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Exhibit No.: SDGE-5A-R
Witness: Brenda Gettig

REVISED PREPARED DIRECT TESTIMONY OF

BRENDA GETTIG – CHAPTER 5A

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

AUGUST 11, 2022

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I. INTRODUCTION

The purpose of my direct testimony is to describe the cost effectiveness (CE) analysis for the proposed San Diego Gas & Electric Company (SDG&E) demand response (DR) programs for the program year 2023. The analysis follows the 2016 Demand Response Protocols ("the Protocols").[1] SDG&E performed CE analyses for each program individually and for the portfolio. In addition, the analysis for 2023 was performed separately from the analysis for the period 2024 through 2027 since 2023 is considered a "bridge" year and no changes were proposed for the 2023 programs.[2]

SDG&E reports its CE results using the four tests described in the Protocols: (1) the Total Resource Cost (TRC) test, (2) the Program Administrators Cost (PAC) test, (3) the Ratepayer Impact Measure (RIM) test, and (4) the Participant test (PCT).[3] The inputs to these tests include the net present value (NPV) of appropriate costs and benefits as specified by the Protocols. Additional detail on the data inputs used is presented in subsequent sections below. Table BG-1 presents the results for the Base Interruptible Program (BIP), the Capacity Bidding Program (CBP),[4] the AC Saver (ACS) program and the overall Portfolio. CBP and ACS both offer Day Ahead (DA) and Day Of (DO) subprograms, and these were analyzed separately. CBP DO and ACS DA include administration and incentive costs for enabling technology. The TRC results for these programs without these costs is discussed in Section III.

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[1] 2016 Demand Response Cost Effectiveness Protocols; Resolution E-4788, July 15,2016, Appendix A.

[2] *See* Prepared Direct Testimony of Brenda Gettig Chapter 5B for the CE analysis for DR program years 2024-2027.

[3] Each of these tests is described in detail in the Commission's Standard Practice Manual: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy_-_electricity_and_natural_gas/energy_programs/cpuc-standard-practice-manual.pdf

[4] The CE analysis for CBP includes only the 11 to 7 products. CBP also offers 1 to 9 Elect products in 2023; however, these were approved in a separate proceeding which waived cost effectiveness. *See* D.21-12-015, p. 63.

Table BG-1: CE Results for 2023

Test	BIP	CBP DA	CBP DO	ACS DA	ACS DO	Portfolio
TRC	0.04	0.004	0.003	0.3	0.2	0.2
PAC	0.04	0.004	0.003	0.2	0.2	0.1
RIM	0.04	0.004	0.003	0.2	0.2	0.1
PCT	1.3	1.3	1.3	2.9	2.9	2.8

All benefits and costs are shown in 2023 dollars. Table BG-2 shows the benefits and costs included in the TRC tests.

Table BG-2: TRC Test Benefits and Costs

	BIP	CBP DA	CBP DO	ACS DA	ACS DO	Portfolio
Benefits	18,341	3,420	1,522	802,611	321,646	1,147,540
Costs	474,858	892,344	578,443	2,823,628	1,755,522	7,307,312
Net Benefits	(456,517)	(888,924)	(576,921)	(2,021,017)	(1,433,876)	(6,159,772)

II. DATA INPUTS AND CALCULATIONS

This section describes the data inputs and calculations used in the CE analysis.

A. The DR Cost Effectiveness Report

The DR Cost Effectiveness Report (DR Calculator) is the Commission approved tool for calculating DR CE. The DR Calculator uses inputs from the Avoided Cost Calculator (ACC). The ACC is the model developed by a third party under contract with the Commission to determine the value of Distributed Energy Resources (DERs).

The DR Calculator was revised for the purposes of this application to accommodate the inputs from the 2021 version of the ACC.[5] Southern California Edison (SCE), on behalf of the electric IOUs, hired Energy and Environmental Economics (E3) in 2021 to update the DR

[5] Resolution E-5150 adopted version ACC 2021 Electric Model v1b on June 24, 2021.

