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**Date of Issuance 6/5/2018**

Decision 18-05-041 May 31, 2018

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

Application of Southern California Edison  
Company (U338E) for Approval of Energy  
Efficiency Rolling Portfolio Business Plan.

Application 17-01-013

And Related Matters.

Application 17-01-014

Application 17-01-015

Application 17-01-016

Application 17-01-017

**DECISION ADDRESSING ENERGY EFFICIENCY BUSINESS PLANS**

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Attachment A - Adopted Common Metrics for Energy Efficiency Business Plans

## **DECISION ADDRESSING ENERGY EFFICIENCY BUSINESS PLANS**

### **Summary**

This decision approves the energy efficiency business plans of eight program administrators (PAs), except as modified in this decision, including:

- Four investor-owned utilities: Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Gas Company, and Southern California Edison Company.
- Three regional energy networks (RENs): BayREN, SoCalREN, and Tri-County REN.
- One community choice aggregator: Marin Clean Energy (MCE).

The business plans, sector strategies, and associated approved budgets will run between 2018 and 2025. Program implementation plans, as further described in Decision (D.) 15-10-028, are required to be finalized and posted within 120 days of the issuance of this decision, after undergoing a stakeholder review process.

The decision includes a required set of metrics and indicators to track progress towards energy efficiency goals at the portfolio and sector levels. Policy guidance is also given in the areas of design of incentives to customers and/or implementers, lighting technologies (prohibiting incentives for compact fluorescent lighting in favor of light emitting diodes, and requiring continuation of incentives for street lighting bulk conversions), and workforce issues. The utility program administrators are also required to undertake certain limited integration activities to realize ancillary demand response benefits when funding energy efficiency projects.

The decision also includes a refined definition of disadvantaged communities and hard-to-reach customers.

Statewide programs are approved, including lead PA assignments, and guidance is included on governance, balancing account treatment, and fund contributions.

The decision includes clarifications of previous requirements applied to REN programs and portfolios, and approves MCE as a single point of contact in its geographic area, on a non-exclusive basis.

The proposal of the Local Government Sustainable Energy Coalition for statewide administration of local government programs is rejected.

Finally, the decision includes detailed requirements for the annual budget advice letter submissions and a standard of review for Commission staff in analyzing these submissions.

This proceeding remains open to consider the standard and modifiable terms proposed for use in contracts associated with third-party solicitations addressed in D.18-01-004.

## **1. Background**

In October 2015, the Commission adopted Decision (D.) 15-10-028, which established a “Rolling Portfolio” process for regularly reviewing and revising energy efficiency program administrators’ portfolios. D.15-10-028 provided guidance to energy efficiency program administrators (PAs) regarding: the general schedule and required contents of business plans, implementation plans, an annual budget advice letter (ABAL) submissions; the collaborative process for developing business and implementation plans through a stakeholder-led coordinating committee; and other details regarding the structure of this new process.

In August 2016, the Commission adopted D.16-08-019, providing further guidance on rolling portfolio elements including regional energy network (REN) program proposals; baseline and meter-based measurement of energy savings; changes to statewide and third-party programs and their administration; and changes to the framework for evaluation, measurement, and verification and the energy savings performance incentive structure.

D.16-08-019 directed the investor owned utility (IOU) energy efficiency PAs, Marin Clean Energy (MCE), and existing or new RENs to file business plan proposals for the 2018-2025 period by January 15, 2017. Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas), and MCE all filed timely business plan applications; and the San Francisco Bay Area REN (BayREN), Southern California REN (SoCalREN), and Tri-County REN (3C-REN) filed timely motions for approval of their REN business plan proposals.<sup>1</sup>

On January 30, 2017, a Chief Administrative Law Judge's ruling consolidated all eight business plan applications and motions and set deadlines for parties to file protests or responses to the applications or motions, and for applicants and REN proponents to file replies to any protests or responses.

On February 10, 2017, SCE filed an amended business plan application. On February 14, 2017 the California State Labor Management Cooperation Committee filed a motion for extension of time to protest or respond to all

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<sup>1</sup> All five applications and three motions were timely filed pursuant to Rule 1.15 of the Commission's Rules of Practice and Procedure. All subsequent references to Rules are to the Commission's Rules of Practice and Procedure.

business plan filings. Assigned Administrative Law Judge (ALJ) Fitch's February 15, 2017 e-mail ruling partially granted the motion, revising the response or protest deadline to March 3, 2017 and the deadline to reply to responses or protests to March 10, 2017.

On March 3, 2017, protests were filed by: the City and County of San Francisco (CCSF); Coalition for Energy Efficiency (CEE);<sup>2</sup> County of Los Angeles on behalf of Local Government Sustainable Energy Coalition (LGSEC); Office of Ratepayer Advocates (ORA); Rural Hard to Reach Local Government Partnerships' Working Group (RHTR); The Utility Reform Network (TURN); MCE; PG&E and SoCalGas.<sup>3</sup> Also on March 3, 2017, responses to the applications were filed by California Energy Efficiency Industry Council (CEEIC); California Housing Partnership Corporation, Natural Resources Defense Council (NRDC) and Association for Energy Affordability (joint response); CodeCycle LLC (CodeCycle); Energy Producers and Users Coalition; City of Lancaster; National Association of Energy Service Companies (NAESCO); NRDC (individual response); Center for Sustainable Energy; BayREN; PG&E; SCE; SDG&E; and SoCalGas.<sup>4</sup> On March 10, 2017, all applicants and REN

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<sup>2</sup> CEE is a coalition of 13 separate entities, representing labor, environmental, and academic groups.

<sup>3</sup> CCSF and MCE filed protests of PG&E's application; PG&E and SoCalGas filed protests of MCE's application; all other protests were not specific to one application or motion.

<sup>4</sup> City of Lancaster filed a response to SCE's application; PG&E filed a response to each REN motion; SCE filed responses to the Counties of Los Angeles and Ventura, and specifically to the LGSEC Local Government Partnerships Statewide administration proposal; SDG&E filed a response to SoCalREN; and SoCalGas filed responses to Tri-County REN and SoCalREN and the LGSEC Local Government Partnerships Statewide administration proposal. All other responses were not specific to a single application or motion.



proponents filed replies to responses and protests of their applications and motions.

On March 16, 2017, the Commission held a prehearing conference in this consolidated proceeding wherein a draft scope and schedule was discussed which had been distributed to the service list ahead of time by the ALJs. On April 14, 2017, the Scoping Memo was issued setting forth the scope and schedule for the proceeding and seeking supplemental information from the PAs and prospective PAs.

On May 10, 2017, an ALJ ruling was issued seeking comments on sector-level metrics proposed by Commission staff.

