplete yet important perspective of the value of a program. It is important to note that the RIM test addresses *all* ratepayers, not just those who participate in the program.

2.1.4 Participant Cost Test (PCT)

The PCT measures the quantifiable value to participants in the program and thus whether participation in the program will be a net economic benefit to that customer. It takes as its benefits incentives, tax credits, and any reduction in the participants’ electricity bills as a result of decreased consumption. Costs include maintenance costs, increase in electricity bills, and the customer’s share of equipment expenses.

The PCT is intended only as an indication of program attractiveness and should not be taken as a measure of the overall value of a program. A benefit/cost ratio greater than 1 for the PCT indicates that the program is a net benefit to the participant, while a ratio less than 1 indicates that it is a net harm. In order to attract participants, all voluntary DER programs should have a benefit/cost ratio greater than 1. It should be noted, however, that consumers do not base their decisions entirely on quantifiable variables and as such the PCT is an incomplete measure of program attractiveness²¹.

2.2 Data Sources and Assumptions

Data for the analysis presented herein is drawn from a variety of sources. Avoided costs are drawn from the CPUC’s Avoided Cost Calculator, which uses data from California’s major IOUs and CAISO. Manual inputs derive from a more diverse set of sources. Whenever possible, energy and economic data are based on reports from a California IOU, CAISO, or a California Government agency. In cases where this was not possible, an effort was made to use the most

¹⁹ “Standard Practice Manual.” CPUC

²⁰ “Costs and Rates.” CPUC

²¹ “Standard Practice Manual.” CPUC

reputable and up-to-date sources, including scientific literature, news reports, industry reports, and economic tracking data. Every external data source used is cited both in the report and in the model.

It is important to note that the model is highly sensitive to assumptions. The smallest change in program participation, incentives, or battery capacity may have large ramifications for the attractiveness of a program. Every assumption in this model is explicitly acknowledged and justified in the report. In most cases, assumptions are intentionally conservative so as to avoid overstating the value of a program. Readers are encouraged to interrogate the assumptions presented herein and to update the model accordingly.

2.3 Impact on Environment

California has set an emissions target of 259 million metric tons of carbon dioxide equivalent per year by 2030.²² Currently, the state emits 424 million metric tons per year, of which 64 million is due to electricity generation.²³ VGI can help the state meet its emissions reduction goals by reducing the need for fossil fuel generation. This has an additional benefit of reducing local air pollutants such as nitrous oxides, sulfuric oxides, volatile organic compounds, and particulate matter.

Based on CPUC guidance, environmental benefits are internalized into the model using a value of greenhouse gas (“GHG”) emissions avoided (\$5.09/MWh in 2021, increasing to \$34.24/MWh in 2025) and an “air quality adder” (constant \$6.00/MWh). GHG abatement measurements assume that peaker plants use natural gas generation, which emits 0.92 pounds of carbon dioxide per kWh.²⁴ In addition to a quantitative accounting of environmental benefits, each cost-benefit analysis includes a qualitative assessment of how the technology in question could reduce the state’s environmental footprint. Considerations include short-term generating activities, long-term capacity investment, and equipment footprint. Each section also addresses the impact the technology would have on the state’s emissions targets.

2.4 Impact on Resiliency

California faced more than 50,000 significant outage events in 2019.²⁵ The state’s electric grid faces two major reliability threats. The first of these is the increasing occurrence and severity of weather events due to global climate change. In California, this has translated to more high-wind events, higher temperatures, and increasing variability in precipitation. Such events can cause both unplanned power outages (when circuits are broken due to unexpected damage

²² Rogers, Paul. “California’s behind on its 2030 climate goals. What’s at stake if it doesn’t catch up?” *Mercury News*. Jan 16, 2020.

²³ “GHG Current California Emission Inventory Data.” *California Air Resources Board*. 2019.

²⁴ “How much carbon dioxide is produced per kilowatt-hour of U.S. electricity generation?” *EIA*

²⁵ [How Power Outages Are Affecting California](#)

to grid infrastructure) and planned outages, as was the case during 2019's anomalously severe wildfire season.

The second reliability threat is increasing penetration of intermittent renewable energy sources. Wind and solar accounted for a combined 23% of California's electricity generation in 2018.²⁶ This level of intermittency has exacerbated the "duck curve," requiring peaker plants to ramp up and down more quickly than before. This type of activity places additional stress on such generating facilities, making them more prone to unexpected breakdowns. High intermittency has also exposed the grid to greater levels of variability in frequency and voltage, placing stress on the transmission and distribution lines.

Each cost-benefit analysis addressed in this study also includes a qualitative discussion of the technology's impact on resiliency. Specifically, we discuss how the program discussed could reduce strain on generation, transmission, and distribution assets and how it could reduce the likelihood and duration of power outages.

²⁶ "Total System Electric Generation." *California Energy Commission*. June 24, 2019.

3 Cost-Benefit Analysis: Residential Peak Shaving

Severe peak demand on the electric grid necessitates inefficient peaking power plants, causes increased grid maintenance costs, and presents risks to grid stability. Stabilizing the demand curve by reducing the magnitude of daily peaks (“peak shaving”) can save grid operators and IOUs money, as well as reduce rates for customers. In this section, we assess the value of V2G technology for peak shaving and compare this value to both demand response programs and home storage,

3.1 Residential V2G

By treating EVs with bidirectional chargers as a distributed storage resource, IOUs can call upon the energy stored within an EV battery to help meet peak demand. California’s daily electricity demand curve (right) reaches peak consumption between 5 and 9 pm each day²⁷. A V2G peak shaving program would allow the IOU to extract electricity from cars plugged into bidirectional chargers, thus reducing the amount of electricity required from peaker plants and the congestion on transmission lines.

3.1.1 Data and Assumptions

EV Stock and Features

In order to model the stock of plug-in electric vehicles in California, we first obtained data from *Inside EV News* on the annual new plug-in electric vehicle registrations and market share in California by type of plug-in from 2010-2018. Using the 2018 values as a base year to calculate the growth projections, we then applied a 12% annual growth rate for each year until 2025. This rate is estimated by Moody’s Investor Services for EV growth in the state.²⁸

It is assumed that only battery electric vehicles (BEVs) will be part of the V2G program, while plug-in hybrid electric vehicles (PHEVs) will not participate as their average battery size is significantly smaller (about 10-15 kWh). This is due to the fact that PHEVs are powered primarily by an internal combustion engine (ICE), and rely on an additional smaller battery to support the ICE, as opposed to BEVs solely relying on a larger battery for power²⁹.

Based on the 2018 and 2019 US sales of the top ten commercial BEV models, we obtained an average battery capacity of 71.4 kWh for BEVs, with an annual growth rate of 1.1% for new BEVs between 2018 and 2019^{30,31}. We applied this growth rate to the years 2020-2025 to project the increase in battery sizes.

²⁷ “CAISO’s proposed TOU periods to address grid needs with high numbers of renewables.” CAISO

²⁸ “Electric Vehicle Growth in California”. *Moody’s Investor Services*. October 2016.

²⁹ “Battery Requirements for Plug-In Hybrid Electric Vehicles.” *NREL*

³⁰ “Final Update: Quarterly Plug-In EV Sales Scorecard.” *Inside EVs*

³¹ “Electric Vehicle Growth in California.” *Moody’s*

The vehicle availability factor is assumed to be 50%³², meaning that vehicles will be available for this program one out of every two days. The round-trip efficiency is expected to be 90%³³ and a yearly battery deterioration rate of 2.3% is included.³⁴

The useful battery capacity for VGI services is assumed to be 75% of the nominal battery capacity.³⁵ This is an industry standard meant to minimize battery degradation.

Charging Infrastructure

It is assumed that all EV owners currently have a unidirectional charger at home, meaning that the current stock of unidirectional chargers is equal to the total current EV stock. Likewise, it is expected that all future EV purchases will be accompanied by the purchase and installation of the same number of chargers. There are three levels of unidirectional EV chargers:³⁶

- Level 1 Chargers: 120 volts, 20 hour charge time
- Level 2 Chargers: 240 volts, 4 hour charge time
- Level 3 Chargers (DC fast charging); 480 volts, 30 minute charge time

As EV batteries grow larger and EV owners seek increased charging flexibility, most new EV owners are purchasing Level 2 chargers. Level 2 chargers cost around \$700 to purchase and around \$1,500 to install.

Every participant in the residential V2G peak shaving program will require a bidirectional charger. Since no VGI program yet exists at scale in California, the initial stock of bidirectional chargers is assumed to be 0. Therefore, the number of bidirectional chargers to be installed each year will equal the number of new participants enrolled in the program each year.

The equipment for a bidirectional charger is assumed to cost around \$5,000, which is the market average published by NREL in 2017³⁷. We assumed that the installation cost is \$2,500, \$1,000 higher than the cost for a unidirectional charger. The bidirectional charger taken into account has a power output (to both the grid and the car) of 10 kW,³⁸ which will serve as the basis for estimates of power impacts.

It is expected that participants will pay the full cost of the equipment installation; they would then expect to both recoup these costs and make a profit on payments from the IOU for providing peak shaving services. For the purposes of our analysis, we only consider equipment costs that

³² Jayakrishnan Radhakrishna Pillai, Student Member, IEEE, and Birgitte Bak-Jensen, Member, IEEE, "Integration of Vehicle-to-Grid in the Western Danish Power System"

³³ Zhiyu Duan, "Comparison of Vehicle-to-Grid versus Other Grid Support Technologies", *Duke Nicholas School of Environment*, April 2012

³⁴ Based on the [Geotab](#) battery deterioration model for the Tesla Model S.

³⁵ Jayakrishnan Radhakrishna Pillai, Student Member, IEEE, and Birgitte Bak-Jensen, Member, IEEE, "Integration of Vehicle-to-Grid in the Western Danish Power System"

³⁶ "Critical Elements of V2G Economics." *NREL*

³⁷ *Ibid.*

³⁸ *Ibid.*

are incurred specifically as a result of program participation. As such, we assume that an EV owner would purchase a Level 2 charger anyway. We therefore only consider the difference in cost between a bidirectional charger and a unidirectional charger. In practice, this means the equipment cost to the consumer of participating in the program is \$5,300. The total equipment costs of the program are substantial, rising from \$32m in 2021 to \$444m in 2025.

NREL estimates that annual maintenance costs for an EV charger amount to 5% of the upfront equipment cost for both unidirectional and bidirectional chargers³⁹. We also allocate this cost similarly to the participant. Like the installation cost, we only consider the additional maintenance cost incurred by participating in the program. The charger maintenance cost incurred by the participants rises from \$2m in 2021 to \$63m in 2025.

Program Participation

It is assumed that a program of this magnitude will have a gradual penetration in the EV market. For the purpose of this exercise, an initial 5% participation rate was assumed for 2020, growing linearly to reach 40% in 2025. Every EV owner participating in the program will possess a bidirectional charger and participate in the peak shaving of the load each day. It is assumed that the participation rate does not reach 100% as not every EV owner will have a single family home or access to their own charger, some will live in apartments and charge at work/public, etc.