Calculator with inputs from the 2021 version of the ACC. The primary revisions made to the DR Calculator include the following:[6]

1. Updated avoided generation capacity costs,
2. Updated on-peak greenhouse gas (GHG) values and on-peak avoided energy costs,
3. Updated Renewable Energy Capacity Planning (RECAP) model availability and dispatchability tables used to calculate the A Factor, and
4. Other minor revisions to improve functionality.

B. Adjustment Factors

The Protocols allow the benefits in the CE calculations to be adjusted by a set of seven adjustment factors, named A through G. The factors are designed to be program specific adjustments to the capacity benefits, energy benefits, and transmission and distribution benefits. Each of the factors is discussed below, along with the values used in the analysis.

1. A Factor

The A Factor adjusts the capacity value according to the availability and dispatchability of the program. The A Factor uses the Renewable Energy Capacity Planning (RECAP) model developed by E3 to estimate loss of load probability.[7] Each DR program has a specified window of time and duration when it can be called upon for load curtailment. Using these parameters, the percentage of time a program can be available when a positive probability of loss of load exists is calculated. If a program event can be called any time there is a positive probability of loss of load, the A Factor for that program would be 100%. Most SDG&E demand response programs have some limitation on when their events can be called, resulting in A Factors below 100%. Table BG-3 presents the calculated A Factors used in the analysis.

[6] A complete description of the updates is provided in: Energy and Environmental Economics, 2022 Demand Response Reporting Template Update Documentation, March 2022.

[7] *See* https://www.ethree.com/tools/recap-renewable-energy-capacity-planning-model/.

Table BG-3: A Factors Used in Analysis

	BIP	CBP DA	CBP DO	ACS DA	ACS DO
Daily hours available to call	Any	11 am to 7 pm	11 am to 7 pm	Noon to 9 pm	Noon to 9 pm
Event duration (hours)	4	4	4	4	4
Maximum hours per year available to call	120	144	144	80	80
A Factor	100%	28%	28%	94%	94%

2. B Factor

The B Factor adjusts the capacity value for differences in notification times. The Protocols specify that day-ahead programs shall use a B Factor of 88%, day-of programs that can be called in 30 minutes or less shall use a B Factor of 100%, and day-of programs that require more than 30-minute notification shall use a B Factor of 94%.[8] Table BG-4 shows the notice times and resulting B Factors for each program in the analysis.

Table BG-4: B Factors Used in Analysis

	BIP	CBP DA	CBP DO	ACS DA	ACS DO
Notice time	DO 20 minutes	DA	DO 40 minutes	DA	DO 20 minutes
B Factor	100%	88%	94%	88%	100%

3. C Factor

The C Factor adjusts the capacity value for differences in triggers or the conditions under which a program can be dispatched. The Protocols allow for a C Factor of 100% when the program can be called at the utility's discretion. All of SDG&E's demand response programs can be called at the utility's discretion; therefore, a C Factor of 100% was used for all programs in this analysis.

[8] Protocols, p. 33.

4. D Factor

The D Factor adjusts the transmission and distribution (T&D) benefits according to a set of four criteria: right time, right place, right certainty, and right availability. SDG&E is not claiming T&D benefits for any of its programs; therefore, a D Factor of 0% was used for all programs in this analysis.

5. E Factor

The E Factor adjusts energy benefits to account for the likelihood that demand response events occur when energy prices are at their highest. The on-peak energy price used in the DR Calculator is the average on-peak energy price when the avoided generation capacity value is forecasted to be nonzero. These forecasted prices are averaged over the period 4 p.m. to midnight; however, SDG&E's demand response programs can only be dispatched until 7 p.m. for CBP and 9 p.m. for ACS. To calculate the E Factor, SDG&E took the ratio of forecasted average energy prices during the dispatch period as compared to the average energy price used in the DR Calculator. The resulting E Factor is 149% for CBP and 132% for ACS. For BIP, 100% was used for the E Factor since a BIP event can be called at any time.