On May 15, 2017, supplemental information responding to the questions in Attachment A of the Scoping Memo was filed by the Association of Bay Area Governments (ABAG) on behalf of BayREN, the County of Ventura on behalf of 3C-REN, the County of Los Angeles on behalf of SoCalREN, LGSEC, MCE, PG&E, SCE, SDG&E,<sup>5</sup> and SoCalGas. Also on May 15, 2017, SCE filed an errata to its business plan exhibits and workpapers.

Also on May 15, 2017, PG&E on behalf of the business plan proponents and TURN, served a motion on the service list requesting an extension to respond to specific questions included in the Scoping Memo, mostly related to budget issues. The motions requested leave to file and serve these responses by June 12, 2017. This motion was granted by ALJ e-mail ruling on May 15, 2017.

On May 26, 2017, Commission staff held a workshop on the proposed sector-level metrics. Additional informal meetings on the sector-level metrics

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<sup>5</sup> SDG&E's response was filed on May 15, 2017 and then amended on May 17, 2017.

proposals occurred in June 2017 arranged through the California Energy Efficiency Coordinating Committee (CAEECC) stakeholder process envisioned in D.15-10-028.

On June 9, 2017, the ALJs issued a ruling modifying the remaining procedural schedule.

On June 12, 2017, supplemental budget information was filed by the following PAs or prospective PAs: ABAG on behalf of BayREN, the County of Ventura on behalf of 3C-REN, the County of Los Angeles on behalf of SoCalREN, LGSEC, MCE, PG&E, SCE, SDG&E, and SoCalGas.

On June 16, 2017, Commission staff held a workshop on third party solicitation issues.

On June 22, 2017, comments on all of the supplemental information, responses to Attachment B questions in the Scoping Memo, and other key issues identified by parties were filed by the following 19 parties: ABAG on behalf of BayREN, California Efficiency and Demand Management Council (Efficiency Council);<sup>6</sup> California Energy Efficiency Alliance (CEA), CEE, the City and County of San Francisco (CCSF); the County of Ventura on behalf of 3C-REN, CodeCycle, the County of Los Angeles on behalf of SoCalREN, LGSEC, MCE, NAESCO, NRDC, ORA, PG&E, SCE, Small Business Utility Advocates (SBUA), SDG&E, SoCalGas, and TURN.

On June 26, 2017, Commission staff held a workshop on its informal proposal, circulated on June 16, 2017 to the service list, to integrate limited aspects of the energy efficiency and demand response portfolios proposed in

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<sup>6</sup> Formerly known as CEEIC.

Applications 17-01-012 et al. On June 30, 2017, the ALJs issued a ruling seeking party comment on the staff proposal for limited integration of energy efficiency and demand response portfolios.

On June 29, 2017, reply comments on the supplemental information and Attachment B Scoping Memo questions were filed by the following 18 parties: ABAG on behalf of BayREN, CCSF, CEE, CodeCycle, County of Ventura on behalf of 3C-REN, County of Los Angeles on behalf of SoCalREN, Efficiency Council, the Future Grid Coalition, GreenFan, LGSEC, MCE, NAESCO, ORA, PG&E, SCE, SDG&E, SoCalGas, and TURN.

Also on June 29, 2017, as required by the Scoping Memo, four parties filed motions requesting testimony and evidentiary hearings: the California City County Street Light Association (CALSLA), CEE, NAESCO, and ORA. On July 14, 2017, responses to the four motions for testimony and evidentiary hearings were filed by five parties: ORA, PG&E, SDG&E, SCE, and SoCalGas.

On June 30, 2017, an ALJ ruling was issued requesting comments on a staff proposal for limited integration of energy efficiency and demand response.

On July 14, 2017, the PAs and prospective PAs all filed revised proposals for sector-level metrics.

On July 24, 2017, the following parties filed comments on the sector-level metrics proposals : CEE; CodeCycle; County of Los Angeles on behalf of SoCalREN; LGSEC; ORA; SBUA; and TURN.

Also on July 24, 2017, the following parties filed comments on the staff proposal for integration of energy efficiency and demand response: County of Los Angeles on behalf of SoCalREN; CPower, EnerNOC, and Energy Hub (Jointly, the Joint Demand Response (DR) Parties); ecobee, Inc. (ecobee);

Efficiency Council; MCE; ORA; PG&E; Robert Bosch LLC (Bosch); SBUA; SCE; SDG&E; and SoCalGas.

On July 25, 2017, the ALJs issued a ruling denying the requests for testimony and evidentiary hearings, but providing for briefs and reply briefs, later clarified by ALJ ruling on August 3, 2017 to be comments and reply comments, to be filed on September 25, 2017 and October 13, 2017, respectively, providing a comprehensive opportunity for parties to argue the merits of the case.

On July 31, 2017, responses to the comments on sector-level metrics were filed by: ABAG on behalf of BayREN; CodeCycle; County of Los Angeles on behalf of SoCalREN; LGSEC; MCE; NAESCO; NRDC; ORA; PG&E; SCE; and SDG&E and SoCalGas, jointly.

Also on July 31, 2017, responses to the comments on energy efficiency and demand response integration issues were filed by: Bosch; County of Los Angeles on behalf of SoCalREN; NAESCO; PG&E; and SCE.

On August 4, 2017, proposals for the third party solicitation process were filed by the following seven parties: CEE; County of Los Angeles on behalf of SoCalREN; ORA; PG&E; SCE; SDG&E; and SoCalGas.

On August 18, 2017, the following parties filed comments on the third party solicitation process: CEE; County of Los Angeles on behalf of SoCalREN; Efficiency Council; GreenFan, Inc. (GreenFan); MCE and BayREN, jointly; NAESCO; NRDC; ORA; PG&E; SBUA; SCE; SoCalGas; and Verified, Inc. (Verified).

On September 1, 2017, the following parties filed reply comments on the third party solicitation process: CEE; County of Los Angeles on behalf of

SoCalREN; Efficiency Council; GreenFan; NAESCO; NRDC; ORA; PG&E; SBUA; SCE; SDG&E; SoCalGas; and Verified.

Also on September 1, 2017, SoCalGas filed a motion to strike portions of comments on the third party solicitation process filed by GreenFan and Verified. On September 13, 2017, GreenFan and Verified filed a response to SoCalGas's motion, arguing that their comments were within scope of this proceeding.

On September 25, 2017, the following parties filed final opening comments pursuant to the July 25, 2017 and August 3, 2017 ALJ rulings providing for a final round of comments on the applications: ABAG, ORA, SoCalREN, SoCalGas, NRDC, County of Los Angeles, CEE, TURN, CLEAResult, CodeCycle, SBUA, CALSLA, MCE, SCE, PG&E, SDG&E, County of Ventura and NAESCO. ORA concurrently filed a motion to file under seal a confidential version of its final comments, which included data request responses provided and marked as confidential by SoCalGas.

