Whitepaper: Evolving Cost-Effectiveness Policy and Tools to Enable Modern Energy Efficiency and Demand-Side Management

October 2019

Adam Scheer,

Recurve

RECURVE
SHAPE THE FUTURE OF ENERGY

TABLE OF CONTENTS

Executive Summary

Recently, California's energy efficiency (EE) portfolios have struggled to meet mandated cost-effectiveness thresholds. As a result, cost-effectiveness has gone from a technical metric understood mainly by subject matter experts to a primary decision-making factor governing the evolution of the EE portfolio. Given the central role cost-effectiveness now plays, there is a need to understand how specific cost-effectiveness policies and tools are enabling or inhibiting EE and demand side management (DSM) program administrators (PAs) in developing portfolios that best serve California's clean energy vision.

Recently, cost-effectiveness was a topic of intense discussion throughout the EE Business Plan process. In various workshops and filed comments, many stakeholders raised concerns over current cost-effectiveness policy and put forward recommendations for changes. In D.18-05-041 the California Public Utilities Commission (CPUC or Commission) acknowledged this feedback and invited development of a more robust record to support policy changes, stating, "If parties believe, and generally agree, that a specific cost-effectiveness policy warrants modification, they should file a motion with cites to specific evaluation studies and/or program data supporting their proposal in R.13-11-005 or its successor proceeding."[1] Since D.18-05-041, D.19-05-019 has been filed in the Integrated Distributed Energy Resources (IDER) proceeding[2] and establishes cost-effectiveness policy for all DSM programs, including EE. This whitepaper intends to provide a data-driven analysis of EE cost-effectiveness policy and implications to help inform discussions in both R.13-11-005, and R.14-10-003 as well as the ongoing development of a Common Resource Valuation Methodology (CRVM) that the CPUC has indicated should govern integrated resource planning.

Based on the research, analysis, and rationale presented here, a number of recommendations for changes to EE cost-effectiveness policy and tools are provided. Some of these recommendations address long-standing logical and technical issues. Other recommendations are more forward looking and geared toward helping EE transition to a modernized portfolio better capable of delivering resource value, transform markets, and focus on equity objectives.

Cost-effectiveness policy must be considered in the context of California's evolving portfolio goals and the rapid transformation of EE and DSM being driven on multiple fronts. With SB 100 the State has established a core focus on aggressive decarbonization[3] while maintaining that reasonable rates and customer affordability will continue to be imperative. In response to this direction the Commission has indicated via a 2018 whitepaper (Staff EE/IRP Proposal) the intention to incorporate EE within the Integrated Resource Planning (IRP) process by 2021.[4] SB 350 doubled targets for energy savings in existing buildings.[5] AB 802 allows PAs to incentivize

[1] D.18-05-041 p. 75
[2] D.19-05-019, Proceeding R.14-10-003
[3] SB 100, full bill text at https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100
[4] Staff Proposal for Incorporating Energy Efficiency into the SB 350 Integrated Resource Planning Process, CPUC, 2018.
[5] SB 350, full bill text at https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

stranded potential and prioritizes meter-based savings.[6] AB 793 requires PAs to support energy management technologies.[7] Along with these objectives, the CPUC has directed PAs to outsource the majority of the EE portfolio to third parties,[8] pushed for a greater focus on equitable program delivery,[9] and has engaged stakeholders in development of a dedicated market transformation framework.[10,11,12]

Recent market dynamics have also had a major impact on the EE portfolio. Low-cost resource savings opportunities from "widgets" have largely evaporated due to wide-scale technology improvements and successes within the Codes and Standards (C&S) portfolio. In particular, with maturation of LED technology, the inexpensive lighting savings opportunities long enjoyed by resource programs are instead being realized via C&S advancements.

In addition, EE and DSM are also evolving in response to accelerating changes in California's broader energy landscape. Natural gas prices are at near 20-year lows[13] and temporal and seasonal changes in the electric avoided cost profile have had a major impact on EE portfolio cost-effectiveness. Mid-day electricity savings have rapidly lost value as the marginal avoided costs of electricity savings have been driven down or eliminated by high solar penetration. A recent study noted that in April of 2019, more than 10% of all 5-minute intervals on California's grid experienced negative pricing.[14] As of Oct. 24, the California Independent System Operator (CAISO) reports that 2019 renewables curtailment has reached 813 GWh,[15] already exceeding all of 2018 by 76%. By 2025 the CPUC forecasts overgeneration in more than 50% of hours between 7 am and 5 pm. By 2030 that value reaches 67%.[16] This leads to the assignment of zero avoided costs for electricity savings achieved during these times. (It is worth note that 2025 avoided costs are already incorporated into the cost-effectiveness calculation of any measure with an effective useful life (EUL) of 6 years or longer.)

---

[6] AB 802, full bill text at https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160AB802
[7] AB 793, full bill text at https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160AB793
[8] D.16-08-109 OP 12 p. 111
[9] D.18-05-041
[10] Administrative Law Judge's Ruling Seeking Comment on Market Transformation Staff Proposal, CPUC, 2018
[11] CAEECC-Hosted Market Transformation Working Group Report and Recommendations to the California Public Utilities Commission, 2019
[12] Proposed Decision Regarding Frameworks for Energy Efficiency Regional Energy Networks and Market Transformation, 10/23/2019
[13] See Presentation on Cost-Effectiveness (A. Scheer of Pacific Gas and Electric Company) to the California Energy Efficiency Coordinating Committee, 8/2/2018, viewable at https://docs.wixstatic.com/ugd/849f65_d1a2a83784ff41f5826babe0cdaf7568.pptx?dn=CAEECC_CostEffectiveness_Scheer.pptx
[14] Golden, M., A. Scheer and C. Best. 2019. "*Decarbonization of Electricity Requires Market-Based Demand Flexibility*". The Electricity Journal. Vol 32. Issue 7 (August-September).
[15] Wind and Solar Curtailment October 24, 2019 California Independent System Operator http://www.caiso.com/Documents/Wind_SolarReal-TimeDispatchCurtailmentReportOct24_2019.pdf
[16] Derived from the 2019 Electric Avoided Cost Calculator available at https://www.cpuc.ca.gov/General.aspx?id=5267

Taking Climate Zone 4 as an example, Figure E1 shows the avoided costs each hour during the week of February 17 – 23 for 2018 (bottom), 2024 (middle) and 2030 (top).

Fig. E1

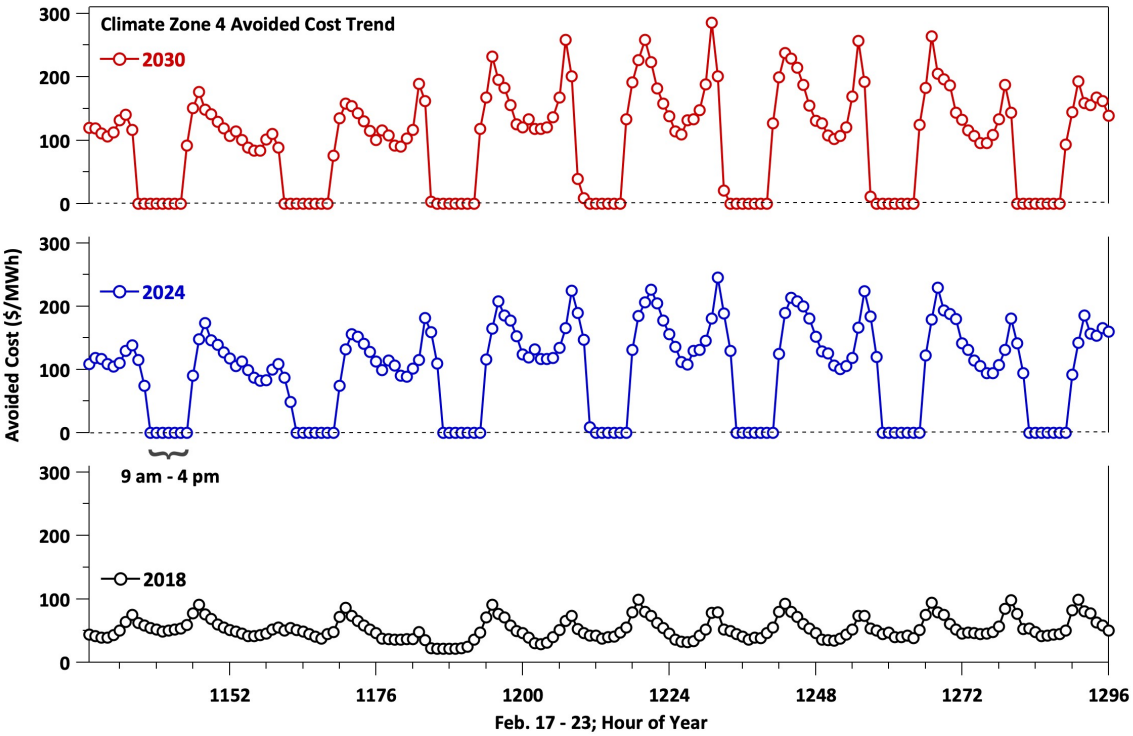


Figure E1: Climate Zone 4 hourly avoided costs Feb. 17 – 23 in 2018 (bottom), 2024 (middle), and 2030 (top)

Several important trends are apparent. First, mid-day avoided costs were uniformly positive for this week in 2018 but are zero for most hours from 9 am – 4 pm by 2024. Second, avoided costs grow substantially at other times of day from 2018 to 2024 and are yet higher in 2030. This is largely due to increasing per-ton greenhouse gas value and energy values. In the summer months during peak hours avoided costs associated with capacity, transmission, and distribution become predominant. Averaged over the full year, hourly electric avoided costs by component are shown in Fig. E2 (Climate Zone 4 and 2025). It is clear that marginal value of a mid-day MWh has plummeted while high summer peak period capacity and distribution costs are driving up average evening avoided costs.

Fig. E2

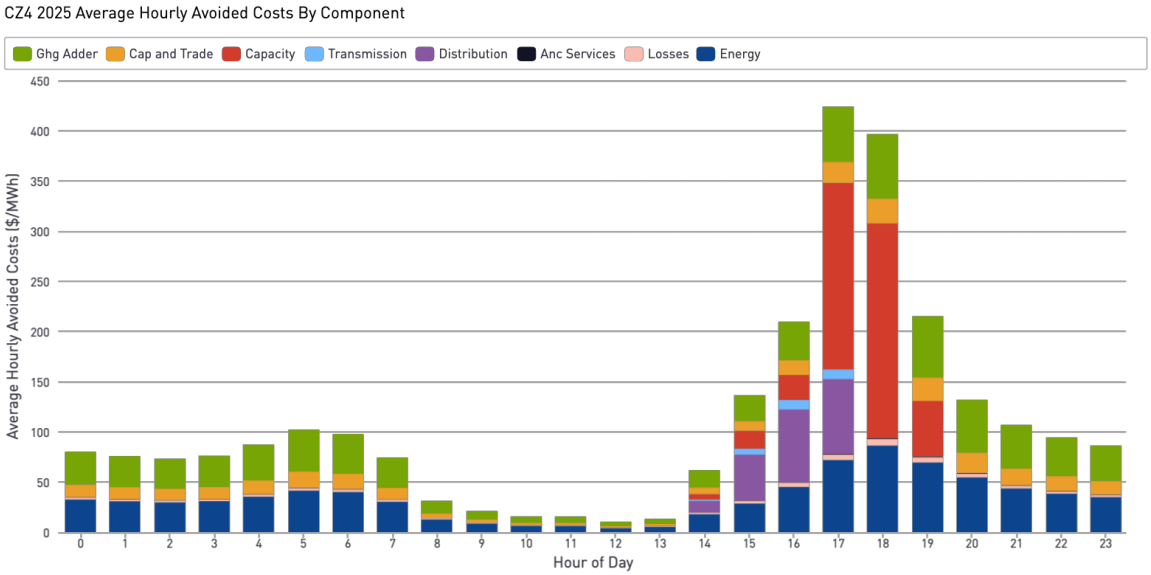


Figure E2: 2025 average hourly avoided costs by component (Climate Zone 4)

In part due to the EE portfolio peak demand reduction goal being set between the hours of 2 – 5 pm until 2019,[17] the PAs have been obligated to maintain a heavy focus on savings during time periods that drive diminishing grid or carbon benefits. With the majority of the portfolio oriented toward mid-day savings, the PAs have experienced a dramatic drop in benefits. For example, Table E1 shows that on average a net lifecycle kWh saved in Pacific Gas and Electric Company's (PG&E's) 2017 energy efficiency portfolio drove $0.105 of avoided costs. By comparison, even with a higher GHG value, according to PG&E's 2019 Annual Budget Advice Letter, in 2019 a kWh was forecast to achieve only $0.074 in avoided costs, amounting to a drop of 30% in just two years.

Table E1

	$ Elec Benefits/ Net LC kWh Savings		
Sector	**2017 CEDARS**	**2019 ABAL**	**2019/2017**
Agricultural	$0.107	$0.063	0.591
Commercial	$0.109	$0.063	0.583
Industrial	$0.096	$0.060	0.623
Residential	$0.115	$0.104	0.904
Public	$0.093	$0.064	0.691
Total	**$0.105**	**$0.074**	**0.699**

Values in Table E1 derived from PG&E's 2017 CEDARS and 2019 ABAL filings.[18,19]

While the drop in mid-day avoided costs has depressed portfolio cost-effectiveness, it also represents a major opportunity for a new generation of EE and DSM programs. Any usage that is shifted onto these hours from other times of day, will achieve 100% of the avoided costs

[17] Resolution E-4952, 2018
[18] PG&E's 2017 Annual EE filing is available at CEDARS https://cedars.sound-data.com/
[19] PG&E Advice 4011-G-B/5375-E-B

associated with the initial time period. Shifting usage, especially from expensive and GHG-intensive summer peak periods can convert traditional cost-ineffective efficiency programs into modern, cost-effective demand flexibility programs.

Unfortunately, several policies and tools serve as barriers to EE and DSM evolving to market-driven, integrated strategies. For instance, the Total Resource Cost (TRC) test treats private capital the same as ratepayer spending, which disincentivizes deeper savings and leveraging incentive or loan pool dollars to maximize clean energy investment. Another example relates to the Cost Effectiveness Tool (CET), the official mechanism for forecasting and reporting cost-effectiveness. The CET only allows for a small number of pre-determined savings profiles (DEER load shapes) to compute cost-effectiveness. Therefore, even if a program's load impacts are measured precisely on an 8,760 basis at the meter, these results cannot be included in the program's official cost-effectiveness calculation. This not only can lead to inaccuracy, but disincentives PAs and program implementers from optimizing the load shape impacts of their programs, and effectively disallows valuation of beneficial load shifting within EE programs. Another major barrier is posed by the separate EE and Demand Response (DR) proceedings, delivery mechanisms, and goals. It is questionable how or even if an EE program can incorporate any type of demand response, including passive load shifting, while remaining compliant with all CPUC policies.