Energy and Power Impacts

In order to estimate the impact of residential V2G for peak shaving in terms of power and energy services offered to the grid, we adopted a twofold approach that includes:

1. An assessment of the amount of power and energy that EVs can offer to the grid on any given day (i.e. the supply);
2. An assessment of the power and energy requirements for peak shaving on any given day (i.e. the demand).

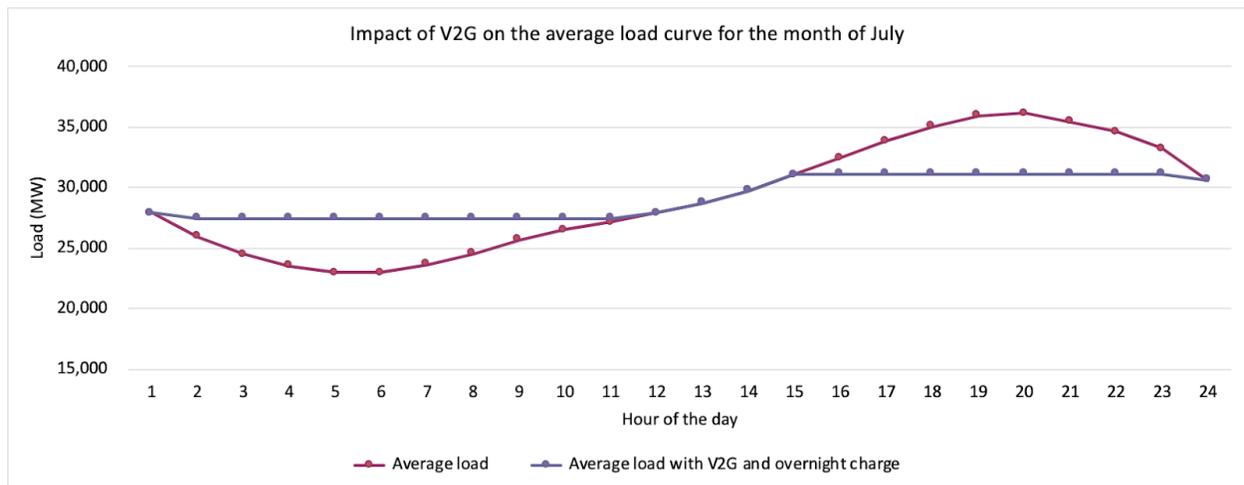
With regard to the supply, we calculated the maximum available power for peak shaving as the product of the number of EVs available for VGI services (which factors in the EV owner participation rate and vehicle availability), and the average charger power. Results range from 0.4 GW in 2021 to 1.8 GW in 2025.

In terms of energy, we calculated the maximum available energy for peak shaving as the product of the number of BEVs available for VGI services, the average battery capacity and the correcting factors explained before: i) participation rate, ii) availability factor, iii) useful battery capacity, iv) round-trip efficiency and v) battery degradation. Results range from 675 GWh in 2021 to 3,122 GWh in 2025 (i.e. from 0.3% to 1.2% of the yearly California electricity consumption, which was 255 TWh in 2018).

³⁹ Critical Elements of V2G Economics." NREL

With regard to the demand, we started from the 2019 data of the hourly load of the California electricity grid provided by CAISO. For each month, we derived the shape of the load throughout an average day and made assumptions on the reasonable amount of power that VGI should offer to the grid to shave the daily peak and make the load curve smoother. The amount of power available for peak shaving for each month corresponds to a certain amount of energy extracted from the EV batteries. We assume that the batteries are then charged overnight (when the cost of electricity and the load are the lowest) to compensate for the energy extracted during the peak. Hence, the load at the valley will increase by an amount comparable to the peak shaved, although the exact amount will depend on the actual shape of the load curve.

Based on the analysis of the daily load curves for each month, the maximum amount of power demanded for peak shaving is set to 2 GW for the months between November and May, 3 GW for June and October, 4 GW for September and 5 GW for July and August. For example, for the month of July the original load curve and the load curve as modified by V2G and the required overnight battery recharge will be the ones shown in the figure below.



Based on the analyses outlined above for the supply and demand sides, we then determined the impact of VGI in terms of power and energy as the minimum between supply and demand. In general, based on the values selected for the different parameters, both power and energy are constrained by the supply (i.e. the demand for VGI services is higher than what the EV stock can offer).

Administrative Costs

Data for the administrative costs of a VGI peak shaving program are based on the PG&E “Monthly Report On Interruptible Load and Demand Response Programs for December 2019,” which details the company’s expenditures on its portfolio of demand response programs. The administration of a residential VGI for peak shaving program is assumed to be similar to

PG&E’s “Smart AC” supply-side program, which accounts for roughly half of all the customers enrolled in PG&E’s DR programs.⁴⁰

The fixed costs for a VGI program would include market, education, and outreach (ME&O) costs, as well as portfolio support costs. We estimate these costs by scaling the reported ME&O and portfolio support costs PG&E incurred in 2018 to reflect the relative size of the Smart AC program; this yields \$756,435 for ME&O and \$3,498,142 for portfolio support. These costs remain fixed for the duration of the cost-benefit analysis.

The variable costs for this program include the direct administrative costs related to managing the enrolled participants, labeled as “Supply-Side DR Programs” in the PG&E report. Dividing the monthly costs by the monthly participants and then summing the results yields a direct administrative cost of \$28.35 per participant per year. This is then multiplied by the total expected participants in the VGI program (total EVs times participation rate) to represent the variable cost portion of the admin cost.

Lastly, marginal admin costs are likely to decrease with increased enrollment due to institutional learning and economies of scale. For this reason, we include a scaling factor of 20%; for every doubling of enrollment (over the total enrollment in the Smart AC program), marginal admin costs decrease by 20%.

Annual administrative costs range from \$5.9m in 2021 to \$17.2m in 2025.

Net Bill Reductions and Incentives

The primary benefit to the program participant is the monetary compensation they receive from the IOU in return for providing grid services. This compensation comes in the form of price arbitrage through a net metering scheme. Though the net energy consumed by the participant remains the same, electricity provided at peak hours is valued more expensively than at off-peak hours. Our model assumes that the IOUs will pay participants the average retail rate for electricity at peak hours, \$0.38/kWh. Consumers will have to replenish their car batteries using electricity at off-peak hours, during which times the average retail price of electricity is \$0.14/kWh. Thus, using price arbitrage, participants in the peak shaving program will be compensated \$0.24 for every kWh contributed. It is important to note that due to efficiency limits in the charging infrastructure, only 90% of the energy contributed by the participant is received and paid for by the IOU.

These compensation benefits are reflected in the “Incentive Cost” and “Net Bill/Revenue Reductions” terms in our model. The “Incentive Cost” reflects the total amount of money the IOU pays for electricity from VGI at peak hours. The “Net Bill/Revenue Reductions” term reflects the

⁴⁰ [Pacific Gas and Electric Company Monthly Report On Interruptible Load and Demand Response Programs for December 2019](#)

total net change in the customers' annual electricity bills as a result of participating in the program. This affects both the IOUs revenues and the rates other customers will pay.

Program participants also receive a capacity payment for the capacity that they made available to the program. The dollar value assigned to each unit of capacity varies by month and is assumed to be similar to the Capacity Bidding Program (CBP).⁴¹ The values used in the model are shown in the tables below.

Incentive Costs		January	February	March	April	May	June
Capacity Payments (IOU Avg)	USD/kW	0.00	0.00	0.00	0.00	2.92	4.31
Capacity Payments (PG&E)	USD/kW	0.00	0.00	0.00	0.00	2.86	3.49
Capacity Payments (SCE)	USD/kW	0.00	0.00	0.00	0.00	2.97	4.46
Capacity Payments (SDG&E)	USD/kW	0.00	0.00	0.00	0.00	2.93	7.79

Incentive Costs		July	August	Sept.	October	Nov.	Dec.
Capacity Payments (IOU Avg)	USD/kW	15.07	19.89	11.18	2.09	0.00	0.00
Capacity Payments (PG&E)	USD/kW	14.67	20.29	12.51	2.04	0.00	0.00
Capacity Payments (SCE)	USD/kW	15.10	17.58	9.36	1.74	0.00	0.00
Capacity Payments (SDG&E)	USD/kW	16.93	29.92	13.86	4.19	0.00	0.00

The resulting capacity payment ranges from \$21m in 2021 to \$142m in 2025.

3.1.2 Test Results and Sensitivity Analyses

Base Case Results					
2020 Dollars	Benefits	Costs	Net Benefits	Net \$/kW-Yr.	Ratio
TRC	\$1,504,700,483	\$454,300,173	\$1,050,400,309	\$239	3.31
PAC		\$326,229,841	\$1,178,470,642	\$268	4.61
RIM		\$1,930,275,861	(\$425,575,378)	(\$97)	0.78
PCT	\$1,883,383,373	\$407,407,686	\$1,475,975,688	\$336	4.62

The TRC ratio of 3.31 indicates that this program is highly beneficial. Specifically, the savings generated by reducing energy consumption at peak hours greatly outweighs the equipment and administrative costs. The PAC score of 4.61 and the PCT score of 4.62 show that both the IOU and the program participant stand to benefit substantially from the program. However, an RIM score of 0.78 shows that other ratepayers will suffer as a result. This is because the IOU will collect less revenue and will be forced to raise rates on its customer base.

⁴¹ https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHS_E-CBP.pdf

The sensitivity analyses in the model show that the TRC score is highly sensitive to capital amortization period and load impact but relatively insensitive to program participation, availability factor, value of generation capacity, and value of transmission and distribution. A 3 year amortization period (base case is 10 years) would reduce TRC to 1.5, whereas a 15 year period would increase TRC to almost 4.0. Notably, higher levels of participation correspond to lower TRC values.

3.1.3 Impact on the Environment

Peak shaving with VGI would not reduce the total electricity generated, but it would reduce the need for “peaker plants” - typically relatively emissions-intensive natural gas generators - enabling utilities to purchase electricity from cleaner sources. By reducing the need to operate natural gas peaker plants, the VGI peak shaving program modeled here is projected to abate 59,000 metric tons of carbon dioxide equivalent in its first year of operation.⁴² This is equivalent to 0.45% of the total annual emissions reductions required for California to meet its 2030 emissions target.

The effect on emissions would extend beyond direct displacement of natural gas combustion. With an expectation of reduced peak demand in the future, energy companies would be less incentivized to invest in new natural gas generation. Natural gas generators have an average lifetime of 22 years;⁴³ by disincentivizing investment in natural gas power plants today, VGI peak shaving would avoid locking in natural gas emissions decades into the future.

Reducing the need for natural gas combustion would also abate other air pollutants, primarily tropospheric ozone. The value of abating these air pollutants is estimated at \$58 million over five years.