Also on September 25, 2017, SoCalGas filed a motion to amend its business plan application, citing the need to modify its proposed budget given the significant difference between SoCalGas's proposed savings and the energy efficiency goals for 2018 and beyond, as proposed by the Commission in R.13-11-005.<sup>7</sup>

On October 3, 2017, SCE filed, on behalf of PG&E, SDG&E and itself, a response to SoCalGas's motion. Also on October 3, 2017, the assigned ALJ granted SoCalGas's motion to strike portions of GreenFan's and Verified's comments.

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<sup>7</sup> R.13-11-005 Proposed Decision Adopting Energy Efficiency Goals for 2018 - 2030, filed August 25, 2017.

On October 13, 2017, the following parties filed final reply comments on the business plan applications: NAESCO; City and County of San Francisco; MCE; CodeCycle; CEE; GreenFan and Verified; San Joaquin Valley Clean Energy Organization; Demand Council; PG&E; San Joaquin Valley Clean Energy Organization, Association of Monterey Bay Area Governments, High Sierra Energy Foundation, County of San Luis Obispo, Redwood Energy Authority; County of Ventura; SoCalGas; California Community Choice Association; SCE; SoCalREN; SBUA; TURN; ORA; SDG&E; LGSEC; ABAG.

Also on October 13, 2017, SoCalGas filed a motion to strike portions of ORA's final opening comments, pertaining to SoCalGas's codes and standards advocacy activities. On October 27, 2017, ORA filed a response to SoCalGas's motion to strike portions of ORA's final opening comments.

On November 13, 2017, the assigned ALJ issued a ruling denying SoCalGas's motion to file an amended business plan, and directing SoCalGas to instead seek approval for its proposed 2018 budget through the ABAL process.

Also on November 13, 2017, the Commission issued a proposed decision to adopt the framework for third party solicitations.

On November 14, 2017, the assigned ALJ issued a ruling denying SoCalGas's motion to strike portions of ORA's final opening comments.

On January 11, 2018, following a round of opening and reply comments on the proposed decision, the Commission adopted D.18-01-004, which established a process for third-party solicitations in the energy efficiency rolling portfolio framework.

We address the remaining issues addressed by parties over the course of this proceeding in the sections below.

## **2. Issues Common to All Business Plans**

This section addresses a number of issues that affect all business plan proposals from all PAs. These issues include the relationship of the business plans to the updated potential and goals and Senate Bill (SB) 350 goals, portfolio and sector-level metrics, limited integration of demand response and energy efficiency efforts, disadvantaged communities issues, cost-effectiveness, and reasonableness and treatment of proposed budgets.

In general in this decision, we discuss issues where parties or the Commission take issue with the proposal presented in the business plan applications. If an item is not discussed or otherwise decided in this decision, the PAs should consider that aspect of the business plans approved.

### **2.1. Relationship to Energy Efficiency Potential and Goals and Senate Bill 350 Targets**

The PAs based their business plans on energy efficiency goals adopted in 2015.<sup>8</sup> On September 28, 2017, the Commission adopted updates to the IOUs' energy efficiency goals for the period 2018 - 2030.<sup>9</sup> The 2018-2030 goals reflect a number of updated assumptions that complicate comparison with the goals adopted in 2015:

- changes to default baseline assumptions and savings from behavioral, retrocommissioning and operational activities (often referred to as "BROs"), pursuant to Assembly Bill (AB) 802;
- estimating energy efficiency potential based on studies that are not restricted by past levels of savings, pursuant to SB 350; and

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<sup>8</sup> D.15-10-028 *Decision Re Energy Efficiency Goals for 2016 and Beyond and Energy Efficiency Rolling Portfolio Mechanics*, issued October 28, 2015.

<sup>9</sup> D.17-09-025 *Decision Adopting Energy Efficiency Goals for 2018 – 2030*, issued October 2, 2017.

- updated avoided cost assumptions adopted in R.14-10-003.<sup>10</sup>

As described in the 2017 decision updating energy efficiency goals, the results of this analysis were intended to inform the California Energy Commission's (CEC) process for adopting annual targets toward achieving a statewide cumulative doubling of energy efficiency savings by 2030, as required by SB 350. On November 8, 2017, the CEC adopted annual targets for both IOUs' and publicly owned utilities' energy efficiency programs.<sup>11</sup>

The 2018-2025 business plans, owing to their timing in relation to the Commission's adoption of 2018-2030 goals and the CEC's adoption of annual targets, do not reflect all of the same assumptions that informed either the 2018-2030 goals or the CEC's annual targets. In general, the goals adopted in 2017 are significantly greater than those adopted in 2015. Nevertheless, the IOU PAs generally agree that the business plans are sufficiently flexible to accommodate and aim for the CEC's annual targets, along with updates to the Commission's goals consistent with our rolling portfolio bus stop schedule. SDG&E states its business plan "provides a framework that is flexible enough to accommodate increased goals over time. The new third party solicitation model provides for increased market participation leading to greater opportunity for market transformation and therefore opportunity for increased savings."<sup>12</sup> Similarly, SCE asserts its business plan strategies and tactics, though based on

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<sup>10</sup> D.17-09-025, at 3 – 6.

<sup>11</sup> Melissa Jones, Michael Jaske, Michael Kenney, Brian Samuelson, Cynthia Rogers, Elena Giyenko, and Manjit Ahuja, 2017. *Senate Bill 350: Doubling Energy Efficiency Savings by 2030*. California Energy Commission. Publication Number: CEC-400-2017-010-CMF.

<sup>12</sup> SDG&E June 22, 2017 comments, Attachment A, at 3.



goals adopted in 2015, will nevertheless advance the State's 2030 doubling goal. SoCalGas notes it will need to update its energy savings forecast in response to future goal updates; this is generally true for all the IOU PAs.<sup>13</sup> Other parties addressing this issue emphasize that new or innovative strategies will be needed in order to achieve the 2030 doubling goal.

Future goal updates may reflect a more comprehensive goal-setting process, in the context of the Commission's Integrated Resource Plan process. As that work continues, the link between energy efficiency goals adoption and integrated resource plans will increase and focus on common goals set by a coordinated analysis of overall grid needs, potentially changing how energy efficiency goals are set and influencing energy efficiency procurement.

We find the business plans are sufficiently flexible to accommodate future goal updates and other policy guidance for this business plan period (2018-2025). The business plans, generally, describe sector-level strategies and metrics while specific programs and budgets are submitted annually in September via advice letter for the upcoming calendar year.<sup>14</sup> However, pursuant to D.15-10-028, several factors may trigger a business plan update including newly adopted energy savings goals. In that regard, PAs are able to re-file their business plans, as needed, to update their sector strategies and overall budget, to reflect any changes to goals. Furthermore, upon our adoption of the business plans

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<sup>13</sup> One potential modification to our potential study process in the future will be to develop energy efficiency potential estimates applicable to the non-IOU PAs' service areas.