In light of recent legislative priorities, the progressing technology landscape, and the rapidly changing demands of a modern grid, California's cost-effectiveness policy should evolve to enable demand-side programs and portfolios that:

- Are more holistic in scope. To increase value for both individual customers and serve dynamic grid needs, EE programs must integrate with other distributed energy resources (DERs, including demand response, load shifting, beneficial electrification strategies, and time-of-use rates).
- Utilize financing offerings that reduce reliance on incentive payments and encourage more comprehensive projects. Financing will be an essential strategy to doubling efficiency savings without over-burdening ratepayers via utility bill surcharges.
- Encourage market transformation and aggressive pursuit of codes and standards advancements.
- Prioritize equity, including serving disadvantaged and hard-to-reach customers.
- Ensure ratepayer spending on programs funded through utility bill surcharges is kept to just and reasonable levels.
- Utilize meter-based measurement and Pay-for-Performance (P4P) designs. Programs that measure and incentivize impacts at the meter will be better positioned to assess and drive high-value time-and-locational savings and flexibility, thus establishing EE as a legitimate grid resource capable of competing within the IRP and related solicitations.

A number of specific revisions to the CPUC's cost-effectiveness policies are needed to allow for a clear focus on these priorities and ultimately to evolve the EE portfolio to the types of competitive, accountable, and transparent programs capable of scaling to achieve the State's long-term climate goals at reasonable cost to ratepayers. Much of the analysis presented in

this whitepaper to support recommendations for policy updates utilizes data from PG&E's EE portfolio. As California's largest dual-fuel utility, these data and trends are expected to provide a sound basis for consideration.

This whitepaper is organized into four main categories:

1. **Cost-Effectiveness Policy that Encourages Private Investment for the Benefit of All Ratepayers**: Leveraging private capital will be essential for California to meet its clean energy goals and aggressive decarbonization targets at a reasonable cost to ratepayers. However, by including participant investment as a cost, on par with utility bill surcharges, the TRC (and societal versions) inhibits demand side programs from motivating private clean energy funding.[20] To counterbalance this aspect of the TRC, the CPUC has long employed the Program Administrator Cost test (PAC), along with the TRC, as arms of a dual cost-effectiveness framework to govern EE. Unfortunately, the formulation of the EE "dual test" acted to entrench the TRC as the only cost-effectiveness test of consequence. In D.19-05-019, the Commission further establishes the TRC as the only cost-effectiveness test of compliance significance for all demand-side resources.

   However, a test that can appropriately facilitate progress toward California's clean energy and affordability goals must recognize the difference between participating customer investment in her home or business versus ratepayer funding for utility-scale projects. As the Commission stated in D.05-04-051:

   > *"[S]ince individual customers that participate in DSM resource programs realize direct bill savings, they are generally willing to fund a greater percentage of the investment than non-participating customers. This is not the case for supply-side resources, where all customers are assumed to benefit from the investment equally…Hence, unlike on the supply-side, bidders on the demand side may be able to leverage participating customers' private funds to the benefit of all ratepayers."*[21]

   Because the TRC treats private capital and ratepayer spending the same, it does not encourage the balanced decision-making needed to achieve California's objectives or the ability to scale demand-side programs that use ratepayer dollars most prudently and effectively.

   To the extent that the TRC continues to be used, much greater attention to the nature of participant costs should be given. Just as savings and costs from free riders are removed from the calculation of the TRC, so should participant investment associated with non-energy benefits. In the past the Commission has recognized that EE programs can piggyback on investments customers are willing to make to receive a range of benefits:

   > *"While many residential building retrofit measures have unacceptably long customer payback periods based on energy prices alone, they can find market acceptance and leverage private sector investment based on attributes other than energy savings (e.g. comfort and noise*

[20] The same is true of the societal variations of the TRC, (the Societal Cost tests; SCT).
[21] D.05-04-051, Appendix 4

> *reduction)…These issues should be considered in updating the methodology for calculating program or portfolio cost-effectiveness."*[22]

As EE and DSM continues to evolve to more holistic, scalable demand flexibility resources, the ability of programs to engage existing markets and become part of a broader package of customer benefits will be essential. Recognizing this now in cost-effectiveness policy by estimating and removing non-energy costs is key to making this transition.

2. **Updates to Cost-Effectiveness Documentation and Tools**: Cost-effectiveness is a fundamental pillar of EE compliance, program planning, and forecasting. Several updates are needed to the Cost-Effectiveness Tool (CET) and supporting resources to facilitate public and stakeholder understanding, enable accurate and transparent cost-effectiveness calculations and optimization, and provide for accessible tools and documentation. Functionality updates are also needed to enable PAs and implementers to incorporate load shifting and demand flexibility strategies and 8,760 resource curves (savings load shapes) that result from Normalized Metered Energy Consumption (NMEC) measurements.

3. **Cost-Effectiveness Formalism**: In its treatment of incentive payments to free-riders the Commission has established an asymmetric TRC test that differs from a standard TRC test and does not align with the Standard Practice Manual (SPM). Addressing this along with several other specific adjustments or clarifications to the formalism of the TRC and PAC applied within California EE are needed to achieve the intention of these tests as stated in California's SPM.

4. **Potential and Goals (P&G) Framework**: Several PAs are in the process of outsourcing their portfolios for statewide and third party design and implementation. Pay-for-performance (P4P) program models based on normalized metered energy consumption (NMEC), and maturing on-bill financing offerings are allowing for more holistic and innovative program designs. On the horizon are a dedicated market transformation framework, and inclusion of EE in the IRP. All of these changes are pushing EE away from measure-based delivery models and toward more flexible, data-driven program designs. The traditional P&G modeling, which is largely based on analysis of individual measures and average cases, is no longer reflective of the current or future EE portfolio. With NMEC/P4P programs especially, there is now an ability and motivation to both identify and recruit customers with high potential for cost-effective savings for specific programs and to tailor offerings for individual participants based on their specific buildings and behaviors. A customer-focused approach that leverages AMI data analytics instead of measure-specific, average case modeling, can help modernize demand flexibility and spotlight potential in an actionable way.

   In addition, the P&G study can help facilitate development of cost-effective programs by investigating the potential for integrated demand management strategies. D.16-08-019 states: "Commission staff should integrate the study of the energy efficiency goals and potential with the potential for demand response in the next two-year study process." Assessing demand response layered on EE as well as opportunities for integration of electrification, storage, and other behind-the-meter interventions would help the CPUC

[22] California Energy Efficiency Strategic Plan January 2011 Update, p. 18

coordinate policymaking and provide direction for currently disparate industries to make these essential connections.

Summary of Recommendations

Specific recommendations that stem from the analysis in this document are summarized as follows:

1. **Treatment of Participant Cost**

   i. In considering a long-term consistent resource valuation framework, the CPUC should carefully weigh the distinction between private investment and ratepayer charges with the recognition that private clean energy capital must be encouraged. In the interim, the CPUC should retire the TRC, which discourages private investment, in favor of the PAC as the primary cost-effectiveness test for resource DSM programs. The Commission should trust customers to make their own decisions on participation, and can screen programs to protect against predatory program designs, potentially via a Participant Cost Test (PCT).[23] Alternatively, the Commission could return to a weighted dual test that emphasizes the PAC test with a 2/3 weighting but incorporates a 1/3 weighting of the TRC to serve as an ingrained protective mechanism against predatory programs. Both the PAC and the TRC will exhibit low values if programs fail to deliver load impacts that are valuable according to the avoided cost calculator.

   ii. The threshold value of the PAC test should be chosen commensurate with California's policy goals, including customer affordability. In the long term, the DSM cost-effectiveness test utilized in a common resource valuation framework and integrated resource planning must recognize the distinction between participant investment in one's home or business vs. ratepayer spending on central generation, something neither the TRC nor societal versions of the TRC test do.

   iii. Participant costs should be clearly defined as the portion of project/measure costs associated with energy savings. To the extent possible, participant investment to improve non-energy factors including, but not limited to, comfort, safety, indoor air quality, property value, productivity, and equipment reliability, should be estimated, quantified, and removed from the determination of measure, program, and portfolio TRC. In the short term, existing research can inform customer perceptions of EE program investment. In the long term, this assessment could be conducted through the impact evaluation Net-to-Gross surveys.[24]

[23] Without removing non-energy related costs the PCT would still undervalue program participation.
[24] See for example, *Impact Evaluation Report: Home Upgrade Program – Residential Program Year* 2017, DNV GL, 2019. In this evaluation, DNV GL reported quantitative values on the degree of participant investment associated with energy and bill savings compared to non-energy factors.

2. Updates to Cost-Effectiveness Documentation and Tools

i. The Commission should publish an updated version of the SPM to clarify issues of formalism and enhance stakeholder understanding of the cost-effectiveness tests. Many updates, interpretations, and new considerations have made the existing SPM, last revised in 2001, out-of-date.

ii. The Commission should publish an updated Equation Reference for use of the CET. The Equation Reference should clearly detail how each input is treated and how the calculations are performed in line with California's current cost-effectiveness policy.

iii. The Commission should improve accessibility of the Cloud-Based CET by providing clear and transparent links, instructions, and resources for parties to access the approved version of the CET on the relevant CPUC websites.

iv. As soon as possible, the Commission should enable capability to add 8,760 hourly resource curves (savings load shapes) derived from NMEC measurements to the CET. As new requirements that impact the calculation of cost-effectiveness are instituted, the CPUC should ensure that the CET tool documentation and functionality are updated accordingly in a timely manner.

v. Where negative avoided costs exist associated with periods of overgeneration or resources that cause grid instability, those costs should be quantified and included in the CET where possible. These costs are needed not only to accurately reflect the value of savings, but also to ascribe proper value to load shifting.

3. Immediate Changes Needed to Cost-Effectiveness Formalism and Parameters

i. Incentives paid to free riders are included erroneously in the CPUC's formalism of TRC and should be removed.

ii. With acceptance of the previous recommendation, to allow for consistent treatment of free ridership in the TRC calculation of Direct Install (DI) measures the Commission should specify that DI costs should be multiplied by the Net-to-Gross ratio (NTG).

iii. The Commission should instruct that for the purposes of cost-effectiveness calculations "excess incentives" should not be distinguished from other incentives.

iv. The Commission should clarify how Evaluation, Measurement, and Verification (EM&V) costs should be treated for the purpose of calculating portfolio cost-effectiveness.

v. With the input of stakeholders, the Commission should develop robust guidance for EE financing programs, including on-bill-financing programs, which raise a number of non-traditional cost and benefit considerations.

vi. The Commission has established clear non-energy related policy objectives for the EE portfolio. Therefore, the Commission should recognize the societal value in achieving these objectives. Without doing so, PAs will struggle to justify the

programs that support these goals while under portfolio cost-effectiveness pressure. Instead of attempting to tie value to non-resource or social and equity policy objectives, the Commission should consider setting aside specific budgets to address these goals outside of the resource portfolio cost-effectiveness framework.

4. Potential and Goals Framework

i. To facilitate the transition of EE into the IRP, the Potential and Goals study and goal setting process should be updated to recognize and facilitate the evolution of the EE portfolio in response to recent policy direction. AMI data analytics, zero-interest non-incentive financing programs, and integrated offerings/load shifting strategies among other advancements are not sufficiently captured by traditional individual deemed measures or custom approaches. Further, the P&G study should assess cost-effective potential not for average cases but for achievable savings from targeted programs. By focusing on average cases, entire classes of interventions are deemed to offer no cost-effective potential. This approach ignores the potential available from interventions that are targeted to customers most in need of a program and who offer the greatest benefits to the ratepayer base. Several studies have demonstrated how effective targeting via AMI data analytics can enhance savings and cost-effectiveness relative to the average case.[25,26,27] The distributions of meter-based results and the associated hourly load impacts from past downstream programs can provide a wealth of valuable information to inform this analysis.

This whitepaper is organized into several sections that each provide a more in-depth analysis in support of these recommendations. For readers who would benefit from a detailed conceptual summary of the various cost-effectiveness tests, Sections I.A and III.C as well as the appendix provide helpful equations, diagrams, and explanation.

[25] *Customer Targeting for Residential Energy Efficiency Programs: Enhancing Electricity Savings at the Meter*, A.M. Scheer, S. Borgeson, K. Rosendo, 2017

[26] *Energy Efficiency Program Targeting: Using AMI Data Analysis to Improve At-the-Meter Savings for Small and Medium Businesses*, S. Borgeson, A.M. Scheer, R. Kasman et. al. 2018

[27] *Customer Targeting via Usage Data Analytics to Enhance Metered Savings*, 2018 ACEEE Summer Study, A.M. Scheer, S. Borgeson, R. Kasman et al.

I. California's EE Cost Effectiveness Policy Should be Modified to Enable Balanced Decision-Making

A. Background and Terminology

Cost effectiveness can be framed through many lenses, each of which imply a set of values and impart a set of constraints. If misaligned with policy, any cost-effectiveness test can impart set of priorities too narrow to meet the broader goals of a portfolio. A basic understanding of several individual tests is helpful before a more detailed discussion. Table 1 gives a breakdown of benefits and costs for a typical TRC test, the California version of the TRC,[28] the PAC, and the PCT.

Table 1

		TRC - Traditional	TRC - California	PAC	PCT
Benefits	Utility Avoided Costs[a]	✓	✓	✓	
	Incentives				✓
	Participant Bill Savings				✓
Costs	Program Administration[b]	✓	✓	✓	
	Incentives to Free Riders		✓	✓	
	Incentives to Non-Free Riders			✓	
	Free Rider Measure Costs				✓
	Non-Free Rider Measure Costs[c]	✓	✓		✓

a = Includes avoided costs of fuel, capacity, T&D, ancillary services, Cap-and-Trade, and GHG adder
b = Includes Administration, Marketing and Implementation and other portfolio costs
c = NTG x Measure costs. This term also represents non-free rider participant investment without incentives

Both the TRC and PAC tests gauge avoided utility costs from energy savings as benefits. Both tests include costs associated with program administration. Being from the participant perspective, the PCT has a very different formalism, with incentives included as a benefit instead of a cost, bill savings recognized, and measure costs included regardless of free ridership.

Important for this discussion is the treatment of participant investment. Because it represents the utility's perspective, the PAC test does not include participant cost, while the PCT does include this cost. (The TRC includes participant costs incurred by non-free riders.) These concepts and the erroneous formalism of the California TRC by inclusion of free rider incentives are covered in greater detail in Section III.

Confusion has arisen around the term "net," which has been interpreted as net of free riders, net cost after an incentive, or both. Table 2 makes explicit the terminology used throughout this section to describe specific costs and how these costs relate to one another. In all cases in this Section the term "net" is used to mean net of an incentive. To signify net of free ridership, the term "non-free rider" is used.

[28] We return to the difference between a standard TRC formulation and the more conservative California version in Section IV.