3.1.4 Impact on Resiliency

Outage likelihood increases at peak demand due to system congestion. In California, yearly peak demand occurs in late summer, when high temperatures cause consumers to use more air conditioning⁴⁴. At high temperatures, electric wires become less efficient, making electricity demand more likely to overload the system capacity. High temperatures also cause electric lines to sag, increasing the likelihood that they may snag on a tree⁴⁵.

VGI for peak shaving has the potential to reduce these threats to grid reliability. By flattening out the daily electricity demand curve, it would reduce the necessity to rapidly ramp up and down peaker plants, reducing the potential for failure. It would also ameliorate the stress placed on the

⁴² [“How much carbon dioxide is produced per kilowatt-hour of US electricity generation?” US Energy Information Administration](#)

⁴³ “Natural gas generators make up the largest share of overall U.S. generation capacity.” *US Energy Information Association*. Apr. 20, 2017.

⁴⁴ “CAISO’s proposed TOU periods to address grid needs with high numbers of renewables.” *CAISO*

⁴⁵ “Heat wave slams the grid. Here's what to know.” *E&E News*

grid during summer months. By reducing the load required of already inefficient and sagging transmission and distribution lines, it would reduce the likelihood of power line overload. Both of these services would provide valuable resiliency in the face of severe weather events and increasing intermittency.

3.2 Residential Demand Response

Behind-the-meter demand response programs allow IOUs to mitigate the severity of peak demand. Using either smart appliances or more analog methods, IOUs can trigger a temporary decrease in energy-consuming activity during peak hours. Such programs reduce the need for peaker plants and reduce congestion on transmission and distribution lines. Here, we compare the value of a peak-shaving DR program to V2G..

3.2.1 Data and Assumptions

AC Cycling Program

For the purposes of this analysis we find PG&E's "Residential AC Cycling" Program to be the most comparable to a VGI peak shaving program. Enrollees in the Residential AC Cycling Program receive a one-time incentive of \$50 and a free installation of a smart AC in return for agreeing to allow PG&E to curtail the operation of their AC during peak hours. The program runs from May to October and has a total of 102,817 participants, whose electricity consumption PG&E can decrease during hot summer days in order to mitigate peak conditions on the grid.

Equipment Costs

Participation in the AC Cycling Program involves allowing the utility to install a smart AC in one's house; the AC unit is equipped with a radio controller box which, during peak hours, can be used for the utility to send a signal that temporarily shuts off the AC unit. The cost and installation of this device is covered by the utility. Given that the price of the device currently in use by PG&E (an Energate LC2200 Load Control Switch) was not available online, we used the cost of the Schneider Electric Load Controller Device, similar to the Energate device and currently priced at \$531. Given that there are no significant installation steps related to the placement of this device, we included a cost of \$280 which is an average cost of hiring an electrician for small residential electrical projects. Per the program guidelines, all of the equipment costs fall on the IOU.

Program Participation

To make the DR program comparable to the VGI case, participation is taken as an endogenous variable and is calculated as the total number of participants necessary to match the available load of the VGI program during July, the month when load per participant under the AC Cycling program reaches its peak. We modeled the evolution of the California population⁴⁶ and the

⁴⁶ [US Census data, 2014-18](#)

number of households⁴⁷ over the years 2021-2025. Based on these projections and power impact obtained for residential V2G, the resulting participating rate (in terms of share of participating households) ranges between 5.4% in 2021 and 36.7% in 2025. This is equivalent to roughly 7 times the size of the current AC Cycling Program in 2021⁴⁸.

Energy and Power Impacts

Because AC use varies based on outside temperatures, the load per customer available for peak shaving services varies from month to month, reaching a maximum of 0.52 kW per household in July⁴⁹. For each year modeled, the load impact in July is held equal to the load impact of the V2G peak shaving program in July of the same year. The total participants required to meet this load is then held constant throughout the year. The power impact therefore increases from 0.3 GW in 2021 to 2.1 GW in 2025.

The energy impact is taken to be the expected monthly available load per household multiplied by the expected hours of AC curtailment per month and the total number of households participating in the program. The expected hours of AC curtailment per month is also supplied by PG&E and reaches its peak in July. The resulting energy impact rises from 232 GWh in 2021 to 1,632 GWh in 2025 (i.e. from 0.1% to 0.6% of the yearly California electricity consumption, which was 255 TWh in 2018).

Administrative Costs

Administrative costs for the DR program derive from PG&E's "Monthly Report On Interruptible Load and Demand Response Programs for December 2019," as it did with the V2G case, with the methodology followed being similar to the one outlined in the corresponding paragraph for residential V2G. A 20% scaling factor is also used. This resulted in total administrative costs rising from \$15m in 2021 to \$46m in 2025.

Net Bill Reductions and Incentives

The benefits of the program to the participants are (i) net bill reductions, which result from the decrease in electricity consumption when AC units are called to run at a lower capacity, and (ii) a direct incentive, in the form of a time rebate for participating.

The net bill reductions, which can only be obtained throughout the duration of the program between May and October, were calculated by multiplying the energy savings obtained in any particular year by the peak retail price of electricity of \$0.38/kWh. This price is the TOU Prime rate offered by Southern California Edison to consumers that use clean energy technologies and can shift peak electricity usage to lower-cost times.⁵⁰ These reductions range from \$88m in 2021 to \$620m in 2025.

⁴⁷ [Public Policy Institute of California Report](#), January 2018

⁴⁸ "Monthly Report On Interruptible Load and Demand Response." *PG&E*

⁴⁹ *Ibid.*

⁵⁰ [Southern California Edison Time-Of-Use Residential Rate Plans](#)

In terms of the direct incentive, PG&E offers the participants of its Smart AC Program a \$50 rebate for enrolling in this program. This amount is only offered once and is not associated with the number of times the utility calls on the participant’s ACs for reduced power consumption. The direct incentive is thus calculated by multiplying the one-off incentive by the total number of participating households. The direct incentive rises from \$32m in 2021 to \$79m in 2025.

Benefit Adjustments

V2G and storage programs are available virtually at any time, any day of the year, while demand response programs do not offer the same high level of availability. In the specific case of the Residential AC Cycling program, the program is available only during summer months and for an average of about 2 hours per day.

Assuming that the ideal number of hours of availability for peak shaving is 4 hours per day (i.e. that the peak is shaved for 4 hours), the residential DR program is only available about 50% of the time. For this reason, we assumed that the benefits in terms of avoided generation capacity and deferred transmission and distribution investments are only 50% of the full potential.

3.2.2 Test Results and Sensitivity Analyses

Cost-Effectiveness of Residential Demand Response for Peak Shaving					
<i>2020 Dollars</i>	Benefits	Costs	Net Benefits	Net \$/kW-Yr.	Ratio
TRC	\$843,499,558	\$2,037,173,989	(\$1,193,674,431)	(\$290)	0.41
PAC		\$1,050,789,718	(\$207,290,160)	(\$50)	0.80
RIM		\$2,232,585,288	(\$1,389,085,730)	(\$338)	0.38
PCT	\$1,377,206,870	\$1,181,795,570	\$195,411,300	\$48	1.17

The TRC ratio of 0.41 indicates that the program is not beneficial to the service area as a whole. The PCT score above 1 indicates that the program is a net benefit to households enrolled in the program (thanks to the incentive offered). However, the RIM score of 0.38 shows that implementing the program would have a net negative effect on ratepayers as a whole. This is because participants in the program would be using less electricity at peak hours, reducing the utility’s revenue collection during those times; the utility would then have to pass on that revenue loss to customers in the form of increased rates. A PAC score of 0.80 demonstrates that the avoided costs to the utility are not sufficient to counteract the incentive expense.

The sensitivity analyses show little sensitivity to generation capacity value, transmission and distribution capacity value, load impact, or A factor. In every case, a 30% increase in the input is not sufficient to bring the TRC value above 1, and in most cases above 0.5. Shortening the capital amortization period to three years brings the TRC score to around 0.25. And the TRC score shows no sensitivity to participation rate, as peak shaving capability is constrained by demand during the months in which the program operates.

3.2.3 Impact on Environment

The primary environmental contribution of the DR program described here would be to mitigate the need to use natural gas-fired peaker plants to accommodate the daily peak demand. The program would abate over 97,000 metric tons of carbon dioxide this way, equivalent to 0.59% of the necessary reductions required to meet California's 2030 emissions target. It would further abate electricity generation-related air pollution, a contribution valued at \$23 million over the course of five years. In the long term, this program would also reduce the need to invest in new natural gas generating capacity.

It is expected that the DR program would have a greater environmental benefit than the V2G program. Whereas the V2G program enables peak shaving by using electricity generated at non-peak hours, DR actually reduces overall electricity consumption. The magnitude of this difference, though, depends on the electricity generation sources used to charge the EV during off-peak hours.

3.2.4 Impact on Resiliency

A DR program like the one described here would have the effect of reducing the strain peak demand conditions placed on transmission lines, distribution lines, and generating stations. In doing so, it would both reduce the momentary likelihood of outages during peak conditions and reduce the long-term need for maintenance on the system.

It is expected that a DR program would have a marginally greater resiliency benefit than V2G peak shaving because of its impact on demand. Whereas V2G enables EVs to contribute electricity to meet peak demand, DR actually reduces peak demand. This means that, while V2G eases the burden on generation and transmission lines, it does nothing to ease congestion on the distribution system. DR does all three.

3.3 Residential Storage

IOUs can also mitigate peak conditions using energy stored within home battery packs. Much like with V2G, the IOU can, at times of peak demand, access this stored energy to reduce the demand on peaker plants and congestion on transmission lines.

3.3.1 Data and Assumptions

Residential Storage Setup

We assumed that residential users install a Lithium-Ion (Li-Ion) energy storage system, which is the dominant technology for residential applications. In terms of power and capacity, we adopted the features of the Tesla Powerwall II, the home battery system developed and

commercialized by Tesla Motors, which has a standard power of 7 kW and a nameplate capacity of 13.5 kWh⁵¹.

We assigned the Li-Ion storage system a round-trip efficiency of 80%.⁵² Round-trip efficiency is defined as the total discharge available divided by the total energy required for charge and it is meant to account for both single-cycle losses and parasitic losses. This means that when the battery is discharged to cater to grid needs, the amount of energy obtained is 20% lower than the amount of energy needed to charge the battery back to the same level.

In addition, we introduced battery degradation using a linear degradation model with a yearly capacity reduction of 3%.⁵³

The battery installed cost for residential Li-Ion storage systems is assumed to be about \$1,400/kWh in 2020 and decrease to about \$1,000/kWh in 2025.⁵⁴ This includes both equipment and installation cost and the cost projection corresponds to a yearly cost reduction of about 6%.

The total battery installed cost ranges from \$960m in 2021 to a maximum of \$1,047m in 2023 and a minimum of \$437m in 2025. As with the V2G program, we assign all equipment costs to the participant with the understanding that costs will be repaid via IOUs compensating them for peak shaving services.