6. F Factor

The F Factor allows additional value for programs that can provide flexible demand response and can meet CAISO's Flexible Resource Adequacy Must Offer Obligation (FRAC-MOO) criteria. The SDG&E programs in this application are not currently designed to meet the FRAC-MOO criteria and therefore SDG&E is not claiming this additional benefit for any of the programs in this analysis.

7. G Factor

The G Factor allows additional value for programs that can provide demand response resources in certain constrained geographical regions. The 2016 Protocols allow SDG&E to use a G Factor of 110%.[9] Therefore, SDG&E used a G Factor of 110% for all programs in this analysis.

C. Treatment of Benefits

The benefits estimated in the analysis include the avoided costs for generation capacity and energy, avoided on-peak greenhouse gas (GHG) emissions, and earned CAISO market

[9] Protocols, p. 34.

revenue. SDG&E did not include benefits for transmission and/or distribution deferrals. Qualitative benefits are discussed in a workpaper attached to this chapter.

1. Capacity Benefits

The forecasted capacity value per kW is estimated in the ACC and adjusted in the DR Calculator by the A, B, C, F and G Factors described above. The forecasted load impacts used are the 50th percentile ex-ante load impacts based on a 1-in-2 weather year, with participation adjusted for the portfolio level. Results using the 10th and 90th percentile ex-ante load impacts are presented as sensitivity analyses later in this chapter. The estimation process and results of the ex-ante load impacts is explained in the Prepared Direct Testimony of Lizzette Garcia-Rodriquez (Chapter 4A).

2. Energy and GHG Benefits

Benefits for avoided energy and GHG are estimated using the expected call hours of the programs. The values for on-peak avoided energy and GHG ($ per MWh) are derived from the ACC. The on-peak average energy price is adjusted by the E Factor explained above.

3. CAISO Market Revenue

The programs analyzed are all bid into the day ahead market. SDG&E used the expected number of awards and the average 2021 award price[10] to estimate earned market revenue.

D. Treatment of Costs

1. Allocation of Support Costs

The Protocols state that indirect costs that support a group of programs should be allocated across those programs and included in their respective CE tests. Where SDG&E was able to identify certain costs directly related to specific programs, those costs were included directly. Where costs were known to support a group of programs but exact amounts were unknown, those costs were allocated across programs based on their total program budgets.[11]

SDG&E allocated support costs from the budget categories of Policy and Program Support, ME&O, EM&V, and IT. Table BG-4 shows the allocation of these support budgets that were included in the CE tests.

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[10] SDG&E escalated the average 2021 award price by 3% annually as a conservative estimate since the average on-peak energy price in the ACC is forecasted to escalate at a higher rate.

[11] Protocols, p. 24.

Table BG-4: Support Costs Included in CE Tests

Program	Policy Support	IT	EM&V	ME&O
BIP	55,039	172,324	139,941	7,514
CBP DA	87,694	362,502	205,128	0
CBP DO	37,691	155,805	88,165	0
ACS DA	41,557	1,090,361	283,276	81,708
ACS DO	99,837	544,699	312,868	68,025
Additional Portfolio Costs	43,617	0	0	0
Total	365,435	2,325,691	1,029,378	157,247

2. Alignment of Incentives and Signaling Costs

The CE tests include only the portion of the proposed incentive budgets that align with the ex-ante forecasted MWs. Additional incentive budget that is not included in the tests is meant to cover additional growth beyond the forecast used in the analysis. The additional budget not included in the tests will only be used if incremental enrollment and/or performance beyond the forecasted impacts is realized.

Similarly, SDG&E excluded a portion of the proposed signaling costs for ACS DA from the CE analysis. These costs are for signaling devices during a DR event and are based on the forecasted number of enrolled and connected devices. The additional signaling budget not included in the tests is meant to cover additional enrollment growth or unforeseen price increases not captured in this budget application. ACS DO also has a signaling budget; however, as the ACS DO signaling costs are budgeted as a fixed fee and not based on enrollment, the entire signaling budget was included in the analysis.