Table 2 **Cost Component Definitions and Interrelationships**

Term	Term or Equation	Definition
Measure Cost	MC	The cost of energy efficiency. This may be incremental or full measure cost depending on the baseline.
Non-Free Rider Measure Cost	= NTG x MC	Measure costs incurred by non-free riders
Incentives	Inc	Total Incentives
Free Rider Incentives	= (1 - NTG) x Inc	Incentives paid to free riders
Non-Free Rider Incentives	NTG x Inc	Incentives paid to non-free riders
Participant Investment	= MC	Participant investment in EE not including an incentive payment. This equals measure cost.
Net Participant Investment	= MC - Inc	Participant investment in EE including (or net of) the incentive payment.
Non-Free Rider Net Participant Investment	= NTG x (MC - Inc)	Non-free rider participant investment in EE including (or net of) the incentive payment
Spillover Measure Costs	= MC x 0.05	Measure costs resulting from spillover
Spillover Private Investment	= MC x 0.05	Private EE investment resulting fom spillover
Direct Install Costs	DI	Costs to cover the direct installation of measures. Often DI costs are equal to measure costs.

B. Portfolio TRC and PAC Benefits, Costs, Sensitivity Analysis, and Implications

Using the Table 2 designations along with the other cost elements that figure into the TRC and PAC, Fig. 1 provides a breakout of the benefits and costs for PG&E's 2017 reported EE portfolio, not including C&S.[29] The TRC costs are shown in two ways, one using the measure cost framework and the other breaking out non-free rider net participant investment.

[29] Figures 1 - 3 were created based on the program-level outputs of the Cost Effectiveness Tool summed to the portfolio level. The NTG used was a weighted average based on lifecycle kWh and Therms savings. Admin, Marketing, and Implementation include resource program costs only to avoid duplicative counting with these fields in the non-resource program budgets. Implementation costs include $85.6 million based on the definition in The Energy Efficiency Policy Manual (Version 5, Appendix F) and $10.6 million associated with other customer support costs, for instance spending for the Home Energy Reports (subprogram of PGE21001). These figures do not include Codes and Standards benefits and costs. While the Energy Savings Performance Incentive is a cost in the TRC and PAC, because of resettlement from the 2006 – 2008 program cycle, PG&E returned its 2017 ESPI.

Fig. 1

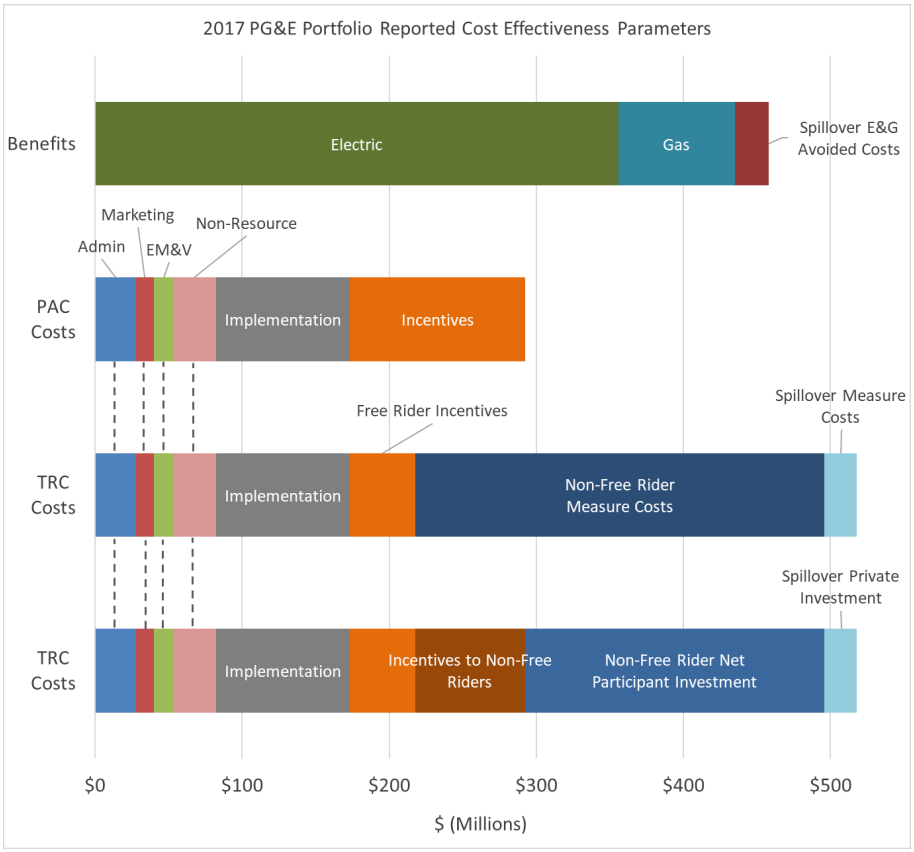


Figure 1: PG&E 2017 portfolio benefits and costs by component

The bottom TRC cost breakout is the most informative for this discussion. This breakout is replicated in Fig. 2, along with several relevant higher-level categories shown to scale in the dashed boxes.

Fig. 2

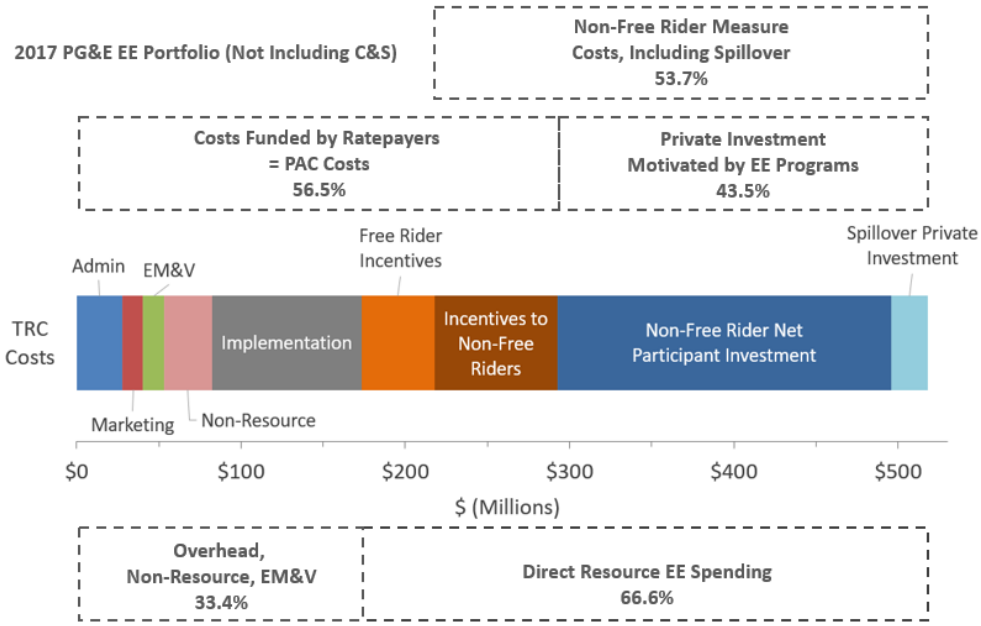


Figure 2: PG&E 2017 portfolio costs by component

Figures 1 and 2 provide a view into several important aspects of PG&E's 2017 portfolio related to cost-effectiveness. First, these figures show that measure costs accounted for 44% of portfolio TRC costs while total incentives were 23% of TRC costs. This means that every incentive dollar brought forward $1.89 of private EE investment. With no distinction in the TRC between program and private spending, this portfolio could have used $226 million additional ratepayer dollars to cover all participant costs at no impact to the TRC. Second, administration costs and incentives to free riders account for 5% and 8% of portfolio TRC cost respectively. In contrast, PAC costs are largely split between implementation and incentives.

These data can be used to construct portfolio-level sensitivity analyses for select TRC and PAC inputs. In figures Figs. 3a and 3b the x-axis represents percentage change in a TRC or PAC input and the y-axis shows how the TRC or PAC would change as a result. The 0% midpoint represents the actual 2017 portfolio. At the left side of the graph, -100% equates to eliminating a TRC or PAC input altogether. Similarly, the rightmost points, at +100%, represent a doubling of that input.

Fig. 3a

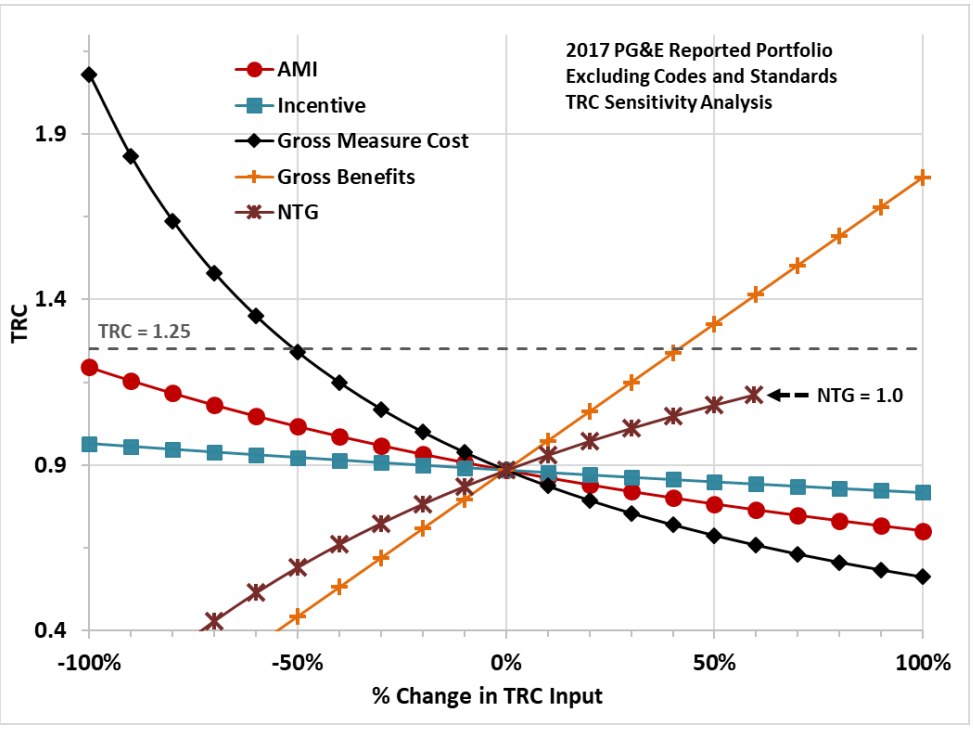


Figure 3a: PG&E 2017 portfolio sensitivity analysis (excluding C&S)

Fig. 3b

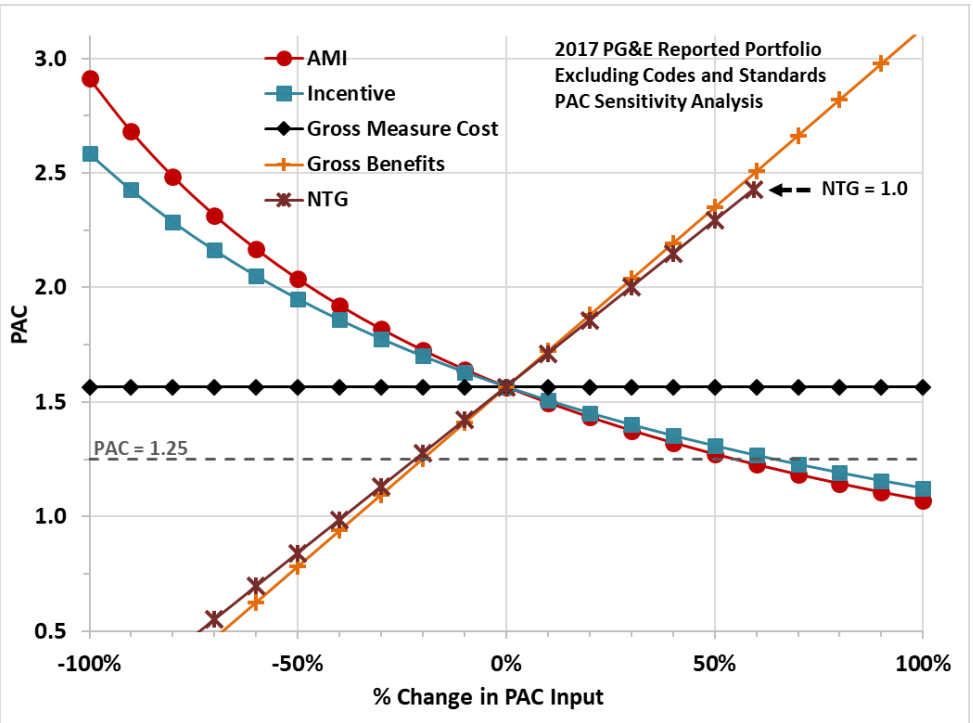


Figure 3b: PG&E 2017 portfolio PAC sensitivity analysis (excluding C&S)

Fig. 3a shows that if no measure costs were included, the portfolio TRC would be near 2.0. In contrast, the PAC does not include measure costs[30] and is therefore insensitive to associated changes. Fig. 3a also shows that if administrative, marketing, and implementation (AMI) spending was doubled, the TRC would fall by 0.18 to 0.70. The PAC is much more sensitive to AMI; a doubling would decrease the PAC by 0.49 to 1.08. The PAC is also highly sensitive to incentive spending. Because the PAC is sensitive to incentives and administrative/implementation costs, which are the components funded directly by ratepayers, the test sends a clear signal to PAs to use ratepayer funding prudently.

The portfolio TRC is clearly most sensitive to measure costs (Fig. 3a), the majority of which are participant costs (Fig. 2). As a result, the TRC pushes PAs to reduce measure costs, and consequently to discourage private EE investment, even if achieving savings goals necessitates increasing ratepayer-funded incentive spending. With the PAs under intense TRC pressure, we are likely to see the portfolios leverage less private EE investment and a higher fraction of measure costs covered by incentive dollars. Economy-wide EE spending is likely to decrease accordingly.

C. Implications of an Isolated TRC Test and Dual Test Considerations

The Commission discusses the relationship between ratepayer funding and participant spending in the context of a dual test in D.05-04-051, which states, "including the PAC test in the performance basis appropriately acknowledges *the dual-cost issue unique to energy efficiency investments*."[31] Because the TRC makes no distinction between ratepayer funding

[30] A portion of incentives cover measure costs and all incentives are included in the PAC.
[31] D.05-04-051 p. 82 (emphasis added)

and private investment, using the the TRC as the only conformant test results in several consequences that run counter to California's objectives, including the prudent use of ratepayer funding to maximize ratepayer benefits.