<sup>14</sup> A sector-level strategy, as opposed to a program strategy, is at a higher and more general level, e.g., technical assistance and tools to facilitate customer energy use awareness as opposed to the specific form of assistance or tools for a given program. Sector-level strategies generally range in number from five to ten in each sector.

(through this decision), we will require the PAs to base their subsequent budget advice letters on both the updated avoided cost assumptions and the 2018-2030 goals adopted in 2017, and any modifications to programs as directed in this decision. We address the process for evaluating ABAL compliance in Section 7 of this decision.

## **2.2. Implementation Plans**

D.15-10-028 outlined the process to be used for implementation plans for the PAs' energy efficiency programs, to be posted as programs are modified and launched after the approval of the business plans. The new implementation plans will replace the preexisting program implementation plans (PIPs), and will not be filed or formally reviewed by the Commission, but will be maintained as specified in D.15-10-028.

At various stages during the development and review of the business plans in this application proceeding, we are aware of stakeholder discussion of whether D.15-10-028 requirements should be modified to require a more formal review of the implementation plans. However, no party formally made this recommendation, so we will continue to follow the process outlined in D.15-10-028 for this first business plan launch. Should disputes arise, as discussed in D.15-10-028, the dispute resolution process outlined in D.13-09-023 may be invoked.

D.15-10-028 also includes discussion of a stakeholder process leading up to the posting of the implementation plans, and numerous parties' comments in this proceeding indicate an expectation that there will be some kind of stakeholder process dedicated to the review, revision, and/or finalization of implementation plans. We agree stakeholder input would be valuable.

D.15-10-028 mentioned the CAEECC process but did not set a particular timeline for posting of the implementation plans.

Here it is useful to distinguish between implementation plans that will be put in place for programs immediately following the adoption of this decision, for existing or slightly modified programs, and those that will be in place only after a third party solicitation has occurred and a third party program designer and implementer has been selected. Because the third party solicitations will occur on a rolling basis over the next few years, our expectation is that the majority of the portfolio will need to reflect implementation plans for programs that already exist that may be transitioned to a third party at some point between now and 2022. We clarify that we do not expect PAs to seek stakeholder input on implementation plans for pre-existing programs that are not being modified, nor do we expect modification to the existing PIPs to convert them into implementation plans. However, we do expect that the PIPs for existing programs will be posted along with the new implementation plans, so that stakeholders may gain an accurate picture of all of the programs offered by the PAs by looking at their PIPs and new implementation plans together in one place.

For new implementation plans, we expect that the PAs will seek stakeholder input, utilizing the CAEECC process and/or workshops hosted by the PAs, immediately following the adoption of this decision. As discussed in the May 2, 2016 Staff Proposal in R.13-11-005,<sup>15</sup> giving guidance to the business plans, considerations for and mitigation of potential conflicts of interest of

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<sup>15</sup> CPUC, Energy Efficiency Rolling Portfolio Business Plan Guidance, at 2-3, available at: [https://docs.wixstatic.com/ugc/0c9650\\_17039cf0febd483ca48440bb6ef41d66.pdf](https://docs.wixstatic.com/ugc/0c9650_17039cf0febd483ca48440bb6ef41d66.pdf)

market participants involved in the CAEECC should be made. To allow time for stakeholder input to occur, we will require that implementation plans be posted no later than 120 days after the effective date of this decision.

For programs that will be designed and implemented through third party solicitations in the future, we will require that the implementation plans be posted no later than 60 days after the third-party contract has been executed, or in the case of contracts that are required to be submitted via advice letter for Commission approval, 60 days after Commission approval of the third party contract.

The implementation plans are also required to contain metrics, as discussed in the next section. As pointed out by TURN, however, there are a number of higher-level programmatic guidance issues that are cross-cutting and not program-specific that the Commission may want to address in response to the business plans.

The utilities, to varying degrees, opposed these suggestions and suggested they are issues for resolution in the implementation plans. While these do relate to program implementation, they are critical to be addressed at the higher business plan level, especially since the implementation plans will only be informally reviewed and posted, without additional opportunity for formal Commission direction.

We take this opportunity to offer this type of high level guidance in the following areas:

- Design of Incentives (program incentives, to customers and/or implementers)
- Lighting Technologies
- Workforce issues and quality standards.

### **2.2.1. Design of Incentives to Customers or Implementers**

TURN offers several general policy recommendations on incentive design, within programs (incentives paid to customers and/or implementers), with which we agree and will require the PAs to use as high-level guidance for incentive design in their programs. These are all designed to maximize value for each dollar of ratepayer investment, without prescribing rules in every particular instance that a program design may encounter.

- 1) Incentives should generally be calculated on a net lifecycle savings basis, not a first-year savings basis, to support and align with achievement of portfolio net lifecycle savings goals.
- 2) Incentives should generally be tiered to promote increasing degrees of efficiency above code, particularly when an existing conditions baseline is used and when the direct install delivery channel is used.
- 3) Incentives should generally be strategically targeted at commercially available products that offer higher and highest degrees of efficiency and quality, not at all above-code high efficiency products.
- 4) Incentive structure should take into consideration the variation in barriers to efficiency upgrades faced by different customer segments, instead of being set uniformly for a measure class.
- 5) For performance-based programs, payment of customer and contractor incentives should tie, in significant part (50 percent or more), to independently verified savings performance estimated on a 12 month post-implementation period for capital projects and 24 months, if the project includes behavioral, retrocommissioning, or operational savings.

The PAs should incorporate this policy guidance into their requests for proposals from third parties as well. As requested by numerous parties in comments on the proposed decision, we clarify that these guidelines are intended as “best practices” and designs to strive for in the portfolio over the

business plan period, but they are not absolute requirements to be applied to every program or measure.

### **2.2.2. Lighting Technologies**

TURN also recommends, and we agree, that the PAs should no longer provide incentives for compact fluorescent bulbs (CFLs). Some PAs had proposed to continue incentives for outdoor lighting and other screw-in applications, at least in the early years of the business plan timeframe. These measures no longer offer the most technologically advanced, customer friendly, or energy savings advantages. Several evaluation studies have shown that the energy savings are diminishing, customer acceptance is lower, and continued funding of CFL incentives may actually delay the adoption of preferable light-emitting diode (LED) technologies. In addition, the potential and goals study addressed in D.17-09-025 does not assume that CFL measures were part of the energy savings potential upon which the goals were based. Therefore, we will require the PAs to take action to end incentives for CFLs of all types and to comply with Commission staff guidance on updating workpapers to reflect accurate savings. CFL incentives should be removed from all portfolios by no later than December 31, 2018.