Program Participation

In order for the comparison among the different peak shaving technologies to be effective and meaningful, we assumed that residential storage provides the same peak power to the grid as residential V2G. In other words, the reduction in peak power obtained by leveraging the distributed storage of these two technologies is assumed to be the same.

Under this assumption, the program participation rate becomes an endogenous variable. We modeled the evolution of the California population⁵⁵ and the number of households⁵⁶ over the years 2020-2025. Based on these projections and the power impact obtained for residential V2G, the resulting participation rate (in terms of share of participating households) ranges from 0.4% in 2021 to 1.8% in 2025. The cumulative number of installed residential storage systems is 55,000 in 2021 and increases to about 255,000 in 2025.

⁵¹ "Powerwall." *Tesla*

⁵² [SGIP "Energy Storage Market Assessment and Cost-Effectiveness" Report](#), December 2019

⁵³ *Ibid.*

⁵⁴ *Ibid.*

⁵⁵ [US Census data, 2014-18](#)

⁵⁶ [Public Policy Institute of California Report](#), January 2018

Energy and Power Impacts

As discussed, the power impact in each program year is assumed to be equal to the one of a comparable residential V2G program. The power impact therefore ranges from 0.4 GW in 2021 to 1.8 GW in 2025.

The corresponding energy impact is given by the amount of energy available on a daily basis for discharge times the number of days in a year, since we assumed that the system is used everyday to shave the load peak. Results range from 218 GWh in 2021 to 940 GWh in 2025 (i.e. from 0.1% to 0.4% of the yearly California electricity consumption, which was 255 TWh in 2018⁵⁷).

Administrative Costs

As in the V2G case, data for the administrative costs of a residential storage peak shaving program are based on the PG&E “Monthly Report On Interruptible Load and Demand Response Programs for December 2019,” which details the company’s expenditures on its portfolio of demand response programs.⁵⁸

The methodology for administrative cost estimation is similar to the one outlined in the corresponding paragraph for residential V2G. Resulting total administrative costs range from \$6.0m in 2021 to \$10.5m in 2025.

Net Bill Reductions and Incentives

Participants are paid for the electricity that they offer to the grid for peak shaving at the peak retail price (\$0.38/kWh) and earn a profit by arbitraging between that price and the price at off-peak times (\$0.14/kWh)⁵⁹. It is to be noted that when discharging the home battery, the grid only receives 80% of the energy capacity due to round-trip losses. The net bill/revenue reductions rise from \$43m in 2021 to \$187m in 2025.

Program participants also receive a capacity payment for the capacity that they made available to the program. The dollar value assigned to each unit of capacity varies by month and is assumed to be similar to the Capacity Bidding Program (CBP).⁶⁰ The values used in the model are the same as the ones used for residential V2G. The resulting capacity value rises from \$17,000 in 2021 to \$22,000 in 2025.

⁵⁷ “State of California Energy Sector.” *Department of Energy*

⁵⁸ [Pacific Gas and Electric Company Monthly Report On Interruptible Load and Demand Response Programs for December 2019](#)

⁵⁹ <https://www.sce.com/residential/rates/Time-Of-Use-Residential-Rate-Plans>

⁶⁰ https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHS_E-CBP.pdf

3.3.2 Test Results and Sensitivity Analyses

Base Case Results					
<i>2020 Dollars</i>	Benefits	Costs	Net Benefits	Net \$/kW-Yr.	Ratio
TRC	\$1,230,580,159	\$1,491,816,119	(\$261,235,961)	(\$59)	0.82
PAC		\$312,408,107	\$918,172,052	\$209	3.94
RIM		\$777,502,265	\$453,077,894	\$103	1.58
PCT	\$744,431,511	\$1,458,745,366	(\$714,313,855)	(\$163)	0.51

The results of the four tests show residential storage for peak shaving to have a net negative impact. The TRC score of 0.82 suggests that total costs (including both ratepayers and the utility) outweigh the total benefits of the program. Both the IOU and the ratepayers benefit from the program (PAC and RIM greater than 1) as a result of avoided generation capacity costs. However, the equipment costs to the participant outweigh the incentives they receive, hence a PCT score of 0.51. It is important to note that most home batteries are not installed for the purpose of peak shaving, but rather to support distributed renewable generation. As such, a peak-shaving program would likely be more attractive to participants as an add-on to existing home storage capacity.

The TRC score shows a high sensitivity to amortization period, generation capacity value, and load impact and a low sensitivity to transmission and distribution capacity value, availability factor, and participation rate. Increasing generation capacity value by 30% or increasing the capital amortization period from 10 years to 15 years make the program net beneficial. Changes in participation rate have no effect on program efficiency.

3.3.3 Impact on Environment

The primary benefit of the residential storage program described here would be to reduce the need for natural gas-fired peaker plants. By doing so, the program is modeled to abate 90,000 metric tons of carbon dioxide emissions, equivalent to 0.55% of the state’s annual emissions reduction requirements. It would also reduce air pollution, providing an environmental benefit valued at \$18 million over five years. In the long term, this program would also reduce the need for new natural gas plants.

The environmental benefit of a home storage program is expected to be similar to the V2G program, as both help meet peak demand by contributing electricity generated at off-peak hours. This is a smaller environmental benefit than DR, but the magnitude of the benefit will depend on the generation profile during off-peak times.

3.3.4 Impact on Resiliency

A home storage peak shaving program would improve system resiliency by reducing the peak demand burden on generation and transmission assets. As total demand is not reduced, it

would not affect resiliency of the distribution grid. The overall effect would be a short-term reduction in the probability of system failure during peak conditions and a long-term reduced need for maintenance and reduced likelihood of infrastructure failure due to less wear and tear.

3.4 Comparing Technologies for Residential Peak Shaving

	RESIDENTIAL PEAK SHAVING		
	RPS_V2G	RPS_DR	RPS_Storage
BENEFIT/COST RATIOS			
TRC	3.31	0.41	0.82
PAC	4.61	0.80	3.94
RIM	0.78	0.38	1.58
PCT	4.62	1.17	0.51

Only V2G for peak shaving has a TRC value greater than 1, making it the only cost-effective program considered. This is because it has relatively low equipment costs (as compared to the DR and storage programs) to enable relatively high savings.

From an administrator perspective, both the V2G and storage program are beneficial. This is because participants in these programs are expected to bear the cost of equipment installation, even though the utility saves because of peak shaving. The DR program is not beneficial to the utility because the costs of installing the smart ACs outweigh the system benefits.

From a ratepayer perspective, only the storage program is beneficial. This is because the revenue changes for the utility in this program enable it to reduce rates for its customer base. For the other two programs, the utility revenue losses translate to rate increases for other customers.

From a participant perspective, the V2G and DR programs are attractive. In the V2G program, compensation from the utility outweighs the participants' equipment expenditures, and in the DR program, the one-time incentive from the utility and the reduction in electricity expenses outweigh the AC services lost. For the storage program, the participants' savings are not sufficient to compensate them for equipment expenditures.

4 Cost-Benefit Analysis: Utility-Scale Peak Shaving

IOUs can also achieve peak shaving using larger sources of distributed storage and variable electricity consumption. Here, we explore how, using the same technologies as those described in section 3, IOUs can engage municipal, commercial, and industrial facilities to mitigate peak demand on their systems. We explore peak shaving through V2G using a fleet of school buses, a DR program with commercial and industrial facilities, and distributed storage in commercial and industrial facilities.

4.1 School Bus Fleet V2G

Electric school buses have large batteries, predictable schedules, centralized ownership, and are parked most of the day and year (notable during peak hours). Thus, they make ideal candidates for V2G programs. Here, we assess the value of a V2G peak shaving program using a fleet of school buses.

4.1.1 Data and Assumptions

Electric School Bus Stock and Features

The way school buses are operated makes them a good candidate to offer VGI services to the electric grid. School buses are used in the morning to transport students to school and then back home, and are parked for most of the time in the afternoon, when the peak of the load curve occurs.

In California there are about 25,000 school buses, according to an estimate by the San Diego Unified School District Transportation Department.⁶¹ This number is fairly low compared to other states because California does not require public schools to provide transportation for students. The California Energy Commission has recently launched the School Bus Replacement Program, which offers funds to replace old diesel buses with electric buses in disadvantaged and low-income communities throughout California. Over 200 electric school buses have been purchased through the program.

The useful life of a school bus ranges from 12 to 15 years.⁶² To be conservative, we assumed that the lifespan of a school bus is 15 years, which means that every year 1/15 of the school buses (about 1,700 buses) are replaced. We also assumed that the share of electric buses out of the amount of buses replaced every year increases from 10% in 2021 to 20% in 2025. This results in a stock of electric school buses of 1,550 units in 2025, with an average yearly growth of 15% over the years 2021-2025.

⁶¹ <http://transportation2.sandi.net/stats.html>

⁶² <http://www.nasdpts.org/Documents/Paper-BusReplacement.pdf>

In terms of technical specifications, we assumed that electric school buses have a battery capacity of 130 kWh, in line with some commercial models available on the market.⁶³ We applied a 1.1% growth factor to the battery size to account for newer models that may enter the market with larger batteries.

The vehicle availability factor is assumed to be 90%, which means that most school buses are available for VGI services 90% of the time they are needed. As mentioned above, this is a fair assumption, because school buses are only used in the morning and afternoon and are parked during evening peak hours. The battery round-trip efficiency is expected to be 90%⁶⁴ and the figure used for yearly battery deterioration is 2.3%.⁶⁵ The useful battery capacity for VGI services is assumed to be 75% of the nominal battery capacity.⁶⁶

It is assumed that all electric school buses will be automatically enrolled in the program, so that the participation rate is 100%.

Charging Infrastructure

Given the large battery capacity, electric school buses require at least Level 2 chargers for their operations. In a similar fashion to the residential V2G case, we assumed that school bus owners (often the school districts) would only install a unidirectional charger as a default, so costs attributed to the program are bidirectional charger costs minus the cost of a unidirectional charger. As with the residential case, the participants are expected to cover all the equipment costs under the assumption that they will then be compensated by the IOU.

Unidirectional Level 2 chargers for school buses cost \$1,344 to purchase and \$2,800 to install. Bidirectional Level 2 chargers cost around \$9,600 to purchase and around \$2,500 to install. The owner therefore pays \$10,176 for each charger (\$8,256 for the equipment and \$1,920 for installation). The charger has a power rating of 19.2 kW.

As for the residential V2G case, we assumed that annual maintenance costs for a charger amount to 5% of the upfront equipment cost for both unidirectional and bidirectional chargers⁶⁷, to be covered entirely by the participants.

Energy and Power Impacts

The impact of school bus fleet V2G for peak shaving in terms of power and energy services offered to the grid is calculated in a similar way to the residential V2G case. Demand (i.e. power and energy needs from the grid) is the same, while supply is significantly lower, since the

⁶³ <https://www.blue-bird.com/buses/electric-school-buses>

⁶⁴ Zhiyu Duan, "Comparison of Vehicle-to-Grid versus Other Grid Support Technologies", *Duke Nicholas School of Environment*, April 2012

⁶⁵ Based on the [Geotab](#) battery deterioration model for the Tesla Model S.