3. Excluded Costs

In addition to incentive and signaling costs explained above, other costs in the proposed budget were not included in the CE tests as they are for activities that do not support the DR programs being analyzed. The Residential CBP pilot costs were not included in the analysis since this initiative is still in the pilot stage and ex-ante load impacts are uncertain. SDG&E also

excluded proposed budget costs for Rates, Electric Rule 32 and Commission-Directed Research as these activities do not directly support the DR programs analyzed. Costs for the Emergency Load Reduction Program (ELRP) and reliability initiatives approved in Decision (D.) 21-12-015 [12] were also not included in the CE analysis.[13] Table BG-5 summarizes the excluded costs.

Table BG-5: Excluded Costs

Description	Amount Excluded	Reason for Excluding
Incentive budget	3,912,854	The proposed budget allows for growth beyond the forecasted program enrollment and impacts.
Signaling budget	448,737	Similar to the incentives, the proposed budget includes an additional amount to allow for growth beyond the forecasted enrollment.
Pilots	1,102,205	Proposed pilots are excluded from the analysis as their ex-ante impacts are uncertain.
Rates and Rule 32	2,096,861	Costs to support dynamic rates and Electric Rule 32 are external to the DR Portfolio.
Commission Directed Research	200,000	This budget is reserved for Commission policy studies which are undetermined at this time.
AutoDR administration supporting rates and DRAM	520,383	A portion of the AutoDR programs support dynamic rates and DRAM, and these costs are not included in the tests.
Total	8,281,041	

4. Additional Costs

The Protocols require all costs supporting the programs to be included in the CE tests, even though they may have been approved iin a separate proceeding.[14] SDG&E included costs budgeted for its Demand Response Management System (DRMS) approved in its recent General Rate Case. The DRMS supports the demand response programs and pilots as well as Rule 32.

[12] Specifically Smart Thermostat and CBP Elect products for 2023.

[13] Cost effectiveness was waived for these initiatives. These costs are not in the DR proposed budget application, and they were not added to the CE analysis. *See* D.21-12-015, p. 63 and D.21-03-056, p.29.

[14] Protocols, p. 17.

5. Portfolio Analysis

The portfolio analysis includes all costs and benefits in the individual programs. In addition, the budgeted amount for Emerging Technology was included in the portfolio tests.

III. AUTO DEMAND RESPONSE

D.17-12-003 directed the IOUs to report cost effectiveness ratios with and without Auto Demand Response (AutoDR) incentives for programs that qualify for those incentives. In addition, the Decision directed the IOUs to indicate the total amount of AutoDR incentives excluded from the analysis and the costs associated with customers participating in each program qualifying for AutoDR incentives.[15] SDG&E administers two AutoDR programs: Technology Incentives (TI) and Technology Deployment (TD). SDG&E forecasts that customers receiving TI incentives will enroll in CBP DO and customers receiving TD incentives will enroll in ACS DA. Each of these is discussed separately.

A. Customers Receiving TI Incentives and Enrolling in CBP DO

SDG&E forecasts customers receiving TI incentives in 2023 will enroll in DRAM programs, CBP DO Elect and CBP DO 11 to 7. A CE analysis was not done for CBP DO Elect for 2023 as this initiative was approved in the Summer Reliability Decision.[16] Similarly, a CE analysis is not presented for DRAM programs as they are outside of the DR portfolio. Table BG-6 presents results for CBP DO 11 to 7 both with and without TI incentives.

Table BG-6: CBP DO 11 to 7 With and Without TI Costs

	TRC	PAC	RIM
CE Results with TI Incentives and Administration costs	0.003	0.003	0.003
CE Results without TI Incentives and Administration costs	0.004	0.004	0.004

Table BG-7 presents the prorated amount of TI costs included in the CE analysis.

[15] D.17-12-003, OP 27.

[16] As stated above, proposals approved in D.21-12-015 are not subject to CE.