We will require the PAs to move their lighting incentives to LEDs, which are far preferable to consumers and for their energy savings benefits, but here we also agree with TURN that incentives for these types of technologies should also generally be offered for those measures that exceed the general level of efficiency available in the general LED market without incentives. Another best practice is that PAs should not be offering incentives for the lowest levels of efficiencies in LEDs that just meet the applicable standard. Rather, incentives should be offered for more advanced forms of LEDs, either in energy savings or application.

Again, this is not an absolute requirement or a prohibition on offering incentives for situations that do not meet these requirements, but rather an articulation of a general guideline to strive for.

The CalSLA also raised the issue of continuing rebates for LED street lighting technologies, to continue to encourage the conversion of street lights to more efficient and clearer lighting options. This issue interfaces with the Commission encouraging utilities to allow acquisition of the utility-owned street lights by municipalities. CalSLA notes that the conversion process has been slow, and that SCE, in particular, has been chastised by the Commission in the past in D.14-10-046 for its lack of progress in this area. The vast majority of installed streetlights are not utilizing LED technologies today. We agree with CalSLA that rebates should still be available for bulk early replacement and conversion projects.

### **2.2.3. Workforce Issues and Quality Standards**

A number of parties, including especially CEE, NRDC, and TURN, recommended throughout this proceeding that the Commission focus on setting more specific workforce quality standards. This topic was also addressed in the context of the recent third party decision, D.18-01-004. As a result of that decision, the utility PAs are required to propose certain workforce quality standards as a part of their proposed standard and modifiable third party contract terms and conditions, which they submitted on March 19, 2018.

CEE, in particular, points out that the utility business plans failed to include any requirements for quality workforce standards, and that the Commission has been focusing on this issue for nearly a decade without major progress.

NRDC recommends that the Commission determine appropriate knowledge, skills, and abilities for a set of end-uses or programs in 2018, starting with the large commercial or municipal, universities, schools, and hospitals sectors. TURN also suggests that the Commission adopt explicit requirements for workforce diversity and inclusion goals, as well as workforce standards, to avoid a “repeat of the problems of the past.” NRDC also recommends that the Commission begin to collect more data on these issues to inform future activities.

More specifically, NRDC recommends outlining initial approaches while working out additional details later. NRDC’s general recommendations include requiring the PAs to:

- 1) Expand/initiate partnerships with entities that do job placement;
- 2) Require placement experience for any new partners in the workforce, education, and training (WE&T) programs and new solicitations;
- 3) Require “first source” hiring from a pool of qualified candidates, before looking more broadly, beginning with self-certification at the beginning; and
- 4) Facilitate job connections, by working with implementers and contractor partners, and utilizing energy centers.

All of these suggestions listed above are straightforward and readily implementable, providing high level guidance to the PAs to utilize in their general practices and in their workforce, education, and training activities specifically. We agree with these suggestions and will require the PAs to adhere to this high level guidance. PAs should also require implementation plans from third party programs to address how this guidance is being implemented.

In addition, as discussed further in Section 10 of this decision (Comments on the Proposed Decision), we intend to provide for further development of options for implementation of workforce quality standards in this proceeding,



both as part of consideration of the third party contract terms and conditions as articulated in D.18-01-004, as well as for potential application to the portfolio as a whole. We anticipate issuing a ruling shortly seeking further input from parties on the appropriate application of the workforce quality standards, with the potential for going beyond the flexible terms proposed thus far by the IOUs as part of the modifiable third party contract terms and conditions.

### **2.3. Portfolio and Sector-Level Metrics, and Associated Baselines and Targets**

The issue of portfolio and program metrics has been subjected to numerous rounds of proposals and feedback, both formally and informally, in this proceeding and in prior Commission processes. This section addresses metrics requirements at a portfolio and sector level.<sup>16</sup> We also clarify the distinction between a metric and an indicator. Generally, a metric is a measure of progress towards achieving desired market effect(s). For example, required portfolio metrics include savings metrics and cost-effectiveness metrics. Metrics are valueless. That is, the wording of the metric itself does not quantify the baseline or target. As such, all PAs should be able to have the same metrics, even if they have different targets.

For metrics to have a functional purpose, baselines and targets associated with each metric must also be provided. Baselines are the minimum or starting point used to compare the metric progress to achieving the stated target. Targets are the quantitative goal towards which a sector metric tracks progress.

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<sup>16</sup> According to D.15-10-028, at 53, “PAs will still need to set more granular metrics than just sector-level metrics, but they will do so in implementation plans, not business plans.” Thus, we do not address program-level metrics in this decision.

Reporting on metrics shows trends over time about how the portfolio is progressing in a given sector. As used in this decision, a metric includes a baseline and a target or targets (short, medium, or long term). An indicator does not include baselines or targets.

On July 14, 2017, all of the PAs filed revised proposed metrics that they will use to track and report progress in their energy efficiency programs. In general, we found the metrics proposals to be comprehensive and responsive to earlier direction offered by Commission staff as well as stakeholder input, but somewhat lacking in terms of setting baselines and targets.

There were still a series of stakeholder comments in this proceeding, suggesting augmentation or improvements to the metrics proposed. Thus, we will discuss those recommended changes we agree with in this section, and require the PAs to make a compliance filing in this proceeding within 60 days of the date of this decision with the final set of portfolio- and sector-level metrics, as further specified in Attachment A to this decision. The final metrics contained in those compliance filings will become the common elements of each PA's reporting in its annual reports. Attachment A lists the minimum set of common metrics to be reported on by each PA. The PAs are directed to work with Commission staff to review, revise, and finalize the portfolio- and sector-level metrics contained in Attachment A in a compliance filing due within 60 days of the issuance of this decision.

Many of the PAs included additional metrics in their business plan filings. PAs may, and should, design and track additional metrics beyond those included in Attachment A. Those additional metrics should be included in the PAs' annual reports but are not required to be included in the compliance filing due within 60 days of this decision.

In addition, if PAs wish to propose new or modify existing metrics in the future, they should make those proposals in their annual budget advice letter filings.

CEE proposes inclusion of metrics to measure progress toward goals for a diverse workforce; workforce, education, and training; and quality installation. We agree these are important items that are not adequately addressed by the metrics previously proposed.

For workforce diversity, we will require the PAs to report progress (from an established baseline to a desired end state) on a metric defined as follows:

- “The percentage of incentive dollars spent on measures verified to have been installed by contractors with a demonstrated commitment to provide career pathways to disadvantaged workers, as demonstrated by one of the following:
  - Adoption of workforce diversity and inclusion goals
  - A contractual agreement to hire through state-certified apprenticeship programs, community colleges, or local or state organizations that provide training and career opportunities to workers from low-income households or disadvantaged communities.”

CEE also suggests that tracking the number of trainings or partnerships in the workforce, education, and training (WE&T) programs is meaningless to predicting the quality of the ultimate energy savings installations. They suggest adding several metrics with this purpose, and we find the following two most feasible and implementable to begin to get some information on the subject:

- Percentage of WE&T program participants that meet the definition of disadvantaged workers.
- The number of business-plan-related energy efficiency projects related to the WE&T training on which an incumbent participant has been employed within 12 months of completing the WE&T training.