⁶⁶ Jayakrishnan Radhakrishna Pillai, Student Member, IEEE, and Birgitte Bak-Jensen, Member, IEEE, "Integration of Vehicle-to-Grid in the Western Danish Power System"

⁶⁷ "Critical Elements of V2G Economics." *NREL*

number of electric vehicles involved is very small compared to the residential V2G case. This means that V2G services will always be constrained by the supply in the school bus fleet case.

Results for the maximum available power range from 0.008 GW in 2021 to 0.027 GW in 2025, while results for the maximum available energy range from 13 GWh in 2021 to 47 GWh in 2025 (i.e. from 0.01% to 0.02% of the yearly California electricity consumption, which was 255 TWh in 2018⁶⁸).

Administrative Costs

Given the small scale of the school bus fleet V2G program, administrative costs are expected to be only a fraction of those for residential peak shaving. The total number of participants is roughly 0.4% of the participants in the residential V2G program. To be conservative, we estimate a constant administrative cost of \$1m per year, or 6% of the administrative costs of the V2G program.

Net Bill Reductions and Incentives

As in the residential V2G case, participants are paid for the electricity that they offer to the grid for peak shaving at the peak retail price (\$0.38/kWh) and make a profit by arbitraging these payments against recharging during off-peak hours (when retail price is \$0.14/kWh). It is to be noted that when discharging the home battery, the grid only receives 90% of the energy capacity due to round-trip losses. The net bill/revenue reductions rise from \$2.8m in 2021 to \$10.3m in 2025.

Program participants also receive a capacity payment for the capacity that they made available to the program. The \$ value assigned to each unit of capacity varies by month and is assumed to be similar to the Capacity Bidding Program (CBP).⁶⁹ The values used in the model are the same as the ones used in the residential V2G case. The resulting capacity payment rises from \$0.4m in 2021 to \$1.5m in 2025.

4.1.2 Test Results and Sensitivity Analyses

Base Case Results					
2020 Dollars	Benefits	Costs	Net Benefits	Net \$/kW-Yr.	Ratio
TRC	\$19,539,472	\$9,159,640	\$10,379,832	\$162	2.13
PAC		\$7,463,252	\$12,076,220	\$188	2.62
RIM		\$31,316,372	(\$11,776,900)	(\$184)	0.62
PCT	\$27,333,920	\$5,177,188	\$22,156,732	\$346	5.28

⁶⁸ "State of California Energy Profile." *Department of Energy*

⁶⁹ https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHS_E-CBP.pdf

With a TRC ratio of 2.13, the municipal peak shaving program has a net benefit. In other words, the savings from leveling peak conditions outweigh the equipment and administrative costs the program requires. A PAC ratio of 2.62 indicates that the utilities would benefit from the program, as the system benefits outweigh any administrative and incentive costs. The PCT score of 5.28 suggests this program would be highly attractive to participants (schools), as their profits from providing peak shaving services would outweigh their equipment expenses. Ratepayers, however, would suffer as revenue losses would be passed through in the form of higher electricity bills.

The TRC score is sensitive to variations in capital amortization period, load impact, and generation capacity value and relatively insensitive to variations in availability factor and transmission and distribution capacity value. However, even with a three-year amortization rate or a 30% reduction in load impact, the TRC ratio would remain above 1.

4.1.3 Impact on Environment

As with residential V2G peak shaving, using bidirectional chargers paired with school buses has the potential to mitigate generation from natural gas peaking plants. The program modeled here is projected to abate 5,500 tons of carbon dioxide, equivalent to 0.03% of California's necessary annual emissions reductions. It would also reduce electricity-related local air pollution, a contribution which our model values at \$864,000 over five years. In the long term, this program would also reduce the need for new natural gas plants.

4.1.4 Impact on Resiliency

V2G peak shaving with a municipal school bus fleet can improve system resiliency by mitigating the strain peak conditions placed on generation and transmission infrastructure. Particularly during summer months, peak conditions can lead to congestion, transformer overload, and sagging wires. By reducing the burden on this infrastructure, this program can reduce the likelihood of outages in the short term and reduce the necessary maintenance in the long term.

4.2 Commercial/Industrial Demand Response

By engaging large commercial and industrial energy consumers to reduce electricity demand during certain hours, IOUs can effectively mitigate peak conditions on their systems. Here, we assess the value of such a DR program in order to compare it to a V2G peak shaving program with a school bus fleet.

4.2.1 Data and Assumptions

Base Interruptible Program

For the purposes of this analysis, we find PG&E's "Base Interruptible Program" (BIP) to be the most comparable to a VGI peak shaving program. This program is intended to provide load

reduction on a day-of basis when the system operator issues a curtailment notice. Enrollees in the BIP Program receive an incentive payment on a monthly basis based on their potential load reduction amount in return for agreeing to allow PG&E to curtail their energy consumption. The program runs year long and has a total of approximately 380 service accounts⁷⁰.

Energy and Power Impacts

For the purposes of comparison, load impacts during peak months for the BIP are made to equal the load impact of the municipal V2G peak shaving program. Accordingly load impacts rise from 7.2 MW in 2021 to 24.7 MW in 2025.

The energy impact is taken to be the expected monthly available load per service account multiplied by the maximum number of curtailment hours per month and the program utilization rate. The resulting energy impact rises from 1.23 GWh in 2021 to 4.24 GWh in 2025 (i.e. from 0.0005% to 0.0016% of the yearly California electricity consumption, which was 255 TWh in 2018⁷¹).

Administrative Costs

The load contributions per customer are larger in the BIP than in the V2G program, the BIP only requires 3.3% of the customers the V2G program requires. As a result, admin costs are expected to be lower than in the V2G program. To be conservative, administrative costs for the DR program are estimated at 10% of those for the V2G program, or \$100,000 per year.

Net Bill Reductions and Incentives

The net bill reductions are calculated by multiplying the energy savings obtained in any particular year by the peak industrial price of electricity of 7 ¢/kWh. This price is an average of the general services and industry peak TOU rates offered by Southern California Edison.⁷² These reductions range from \$85k in 2021 to \$294k in 2025.

In terms of the incentive, PG&E offers the participants of its BIP Program a payment on a monthly basis based on the service accounts' monthly potential load reduction amount. This amount is multiplied by the appropriate incentive level (\$8-9/kW depending on the potential load reduction⁷³) to determine the monthly incentive payment. For the purposes of this analysis, we used \$8.5/kW as an average of the monthly incentive value for all service accounts. The incentive is thus calculated by multiplying the monthly incentive by the total number of service accounts and the total load impact for the entire year. The incentive ranges from \$0.7m in 2021 to \$2.5m in 2025.

⁷⁰ "Monthly Report On Interruptible Load and Demand Response." *PG&E*

⁷¹ "State of California Energy Profile." *Department of Energy*.

⁷² [Southern California Edison Time-Of-Use General Service and Industrial Rates](#)

⁷³ https://www.pge.com/en_US/large-business/save-energy-and-money/energy-management-programs/demand-response-programs/base-interruptible/base-interruptible.page

Benefit Adjustments

V2G and storage programs are available virtually at any time, any day of the year, while demand response programs do not offer the same high level of availability. In the specific case of the BIP, the program is available only for up to 180 hours per year⁷⁴.

Assuming that the ideal number of hours of availability for peak shaving is 4 hours per day⁷⁵ (i.e. 1,460 hours per year), the utility-scale DR program is only available about 12% of the time. For this reason, we assumed that the benefits in terms of avoided generation capacity and deferred transmission and distribution investments are only 12% of the full potential.

4.2.2 Test Results and Sensitivity Analyses

Cost-Effectiveness of Utility-Scale Commercial/Industrial Demand Response for Peak Shaving					
2020 Dollars	Benefits	Costs	Net Benefits	Net \$/kW-Yr.	Ratio
TRC	\$2,933,328	\$1,132,522	\$1,800,806	\$30	2.59
PAC		\$6,349,603	(\$3,416,275)	(\$58)	0.46
RIM		\$7,038,756	(\$4,105,428)	(\$69)	0.42
PCT	\$6,595,387	\$689,153	\$5,906,234	\$100	9.57

The TRC ratio of 2.59 indicates that the program is beneficial to the service area as a whole. PAC and RIM scores of below 1 indicate that the program isn't a net benefit to the utility or to the ratepayers because the system benefits are not sufficient to compensate for revenue losses and incentive costs. A PCT score of 9.57 shows this program to be extremely beneficial to the participants enrolled in the program. This is mainly due to the high incentive offered by the utility compared to the minimal costs incurred by the participants.

The TRC score shows high sensitivity to load impacts and availability factors and low sensitivity to generation capacity value, transmission and distribution capacity value, and capital amortization period. A 30% reduction in load impact decreases the TRC score to 1.7, whereas an availability factor of 100% is enough to increase the TRC fourfold. As the equipment costs are virtually nil, the capital amortization period has little effect.

4.2.3 Impact on Environment

Like the V2G program, commercial/industrial DR has a positive impact on the environment by reducing the need for operating polluting peaker plants. Specifically, the program modeled here would abate 513 metric tons during its first year of operation, or 0.003% of the total necessary emissions reductions for that year. It would also reduce local air pollution, a benefit our model values at \$79,000 over five years. In the long term, it would also reduce the need for new natural gas plants.

⁷⁴ "Monthly Report On Interruptible Load and Demand Response". PG&E

⁷⁵ "CAISO's proposed TOU periods to address grid needs with high numbers of renewables." CAISO

A DR program would have some environmental benefits that would not be provided by a V2G program. Namely, a DR program actually reduces demand, rather than displacing it, so overall electricity generation requirements would be less than in the V2G case. Additionally, the program here would not incur equipment-related emissions. Unlike V2G and unlike the AC Cycling Program (the template for residential DR), the BIP does not require any equipment installation, eliminating the lifecycle emissions incurred by bidirectional chargers or smart ACs.

4.2.4 Impact on Resiliency

By reducing the burden on generation, transmission, and distribution infrastructure during peak hours, a commercial/industrial DR program would improve system resiliency. In the short term, it would reduce the likelihood of an outage during peak demand. In the long term, it would reduce wear and tear on electricity infrastructure. Unlike V2G, it would reduce congestion on the distribution grid, improving resiliency at a local level.

4.3 Utility-Scale Storage

Utility-scale energy storage can be an effective method of addressing peak demand. By storing electricity generated during off-peak hours, IOUs can draw on large, stationary storage facilities to satisfy the increase in demand that occurs during peak hours. Utility-scale storage can take many forms, but here we focus on Li-ion battery packs so as to be most analogous to VGI peak shaving.

4.3.1 Data and Assumptions

Utility-Scale Storage Setup

Utility-scale energy storage systems can have very different sizes, ranging from a few MW to hundreds of MW. This is because they are designed to be modular, so that larger plants are essentially battery packs.