Table BG-7: TI Costs Related to CBP DO 11 to 7

	Total Budget	Included in CE Tests
TI Administration Costs	$671,420	$194,712
TI Incentive Costs	$100,000	$41
Total	$771,420	$194,753

B. Customers Receiving TD Incentives and Enrolling in ACS DA

SDG&E forecasts customers receiving TD incentives in 2023 will enroll in ACS DA and dynamic rates. Rates are not included in the CE analysis. Table BG-8 presents results for ACS DA both with and without TD incentives.

Table BG-8: ACS DA With and Without TI Incentives

	TRC	PAC	RIM
CE Results with TD Incentives and Administrative costs	0.2	0.2	0.2
CE Results without TD Incentives and Administrative costs	0.4	0.3	0.3

Table BG-9 presents the prorated amount of TD costs included in the CE analysis.

Table BG-9: TD Costs Related to ACS DA

	Total Budget	Included in CE Tests
TD Administration Costs	$623,928	$580,253
TD Incentive Costs	$486,000	$345,200
Total	$1,109,928	$925,453

IV. SENSITIVITY ANALYSIS

The Protocols require sensitivity analyses showing the impact on the TRC resulting from a change in key variables. In particular, the variables specified are the A Factor, the ex-ante load impacts, participant costs and the generation capacity values. Each of these is described below.

A. Sensitivity Analysis of A Factor

To evaluate how sensitive the TRC is to changes in the A Factor, SDG&E used a value of 10% lower than the base case as the low value, and a value of 100% as the high value. Table BG-10 shows these changes in the A Factor has no significant impact on the TRC results.

Table BG-10: Sensitivity of A Factor on TRC

Program	Base Case		Sensitivity			
	A Factor	TRC	A Factor	TRC	A Factor	TRC
BIP	100%	0.04	90%	0.03	100%	0.04
CBP DA	28%	0.004	25%	0.004	100%	0.01
CBP DO	28%	0.003	25%	0.003	100%	0.01
ACS DA	94%	0.3	85%	0.3	100%	0.3
ACS DO	94%	0.2	85%	0.2	100%	0.2

B. Sensitivity Analysis of Ex-Ante Load Impacts

The protocols specify to use the 10th and 90th percentile values of the load impacts in the sensitivity analysis. The 10^{th} and 90^{th} percentile load impacts for CBP do not change significantly; therefore, the TRC stays the same. Table BG-11 shows the impact on the TRC when the load impacts vary for BIP and ACS.

Table BG-11: Sensitivity of Load Empacts on TRC

Program	50th Percentile (Base Case) 1-in-2 Portfolio Ex-Ante Impacts		10% Percentile		90th Percentile	
	Sept. MW	TRC	Sept. MW	TRC	Sept. MW	TRC
BIP	0.14	0.04	0.12	0.03	0.16	0.04
CBP DA	0.05	0.004	No significant change in impacts			
CBP DO	0.02	0.003	No significant change in impacts			
ACS DA	5.97	0.3	2.9	0.1	10.4	0.4
ACS DO	2.16	0.2	0.4	0.03	4.7	0.4

C. Sensitivity Analysis of Participant Costs

Participant costs used in the cost effectiveness tests are meant to represent transaction costs, value of service lost, and financial expenditures for equipment or other capital costs related to the program. Since the value of these costs are unknown, the Protocols specify to use a percentage of the value of incentives paid to the participant plus their bill reductions less their

capital costs as a proxy for transaction costs plus value of service lost. For most programs, the percentage used for this is 75%. In addition, the low and high values for sensitivity analysis are 50% and 100%. A modification is specified in the Protocols for voluntary AC cycling programs. For these, the base case is 35% and the low and high values for sensitivity analysis are 10% and 60% respectively. [17] Table BG-12 presents the change in TRC as a result of a change in participant costs. As shown, there is no significant impact.