- The TRC in isolation does not motivate PAs to tune incentive spending only to the levels needed to motivate customers to pursue EE. The Commission has recognized this issue and that the PAC test must be considered "in order to ensure that program administrators and implementers do not spend more on rebates/cash incentives than absolutely necessary to achieve TRC net benefits."[32]
- Because private investment is needed to achieve comprehensive projects at reasonable levels of portfolio spending, the TRC is a barrier to California policy objectives focused on the deep savings projects needed to address the duck curve.[33] This is especially true in the residential sector where inefficient building shell and air conditioning usage is widely recognized to drive steep evening demand ramp and peak load. PAs should be motivated to educate customers and encourage investment in their own properties where such investment can benefit the participants from their own perspectives, and ratepayers as a whole. Using the PAC as the primary test potentially with a PCT screen, or a primary PAC, secondary TRC weighted dual test, would enable exactly this type of approach.
- Without an abundance of cheap savings opportunities, the TRC will be a major barrier to achieving the SB 350 goal of doubling EE savings in existing buildings. This is clearly evidenced by the Commission's recent Decision Adopting Energy Efficiency Goals for 2020 – 2030,[34] which cuts savings goals based exclusively on an a TRC screen and measure-level modeling that was conducted on an average basis. The measure-level TRC averaging results in no cost-effective savings potential identified for measures that would offer significant cost-effective savings potential when targeted at the right customers. New pay-for-performance programs based on measurement of normalized metered energy consumption are incentivized to do exactly this, whereas the deemed savings that form the foundation of the current portfolio give every technology and intervention type a point savings value. To reach aggressive SB 350 targets, PAs must not be limited in their ability to leverage ratepayer funding to encourage private EE investment and should be rewarded for finding cost-effective savings on an individual-customer basis.

With a PAC and threshold PCT dual test, or primary PAC secondary TRC weighted dual test, PAs would be incentivized to minimize incentive spending while maximizing the participant investment in EE while ensuring that programs must also benefit participating customers.

If multiple tests are to be legitimately considered, a weighted basis is needed to ensure that all associated tests remain relevant as markets evolve. Consider the formulation of the recent EE dual test, which consisted of the TRC and PAC. By definition both the California TRC and PAC tests include all costs borne by ratepayers. This can be seen in Fig. 2, which shows that the PAC costs accounted for 56.5% of portfolio TRC costs. Because the California TRC is

[32] D.06-06-063 p. 72-73
[33] See for example the California Energy Efficiency Strategic Plan January 2011 Update, p. 18 - 20
[34] D.19-08-034

inclusive of all PAC costs, there will never be a case in which the TRC is higher than the PAC. This is consistent with the fact that of the more than 150 programs PG&E reported for 2017[35] or forecast for 2019,[36] none have a TRC higher than the PAC. Because the California TRC must always be higher than the PAC, if a dual test simply consists of the same minimum threshold mandate for both tests, the TRC becomes by default the only test of consequence in achieving compliance, relegating the PAC to a purely informative metric.[37]

D. Examples

The need for a modern dual test may be best considered via real world examples that confront PAs in selecting a portfolio.

i. Deep Retrofit vs. Light Touch

The Advanced Home Upgrade Pathway of Energy Upgrade California (AHUP) is a whole house deep retrofit offering and the Residential Energy Fitness Program (REF) is a light touch intervention that largely delivers direct install lighting and select HVAC tune-up measures. These programs serve different purposes and different customer segments. Based on Commission guidance,[38] the AHUP model is oriented toward market transformation;[39] the program provides contractors training on home performance best practices and incentivizes customers to upgrade their homes with the long-term goal of creating self-sufficient markets for deep home retrofits. AHUP aligns with the Commission's observation that California's savings goals "can only be achieved by moving toward comprehensive whole house retrofits, which is a significant departure from relying on massive single measure rebate programs such as a few light bulbs now, new high-efficiency windows later."[40] In late 2017 PG&E merged its Moderate Income Direct Install offering with REF. The REF/MIDI programs are often deployed for customers without the means to pursue a comprehensive home retrofit.

Figure 4 gives the TRC and PAC benefit/cost breakout for PG&E's reported 2017 AHUP program.

[35] See PG&E's 2017 Annual EE filing available at CEDARS https://cedars.sound-data.com/
[36] See PG&E's 2019 Annual Budget Advice Letter CET Results available at CEDARS https://cedars.sound-data.com/
[37] It must be noted that with the EE portfolio in a transition phase associated with implementation of Rolling Portfolio guidance, the CPUC has granted temporary relief with a lowered TRC threshold of 1.0. The PAC requirement continues to be at the 1.25 level traditionally required for both tests. The CPUC has signaled an intention to return to the 1.25 threshold for the TRC in 2022 (see D.18-05-041).
[38] For instance, D.09-09-047 directs utilities to "offer a tiered suite of residential "whole house" saving options aimed at reducing the annual energy consumption of 130,000 homes over three years by 20% through comprehensive retrofits." p. 7
[39] D.12-05-015 p. 163-167
[40] D.09-09-047 p. 116-117

Fig. 4

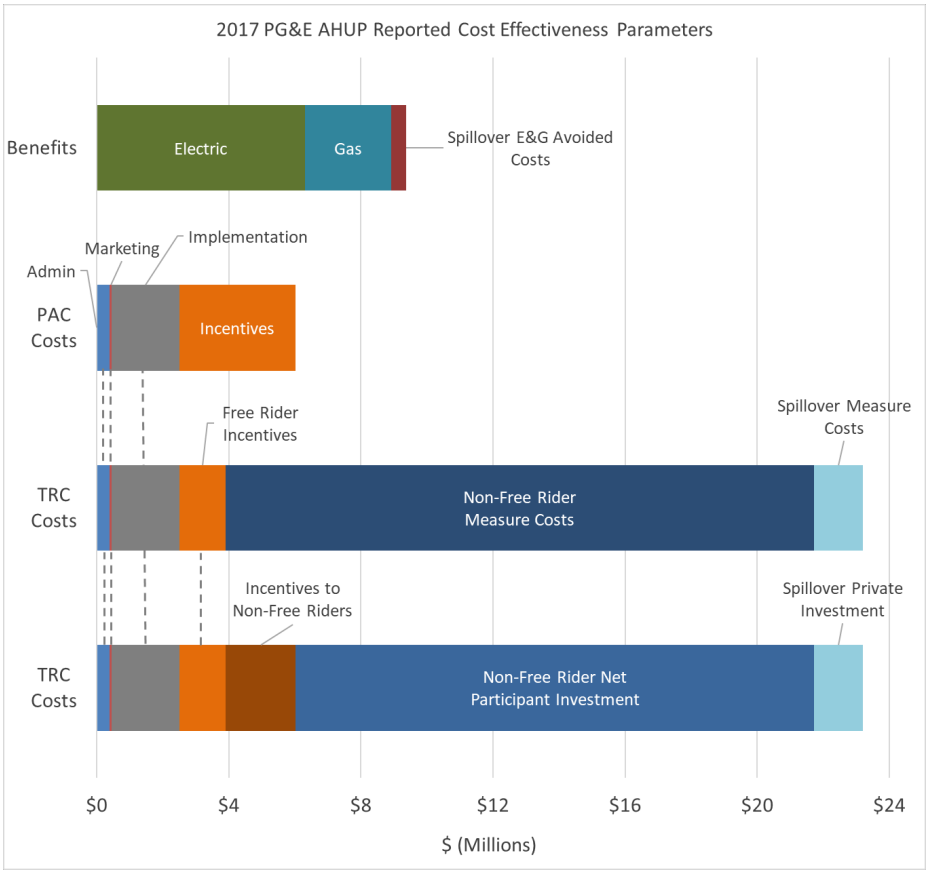


Figure 4: PG&E 2017 Advanced Home Upgrade program benefits and costs by component

Figure 4 makes apparent that the majority of AHUP costs originate from participant investment in their home retrofits. Despite multiple studies demonstrating that the majority of participant investment in AHUP is devoted to non-energy benefits,[41,42,43] all participant spending is traditionally counted in the TRC. This participant spending leads to a very low TRC of 0.4[44] despite the reasonable PAC of 1.56 (Table 3). By comparison, Table 3 shows that with

[41] *Impact Evaluation Report: Home Upgrade Program – Residential Program Year* 2017, DNV GL, 2019.
[42] *Energy Upgrade California – Home Upgrade Program Process Evaluation 2014-2015* EMI Consulting, 2015. CALMAC ID: PGE0389.01
[43] *PG&E Whole House Program: Marketing and Targeting Analysis.* Opinion Dynamics Corporation, 2014. CALMAC ID: PGE0302.05
[44] Does a low TRC indicate that customers are getting a bad deal by participating in AHUP? Consider first that the TRC values utility avoided costs, which largely reflect wholesale pricing. The participant of course experiences bill savings, which occur at (higher) retail rates. Second, the TRC uses the utility's discount rate (the weighted average cost of capital), which is usually between 7 - 8% and acts to heavily discount benefits over longer-lived measures. The appropriate discount rate for a customer isn't immediately obvious, but it is not the utility's cost of capital. One may instead use the estimated achievable rate of return on a risk free investment, like the 10-year treasury rate, which was 1.63% at the time of this writing. Using the 10-year treasury rate in place of an estimated 7.5% utility weighted average cost of capital increases benefits relative to the TRC by 57% for a measure with a 20-year effective useful life. Finally, as covered in Section IV.C, multiple studies show that customers value non-energy factors as much as energy benefits from AHUP participation. It would appear that a 0.4 TRC has little bearing on the value customers perceive from participation.

the REF program delivered nearly entirely through direct install interventions, the program achieves a much lower PAC of 0.59. However, in large part because the program does not secure EE investment from customers, the REF TRC of 0.59 is significantly higher than the AHUP program.

Table 3

Program	TRC	PAC	$ Private EE Investment Leveraged per $1 Program Spend*	TRC Benefits/ $1 Program Spend
Advanced Home Upgrade	0.40	1.56	$2.85	$1.56
Res Energy Fitness	0.59	0.59	$0.03	$0.68
2017 PG&E Portfolio	0.88	1.57	$0.90	$1.50

*= Non-Free Rider Net Participant Investment (Including Spillover)/Total Program Spend

The AHUP/REF comparison illustrates serious policy contradictions:

- If AHUP incurred no cost to ratepayers whatsoever, the program TRC would only reach 0.55. Given that the CPUC established the Energy Upgrade California program as a major market transformation policy priority,[45] it would seem that customers and contractors motivated to complete energy saving retrofits would be highly desirable. The TRC used in isolation clearly creates a conflicting policy dynamic.
- With every $1 of ratepayer funding, the AHUP program leverages $2.85 of non-free rider net private investment while REF drives virtually no private investment to match the ratepayer spend. Additionally, AHUP achieves $1.56 of TRC (and PAC) benefits for every $1 of ratepayer investment compared to $0.68 for REF. Nonetheless, an isolated TRC metric would strongly favor REF compared to AHUP.
- If free ridership in AHUP were eliminated, PG&E's portfolio TRC would *decrease* (due to the additional measure costs incurred by the portfolio).
- Spillover measure costs in AHUP are greater than spillover benefits. In other words, if the program ended but spillover effects continued and were counted, the TRC of the ghost of AHUP would be less than 1.0.

A balanced cost-effectiveness policy should not result in these types of skewed signals. All of these paradoxes would be resolved by a switching to a primary PAC framework.

ii. Zero-Incentive Financing

Typical large custom incentive packages cover about half of total project costs, often an expensive proposition for ratepayers. In contrast, by providing 0% interest loans that cover full project costs, the On-Bill Financing Non-Incentive program (OBF-NI)[46] eliminates the need for large rebate payments. With the ratepayer funds recovered via loan repayments, the only costs to ratepayers are those from program administration and the cost of capital. This is

[45] D.12-05-015 p. 163-167

[46] See PGE Advice Letter 3697-G /4812-E, 3697-G-A/4812-E-A The OBF-AP program was established as a High Opportunity Program or Project (HOPP) per CPCU implementation of AB 802.

reflected in PG&E's forecasted OBF-NI PAC of 7.9, which is more than double the forecasted PAC of the incentive-based large custom portfolio.[47]

Because financing can fully address the up-front-cost barrier[48] customers face when considering EE projects, the OBF-NI model can serve to meet the vision of EE scalability recognized by the CPUC in the recent Energy Efficiency Portfolio report, which states,

> *"Addressing these up-front cost barriers is a crucial aspect of achieving the doubling of energy efficiency statewide. As the "low-hanging fruit" efficiency measures are implemented, financing for larger, more ambitious efficiency projects will become of increasing importance."*[49]

From the participant's perspective OBF-NI eliminates the opportunity cost of EE.[50] Despite the ability of OBF to deliver savings at a fraction of the cost to ratepayers while better addressing customer financial barriers to EE, with all project costs included, the OBF-NI program is forecast at mediocre 1.4 TRC, with a number of projects available that would not meet a 1.25 or 1.0 TRC threshold. The OBF-NI program forecast highlights an example of a modern, market based, scalable program model with a high return on ratepayer investment that is nevertheless at risk under the current cost-effectiveness framework due to low TRC. A primary PAC test would better capture the transformational value and benefits from zero-incentive financing programs while also enabling scalability of EE at a low cost to ratepayers.

iii. The Residential Pay for Performance Program

The Residential Pay for Performance Program (P4P)[51] utilizes normalized metered energy consumption (NMEC) for the measurement of savings as prioritized by AB 802.[52] The P4P model provides greater accountability for ratepayers with payment structures that are largely dependent on realized savings measured at the meter. With the accountability from metered savings, the P4P program can offer implementers greater flexibility to pursue unique and holistic program models tailored to the needs of individual customers. Importantly, the

---

[47] PG&E Advice 4011-G-B/5375-E-B

[48] California 2010 – 2012 On-Bill Financing Process Evaluation and Market Assessment, Cadmus, 2012. CALMAC ID# CPU0056.01, The evaluation reports that "Customers, vendors, and utility staff members all commented that OBF removes upfront costs, enabling customers to complete energy-efficiency projects they otherwise would not have pursued." The report continues, "Focus group participants report two main barriers to implementing energy efficiency projects: lack of knowledge about appropriate retrofits and the initial cost of making those retrofits. Although upfront cost issues are a much greater barrier for customers than is the lack of knowledge, most focus group participants reported they had not considered financing energy efficiency projects."

[49] Energy Efficiency Portfolio Report, California Public Utilities Commission, 2018, p. 107

[50] OBF loans are specifically designed such that energy savings balance loan repayments. In addition, with the utility-as-lender, and on-bill repayment mechanism, the OBF-AP loan does not impact the customer's ability to retain additional capital from traditional loans. Because neither the participant's cash flows nor borrowing capacity are impacted through participation in OBF-AP, the customer can pursue energy-efficiency retrofits via operational expenditure budgets as opposed to the capital expenditure that would typically be required.

[51] The Residential Pay for Performance program was established as a High Opportunity Program or Project (HOPP) in response to AB 802. Advice 3698-G/4813-E

[52] In AB 802 the Commission was instructed to authorize EE program administrators to authorize programs with incentives informed by "taking into consideration the overall reduction in normalized metered energy consumption as a measure of energy savings."

metered results required for P4P enable EE to be more directly considered as a competitive resource alongside other DER and supply side options. Like OBF-NI, data from the market-driven P4P solicitations to-date indicate that savings can be achieved at lower program costs compared to traditional models.