We assumed that the Li-Ion battery unit has a power of 1 MW and a nameplate capacity of 4 MWh, meaning that the unit can provide energy for up to 4 hours. As in the residential storage model, we assigned the Li-Ion storage system a round-trip efficiency of 80%.⁷⁶ This means that when the battery is discharged to cater to grid needs, the amount of energy obtained is 20% lower than the amount of energy needed to charge the battery back to the same level. In addition, we introduced battery degradation using a linear degradation model with a yearly capacity reduction of 3%.⁷⁷

⁷⁶ [SGIP “Energy Storage Market Assessment and Cost-Effectiveness” Report](#), December 2019

⁷⁷ Ibid.

The battery installed cost for utility-scale Li-Ion storage systems is assumed to be about \$320/kWh in 2020 and decrease to about \$230/kWh in 2025.⁷⁸ This includes both equipment and installation cost and the cost projection corresponds to a yearly cost reduction of about 6%. The total battery installed cost ranges from \$9m in 2021 to \$5m in 2025, and with a minimum of \$4m in 2022.

In order for the comparison among the different peak shaving technologies to be effective and meaningful, we assumed that utility-scale storage provides the same peak power to the grid as school bus fleet V2G. In other words, the reduction in peak power obtained by leveraging the distributed storage of these two technologies is assumed to be the same.

Under this assumption, the number of battery units installed becomes an endogenous variable. Based on the power impact obtained for utility-scale V2G, the resulting number of battery units installed ranges from 8 in 2021 and 27 in 2025.

Energy and Power Impacts

As discussed, the power impact in each program year is assumed to be equal to the one of a comparable residential V2G program. The power impact therefore ranges from 8 MW in 2021 to 27 MW in 2025.

The corresponding energy impact is given by the amount of energy available on a daily basis for discharge times the number of days in a year, since we assumed that the system is used everyday to shave the load peak. Results range from 9 GWh in 2021 to 29 GWh in 2025 (i.e. from 0.004% to 0.01% of the yearly California electricity consumption, which was 255 TWh in 2018).

Administrative Costs

Given the small scale of the utility-scale storage program, administrative costs are assumed to be smaller than those for the V2G school bus program. As a result, we assume administrative costs to be the same as for the BIP, equal to \$100,000 per year.

Net Bill Reductions and Incentives

The owners of utility-scale storage systems are paid the electricity that they offer to the grid for peak shaving at the peak industrial price (0.07 USD/kWh⁷⁹). It is to be noted that when discharging the batteries, the grid only receives 80% of the energy capacity due to round-trip losses⁸⁰. The net bill/revenue reductions rise from \$191,000 in 2021 to \$619,000 in 2025.

Storage system owners also receive a capacity payment for the capacity that they made available to the program. The dollar value assigned to each unit of capacity varies by month and

⁷⁸ [SGIP "Energy Storage Market Assessment and Cost-Effectiveness" Report](#), December 2019

⁷⁹ ["Document Library." SCE](#)

⁸⁰ "Energy Storage Technology and Cost Characterization Report." *Department of Energy*

is assumed to be similar to the Capacity Bidding Program (CBP).⁸¹ The values used in the model are the same as the ones used for V2G. The resulting capacity payment ranges from \$0.4m in 2021 to \$1.4m in 2025.

4.3.2 Test Results and Sensitivity Analyses

Base Case Results					
<i>2020 Dollars</i>	Benefits	Costs	Net Benefits	Net \$/kW-Yr.	Ratio
TRC	\$17,411,411	\$10,793,598	\$6,617,813	\$103	1.61
PAC		\$3,879,045	\$13,532,365	\$211	4.49
RIM		\$5,363,773	\$12,047,638	\$188	3.25
PCT	\$4,965,528	\$10,395,353	(\$5,429,825)	(\$85)	0.48

The TRC score of 1.61 shows that the commercial/industrial storage program described here is net beneficial. Both the utility and the ratepayers benefit from the program, as the benefits to the system outweigh any revenue losses or incentive payments and these parties do not pay for the equipment. However, the program is not attractive to the participants because the cost of installing the batteries outweighs the incentives and energy benefits.

The TRC score is highly sensitive to capital amortization period, load impact, and generation capacity value, and relatively insensitive to transmission and distribution capacity value and availability factor. Because of the high equipment costs, reducing the amortization period to 3 years would reduce the TRC score to 0.6, whereas increasing the amortization period to 15 years would increase the TRC score to above 2.0. A 30% reduction in the load impact reduces the TRC score to just over 1.0.

4.3.3 Impact on Environment

The primary environmental benefit of a commercial/industrial energy storage program would be to reduce the use of polluting peaker plants. The program discussed here is projected to abate 3,800 metric tons of carbon dioxide in its first year, or 0.02% of the state's required reductions for that year. It would also reduce electricity-related local air pollution, a benefit that our model values at \$557,000 over the course of five years. In the long term, it would reduce incentive to invest in further natural gas-fired power plants.

4.3.4 Impact on Resiliency

Much like a municipal V2G program, the distributed storage program modeled here would improve system resiliency by reducing the burden on peaker plants and transmission lines. In

⁸¹ https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHS_E-CBP.pdf

the short term, this would reduce the likelihood of outages during peak demand. In the long term, it would reduce wear and tear on system infrastructure.

4.4 Comparing Technologies for Utility-Scale Peak Shaving

	MUNICIPAL PEAK SHAVING		
	MPS_V2G	MPS_DR	MPS_Storage
BENEFIT/COST RATIOS			
TRC	2.13	2.59	1.61
PAC	2.62	0.46	4.49
RIM	0.62	0.42	3.25
PCT	5.28	9.57	0.48

All of the technologies for peak-shaving using large municipal, commercial, and industrial consumers are net beneficial, with demand response standing out as the most cost-effective. This is due to it enabling substantial system benefits while having no equipment costs. V2G and distributed storage are only marginally less cost-effective.

From the program administrator’s perspective, distributed storage and V2G are both beneficial, due to the participants covering equipment costs and the utility receiving system benefits. The DR program is not cost-effective for the utility, as the system benefits are not sufficient to compensate for the incentives paid out.

From the ratepayer’s perspective, only the distributed storage program is beneficial, as changes to the utility revenue stream enable it to lower rates on its customers. With the DR and V2G program, the revenue lost to lower peak demand payments are passed on to the customers in the form of increased rates.

The V2G and DR programs are attractive to the participants, as the incentives and bill reductions outweigh the equipment costs (which are nil in the case of DR). For the storage program, the savings are not sufficient to compensate the participants for their equipment costs.

5 Cost-Benefit Analysis: Home Backup

Californians experienced an average of 115 minutes of power outages in 2019^{82,83,84}. Due to increasing renewable energy penetration and extreme weather events, power outages are becoming a more regular occurrence in the state. Thus there is significant interest in both grid resiliency measures and emergency backup measures for homes affected by the outages.

Vehicle-to-home (“V2H”) technology refers to the bidirectional flow of energy to and from an EV battery to provide energy services to a home. Such activities occur “behind the meter” and thus do not directly interact with the distribution grid. One use for this technology is as an emergency power source in the case of a grid failure. In this section, we assess the value of V2H as a home backup source against the value of home storage in the form of a stationary battery.

5.1 Residential V2H

5.1.1 Data and Assumptions

Program Participation

In many cases, customers enrolled in a VGI program would view V2H emergency backup as an ancillary benefit. Thus, participation in the V2H home backup program is assumed to be the same as for V2G residential peak shaving. This amounts to 398,000 participants by 2025, or a 40% participation rate.

Energy and Power Impacts

The annual energy contribution from V2H for a single household is assumed to be equal to the energy that household loses to outages during the same year. Therefore, it is necessary to ascertain the average energy lost to outages each year per household.

Outage data is compiled from each of the three major IOUs annual reliability reports. The two key measures of system reliability are system average interruption duration index (“SAIDI”) and system average interruption frequency index (“SAIFI”). SAIDI corresponds to the minutes the average customer is without power in a year and SAIFI corresponds to the average number of sustained outages (>5 minutes) a customer experiences in a year⁸⁵. For the purposes of this study, we use 5- or 10-year SAIFI and SAIDI averages from each of the three major IOUs and take a weighted average based on the total number of customers each IOU serves. Using this

⁸² [“Annual Reliability Reports.” PG&E](#)

⁸³ [“Reliability Reports.” SCE](#)

⁸⁴ [“System Reliability.” SDG&E](#)

⁸⁵ [“Annual Reliability Reports.” PG&E](#)

method, we find that the average Californian household experiences 128 minutes of outage per year (SAIDI).

Californian households consume on average 6,564 kWh per year (substantially less than the national average)⁸⁶, growing at a rate of 2.5% per year⁸⁷. Dividing this amount by the number of minutes in a year and multiplying by the SAIDI value above yields the household's amount of electricity lost to outages in a year: 1.68 kWh in 2021, rising to 1.85 kWh in 2025. This, ultimately, is each household's total backup requirement, and thus the total amount of energy a V2H system would contribute. Using this formula, the total energy contribution from the V2H program rises from 36.8 MWh in 2021 to 443.5 MWh in 2025. The load impacts are the total energy impacts divided by the hours over which they are used, rising from 16.4 MW in 2021 to 198.0 MW in 2025.

For the purposes of this study, it is assumed that an EV battery has enough energy to power the household for the duration of the outage. A fully charged 72 kWh EV battery could power a Californian house for over 40 hours. As the average duration of a sustained outage in 2019 was just under 2 hours⁸⁸, a 40+ hour outage is deemed to be a relatively infrequent occurrence.

Net Bill Increases and Incentives

Unlike the other programs addressed in this study, an emergency backup program would actually increase a household's energy consumption. By supplying electricity to the home during an outage, the EV is providing what would otherwise be unserved kWhs, which must be recharged at another time (presumably during off-peak hours). The change in a customer's bill is therefore the total backup energy supplied by the EV multiplied by the off-peak retail rate per kWh. As a result, total bill increases amount to \$1,800 in 2021 and \$22,000 in 2025, a relatively insignificant amount.

While IOUs do offer incentives for home storage, such incentives are not designed for V2H applications and in any case are incompatible with the scale of the storage supplied by V2H. As a result, we analyze both V2H and home storage in the absence of any incentives.

Equipment Costs

Equipment costs use the same data as the V2G peak shaving scenario. The equipment cost reflects the additional equipment that an EV owner would require to participate in a V2H program. Accordingly, the equipment cost is taken to be the cost of purchasing and installing a bidirectional charger (\$5,000 and \$2,500 respectively) *minus* the cost of purchasing and installing a Level 2 unidirectional charger (\$1,500 and \$700, respectively). Equipment maintenance is taken to be 5% of total equipment cost, based on NREL reporting⁸⁹.