Finally, CEE's comments focus on metrics to measure actual installation quality, measured against particular industry standards in particular sectors. Those recommendations were already discussed more fully above in Section 2.2.3.

CodeCycle points out that compliance improvement programs include metrics for counting interactions but not for measuring the depth of interventions. We agree that indicators for anticipated savings are appropriate, where feasible, and could be based on savings anticipated as a percent of baseline, or savings per square foot, setting the baseline using best-available information initially and then refining over time as more evaluation data becomes available.

Further, CodeCycle comments on the proposed metrics by pointing out that the most important metric for all programs is likely related to the energy savings, including for codes and standards programs and for other programs that may be considered non-resource but where some energy savings measurement may be possible. CodeCycle suggests that the statement of the "common problem" by Commission staff related to the codes and standards metrics should include capturing energy savings, for any resource program "or resource subcomponent of a traditionally non-resource program that begins measuring energy and demand reduction benefits." We agree, and will direct the PAs to include this concept as an indicator. However, we clarify that, for all resource and non-resource programs, unless the efficiency savings tracked against savings indicators are supported by Commission-approved ex ante claims, or evaluated as part of the Commission's impact evaluations, this indicator will not constitute a claim. We also clarify that savings tracked by

savings indicators will not count towards goals or cost-effectiveness unless they constitute a claim.

TURN's comments on the metrics are limited to three actionable items with which we agree. The first two relate to the formulation of the "capturing energy savings" metrics. First, TURN recommends clarification of the term "ex ante" to make clear that it does not necessarily mean that the savings have been verified by Commission staff evaluation. This should make it clear that the reporting on these metrics is not intended as a substitute for the measurement of portfolio gross and net energy savings impacts through independent evaluation, measurement and verification (EM&V).

Second, TURN and ORA both recommend including both annual and lifecycle savings for the "capturing energy savings" metric, to keep a focus on the development of long-term and enduring energy savings. We agree; this is consistent with our previously-stated policy goal of prioritizing long-term savings. Thus, the PAs shall include metrics and reporting on both first-year savings and lifecycle savings under the "capturing energy savings" metrics.

Finally, TURN and ORA both point out that the "cost per energy saved" metric did not specify the formulation of levelized costs, and the utility PAs appeared only to plan to report based on the program administrator cost (PAC) test. TURN and ORA recommend, and we agree, that the PAs should report on both the total resource cost (TRC) and PAC formulation of levelized costs, providing a useful comparative perspective on the cost of energy efficiency. Therefore, we will require this in the revised metrics.

Also on the subject of the levelized cost of energy metric, SCE seeks clarity on whether codes and standards advocacy costs and savings should be included or excluded, noting that the different PAs handled it differently in their initial

filings, and provided a revised set of metrics removing codes and standards advocacy should the Commission adopt this outcome. ORA also points out that codes and standards advocacy costs are demonstrably different than other program costs, and should not be included in the metric, but should be tracked separately.

CodeCycle's reply comments suggest that this discussion apply only to codes and standards advocacy, and not other aspects of codes and standards work that may produce measurable savings, such as code compliance programs. We agree, as prior decisions have only discussed and decided upon special rules for savings associated with Codes and Standards advocacy. The "cost of saved energy" metrics, and associated baselines and targets, should exclude costs or savings associated with all codes and standards advocacy activities, and SCE should utilize its July 24, 2017 revised metrics for this purpose.

ORA also comments that the metrics submitted by PAs on July 14, 2017 contained some omissions and errors which should be corrected prior to finalizing the metrics. In particular, SoCalGas provided a description of how to calculate baselines, but did not provide baselines against which targets can be benchmarked. SDG&E also declined to set baselines or targets for most metrics. ORA also points out that SCE's savings benchmarks were lower for the overall portfolio than for hard-to-reach customers or disadvantaged communities, which should be corrected.

ORA also seeks clarity on how and when the metrics would be finalized and then how reporting on metrics would actually occur. We have clarified above that the PAs will be required to make compliance filings in this docket following the issuance of this decision to finalize metrics to be tracked. PAs will also be required to include reporting on progress towards all of the metrics in

their annual reports. We direct Commission staff to develop reporting templates, frequency, and instructions and to develop a review strategy incorporating input from the CAEECC. ORA suggests quarterly reporting of metrics, but we find this to be too frequent, at least at the outset. PG&E also supports annual metrics filings.

SBUA comments on the setting of targets for program penetration for small commercial customers. They suggest that all of the utilities set targets that are too low for this subsector, and that the penetration targets should not be set any lower than five percent. We agree this is a reasonable initial target and will require all of the utilities to use this as a minimum penetration target for small commercial businesses.

We also agree with SBUA that since this decision clarifies the definition of hard-to-reach customers below in Section 2.5, in particular with respect to the commercial sector, all of the PAs whose portfolios include commercial sector programs should be required to identify metrics for energy savings for hard-to-reach commercial customers.

PG&E also filed comments objecting to one portion of MCE's proposed metrics. With respect to the MCE metric in the industrial sector, PG&E objects to MCE's request to provide prior program participation data, which PG&E characterizes as "overly broad." PG&E then offers to provide MCE "aggregated" customer participation data for the most recent three years, along with the number of customers receiving a financial incentive within the current reporting year, in order to assist with the development of an appropriate metric for MCE's industrial programs.

This issue is somewhat moot because, as discussed in Section 5.1 below, we are not approving MCE's industrial sector proposals at this time, but we still

take the opportunity to provide general direction on the issue of PG&E provision of historical program participation data to MCE.

While we agree with PG&E that MCE's request may not be worded specifically enough, we appreciate and support PG&E's refinement and offer to provide the aggregated participation data, and will require PG&E to provide this information. In addition, we suggest that PG&E interpret its responsibility to provide historical program participation information liberally in order to minimize the chances of duplication of program or incentive expenditures.

At the same time, we do not agree that MCE should have complete access to all historical customer program participation information. PG&E is correct that individual customer information is subject to confidential treatment. This may be a matter that is more appropriately addressed in the energy efficiency rulemaking proceeding for CCAs going forward. And there is likely an appropriate distinction to be made between those customers served by a CCA and those that are not. For now, we offer the above general direction.

Finally, ORA suggests that the Commission should keep all of the metrics proposed by staff, but make a distinction between metrics that have specific associated targets, and indicators, which are simply tracked. Several commenters also agree with this idea, including NRDC and SDG&E. We agree that this is a useful distinction that has been made in the past and we will utilize it again here, further clarifying that progress towards a target must be measured, verified, and evaluated to qualify as contributing to a metric.