With these features P4P stands to be a preferred option for building shell, HVAC, and retrofit work, where evaluations have consistently shown poor realization rates.[53] When combined with the fact that air conditioning usage occurs largely during GHG-intensive summer peak periods, the P4P program model can be a powerful tool for California to address this key area of energy waste. However, despite the need for workforce development, HVAC system upgrades, and building shell enhancements across California, as in AHUP these measures require customers to invest in their homes. As discussed in Section IV.C, participants are often willing to put forth this investment to improve home comfort, safety, and home value, along with bill savings. Yet with the inclusion of full measure cost, the TRC for such measures, even in a P4P model, can weigh the entire portfolio down and a primary PAC test would better enable NMEC programs to root out stranded potential as intended by AB 802.

E. Summary and Recommended Formulation of a Modern Dual Test

With California policy objectives evolving toward more holistic programs, reaching stranded potential, achieving deeper savings, transforming markets, and striving for aggressive decarbonization and the doubling of savings mandated by SB 350, a new cost-effectiveness framework will be vital. The need to enable private investment to achieve California's clean energy policy objectives without over-burdening ratepayers is inhibited by reliance on the TRC test, which treats private spending for private benefit the same as ratepayer spending on central generation. The PAC is the only current test geared to ensure "that program administrators and program implementers do not spend more on financial incentives or rebates to participating customers than is necessary to achieve TRC benefits"[54] and to enable PAs to "leverage participating customers' private funds to the benefit of all ratepayers."[55] Utilizing a PAC test framework, potentially with a PCT screen for program approval or a 2/3 PAC 1/3 TRC weighted test for portfolio compliance would create a durable solution in better alignment with the needs of a modern DSM portfolio.

Regarding budget, it is important to note that a PAC test need not unleash an unintended torrent of ratepayer-funded EE spending simply because a stringent cost-effectiveness requirement is relaxed. Rather, in utilizing the PAC, the Commission, in consultation with stakeholders, should determine the appropriate threshold for goal-setting that also provides balance with affordability challenges faced by California customers. In the long-term, a primary PAC framework paired with accurate avoided cost and NMEC programs for the reliable determination of load impacts can provide California the demand flexibility via the IRP that will be essential for affordable and effective deep decarbonization.

[53] See for example California HVAC Contractor & Technician Behavior Study, Phase II, EMI Consulting, 2015, CALMAC Study ID: SCE0375.01 and Final Report: 2014-16 HVAC Permit and Code Compliance Market Assessment (Work Order 6) Volume I – Report, DNV GL, 2017, CALMAC Study ID: CPU0172.01
[54] D_05_04_051 p. 80
[55] D_05_04_051, Appendix 4

II. The Need for Updated Documentation and Tools

A. The Commission Should Publish an Updated Version of the Standard Practice Manual

The SPM serves as the foundation for calculating and as the first resource for understanding the various cost effectiveness tests defined for use in California. As described in Section IV and V, various clarifications and changes to the latest SPM, which was last published in 2001, have resulted from updated Commission guidance, and confusion over certain language and terms in the SPM have created room for interpretation where none was likely intended. In addition, the SPM does not contemplate modern program models such as financing offerings or upstream incentives. Recognizing that proper treatment of cost-effectiveness calculations is "critical to program planning and evaluation,"[56] the Commission issued Ordering Paragraph 3 of D.08-01-006, which states, "We direct Energy Division to update the 2001 SPM so that this document reflects the direction provided in D.06-06-063, the Compliance Ruling, D.07-09-043 and today's decision, with numerical examples for various program delivery strategies."[57] We are unaware of efforts to update the SPM, but request that the Commission convene a group of subject matter experts to undertake this important task.

B. The Commission Should Publish an Updated Equation Reference for Use of the CET

The CET serves as the only approved tool to implement cost-effectiveness calculations for official EE filings.[58] As such, transparency, clarity, and accuracy of the CET are just as important as transparency, accuracy, and clarity of the SPM. The California Energy Data and Reporting System website (CEDARS) includes a "CET User Guide" and "CET Specification" guidance.[59] The CET User Guide focuses on the mechanics of running the CET, while the CET Specification guidance informs the user of the data formats and selections needed for the CET to run properly. However, neither of these resources provide expanded definitions for the input fields for the CET calculations, or detailed formulas for the calculations the CET is performing.

The most current, publicly-available reference document that details inputs, outputs, and mathematical operations of the cost-effectiveness calculations was published in 2012, and originates from the CET's predecessor, the E3 Calculator.[60] This 'E3 Equation Reference' is the best available resource for understanding how the CET calculates net saving and cost-

[56] D.08-01-006 OP 3, p. 3
[57] D.08-01-006 OP 3, p. 36
[58] D.18-05-041, p.130
[59] CET documentation accessible via the CEDARS website, https://cedars.sound-data.com/cet_ui/ (note that a valid CEDARS login is required to access all CET materials)
[60] This E3 calculator document is titled "Energy Efficiency 'E3 Calculator' Tool Quick Guide and Equation Reference for 2013-2014 v1c4" (E3 Equation Reference). The most recent CET equation reference documentation publicly available is the document appears to be the "Energy Efficiency 'E3 Calculator' Tool Quick Guide and Equation Reference for 2013-2014 v1c4" with the file name "E3_Calculator_TechMemo_6d.docx," accessible on E3's website at http://www.ethree.com/wp-content/uploads/2017/02/E3_Calculator_TechMemo_6d.docx.

effectiveness, how the calculator inputs and outputs are defined, and for verifying if the CET is performing TRC and PAC calculations in alignment with Commission policy.

Given its age, it is not surprising that the E3 Equation Reference contains certain inconsistencies with Commission policy and does not readily facilitate PAs, program implementers, or stakeholders in confidently forecasting programs or portfolios.[61] With hundreds of consumers of these cost-effectiveness tools, it would be very helpful for the Commission to provide updated technical documentation to enable a full understanding of CET operations. This documentation could be made available for continual stakeholder feedback and updates as the Commission updates relevant policies and as various parties use the CET and identify any inconsistencies or needs for further clarification.

C. The Commission Should Improve Accessibility of the Cloud-Based CET

Currently, the CPUC Energy Efficiency homepage links users to the E3 calculator for calculating cost-effectiveness, which is a cost-effectiveness tool is not currently in use. The approved version of the CET is cloud-based and resides on the CEDARS website. To access the approved version of the CET, a non-PA user must first know where it is located on CEDARS,[62] then create a new user account and register under the "Community" affiliation to create a valid CEDARS account. Registrations under other affiliations are rejected for a non-PA user, in which case the CET module will not be accessible or visible. Once registration is completed and accepted, the CET module will then appear in the CEDARS dashboard for user access. It would be helpful for the Commission to provide clear and transparent links, instructions, and resources for parties to access the approved version of the CET on the relevant CPUC websites.

D. The Commission Should Add Load Shape Functionality to the CET

Because avoided costs of electricity savings now vary dramatically by time-of-day and season, accurate resource curves (savings load shapes) are vital, as are the ability of EE programs to optimize savings for maximum TRC and PAC benefits. With established techniques to measure savings based on normalized metered energy consumption, PAs now have the capacity to send price signals to the market to enhance cost-effectiveness of energy savings, and to measure actual resource curves with meter-based measurements. Also, load shifting strategies are set to play a vital role in maximizing value from EE and other DERs[63] and these integrated approaches will be essential for DSM programs to compete effectively and be valued appropriately in the IRP. However, currently the CET is only capable of utilizing pre-programed savings load shapes, even within an NMEC program, which can be inaccurate and do not motivate the kinds of integrated strategies, innovative program designs, and cost-

[61] See PG&E AL 4011-G-B/5375-E-B. p. 16

[62] There does not appear to be any reference in CPUC documents or websites that the CET can be found on CEDARS. CPUC websites such as the California Energy Efficiency Statistics (http://eestats.cpuc.ca.gov) have a CET link that takes the user to the "CET Desktop" website, which contains information for an unsupported and invalid version of the CET as of 2019. The CET Desktop website does not indicate that the desktop-version of the CET is no longer valid, nor does it direct the user to CEDARS to access the cloud-based CET.

[63] Final Report of the California Public Utilities Commission Working Group on Load Shift, 2019

effectiveness optimization from third parties that the PAs describe in their EE Business Plans or the Commission envisions in D.16-08-019 or D.18-05-041.[64] Especially in an IRP/procurement context, discrepancies between estimated savings load shapes and actual grid impacts could have consequences far beyond improper valuation.

To unleash the kind of third party innovation and capacity for PAs to orchestrate a successful modern portfolio desired by the Commission, the ability to shape load as well as save energy - and accurately calculate the associated value in the CET will be vital.

E. The Avoided Cost Calculator Should Incorporate Negative Values

Though detailing a full set of considerations and recommendations associated with the calculation of avoided costs is beyond the scope of this paper, we do make one important conceptual point. Currently the CPUC's Electric Avoided Cost Calculator[65] assigns a value of $0 to the marginal cost associated with any location and hour combination for which overgeneration is forecasted. In reality, there are often costs associated with curtailment that should manifest as negative prices for accurate valuation. Energy savings during these times can increase cost to ratepayers[66] while increased usage during these times can actually save ratepayers money.

Accurate valuation associated with negative pricing will become more important given that overgeneration events are occurring with greater frequency in California. For example, the California Independent System Operator reports that 461 GWh of renewables were curtailed in 2018.[67] As of Oct. 24, 2019, renewables curtailment had reached 813 GWh, exceeding all of 2018 by 76%.[68] In April 2018 5.3% of five-minute intervals experienced negative pricing.[69] For comparison, in April 2019, 191 GWh of renewables were curtailed,[70] more than 2.5 times that of the same time period in 2018, with the frequency of negative pricing also more than doubling. As a higher penetration of renewables continues to be incorporated, recent projections indicate much higher levels of curtailment and system costs could occur.

---

[64] See for example D.16-08-019 p. 70 and D.18-05-041 p. 71
[65] Found at https://www.cpuc.ca.gov/General.aspx?id=5267
[66] https://www.latimes.com/projects/la-fi-electricity-solar/
[67] Wind and Solar Curtailment December 31, 2018. (2019). Retrieved from http://www.caiso.com/Documents/Wind_SolarReal-TimeDispatchCurtailmentReportDec31_2018.pdf
[68] Wind and Solar Curtailment October 24, 2019 California Independent System Operator http://www.caiso.com/Documents/Wind_SolarReal-TimeDispatchCurtailmentReportOct24_2019.pdf
[69] California Monthly Renewables Performance Report (April 2018). http://www.caiso.com/Documents/MonthlyRenewablesPerformanceReport-Apr2018.html
[70] California Monthly Renewables Performance Report (April 2019). http://www.caiso.com/Documents/MonthlyRenewablesPerformanceReport-Apr2019.html

III. D.07-09-043 Should be Modified to Remove Free Rider Incentives from the TRC

A. Introduction

In D.07-09-043 the Commission updated California policy related to the treatment of incentive payments to free riders in the calculation of EE TRC.[71] As a result the EE TRC cost formalism changed from Eq. 1 to Eq. 2.

$$TRC\ Costs = AMI + NTG \times MC \quad (1)$$

$$TRC\ Costs = AMI + (1 - NTG) \times Inc + NTG \times MC \quad (2)$$

where:

AMI = Administrative, Marketing, and Implementation Costs (i.e. Non-Incentive Program Costs)

NTG = Net-to-Gross Ratio

Inc = Incentives

MC = Measure Cost[72]

D.08-01-006 corroborated this approach. However, this change is inconsistent with the Standard Practice Manual and its description of the TRC as a representation of "the combination of the effects of a program on both the customers participating and those not participating in a program."[73] Below the rationale given in D.07-09-043 is summarized and the case made for a return to the treatment of EE costs indicated in Eq. 1.

B. Summary of D.07-09-043

Framing the question around treatment of incentives paid to free riders in the TRC, D.07-09-043 states,

> *"[R]ebate incentive dollars can intuitively be thought of as canceling because they appear both as a cost to all ratepayers and as a benefit to participating ratepayers, or as "transfer payments" that cancel out when subtracting total cost from total benefit in calculating the net benefit of the program. Historically, for the reasons just*

[71] D.07-09-043 p. 149-162

[72] Depending on the measure application type, and the associated measure baseline, measure costs can embody the full labor and material cost to install a technology or service (Full Measure Cost; FMC), or the incremental cost beyond a code or industry standard practice technology or service (Incremental Measure Cost; IMC). Across the EE portfolio, a portion of measure costs is covered by incentives, and a portion is covered by participating customers. For example, a program may offer a customer a $2.00 rebate to install a $6.00 LED instead of a $2.50 CFL in a replace-on-burnout scenario. In this hypothetical case the IMC would $6.00 - $2.50 = $3.50. The incentive covers $2.00 of the IMC and the participant covers $1.50 of the IMC. A discussion of full vs. incremental costs is included in D.06-06-063, p.64, footnote 60, while Table 1 of Resolution E-4818 clarifies the baselines for different measure
application types that inform applicable cost types.

[73] California Standard Practice Manual, 2001 p. 18

mentioned, these dollar rebate payments have been excluded on both the benefit and cost side of the TRC equation, and considered to be a transfer payment between participating and non-participating customers. However, as discussed further below, the SPM formulas and definitions do not explicitly address how to account for these rebate incentive costs when there are free rider participants who receive them."[74]

In reasoning for inclusion of incentives paid to free riders, D.07-09-043 subsequently makes three main points:

1. Citing the intent of the TRC to capture all EE costs, whether borne by participants or non-participants, the Decision states, "Ratepayers, through the energy efficiency revenue requirements collected to fund these programs, incur a cost for free rider participants that must not be ignored in the formulation of the TRC test."[75]
2. The Decision draws attention to apparent confusion in the use of the term 'net' in the Standard Practice Manual (SPM), noting that "the term "PCN" that appears in the TRC formula is simply defined as "Net Participant Costs," which does not indicate whether this means "net" of free riders, net of incentives, or both."[76] With this lack of precision or consistency in terms, D.07-09-043 provided an interpretation consistent with inclusion of free rider incentives.
3. The Decision noted an apparent inconsistency between TRC treatment of rebate and DI programs if free rider incentives were not included in the former.

The sections that follow demonstrate how the Commission erred in its interpretations of D.07-09-043 regarding free rider incentives and discuss an issue with the current TRC treatment of direct install (DI) measures.

C. The Case that the Commission Erred in Updating the TRC in D.07-09-043

To address point 1 above, it is beneficial to revisit foundational elements of the TRC. In the following discussion we derive the TRC benefits and costs and then assemble the ratio form of the equation. Where, when, and how to accurately account for free ridership adds complexity. Therefore, in the next section we build a foundation by deriving the TRC assuming no free ridership. In the subsequent section we incorporate free ridership explicitly. For simplicity, throughout these derivations only benefits and costs are included that are relevant to non-fuel switching EE programs. It is also assumed that the EE intervention does not cause an increase in usage. The net-present-value of the cost-effectiveness tests is also not germane to these comparative derivations and is ignored.