⁸⁶ <https://www.chooseenergy.com/news/article/the-states-that-use-the-most-and-least-amount-of-energy-per-household/>

⁸⁷ "State of California Energy Profile." *Department of Energy*

⁸⁸ Weighted average SAIDI divided by weighted average SAIFI

⁸⁹ "Critical Elements of V2G Economics." *NREL*

As the consumer accrues all the benefits of V2H, installation and maintenance costs are expected to be borne by the customer. For each year, total equipment costs are equal to the upfront charger costs multiplied by the new bidirectional charger installations, plus the annual maintenance expense multiplied by the total bidirectional charger stock.

Administrative Costs

Administrative costs are based on the reported administrative costs in the 2017-2019 SGIP Budget Report. In this report, yearly administrative costs are proportional to the total incentive payments disbursed and are equal to (on average) 7% of the yearly incentive payments. While our analysis does not include incentive costs, it is possible to calculate the incentive that *would* be disbursed if V2H qualified for SGIP. Using this formula, administrative costs for the V2H program run from \$2.6m in 2021 to \$9.9m in 2025.

Benefits

The primary benefit of using a V2H system for home backup is the continuation of energy services during a blackout. To quantify this, we used the “cost per unserved kWh” calculated in the “2019 SGIP Energy Storage Market Assessment and Cost-Effectiveness Report.” This assumes that, for a residential customer, the economic cost of 1 kWh lost to an outage is \$3.30. The cumulative benefit of emergency backup increases from \$121,000 in 2021 to \$1.5 million in 2025.

5.1.2 Test Results and Sensitivities

Base Case Results					
2020 Dollars	Benefits	Costs	Net Benefits	Net \$/kW-Yr.	Ratio
TRC	\$2,445,752	\$428,625,363	(\$426,179,611)	(\$1,259)	0.01
PAC		\$21,217,678	(\$18,771,926)	(\$55)	0.12
RIM		\$21,253,751	(\$18,807,999)	(\$56)	0.12
PCT	\$36,074	\$407,407,686	(\$407,371,612)	(\$1,204)	0.00

A TRC score of 0.01 shows that the benefits of such a program are vanishingly small compared to the cost. While the administrator and ratepayer accrue marginally more benefit than the participant, the program has a net negative impact on all involved.

The low scores for such a program are unsurprising. Given around two hours of outage per year, the energy impacts of this program are low, particularly compared to the cost of installing a bidirectional charger. It is unlikely that any customer would enroll in a VGI program specifically for the purposes of home backup. Rather, customers already equipped with a bidirectional charger for a different program would accrue additional benefit from using their EVs as home backup.

5.1.3 Impact on Environment

A V2H emergency backup program would have a negative, though minimal, effect on the environment. If outages are thought of as unserved kWhs, then providing electricity through V2H during outages can be seen as requiring additional generation. However, this additional generation would only emit 6 additional metric tons of carbon dioxide per year (here we use the average carbon intensity of California's electric grid - 0.161 mTCO₂/MWh - rather than the carbon intensity of peaker plants - 0.417 mTCO₂/MWh - as the EV is unlikely to be charged at peak hours⁹⁰). This can be considered negligible, as the total emissions of the program are equivalent to 12% of the annual emissions of a *single* American household.⁹¹

5.1.4 Impact on Resiliency

As V2H is considered separate from the grid, emergency home backup would have no effect on system-level resiliency. However, it would have a significant positive effect on the resiliency of a household's energy supply. By eliminating all outages, it would provide households with an expected benefit equivalent to \$3.3 million over five years, based on a CPUC-estimated \$3.30 per unserved kWh⁹².

5.2 Residential Storage

The DER most comparable to V2H emergency backup is a home battery. Batteries can be installed within a home and charged using electricity drawn from the grid; this electricity can then be drawn upon in the event of an outage to power the house for a limited amount of time. The best selling home battery on the market is the Tesla Powerwall II⁹³. For the purposes of this model, the V2H emergency backup scenario will be compared against using a Tesla Powerwall II for emergency backup.

5.2.1 Data and Assumptions

Energy and Power Impacts, Participation

For comparison's sake, energy and power impacts were made to be equal to the energy and power impacts of the V2H scenario. Because each household is modeled as having the same emergency backup needs, as in the previous scenario, the total participants in the program is equal to the total projected bidirectional charger stock. Ultimately this translates to program participation reaching 1.7% of Californian households by 2025.

⁹⁰ "CO₂ Emissions." CAISO

⁹¹ "CO₂ Emissions per Capita." World Bank

⁹² "2019 SGIP Energy Storage Market Assessment and Cost-Effectiveness Report." SGIP Working Group

⁹³ <https://www.energysage.com/solar/solar-energy-storage/what-are-the-best-batteries-for-solar-panels/>

Net Bill Increases and Incentives

As with the V2H scenario we assume no incentives are disbursed. The net bill increases amount to the total additional electricity payments required to purchase the backup power. As the energy savings in this program are equal to those in the V2H program, the net bill increases are the same as in the V2H scenario: \$1,800 in 2021 and \$22,000 in 2025.

Equipment Costs

The installed cost (price of equipment, installation, supporting equipment, and transformer) of a Li-ion battery in 2021 is projected to be \$1,288 per kWh, falling 6% per year, according to a report by Navigant. The participant is expected to pay for the whole of the equipment cost as in the V2H scenario.

Administrative Costs

Given an energy impact and participation equal to that of the V2H program, administrative costs are set equal to the administrative costs for the V2H program: \$2.6m in 2021 and \$9.9m in 2025.

Benefits

The benefits in this scenario are exactly the same as in the V2H scenario. Using SGIP's estimation of \$3.30 per unserved kWh, we calculated the total benefit provided by emergency backup through home storage.

5.2.2 Test Results and Sensitivities

Base Case Results					
2020 Dollars	Benefits	Costs	Net Benefits	Net \$/kW-Yr.	Ratio
TRC	\$2,445,752	\$893,750,979	(\$891,305,227)	(\$2,634)	0.00
PAC		\$21,217,678	(\$18,771,926)	(\$55)	0.12
RIM		\$21,253,751	(\$18,807,999)	(\$56)	0.12
PCT	\$36,074	\$872,533,302	(\$872,497,228)	(\$2,578)	0.00

With a TRC score that is infinitesimally small (rounded to zero), this program is highly unattractive. The IOU, the participant, and the other customers all stand to be harmed economically by implementing such a program. This is because the cost of a Li-ion battery far exceeds the meager benefit of providing 2.4 hours per year of emergency backup.

Like the V2H program, a home storage setup for emergency backup makes more sense as an add-on to a pre-existing storage system.

5.2.3 Impact on Environment

Much like V2H emergency backup, home storage for emergency backup is expected to have a minimal negative effect on the environment. As a result of compensating for unserved kWh, there is a slight increase in the electricity demanded. Our model projects 6 metric tons of carbon dioxide will be emitted in the first year of the program as a consequence of recharging the battery after using it as emergency backup. This is the same as for the V2H program.

5.2.4 Impact on Resiliency

As with the V2H program, the home storage emergency backup program is expected to provide \$3.3 million in resiliency services to the households participating. It provides no resiliency services to the grid as a whole, however.

5.3 V2H Emergency Backup Add-On

Based on the extremely low benefit/cost ratios reported in Section 5.1, it is unlikely that any customer or IOU would deploy bidirectional charging capacity solely for the purpose of emergency backup. Indeed, it is assumed that customers would set up V2H for emergency backup only as an ancillary benefit for a pre-existing V2G program (for the purposes of peak shaving or some other grid service). For this reason, we include a separate cost-benefit analysis for V2H as an add-on to a pre-existing V2G program.

The V2H add-on assumes that the customer has already enrolled in a separate V2G program and now wants to also use their bidirectional charger as a source of emergency power. Thus, the cost-benefit analysis for the V2H Add-On presents the benefit/cost ratio, *for a customer who already has bidirectional charging equipment*, of using this equipment for the additional service of emergency backup. As such, the model includes no additional equipment cost. The only costs involved are administrative costs and the cost of recharging the EV battery after emergency use. The only benefits are the value of unserved kWh avoided. As all the benefits and costs accrue to the customer, we only report the TRC test score here, which can be viewed as a PCT score. It is important to note that all the costs and benefits included in the calculation are incremental and do not represent the real cost or benefit of a V2H add-on. Thus, the actual TRC ratio is meaningless; the only metric of interest is whether it is greater than 1, meaning the benefits outweigh the costs.

Base Case Results					
2020 Dollars	Benefits	Costs	Net Benefits	Net \$/kW-Yr.	Ratio
TRC	\$2,445,752	\$398,245	\$2,047,507	\$6	6.14

With a TRC score greater than 1, this program is a net benefit to the customer. This stands to reason, as a V2H emergency backup add-on can be seen as extracting additional benefit from

already-purchased equipment. Thus, we would expect that participants in a V2G program would also want to use their bidirectional charger for V2H emergency backup.

5.4 Storage Emergency Backup Add-On

The storage emergency backup add-on follows the same logic as the V2H add-on. For this scenario, it is likely that the customer has already purchased home storage capacity to support a rooftop solar array with support from SGIP. Here, benefits include the value provided by emergency backup and costs are limited to administrative costs and recharging the battery. Again we use the TRC test score as an indicator of the customer's benefit/cost ratio.

Base Case Results					
<i>2020 Dollars</i>	Benefits	Costs	Net Benefits	Net \$/kW-Yr.	Ratio
TRC	\$2,445,752	\$398,245	\$2,047,507	\$6	6.14

With a TRC ratio greater than 1, this program is beneficial to any customer who already owns home storage. Accordingly, we would expect that any customer already enrolled with SGIP would use their storage as emergency backup as well.

5.5 Comparing Technologies for Home Backup

Home Backup				
B/C Ratios	HB_V2H	HB_Storage	HB_V2H_Add-on	HB_Storage_Add-on
TRC	0.01	0.00	>1	>1
PAC	0.12	0.12		
RIM	0.12	0.12		
PCT	0.00	0.00		

With a TRC ratio of 0.01, emergency backup using V2H is marginally more beneficial than using home storage, which has an infinitesimally small TRC score (rounded to 0.00). The key difference between the two programs is the equipment costs; purchase and installation of a home battery rack is more expensive than a bidirectional charger, yet it provides the same (relatively insignificant) benefits. For all other perspectives, the value of the programs are equal and poor.

As add-ons, both V2H and home storage yield a positive value. This is because they provide the same value as emergency backup and they have the same administrative cost and recharging cost. Both programs are highly and equally attractive as an add-on.

Overall, our cost-benefit analysis for these programs show that emergency backup is not cost effective as a standalone program. However, both are highly attractive as an added service once the customer is already enrolled in a different program. Ultimately, the relative value of storage versus VGI will be more dependent on other services, with emergency backup seen as an added benefit.