Table BG-12: Sensitivity of Participant Costs on TRC

Program	Base Case		Sensitivity			
	% Used in Proxy	TRC	% Used in Proxy	TRC	% Used in Proxy	TRC
BIP	75%	0.04	50%	0.04	100%	0.04
CBP DA	75%	0.004	50%	0.004	100%	0.004
CBP DO	75%	0.003	50%	0.003	100%	0.003
ACS DA	35%	0.3	10%	0.3	60%	0.3
ACS DO	35%	0.2	10%	0.2	60%	0.2

D. Sensitivity Analysis of Generation Capacity Value

For sensitivity tests on the adjusted generation capacity values, the values were lowered and raised by 30%. Table BG-13 shows the results of changes to the TRC for each program when the adjusted generation capacity values are adjusted 30% lower or 30% higher than the values used in the base case analysis.

Table BG-13: Sensitivity of Generation Capacity Value

Program	Base Case TRC	TRC with Adjusted Capacity Value Reduced 30%	TRC with Adjusted Capacity Value Increased 30%
BIP	0.04	0.03	0.05
CBP DA	0.004	0.003	0.004
CBP DO	0.003	0.002	0.003
ACS DA	0.3	0.2	0.4
ACS DO	0.2	0.1	0.2

[17] Protocols, p. 47.

V. QUALITATIVE ANALYSIS OF NON-ENERGY IMPACTS

The Protocols require a qualitative analysis of social, utility, participant and market non-energy benefits or costs that may result from implementation of the proposed demand response programs, including possible impacts that may not exist.[18] SDG&E has provided an analysis of qualitative benefits and costs of demand response in supporting workpapers.

VI. CONCLUSION

This concludes my prepared direct testimony.

[18] Protocols, pp. 16-17.

VII. WITNESS QUALIFICATIONS

My name is Brenda Gettig. My business address is 8335 Century Park Court, San Diego, California 92123. I have been employed by SDG&E as a Senior Business Analyst in the Measurement and Evaluation Group for Customer Programs since 2006. My responsibilities include the evaluation and cost effectiveness analysis of SDG&E's demand response and low-income programs. I have a Masters in Economics from the University of California San Diego and a Master of Business Administration from the University of South Florida.

I have previously testified before the California Public Utilities Commission.

APPENDIX A

SDG&E DEMAND RESPONSE COST EFFECTIVENESS REPORT 2023

(*This document will only be provided electronically due to it's size*)

APPENDIX B

SDG&E QUALITATIVE ANALYSIS OF NON-ENERGY IMAPCTS 2023-2027

Qualitative Analysis of Non-Energy Impacts
Related to SDG&E Proposed Demand Response Programs for 2023 to 2027

Overview

As required by the Protocols, SDG&E provides this qualitative assessment of non-energy and non-monetary impacts related to its proposed demand response (DR) programs. The discussion addresses potential impacts related to SDG&E's proposed programs of Capacity Bidding (CBP) and AC Saver (ACS)[1] and is not meant to be a comprehensive analysis of impacts related to demand response in general. SDG&E does not quantify the impacts and does not include them in its cost effectiveness analysis. The Protocols require a descriptive analysis of potential impacts (benefits or costs) for four areas: social, utility, participant, and market. Each of these is discussed below.

Social Impacts

Social impacts may include health impacts, environmental impacts, and job creation or loss. The generation capacity avoided costs used in the cost effectiveness analysis include approved estimates of reduced emissions costs. While some research has been done to identify additional air quality benefits related to energy efficiency, no approved estimates are available at this time. Furthermore, the energy saved as a result of SDG&E's CBP and ACS programs is relatively small due to narrow event windows as well as pre-cooling and rebound effects.

SDG&E is unaware of any health or job impacts directly resulting from its programs. Were the CBP and ACS programs to cease operating, it is likely SDG&E staff would be assigned to other areas of operation, and aggregators and contractors working for SDG&E programs would continue working in the industry for other programs or in other capacities. Furthermore, any increase in jobs as a result of SDG&E's programs would potentially be offset by the loss of jobs related to producing additional generation which would be needed if DR programs did not exist.