[74] D.07-09-043 p. 151-152
[75] D.07-09-043 p. 156
[76] D.07-09-043 p. 156

i. Derivation of EE TRC with No Free Ridership

Consistent with the concept that the TRC test intends to gauge the combined perspective of both the utility and its customers, the SPM states: "In a sense, [the TRC] is *the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests*."[77]

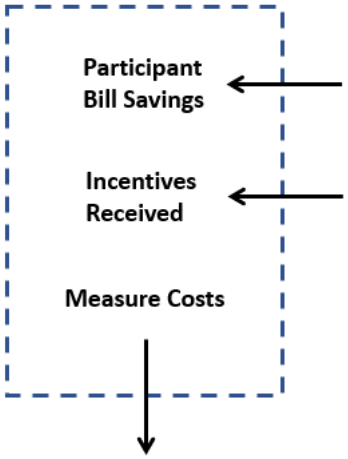
This conceptual framework allows for a straightforward derivation of the TRC and we begin with the Participant Cost Test (PCT). The SPM describes the PCT benefits and costs as follows: "The benefits of participation in a demand-side program include the reduction in the customer's utility bill(s), [and] any incentive paid by the utility or other third parties…The costs to a customer of program participation are all out-of-pocket expenses incurred as a result of participating in a program."[78] Expressed as equations these benefits and costs are:

$$PCT\ Benefits = Participant\ Bill\ Savings + Incentive \quad (3)$$

$$PCT\ Costs = Measure\ Costs \quad (4)$$

It is important to note that because incentives are a PCT benefit, participant costs are taken to be measure costs, not measure costs less incentives. These benefits and costs can be visualized as in Fig. 5, where inward arrows illustrate benefits and outward arrows illustrate costs. The box indicates the boundary of the test, a premise that is clear for the PCT but will become conceptually important below.

Fig. 5 **Participant Cost (PCT) Test**



Similarly for the RIM, the SPM describes the benefits and costs as follows: "The benefits calculated in the RIM test are the savings from avoided supply costs…The costs for this test are the program costs incurred by the utility, and/or other entities incurring costs and creating or administering the program, the incentives paid to the participant, [and] decreased revenues

[77] California Standard Practice Manual, 2001. p. 18. The full quote in context is "In a sense, [the TRC] is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel (except for the differences in net and gross savings)." We will return to the latter part of this description below.
[78] California Standard Practice Manual, 2001. p. 8

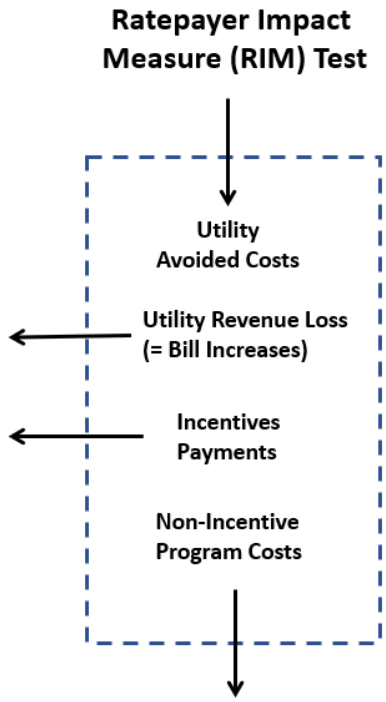
for any periods in which load has been decreased."[79] Expressed as equations these benefits and costs are:

$$RIM\ Benefits = Utility\ Avoided\ Costs \quad (5)$$

$$RIM\ Costs = AMI + Incentive + Utililty\ Revenue\ Loss \quad (6)$$

Figure 6 provides a visual for the RIM benefits and costs.

Fig. 6



Equations 3 – 6 can be combined to figure the TRC benefits – costs (Eq. 7):

$$TRC = (PBS + Inc + UAC) - (AMI + MC + Inc + URL) \quad (7)$$

where

PBS = Participant Bill Savings

Inc = Incentives

UAC = Utility Avoided Costs

AMI = Administrative, Marketing and Implementation costs (i.e. non-incentive program costs)

MC = Measure Costs

URL = Utility Revenue Loss

The incentive (Inc) terms cancel as they appear as a benefit in the PCT and a cost in the RIM. Similarly, the Participant Bill Savings are a PCT benefit that has been often considered equal to the Utility Revenue Loss cost of the RIM and these terms also cancel. Making these simplifications yields Eq. 8:

$$TRC = UAC - (AMI + MC) \quad (8)$$

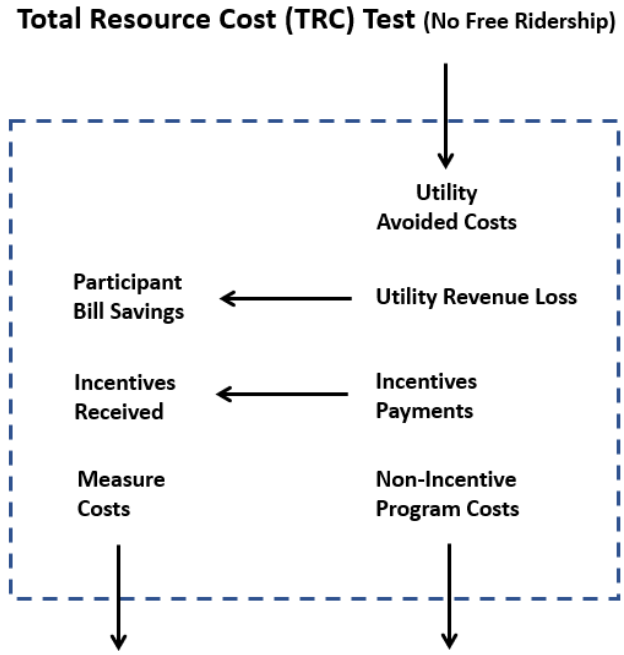
[79] California Standard Practice Manual, 2001. p. 13

As done in the SPM, now that total benefits (positive terms in right hand side of Eq. 9 and costs (negative terms in right hand side of Eq. 9) are figured, the ratio form of the TRC is created,[80]

$$TRC_{Ratio} = \frac{UAC}{AMI + MC} \tag{9}$$

These concepts can be visualized as in Fig. 7.

Fig. 7



In deriving the TRC there is a natural cancellation of terms that occurs between the incentives paid (ratepayer cost) and incentives received (participant benefit). Similarly, the participant bill savings lead to revenue loss that must presumably be made up via broader ratepayer bill increases and therefore the corresponding terms cancel. Both of these natural cancellations are shown in Fig. 7 as arrows fully contained in the box, indicating a transfer payment from one set of ratepayers (non-participants) to another (participants).

ii. Adjusting EE TRC for Free Ridership

Of critical importance to the discussion at hand is the concept of free ridership. Revisiting the RIM test, because the test gauges impacts of a program on non-participants, the RIM benefits should be discounted for free ridership. The SPM specifies this for the RIM, noting that reductions in supply costs (i.e. utility avoided costs) "should be calculated using net energy savings."[81] Because Utility Avoided Costs are not tied to a PCT benefit, the usage of net is

[80] In determining the ratio form of the cost-effectiveness tests, it is common practice, as is done in the SPM, to algebraically cancel any symmetric benefit and cost terms before constituting the ratio equation. This practice increases the sensitivity of the test, but does not change whether a program is above or below 1.0.
[81] California Standard Practice Manual, 2001. p. 13

appropriate as well in the context of the TRC.[82] Accounting for free ridership is accomplished by multiplying the RIM benefits of Utility Avoided Costs by NTG and both RIM and TRC benefits are thus given by Eq. 10.

$$TRC\ Benefits = RIM\ Benefits = NTG \times Utility\ Avoided\ Costs \tag{10}$$

The SPM is also definitive that RIM costs associated with Utility Revenue Loss be calculated on a net basis.[83] However, in the TRC the full gross Utility Revenue Loss usually remains a cost. This is because Utility Revenue Loss ties to Participant Bill Savings, which remain on a gross basis.[84]

In a similar manner, incentives represent a transfer payment from one group of ratepayers (non-participants) to another (participants) despite the presence of free ridership. Therefore, in a standard formulation of the TRC, the incentive benefits received by participants cancel the incentive costs to non-participants, *regardless of the free rider status of participants.* This is recognized in the National Standard Practice Manual as follows:

> *Consider the example…in which a customer that receives a $100 rebate from a utility efficiency program for an efficiency measure that it would have installed absent the program…[T]he $100 is a utility system cost. Thus, if the jurisdiction's cost-effectiveness test included utility system impacts (as all tests must) but did not include participant impacts, there would be a net cost from the free-rider of $100. However, that changes if the jurisdiction's cost-effectiveness test also includes participant impacts because $100 cost to the utility system is offset by a $100 benefit to the free-rider participant. Put another way, under a test that includes both utility system and participant impacts, the $100 rebate is what is often called a transfer payment. It has distributional impacts—by moving money between customers—but no net cost to customers as a whole (which is the perspective that matters under cost-effectiveness tests that include participant impacts as well as utility system impacts).*[85]

The TRC is indeed a test that "includes participant impacts as well as utility system impacts." Finally, because TRC benefits (Utility Avoided Costs) are discounted for free ridership (as discussed above), a symmetric treatment of participant costs is warranted. Conceptually, because the portion of measure costs associated with free riders would have occurred in the absence of the program, it should be removed from the TRC. This issue was the topic of the 1988 Standard Practice Manual Correction Memo referenced in D.07-09-043.[86] Referring to this free ridership adjustment to participant costs, D.07-09-043 states, "The 1988 SPM Correction Memo acknowledges that some portion of the TRC costs would have been incurred anyway (by free riders that would have purchased the measure on their own without the

[82] Any TRC benefit or cost that is tied to a symmetric cost or benefit amounts to a transfer payment in which one group of ratepayers benefits and one incurs a cost. This is true regardless of free ridership
[83] California Standard Practice Manual, 2001. p. 13
[84] Regardless of free ridership, both the PCT and the TRC recognize that EE programs deliver participants, who are a subset of ratepayers, the benefit of bill savings. We return to these points below.
[85] National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, The National Efficiency Screening Project, 2017.
[86] See Appendix 9 of D.07-09-043

program being available), and therefore those costs should be excluded form the TRC calculation, as are the savings attributed to free riders on the benefit side."[87] A previous CPUC Ruling had also determined this to be the correct approach.[88] This NTG adjustment is given in Eq. 11.

$$TRC\ Participant\ Costs = NTG \times Measure\ Costs \qquad (11)$$

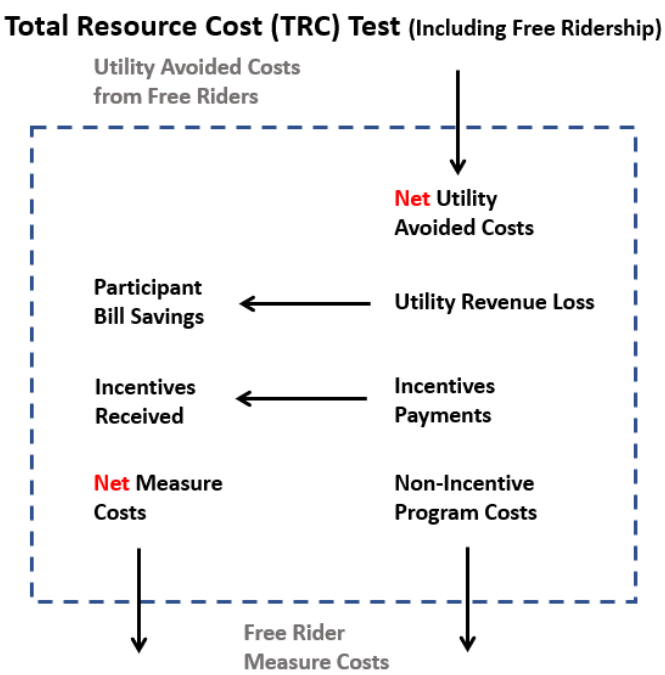
Making each of the above TRC free rider adjustments yields Eq. 12, which simplifies to Eq. 13 and yields the ratio form of Eq. 14, which is the form of the EE TRC recommended here for immediate and future use. These results are also shown in Fig. 8 where Utility Avoided Costs and Measure Costs included in the TRC are specified to be on a net basis. Free rider utility avoided costs and measure costs have been removed and are shown in grey text outside of the calculation boundary.

$$TRC = PBS + Inc + NTG \times UAC - AMI - NTG \times MC - Inc - URL \qquad (12)$$

$$TRC = NTG \times UAC - AMI - NTG \times MC \qquad (13)$$

$$TRC_{Ratio} = \frac{NTG \times UAC}{AMI + NTG \times MC} \qquad (14)$$

Fig. 8

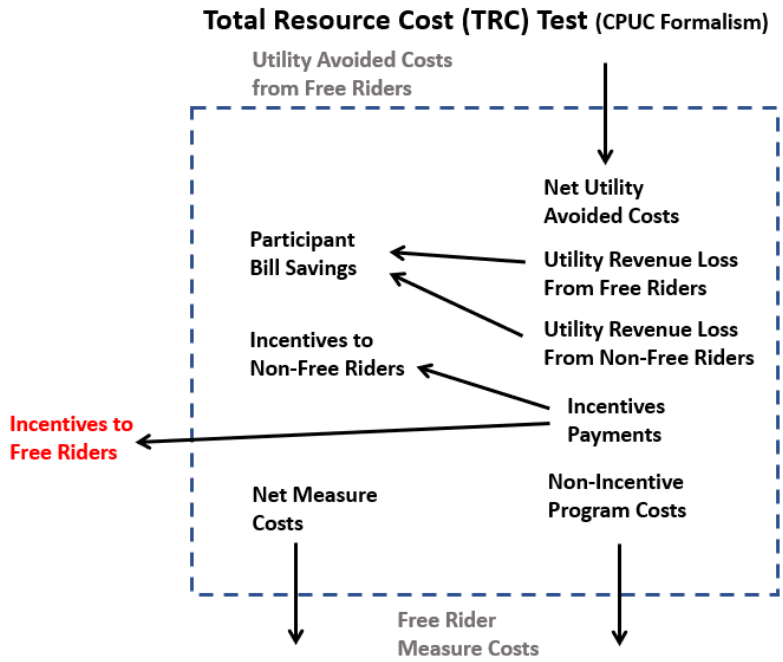


1. Formalism Introduced by D.07-09-043

By including incentives to free riders as a TRC cost, D.07-09-043 results in an asymmetrical TRC calculation that can be visualized as in Fig. 9, where both incentives and utility revenue loss terms are broken into free riders and non-free riders, with only the free rider portion of the former now included as a cost.