6 Interpretation and Conclusions

6.1 How does VGI compare with DER?

Using the benefit/cost ratio from each test, it is possible to compare the value of different technologies and programs for the same application. The results of our analysis are presented in the table below:

	RESIDENTIAL PEAK SHAVING			MUNICIPAL PEAK SHAVING			HOME BACKUP	
	RPS_V2G	RPS_DR	RPS_Storage	MPS_V2G	MPS_DR	MPS_Storage	HB_V2H	HB_Storage
BENEFIT/COST RATIOS								
TRC	3.31	0.41	0.82	2.13	2.59	1.61	0.01	0.00
PAC	4.61	0.80	3.94	2.62	0.46	4.49	0.12	0.12
RIM	0.78	0.38	1.58	0.62	0.42	3.25	0.12	0.12
PCT	4.62	1.17	0.51	5.28	9.57	0.48	0.00	0.00

For more detailed information, including costs and benefits, see the full table in Appendix A.

Our analysis finds VGI to be more favorable than DR and storage for residential peak shaving, less favorable than DR but more favorable than storage for municipal peak shaving, and indistinguishable from storage for emergency home backup.

In the case of peak shaving with residential consumers, V2G stands out as the most favorable option. Our analysis shows that, notwithstanding its negative effect on IOU ratepayer electricity bills, V2G peak shaving could create significant savings by avoiding generation at peak conditions. The program administrator and program participants would benefit substantially from the program due to avoided electricity/system costs for the IOU and avoided bills and a favorable incentive for the participant. Other customers would suffer, as the reduced IOU revenue would be passed on to them in the form of higher rates. Overall, the program would provide benefits more than three times the scale of its costs, making it more cost-effective than DR or storage, which both incur costs higher than savings. DR, while beneficial to the participant, is only available during part of the year and thus offers smaller energy savings; in this case, the participant would benefit due to zero equipment costs, but the program would have a negative effect on IOUs and ratepayers. Home storage offers comparable benefits to V2G, but is less overall beneficial due to the high cost of Li-ion batteries; IOUs and ratepayers would see a benefit, but the high upfront cost would make the program unattractive to potential participants.

For municipal peak shaving, VGI is more favorable than distributed storage but less favorable than DR. Both the IOUs and the participants would see benefits at least twice the magnitude of the program costs, making it an attractive program for both. But the loss of bill revenue to the

IOU would negatively impact customers as a whole. In other words, by no longer providing high-priced electricity to large municipal consumers at peak hours, the IOUs would lose revenue which would then force them to raise rates on other customers. DR with large commercial and industrial consumers is a more attractive peak shaving option due to minimal equipment costs and high energy savings; though the participants would reap a large benefit, ratepayers and IOUs would be hurt because of the expensive incentives (at current rates). Commercial/industrial distributed storage is also a net positive program for peak shaving, though it is less positive than commercial/industrial DR and VGI. Large energy savings and low costs make the program attractive to IOUs and their ratepayers, though the incentive as it currently stands is not enough to compensate participants for the equipment costs.

Both V2H and home storage are highly inefficient as sources of emergency backup. The large equipment costs of both overwhelm the meager economic benefit of maintaining power during outages. Though V2H has lower equipment costs, both programs are highly unfavorable. As an add-on to a pre-existing V2G or home storage program, both technologies are highly - and equally - favorable. It is expected that participants in these other programs would be incentivized to provide emergency backup to their homes as an ancillary benefit.

Our data suggest that individual VGI programs could capture more value when combined. Much as the V2H emergency was only beneficial as an add-on to pre-existing V2G capability, other applications of VGI would compound each others' benefits. For instance, a VGI program that enabled peak shaving during peak hours, emergency backup during outages, and ancillary grid services at other times would have the same equipment costs as a program that just provided peak shaving, but would have far greater benefits.

6.2 Assumptions and Sources of Error

It is not the intention of this study to provide a definitive ruling on whether VGI programs are beneficial or not; rather, test scores for each application should be considered only in comparison to each other to gauge the effectiveness of each technology in providing a certain service. Additionally, the results expressed here are highly assumption dependent. By providing the model and addressing the assumptions we made in this report, we hope that readers will update and rework the assumptions as they see fit.

In many cases, the underlying assumptions for each scenario can be altered either by program design or technology improvement. For instance, V2G benefit/cost ratios are dependent on the installation cost of bidirectional chargers. As more providers enter the market and costs for this equipment fall, V2G programs will become more attractive. Similarly, PAC and PCT scores depend on the incentives offered. For any program with a TRC score above 1, it is possible to design an incentive that makes the program a benefit to both IOUs and participants.

Lastly, it is important to note that cost-benefit analyses are prone to underestimating benefits. While costs (e.g. equipment, incentive, admin, or fuel) are easily quantifiable, many potential

benefits are less so. For instance, VGI programs show promise as a way to reduce greenhouse gas emissions, improve system resiliency, and provide emergency backup. While CPUC guidance monetizes each of these services, the actual value of the service may vary depending on the beneficiary. There are additional benefits to VGI services - including the value to a participant of providing support to the grid and the value of innovation that such a program may catalyze - that were deemed unquantifiable and therefore are not included in the model.

6.3 Policy Considerations

While this study makes no specific policy recommendations, it is our hope that the results and the model may provide support to those designing VGI policies in California.

The test results suggest both opportunities and pitfalls that potential VGI policies may encounter. As stated before, VGI programs can capture additional value by including several use cases - and thus several revenue streams - in a single policy. However, policymakers must be careful when addressing the effect VGI programs may have on IOUs' revenue from bill collection. Our analysis shows that otherwise beneficial VGI programs can have a negative impact on ratepayers when IOUs pass on revenue reductions in the form of bill increases.

Altering the assumptions in the model can help policymakers design VGI policies that maximize benefits while minimizing costs. As stated before, any program with a TRC score greater than 1 has the potential to benefit both IOUs and participants as long as the incentive is designed properly. By altering the incentive amount or structure in the "Additional Inputs" tabs of the model, users can optimize the programs. And as stated before, the benefit/cost scores are highly dependent on equipment and administrative cost assumptions. By altering these assumptions in the "Additional Inputs" tabs, users can ascertain what innovations will be required to make a program beneficial.

6.4 Next steps

We submit this report and the accompanying "VGI Cost-Benefit Comparison Tool" to the VGI Working Group on April 29, 2020 with the hope of providing a quantitative basis for answering the question, "How does the value of VGI use cases compare to other storage or DERs?" While this represents the termination of this study, it is our hope that the model continues to evolve and to support the Working Group's efforts to answer this question. We encourage members of the Working Group to interrogate the assumptions in the model and even to expand it to include additional use cases. By engaging with the model, members of the Working Group will be able to better gauge how the value of VGI compares to DERs and storage.

Appendix A: Full Cost-Benefit Results

	RESIDENTIAL PEAK SHAVING			MUNICIPAL PEAK SHAVING			HOME BACKUP	
	RPS_V2G	RPS_DR	RPS_Storage	MPS_V2G	MPS_DR	MPS_Storage	HB_V2H	HB_Storage
BENEFIT/COST RATIOS								
TRC	3.31	0.41	0.82	2.13	2.59	1.61	0.01	0.00
PAC	4.61	0.80	3.94	2.62	0.46	4.49	0.12	0.12
RIM	0.78	0.38	1.58	0.62	0.42	3.25	0.12	0.12
PCT	4.62	1.17	0.51	5.28	9.57	0.48	0.00	0.00
Load Impacts (MW) (2021-25 avg)	1,142	1,086	1,142	17	15	17	90	90
Energy Savings (MWh) (2021-25 avg)	1,942,554	845,333	617,945	28,799	2,627	18,579	203	203
BENEFIT/COST SUMMARY (\$ Million)								
TRC/PAC/RIM Benefits	\$1,505	\$843	\$1,231	\$20	\$3	\$17	\$2	\$2
PCT Benefits	\$1,883	\$1,377	\$744	\$27	\$7	\$5	\$0	\$0
TRC Costs	\$454	\$2,037	\$1,492	\$9	\$1	\$11	\$429	\$894
PAC Costs	\$326	\$1,051	\$312	\$7	\$6	\$4	\$21	\$21
RIM Costs	\$1,930	\$2,233	\$778	\$31	\$7	\$5	\$21	\$21
PCT Costs	\$407	\$1,182	\$1,459	\$5	\$1	\$10	\$407	\$873
TRC Net Benefit	\$1,050	(\$1,194)	(\$261)	\$10	\$2	\$7	(\$426)	(\$891)
PAC Net Benefit	\$1,178	(\$207)	\$918	\$12	(\$3)	\$14	(\$19)	(\$19)
RIM Net Benefit	(\$426)	(\$1,389)	\$453	(\$12)	(\$4)	\$12	(\$19)	(\$19)
PCT Net Benefit	\$1,476	\$195	(\$714)	\$22	\$6	(\$5)	(\$407)	(\$872)
BENEFIT BREAKDOWN (\$ Million)								
TRC/PAC/RIM Benefits	\$1,505	\$843	\$1,231	\$20	\$3	\$17	\$2	\$2
Generation Capacity Value	\$967	\$382	\$967	\$12	\$1	\$12	\$0	\$0
T&D Capacity Value	\$136	\$285	\$136	\$2	\$1	\$2	\$0	\$0
Energy Value	\$259	\$110	\$83	\$4	\$0	\$3	\$0	\$0
GHG Value	\$98	\$48	\$30	\$1	\$0	\$1	\$0	\$0
Optional Benefits	\$44	\$19	\$14	\$1	\$0	\$0	\$2	\$2
CAISO Market Value	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
PCT Benefits	\$1,883	\$1,377	\$744	\$27	\$7	\$5	\$0	\$0
Net Bill/Revenue Reductions	\$279	\$195	\$279	\$3	\$6	\$3	\$0	\$0
Ammortized Equipment Costs (entered below)	\$1,604	\$1,182	\$465	\$24	\$1	\$1	\$0	\$0
COST BREAKDOWN (\$ Million)								
TRC Costs	\$454	\$2,037	\$1,492	\$9	\$0	\$11	\$429	\$894
PAC Costs	\$326	\$1,051	\$312	\$7	\$6	\$4	\$21	\$21
RIM Costs	\$1,930	\$2,233	\$778	\$31	\$7	\$5	\$21	\$21
PCT Costs	\$407	\$1,182	\$1,459	\$5	\$0	\$10	\$407	\$873
Admin Costs	\$46.9	\$113.5	\$33.1	\$4.0	\$0.4	\$0.4	\$21.2	\$21.2
Incentive Cost	\$279.3	\$195.4	\$279.3	\$3.5	\$5.9	\$3.5	\$0.0	\$0.0
Net Bill/Revenue Reductions	\$1,604.0	\$1,181.8	\$465.1	\$23.9	\$0.7	\$1.5	\$0.0	\$0.0
Ammortized Equipment Costs (entered below)	\$0.0	\$741.9	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Charger maintenance (utility)	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Other	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
Ammortized Equipment Costs (entered below)	\$299.1	\$0.0	\$1,458.7	\$3.7	\$0.0	\$10.4	\$299.1	\$872.5
Charger maintenance (participant)	\$108.3	\$0.0	\$0.0	\$1.4	\$0.0	\$0.0	\$108.3	\$0.0
Value of AC Services Forfeited	\$0.0	\$1,181.8	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0

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