The PAs' compliance filings (due within 60 days of the issuance of this decision) will contain the full list of metrics and indicators, including common metrics specified in Attachment A of this decision, as well as the PAs' business plan metrics, adjusted (in some cases) according to the guidance we have given



in this decision and finalized in coordination with Commission staff.

Compliance filings will also contain baselines, specific targets (short-, medium-, and long-term), and any interim progress milestones for each of the metrics.

#### **2.4. Energy Efficiency and Demand Response Limited Integration Issues**

On June 26, 2017, Commission staff held a workshop on its informal proposal, circulated on June 16, 2017 to the service list, to integrate limited aspects of the energy efficiency and demand response portfolios proposed in A.17-01-012 et al. related to demand response portfolios. On June 30, 2017, the ALJs issued a ruling seeking party comment on the staff proposal for limited integration of energy efficiency and demand response portfolios.

In the staff proposal, Energy Division staff recommends a limited integration of energy efficiency and demand response in three areas: 1) residential HVAC controls; 2) non-residential HVAC and lighting controls; and 3) integration of the demand response and energy efficiency potential studies to support analysis under the integrated resource planning (IRP) process in Rulemaking (R.) 16-02-007.

The purpose of this staff proposal was both to take advantage of opportunities for adding demand response functionality for very little incremental cost, when an energy efficiency investment is already incurred, and also to assist customers in preparing for the rollout of time-varying electric rates happening over the next several years.

Commission staff propose to repurpose the integrated demand-side management (IDSM) budget to fund this limited integration and to ensure the cost-effectiveness of integrated energy efficiency programs are not negatively

affected. Staff also propose that the third element be funded through existing EM&V funds.

#### **2.4.1. Positions of the Parties**

Bosch strongly supports the staff proposal, with particular interest in non-residential HVAC and lighting controls, to allow for exploring the feasibility of an additional incentive adder for a demand response-ready energy efficiency resource. Bosch also points out that staff's proposed activities are considerably more specific than the general marketing and education activities that the IOUs describe as currently being funded by their IDSM budgets, and recommends that the staff proposals be piloted for now.

CEA generally supports the staff proposal, but recommends that revisions are necessary to make significant inroads in increasing demand response capabilities and to ensure that the business plans are consistent with state goals and directives. In particular, CEA argues that current programs are focused on incentivizing shallow lighting retrofits such as CFL and LED lighting upgrades, potentially delaying the installation of demand-response-capable controls.

The Efficiency Council is generally supportive of the high level goals of the staff proposal, and of inclusion of demand response-enabled HVAC and lighting controls or energy management systems in energy efficiency programs. Their comments raise several concerns about consumer preferences and behavior relative to the prescriptiveness of the staff proposal both in technology and behavior, and emphasize innovation and allowing multiple paths to achieve the integration goals.

Ecobee also generally supports the concepts in the staff proposal but urges flexibility to avoid narrowing the options consumers have and the actions they

might take to respond to dynamic rates. Instead, ecobee recommends that the Commission allow the market and competition to deliver solutions to consumers.

The Joint DR Parties support the general concept but express concern about the process of handling these integration issues in both the demand response and energy efficiency proceedings. Substantively, they also express concern about the technology focus and the proposal to utilize demand response funds for what they view as essentially energy efficiency purposes.

MCE's comments are focused on ensuring competitive neutrality in demand response program delivery, ensuring CCA customers are not excluded from the integration opportunities, seeking authority for MCE to request funds to integrate demand response and energy efficiency program delivery in its ABAL, and taking note that integration is a core component of MCE's single-point-of-contact proposal discussed later in this decision.

NAESCO recommends that each IOU conduct a solicitation for third parties to design integrated energy efficiency and demand response activities and programs.

ORA does not oppose the staff proposal to combine the energy efficiency and demand response potential studies, though comments that funding should be reduced over time once this integration occurs. ORA also suggests that if the first two elements of the staff proposal for residential HVAC and commercial lighting and HVAC are approved, the utilities should be required to conduct an evaluation within a year to determine allocation of technology incentive funding for cost-effectiveness evaluation purposes. ORA also supports taking funding from existing IDSM budgets, though also recommends reexamining programs currently funded out of this budget category given what they characterize as major fluctuations in spending over the past few years.

PG&E argues that the staff proposal conflicts with the Commission's guidance on the energy efficiency business plan filings with respect to third party design and is concerned about the technology specifics of the proposal, arguing that it could result in stranded technology investments. PG&E does, however, support the intent to assist customers in responding to new rate designs that they will face over the coming years. PG&E also does not oppose selective repurposing of some IDSM funding.

SBUA generally supports the staff proposal and agrees that it is appropriate to develop policy and program integration in both energy efficiency and demand response proceedings. SBUA specifically supports efforts to encourage involvement and target the needs of small business customers.

SCE generally supports the goals of integration, but recommends that rather than design programmatic approaches, the Commission establish policy goals for integration of energy efficiency and demand response, and lay out a roadmap to achieve those goals. SCE recommends that the Commission set goals in an integrated fashion, such as in the integrated resource planning proceeding, and then allow certain programs to be designed to achieve those goals. Though SCE does not oppose repurposing IDSM funds, SCE recommends developing a bottom-up budget estimate based on the policy goals and the technology needs. SCE also focuses on designing programs to ensure and validate that any additional demand response functions are actually being used by the customer.

SDG&E is generally supportive of encouraging technologies to help customers react to time-of-use pricing and integrating across different issue areas. However, SDG&E is concerned that the staff approach may be too prescriptive, especially from a technology perspective, and that the energy efficiency and demand response portfolio proceedings separately may not be the

appropriate place to accomplish integration, instead suggesting the integrated distributed energy resource (IDER) proceeding (R.14-03-003) as a more appropriate venue. In addition, SDG&E notes that it already allocates funds from its IDSM budget for local marketing efforts, statewide efforts, and behavioral programs, which produce energy savings.

SoCalGas's comments oppose the repurposing of IDSM funding, since it represents budget already committed to certain activities. Instead, SoCalGas proposes to continue incubating new program integration ideas with the other IOUs and through the third party programs planned as part of the rolling portfolio.

SoCalREN generally supports the staff proposal and recommends that funding be expanded to include non-IOU PAs in IDSM activities.

#### **2.4.2. Discussion**

The most straightforward portion of the staff proposal for limited energy efficiency and demand response integration is with respect to the idea of conducting a combined potential and goals study to look at both energy efficiency and demand response opportunities within the same customer base. No party has major objections to this idea and Commission staff are already working on a way to design such an integrated study. The potential and goals study is already scheduled and funded on a regular basis out of the energy efficiency evaluation funding, and we expect that the next solicitation for consultant assistance in conducting the potential and goals study will include elements of energy efficiency and demand response potential in an integrated manner.