[87] D.07-09-043 p. 155
[88] 2006 ALJ Compliance Ruling

Fig. 9



2. Alternate Symmetric TRC Formulation

In justifying inclusion of incentives paid to free riders, D.07-09-043 states that doing so is "fully consistent with the text description of the TRC test in the SPM, which recognizes that the "incentives" (INC) term will cancel from the benefit and cost side of the equation "*except for the differences in net and gross savings*.""[89] The italicized text is quoted in the Decision from the SPM. However, in light of the context developed here, it is worth revisiting the fuller quote from the SPM,

> *"[The TRC] test represents the combination of the effects of a program on both the customers participating and those not participating in a program. In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel (except for the differences in net and gross savings).*[90]

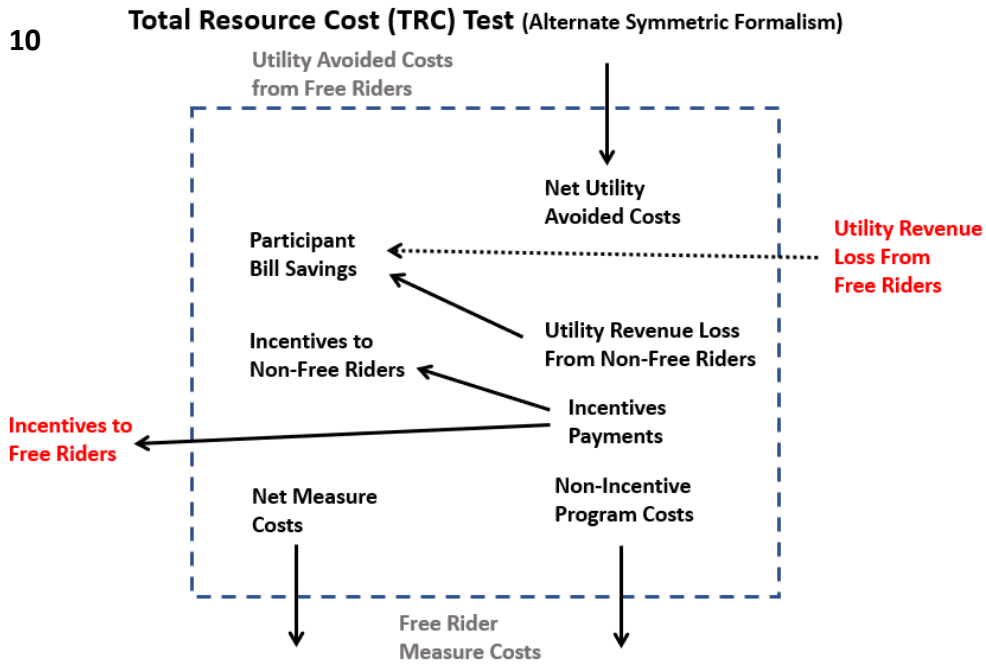
In this quote it is clear the authors of the SPM were not just referring to incentives, *but were also referring to the revenue shift* (underlined text). As discussed previously, like incentives, the revenue shift (utility revenue loss from participant bill savings) is typically treated as a zero sum transfer payment in the TRC regardless of free ridership.[91]

Therefore, if the cancellation of free rider incentives (non-participant cost) is to be overridden as instructed in D.07-09-043, the revenue loss from free riders (also a non-participant cost) should also be explicitly determined and removed from TRC costs, as in Fig. 10 and Eq. 15. (The dotted arrow in Fig. 10 indicates that Utility Revenue Loss from Free Riders is a cost that should be negated, not a benefit that should be added.) While adding unnecessary complexity

[89] D.07-09-043 p. 162
[90] California Standard Practice Manual, 2001. p. 18 (underline added)18
[91] This is because the participant bill savings that correspond to utility revenue loss are a program benefit to participants (both free-riders and non-free riders), who are a subset of ratepayers.

compared to Eq. 14, taking this step would at least ensure a more balanced treatment of free ridership.

Fig. 10



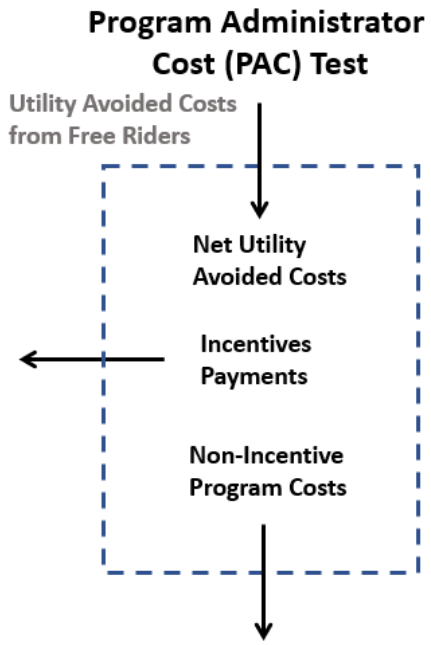
$$TRC_{Ratio} = \frac{NTG \times UAC}{AMI + (1 - NTG) \times (Inc - URL) + NTG \times MC} \tag{15}$$

where URL is Utility Revenue Loss. By applying the 1 – NTG factor to the Inc – URL term, the incentives to free riders *as well as utility revenue loss from free riders* are both explicitly accounted for.

If there is concern that excluding incentives to free riders in the TRC would send the wrong signal to PAs, it should be noted that the PAC as the other arm of California's "dual test" is intended to provide balance specifically around the consideration of incentives. The CPUC notes in D.08-01-006 that "we apply the 'dual cost' test of cost-effectiveness in evaluating energy efficiency activities to ensure that utilities design rebates that are not excessive and use program funds cost-efficiently." All incentive payments are included as costs in the PAC (Eq. 16 and Fig. 11) while benefits from non-free riders are excluded as in the TRC.

$$PAC_{Ratio} = \frac{NTG \times UAC}{AMI + Inc} \tag{16}$$

Fig. 11



iii. Contextual Clarification of the Term "Net"

D.07-09-043 draws attention to a '1988 SPM Correction Memo,'[92] which noted that if TRC benefits were to be adjusted by the NTG factor, then to "retain symmetry" participant costs should also be adjusted by a NTG factor. This 1988 Memo recommended renaming the participant cost term to designate "participant cost – net." The Decision then describes the California Standard Practice Manual's (SPM) use of the term "Net Participant Costs,"[93] stating that it is presumably unclear if the term "net" refers to net of free riders, or net of incentives. From the Decision:

> *[W]hile there was general consensus that the 1988 SPM Correction Memo permitted the application of the free rider adjustment (NTG ratio) to the participant cost term of the TRC test, the correction formulation left unaddressed the appropriateness of adjusting for free riders (i.e., reducing) the "rebate" incentives term ("INC") paid to program participants. Even the most recent version of the SPM does not clarify this issue, as the term "PCN" that appears in the TRC formula is simply defined as "Net Participant Costs," which does not indicate whether this means "net" of free riders, net of incentives, or both."*[94]

With the basic starting point that TRC costs are the sum of PA costs and participant costs the below derivation shows that Eq. 1 is derived when "Net Participant Costs" is taken to mean net of incentives.

$$TRC\ Costs = PA\ Costs + Net\ Participant\ Cost \qquad (18)$$

[92] Memo sent to the Standard Practice Manual Distribution List titled, "Correction to Total Resource Cost test in Standard Practice Manual", Oct. 7, 1988. This memo can be viewed in Attachment 9 of D.07-09-043.
[93] California Standard Practice Manual, 2001. p. 22
[94] D.07-09-043 p. 156

$$= AMI + Inc + (MC - Inc) \quad (19)$$

$$= AMI + MC \quad (20)$$

Note that consistent with the derivations of TRC in the previous section, incentives cancel in Eq. 19. Upon arriving at Eq. 20, application of NTG to the MC term is done as per the 1988 SPM correction memo, which describes participant costs as "participant device costs," making no mention of incentives. Doing so yields Eq. 1.

This formalism is also consistent with the treatment of incentives as a participant benefit that balances the corresponding ratepayer cost as in the SPM; PA costs typically include incentives while Net Participant Costs equate to measure costs less incentives.

In contrast, the steps below show that Eq. 2 can only be derived if the SPM's description of "Net Participant Costs" is taken to mean *both* net of free riders *and* net of incentives.

$$TRC\ Costs = PA\ Costs + Net\ Participant\ Cost \quad (21)$$

$$= AMI + Inc + NTG \times (MC - Inc) \quad (22)$$

$$= AMI + Inc - NTG \times Inc + NTG \times MC \quad (23)$$

$$= AMI + (1 - NTG) \times Inc + NTG \times MC \quad (24) = (2)$$

This treatment does not adhere to a logical application of the TRC for multiple reasons. First, the application of NTG in Eq. 22 implies the existence of an incentive in the absence of the program. Second, it must be remembered that the SPM was developed and formulated for a wide variety of demand side programs, not just for EE. Most other DERs do not invoke the concept of free ridership and NTG. When looking through the lens of one of these non-EE DERs, it is clear the SPM intends "Net Participant Costs" to imply net of incentives, which is needed for the natural cancellation of incentives discussed throughout this appendix. Finally, where an EE-specific distinction between net and gross needs to be made, the SPM does so clearly in several other instances.[95] There is no reason to believe the SPM authors simply neglected to provide this critical piece of specificity.

[95] See for example California Standard Practice Manual, 2001. p. 17

IV. Addressing Additional TRC and PAC Formalism Issues

A. Consistent Treatment of Direct Install

D.07-09-043 highlights an apparent inconsistency between rebate and direct install (DI) programs if the (1 – NTG) x Incentives term is not included in the former. While the Decision presumes that this inconsistency confirms an issue with the rebate formulation of the TRC, here it is equally fair to assume the issue rather lies in the choice of TRC costs for DI programs. Currently, the TRC for DI programs is formulated as in Eq. 25,

$$TRC_{Ratio} = \frac{NTG \times UAC}{AMI + DI} \tag{25}$$

where DI refers to the direct installation costs. Very often the DI costs are equal to or nearly equal to measure costs. Because the original (pre-D.07-09-043) treatment of the TRC for EE rebate programs includes multiplication of measure costs by NTG, not doing so to the DI costs creates an inconsistency whereby the exact same project, with the same NTG, installed through a rebate channel would yield a different TRC than a DI channel. The issue is complicated by Commission guidance to treat all DI costs as administrative program costs,[96] all of which would be included in TRC costs by definition. However, unlike administrative, marketing and implementation costs, with the utility covering all installation and product costs in a DI program, the customer is essentially receiving a service that parties have argued is better aligned with the concept of an incentive than that of administration. Nevertheless, In D.06-06-063 the Commission justifiably reasoned that treating full DI costs as an incentive would create a TRC metric that would reward costly DI interventions over potentially more efficient program delivery models.

Ultimately, the treatment of DI costs in the TRC (and PAC) is a policy choice, not something that strikes at the heart of TRC philosophy as is the case with free rider incentives. This policy choice should not serve as a basis to establish the TRC formulation for other (non-DI) program delivery models for the sake of consistency as was argued in D.07-09-043. Rather, as was done above, a thorough analysis of TRC inputs, rooted in the principals of the test described in the SPM, should be conducted for a typical rebate program as a basis. If DI cost treatment then results in an inconsistency, it is the DI TRC formulation that should be revisited. In this case, making the policy choice to multiply DI costs by NTG, as is done for measure costs for a rebate program, would result in a symmetric treatment of DI and rebate TRC. Based on this logic, we recommend that the Commission adopt Eq. 26 for DI TRC and PAC, which essentially treats DI costs as measure costs.

$$TRC_{Ratio} = PAC_{Ratio} = \frac{NTG \times UAC}{AMI + NTG \times DI} \tag{26}$$

This formulation of TRC for DI programs still adheres to the Commission's reasoning that, "A direct install program where the utility or its contractor performs the installation of a measure

[96] D.06-06-063 p. 71 "Under both the TRC and PAC tests, the full $2,000 measure installation cost should appear asprogram administrator cost (rather than a participant cost)."

should not be more cost-effective from a TRC perspective than a rebate program that provides a cash rebate to the customer up to the full cost of installation."[97]

B. Justification to Treat "Excess Rebates" as Normal Incentives

Currently the Cost Effectiveness Tool (CET) includes 100% of any rebate paid to a customer that exceeds the measure cost in the TRC cost.[98] While rare but at times needed[99] to overcome market barriers to EE adoption, like typical rebates, excess rebates constitute a transfer payment from the perspective of the TRC because they benefit a subset of ratepayers (participants). Because of this, excess rebates should be treated as normal incentives for the purposes of calculating the TRC. The Commission has also expressed this view in various instances. For example, Attachment 9 of D.07-09-043 states that such "'excess' rebate dollar amounts are treated as a revenue shift from all ratepayers to participating ratepayers and are not counted as a program cost."[100] D.06-06-063 discussed "excess rebates" and specifically called attention to the calculation of TRC, citing a "need to ensure that the program cost components and transfer payments are properly entered into the E3 calculator (or in other platforms for calculating and reporting cost effectiveness results) consistent with the SPM formulas and definitions, rather than the need to cap incentive payments"[101] Based on this guidance, the Commission should remedy of this inconsistency in the CET.

C. The Commission Should Define and treat Participant Cost as the Incremental Participant Investment in Efficiency

The nature of participant investment raises important considerations for an accurate assessment of TRC. In particular, the Commission has recognized that retrofit programs can piggyback on investments customers are willing to make to receive a range of benefits:

> *"While many residential building retrofit measures have unacceptably long customer payback periods based on energy prices alone, they can find market acceptance and leverage private sector investment based on attributes other than energy savings (e.g. comfort and noise reduction)…These issues should be considered in updating the methodology for calculating program or portfolio cost-effectiveness."*[102]

Recent evaluations confirm that participating customers in Energy Upgrade California (EUC) value non-energy factors as much or more than bill savings.[103,104] Unfortunately, despite the Commission's recommendation, relatively few efforts have been taken to quantify and remove

---

[97] D.06-06-063 p. 72
[98] Based on testing conducted by PG&E
[99] See for example D.06-06-063 p. 72. "We recognize that there may be limited instances for program design purposes where the cash rebate to the customer exceeds the measure installation cost."
[100] See p. 3 of Attachment 9 of D.07-09-043
[101] D.06-06-063 p. 74
[102] California Energy Efficiency Strategic Plan January 2011 Update, p. 18
[103] PG&E Whole House Program: Marketing and Targeting Analysis. Opinion Dynamics Corporation, 2014. CALMAC ID: PGE0302.05
[104] Energy Upgrade California – Home Upgrade Program Process Evaluation 2014-2015, EMI Consulting, 2015. CALMAC ID: PGE0389.01. Non-energy factors include home comfort, improved indoor air quality, health benefits, and improved home resale value, among others.

non-energy related participant costs associated with EE. As a result, a program like AHUP can deliver deep savings while driving nearly $3 in non-free rider net participant investment for every $1 in program costs (Table 3), yet fail to achieve a TRC of even 0.5. Similar to AHUP, along with improved efficiency, projects enabled through commercial, industrial, and agricultural custom offerings often provide businesses enhanced equipment reliability, increased productivity, and other benefits incremental to energy savings. Assessing the nature of this investment is needed to accurately assess cost-effectiveness.