Utility Impacts

Examples of non-energy impacts for the utility potentially could include changes in the number of customer calls requesting assistance and changes in arrearages or collection costs due to customer bill savings. Due to the relatively small amount of energy saved during event windows and resulting bill savings (assuming energy is saved and not shifted), it is unlikely there is any impact in arrearages or collection costs to the utility as a result of these programs. It is possible, however, there is an increase in customer calls related to program participation. For example, customers may call for additional information on the program , to complain about discomfort due to their air conditioning being cycled, or to opt out of program events. SDG&E does not have data supporting any change in utility costs as a result of operation of its DR programs. These impacts are difficult to quantify, and, even if they exist, likely do not result in a significant impact to the utility.

Participant Impacts

Negative participant impacts can include discomfort from reduced air conditioning, shifting energy intense activities to inconvenient times, and time and hassle related to participating in events. Positive impacts may include feeling good about helping the environment and contributing to corporate sustainability goals. In this section, results from recent customer surveys of ACS and CBP participants are provided to support the discussion.[2]

[1] For 2024 to 2027, SDG&E proposes to replace ACS with Smart Energy Program (SEP).

[2] See Nexant, 2021 Process Evaluation of San Diego Gas and Electric's Demand Response Programs, October 2021. CALMAC Study ID SDG0343.01.

ACS program participants indicated many of them participate for environmental reasons in addition to financial incentives. For example, slightly less than half of ACS participants indicated one reason they participate is to help ensure grid reliability and to help the environment. Program participants also reported negative impacts related to their participation. For example, roughly 15% of ACS participants reported being uncomfortably warm on event days. In addition, approximately 40% of respondents reported they opted out of events due to negative impacts to their normal routines or because they could not leave home due to Covid-19 shelter in place restrictions.

CBP participants also reported they were motivated to participate by contributing to environmental benefits and prevention of rolling blackouts. Many companies promote their social, cultural, and environmental contributions and include participation in DR programs as part of a larger set of corporate sustainability goals. CBP participants also reported a negative impact from multiple consecutive event days where there was no opportunity between down times to return to previous production levels. The high number of events was reported as one of the primary reasons for customer withdrawal from the program.

CBP aggregators reported customer dissatisfaction with events called during periods of mild temperatures. In San Diego, the rationale for dispatch is not always clear to customers because the trigger price does not always correlate to high temperatures in San Diego, and this lack of understanding why events are being called leads to some customers feeling overused and undervalued. Non-participating businesses were also surveyed, and nearly half reported they did not want to join the program because it would impact business operations or customers' comfort.

Market Impacts

Potential impacts suggested in the Protocols such as market power mitigation and market transformation may be developing but have not been evaluated. Potential market impacts associated with DR may include technology and signaling advancements related to enabling technologies and Auto Demand Response (AutoDR); however, SDG&E has proposed sunsetting its AutoDR programs and is not proposing any technology incentives for program years 2024 through 2027.

Conclusion

Non-energy impacts in general are imprecise and difficult to identify and quantify. While a large body of research exists on non-energy impacts resulting from low-income energy efficiency programs, much of it is based on generalized assumptions rather than specific program attribution. A recent assessment of non-energy impacts related to the California Energy Savings Assistance (ESA) Program found that many of the impacts that had been used in cost effectiveness tests for years were not supported by research, overlapped with other benefits, or lacked supporting data to provide a reasonable calculation. While the study made some recommendations for improvement, it acknowledged there was still a high degree of uncertainty in estimating these impacts.[3]

In the sections above, SDG&E presents a discussion of potential non-energy impacts related to its proposed CBP and ACS DR programs. While customer survey responses present some evidence of both positive and negative impacts to participating customers, these impacts cannot be quantified at this time. In addition, social, utility and market impacts resulting from CBP and ACS program operations likely are insubstantial or do not exist.

[3] APPRISE, INC.; California Energy Savings Assistance Program Non-Energy Benefits, January 2021. https://pda.energydataweb.com/api/view/2471/Final%20CA%20ESA%20NEB%20Report%201-25-21_.pdf