PG&E's plan to evaluate and remove participant investment in non-energy benefits for select programs discussed in its 2019 Annual Budget Advice Letter accomplishes just this.[105] An attempt to quantify and remove non-energy participant costs was also made in past CPUC research to update measure cost data.[106] In this study evaluators compiled models that isolated the portion of incremental measure cost associated with improved efficiency (as opposed to other factors) for several classes of products.

Further research to assess participant perception of their EE investment should be undertaken with the goal of adjusting measure cost TRC inputs accordingly. While such quantification and removal of participant costs unrelated to efficiency savings has not to date been common practice, as EE portfolios strive to move from "widget" measures to the modern, holistic programs described in PAs Business Plans, it will be even more important to estimate and remove non-EE costs. Assessing the fraction of non-energy related EE investment should be considered of similar importance to an accurate valuation of EE TRC as estimating the portion of free ridership. This recommendation could be readily addressed by embedding questions in the impact evaluation NTG survey batteries to gauge the nature of participant investment in their EE projects.

Finally, while it may be possible to assess and include non-energy benefits, studies that attempt to do so yield results that are often highly uncertain and can draw attention away from the core purpose of EE programs to deliver energy savings and utility avoided costs. Further, with the future of EE as a competitive resource in the IRP, focusing on the cost side of the TRC is will be necessary to enable consistent valuation when comparing EE to other resources.

D. The Commission Should Clarify the Proper Treatment of EM&V in Portfolio TRC

The SPM specifies that "Program administration cost estimates used in program cost-effectiveness analyses should exclude costs associated with the measurement and evaluation of program impacts unless the costs are a necessary component to administer the program."[107] This guidance clearly indicates that only a fraction of EM&V costs (those needed to administer a program) should be included in the calculation of portfolio cost-effectiveness. EM&V costs

[105] PG&E Advice 4011-G-B/5375-E-B

[106] 2010-2012 Ex Ante Measure Cost Study Final Report, Itron (2014). This study utilized hedonic price modeling to eliminate non-EE costs for a number of deemed measures. This study was supplemented by: CPUC Measure Cost Study for Work Order 017-1 Industrial Custom Measures, Energy Resource Solutions (2015).

[107] California Standard Practice Manual, 2001. p. 26 – 27

associated with market studies, process evaluations, impact evaluations, methods development, etc. presumably would not be included.

In contrast, D.09-09-047 provides guidance that cost-effectiveness calculations should, "include costs not assignable to individual programs, such as overhead, planning, and EM&V, but do not include ETP costs."[108] It is worth noting that the PAs control a minority of the EM&V budget, with the majority under the Commission's direction.[109] It would be helpful for the Commission to reconcile if and what EM&V spending should be incorporated into the cost-effectiveness calculations.

E. The Commission Should Develop Cost-Effectiveness Policy for EE Financing Programs

Energy efficiency financing programs are maturing and rapidly achieving scale. PG&E alone has financed more than $135 million in loans through the end of 2018.[110] The rapid expansion of the On-Bill Financing (OBF) program model is encouraging as recent evaluation reports that OBF succeeds in eliminating the up-front cost barrier, which customers report as the largest impediment to implementing EE projects.[111] This marks important progress toward the Commission's vision for the role of financing in helping EE scale in California. For instance, the recent Energy Efficiency Portfolio report states: "Addressing these up-front cost barriers is a crucial aspect of achieving the doubling of energy efficiency statewide. As the "low-hanging fruit" efficiency measures are implemented, financing for larger, more ambitious efficiency projects will become of increasing importance."[112]

In particular zero-incentive OBF offerings bring forth several key features that potentially lead to different cost/benefit considerations compared to rebate programs: a.) The program utilizes a revolving loan pool, maintained by the PA. instead of an incentive or third-party loan; b.) With the on-bill financing mechanism, loans can be designed specifically to achieve bill-neutrality, meaning that energy savings balance monthly loan repayments until the loan is fully repaid; c.) With the utility serving as the lender and the utility bill serving as the collection mechanism, the program loan does not impact a customer's ability to retain additional capital through traditional third-party loans; d.) OBF Non-Incentive (OBF-NI) loans are delivered at 0% interest. These unique program features ensure that neither the participant's cash flows nor borrowing capacity are impacted through participation in OBF-NI. In turn, the participant can pursue energy-efficiency retrofits via operational expenditure budgets as opposed to the capital expenditure that would typically be required. These program elements create market dynamics that are not at play in rebate programs and raise questions on treatment of core cost-effectiveness inputs.

With these distinct programmatic aspects, financing offerings create a number of unique cost/benefit considerations that are not readily addressed by existing cost-effectiveness policy

[108] D.09-09-047 p. 68 – 69
[109] D.16-08-019 sets a maximum of 40% of EM&V funds to be allocated to the PAs. p. 80
[110] Advice 4011-G-B/5375-E-B
[111] California 2010-2012 On-Bill Financing Process Evaluation and Market Assessment, Cadmus, 2022. CALMAC ID# CPU0056.01
[112] Energy Efficiency Portfolio Report, California Public Utilities Commission, 2018, p. 107

or tools. A recent whitepaper prepared by Dunsky Energy Consulting for the CPUC on cost-effectiveness in financing programs[113] observes that properly assessing financing programs "will require adaptations to California's current cost-effectiveness algorithms – primarily the addition of new inputs not previously considered, as well as reconsideration of others."[114] The report also states that "not adapting tests to [financing] characteristics would be very problematic…the differences presented by finance programs are simply too large to ignore if we wish to assess their real net value, whether on a TRC or a PAC basis."[115] Finally, the study acknowledges, "because of the fundamentally different nature and objectives of financing programs (compared with rebate programs, for example), we argue that for certain issues, the most appropriate methodological approach for financing programs may be different from the one that is suitable – and currently applied to – incentive programs."[116]

Given a lack of policy guidance, PG&E utilized an interim approach for the calculation of its On-Bill Financing program in its 2019 Annual Budget Advice Letter.[117] We recommend that the Commission seek stakeholder input and develop cost-effectiveness policy for financing programs. This recommendation is consistent with recent Commission order to address "how the cost effectiveness of on-bill financing loans should be analyzed and evaluated."[118]

F. The Commission Should Ensure that Societal Policy Objectives are Valued

The Commission has established a number of social policy objectives that, along with savings and cost-effectiveness, are embedded in the EE portfolio. These priorities include programs focused on disadvantaged communities (DAC) and/or hard-to-reach (HTR) customers, portfolios for emerging technologies and workforce education and training (WE&T), other traditional non-resource programs that do not claim EE savings, programs designed to achieve deep savings,[119] programs designed to enable workforce and code readiness that are not part of the WE&T portfolio,[120] and programs designed to serve certain populations or customer classes required to meet specific policy objectives.[121]

Without recognizing some benefit from accomplishing these goals, PAs will struggle to justify the programs that support them while under portfolio cost-effectiveness pressure. While there may not be a wealth of data and analysis to support the precise valuation of specific equity policy goals, that should not be justification for assigning them zero benefit.[122] It is arguable

[113] Cost-Effectiveness of Energy Efficiency Financing Programs: Methodology and Strategic Issues Whitepaper, December 2016.
[114] Ibid, p. 1
[115] Ibid, p. 22
[116] Ibid, p. 25
[117] PG&E Advice 4011-G-B/5375-E-B
[118] Proposed Decision Granting Petition for Modification of Decision 09-09-047 Concerning On-Bill Financing, 2019, OP 5 p. 17.
[119] For instance Energy Upgrade California
[120] Such as the California Advanced Homes, Savings By Design, Multifamily New Construction, and Zero Net Energy programs
[121] For instance, the Moderate Income Direct Install Program (MIDI) delivers EE to the moderate-income sector and Government Partnership programs deliver EE largely to small and medium businesses, both underserved populations.
[122] See the Universal Principals and Chapter 3 of the National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, The National Efficiency Screening Project, 2017.

whether programs that are geared toward a clear social objective set by the legislature or the Commission should even use a standard cost-effectiveness test.

One recent study from Lawrence Berkeley National Laboratory sheds some light on the additional costs programs accrue to service social policy goals.[123] This study found that achieving a kWh of savings in the low-income sector cost three times that of the market rate sector. While not a perfect match with DAC and HTR customers, this does provide important directional information. Many of the direct install program interventions needed for the low-income segment are similar to those utilized for DAC and HTR customers.

Instead of attempting to tie value to non-resource or social and equity policy objectives, the Commission should consider setting aside specific budgets to address these goals outside of the resource portfolio cost-effectiveness framework.

[123] *The Cost of Saving Electricity Through Energy Efficiency Programs Funded by Utility Customers: 2009–2015.* I. Hoffman et al. (LBNL, 2018)

V. Potential and Goals Framework

The Potential and Goals study has long been a bedrock of California EE. The results of the study feed directly into statewide forecasts, PA goals and budgets, and portfolio planning. The P&G study methodology is in need of updates to recognize and facilitate the evolution of the EE portfolio in response to recent policy direction. While beyond the scope of this work to recommend thorough, detailed changes, brief comments are provided on two topics.

First, there is an opportunity for the P&G study to assess cost-effective potential for downstream programs not for average cases but for targeted programs. By focusing on average cases, entire classes of interventions are deemed to offer no cost-effective potential. For instance, refrigerator replacement may be determined to have little or no cost-effective potential, while a program targeted at customers with high baseload usage may be better able to root out stranded potential and achieve cost-effective results. Several studies have demonstrated how effective targeting via AMI data analytics can enhance savings and cost-effectiveness relative to the average case.[124,125,126] Figure 12 is reproduced from ref. 126. This plot shows how both savings magnitude and depth increase dramatically for the Advanced Home Upgrade Program when targeting customers based on a combination of their baseline-period summer kWh consumption and the ratio of their summer kWh usage to shoulder-month kWh usage.

Fig. 12

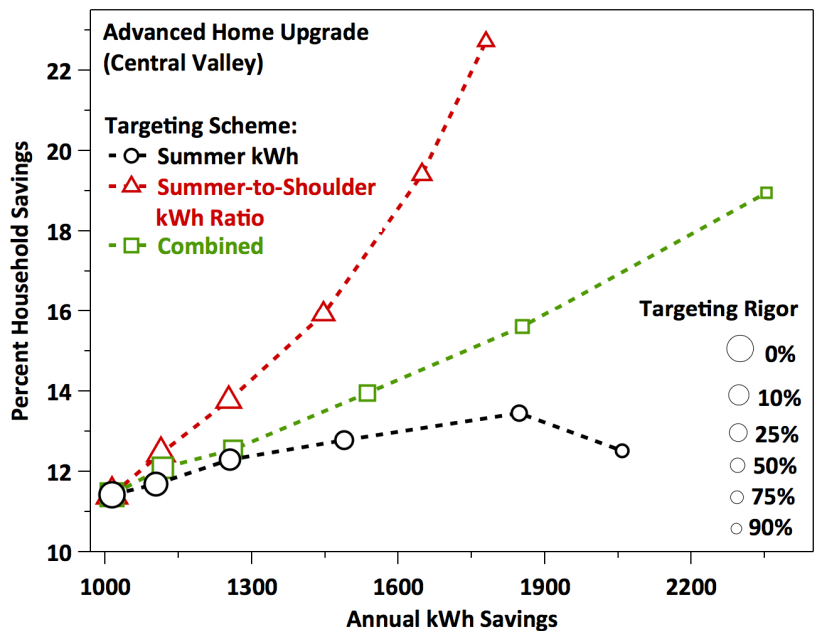


Figure 12: Reproduced from Ref. 126. The impact of targeting customers in the PG&E AHUP program. Average project savings and depth can be significantly improved with focused recruitment.

---

[124] *Customer Targeting for Residential Energy Efficiency Programs: Enhancing Electricity Savings at the Meter*, A.M. Scheer, S. Borgeson, K. Rosendo, 2017

[125] *Energy Efficiency Program Targeting: Using AMI Data Analysis to Improve At-the-Meter Savings for Small and Medium Businesses*, S. Borgeson, A.M. Scheer, R. Kasman et. al. 2018

[126] *Customer Targeting via Usage Data Analytics to Enhance Metered Savings*, 2018 ACEEE Summer Study, A.M. Scheer, S. Borgeson, R. Kasman et al.

Similar patterns to Fig. 12 are observed with different targeting strategies for a number of different programs across both residential and commercial customers. Conceptually, this indicates that cost-effective savings can be achieved when focusing programs on the customers both most in need of specific interventions and who offer the most benefits to the rate base.

In addition, the P&G study can help facilitate development of cost-effective programs by investigating the potential for integrated demand management strategies. D.16-08-019 states: "Commission staff should integrate the study of the energy efficiency goals and potential with the potential for demand response in the next two-year study process." Assessing demand response layered on EE as well as opportunities for integration of electrification, storage, and other behind-the-meter interventions would help the CPUC coordinate policymaking and provide direction for currently disparate industries to make these essential connections. These changes are not necessarily straightforward, but can help make the P&G study more relevant and actionable for modern EE and DSM programs.

Appendix: Portfolio TRC and PAC Equations

Eq. 27 and 28 provides equations for the current treatment of TRC and PAC based on analysis of E3 CET documentation and various CPUC Decisions described throughout this document.

$$TRC = \frac{NPV\ of\ (NTG + ME) \times Lifecycle\ Benefits\ of\ Avoided\ Electricity\ and\ Gas}{\underbrace{NPV\ of\ Admin}_{\text{Admin costs}} + \underbrace{Marketing}_{\text{Marketing costs}} + \underbrace{EM\&V}_{\text{EM\&V Costs}} + \underbrace{Non - Resource}_{\text{Non-Resource Programs}} + \underbrace{ESPI}_{\text{ESPI (shareholder incentive)}} + \underbrace{Imp.}_{\text{Implementation}} + \underbrace{Ex\ Reb}_{\text{Excess Rebates}} + \underbrace{(1 - NTG) \times Incentives}_{\text{Incentives paid to free riders}} + \underbrace{Measure\ Cost \times (NTG + ME)}_{\text{Measure costs incurred by non-free riders, including Market Effects, or 'Spillover'}}} \quad (27)$$

$$PAC = \frac{NPV\ of\ (NTG+ME) \times Lifecycle\ Benefits\ of\ Avoided\ Electricity\ and\ Gas}{\underbrace{NPV\ of\ Admin}_{\text{Admin costs}} + \underbrace{Marketing}_{\text{Marketing costs}} + \underbrace{EM\&V}_{\text{EM\&V costs}} + \underbrace{Non-Resource}_{\text{Non-Resource Programs}} + \underbrace{ESPI}_{\text{ESPI (shareholder incentive)}} + \underbrace{Implementation}_{\text{Implementation cost}} + \underbrace{Incentives}_{\text{Incentives}}} \quad (28)$$