On the programmatic side, the general purpose of the staff proposal to suggest program designs for integration of energy efficiency and demand

response is focused on driving additional demand response benefits, since IDSM funds are primarily for demand response purposes, when energy efficiency investments are already being made. Staff proposes integration element 1 for residential HVAC systems, where the additional IDSM investment would be in ensuring that demand response functionality is programmed or added at a time when a customer is already installing a programmable or advanced thermostat. The purpose for this element is primarily to assist customers in being prepared to respond to default time-of-use and other time-varying rates that customers will begin facing very soon.

Similarly, for the second integration element, the staff proposal focuses on adding additional demand response capability at a time when a non-residential customer is already making an investment in a lighting or HVAC control technology, primarily for energy efficiency purposes, where additional demand response benefits could be harvested.

In both cases, the key concept is that additional demand response value can be gleaned for very little incremental cost.

We do agree with a number of parties who comment that the control technologies that would be involved in programs like those proposed by staff are changing very quickly, and multiple solutions may be available that provide similar functionality depending on customers' individual preferences. Thus, we want to avoid being too prescriptive in either program designs or technology specifications to allow multiple solutions to flourish while still avoiding stranded technology investments. In response to the specific comments of Bosch on the proposed decision, we clarify that any integration program tested or deployed by a program administrator should be technology agnostic, including whether it uses direct or alternating current. An incentive adder for customer participation

in a demand response program after an energy efficiency retrofit is also a program design option.

We also agree with PG&E that the focus in the energy efficiency business plan of moving toward third party designed and implemented programs should be utilized to test delivery and technology options in this area.

Thus, we will adopt a set of general requirements and a minimum budget allocation, to be funded out of IDSM funds, for the utility PAs to begin to integrate delivery of energy efficiency and demand response capabilities to customers, especially in light of the imminent arrival of new rate structures for residential customers. We will also allow IOUs to meet these requirements through solicitation of programs from third parties.

The requirements and general policy principles we will institute are as follows:

- The IOU PAs shall solicit, and other PAs should consider soliciting, third parties to design and implement programs to test various strategies and technologies for integrating demand response capability with existing energy efficiency activities. The PAs should consider if contractor training or partnerships between energy efficiency and demand response providers are necessary for energy efficiency implementers to understand and promote demand response.
- For the residential sector, the energy efficiency and demand response integration efforts should be focused, initially, on HVAC technologies and facilitating automatic response to new time-varying rates, possibly involving customer education on the rates and thermostats. Each IOU shall budget a minimum of \$1,000,000 annually from its IDSM budget, to test and deploy such strategies in the residential sector.
- For the non-residential sector, including small commercial customers, the energy efficiency and demand response integration efforts should be focused initially on HVAC and

lighting controls. For non-residential customers, the programs must validate that, if IDSM funds are used to facilitate integration of demand response capabilities into energy efficiency efforts already occurring, the customer is enrolled in a demand response program (e.g., dispatchable capacity program or, for bundled customers, an event-based rate or real-time pricing), for at least one year after the installation of the technology at the customer site, and up to 36 months if a large, deemed, or calculated incentive is involved. At least \$20 million annually in IDSM funds shall be divided among the IOU PAs on the basis of load share to test and deploy solutions in non-residential HVAC and lighting controls.

- IOU PAs shall coordinate with Commission staff regularly on the design of these integrated energy efficiency and demand response strategies. Commission staff may, at its discretion, hold additional workshops or discussions to help facilitate ongoing improvement and evaluation of efforts in energy efficiency and demand response integration over the course of this business plan period (through 2025).
- IOU PAs shall budget IDSM funds for, and conduct program process evaluations to determine:
  - How well customers are responding to the marketing, education and outreach (ME&O) efforts;
  - Any additional benefits or costs to integrated programs that do not exist in separate energy efficiency and demand response programs, such as decreased customer transaction costs (filling out forms, learning about the programs and new concepts), decreased equipment costs (one programmable communicating thermostat that can serve both demand response and energy efficiency purposes); and
  - The extent to which there may be positive “interactive effects” (e.g., energy efficient HVAC combined with demand response provides an overall increased load reduction effect when



compared to inefficient HVAC;<sup>17</sup> or time varying rates that embrace the value of the efficient end use, by shifting end uses to periods of off-peak pricing and high renewable generation).

We offer these policy principles to guide the design of integrated programs:

- Help customers save on their energy bill by shifting HVAC use away from peak pricing periods (e.g., pre-cooling or pre-heating strategies in insulated buildings) through automated response to time-of-use (TOU) rates, and where there is customer interest, critical peak pricing events;
- Insure there is no incremental measure or transaction cost for a building to participate in a demand response program after an energy efficiency retrofit by installing automated and communicating demand response control technologies as part of energy efficiency retrofits, or design and commissioning of new construction;
- Capitalize on “co-benefits,”<sup>18</sup> where the same technologies or device upgrades that enable demand response (e.g., smart thermostats, building energy management systems or lighting controls), produce other benefits by allowing a building to operate more efficiently – and can be reflected as reduced upfront costs for adding demand response capability to energy efficiency controls.<sup>19</sup>
- In addition, minimize duplication of outreach, marketing, site visits, etc. and associated costs, both to PAs and participants, through integrated programs.

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<sup>17</sup> Alstone, Peter et al. *2025 California Demand Response Potential Study: Charting California's Demand Response Future*, 1 March 2017, Section 8.2 at <http://www.cpuc.ca.gov/General.aspx?id=10622>

<sup>18</sup> Goldman, Charles et al. “Coordination of Energy Efficiency and Demand Response,” *Lawrence Berkeley National Laboratory*, January 2010.

<sup>19</sup> See Alstone, Section 4.6.

## **2.5. Disadvantaged Communities and Hard-to-Reach**

The Scoping Memo invited comments on what should be improved to ensure the business plans address the needs of disadvantaged communities and hard-to-reach markets. Several parties emphasize the need for clear definitions of each of these terms; we agree it is worthwhile to make clear what we mean by disadvantaged communities, in the context of energy efficiency, and to confirm the Commission's definition of hard-to-reach customers and to identify specific overlaps with, and distinctions from, disadvantaged communities.

### **2.5.1. Definition of Disadvantaged Communities**

Our purpose for focusing on disadvantaged communities is to fulfill the statutory requirement, enacted by SB 350, to report on and include specific strategies for maximizing the contribution of energy efficiency savings in disadvantaged communities as identified pursuant to Section 39711 of the Health and Safety Code.<sup>20</sup> To that end, the May 10, 2017 ruling inviting comments on business plan metrics includes metrics for energy savings "in zip codes and/or census tracts in the top 25 percent as defined by the CalEnviroScreen Tool."

Pursuant to Section 39711 of the Health and Safety Code, the California Environmental Protection Agency (CalEPA) developed a means for identifying disadvantaged communities, which may include, but are not limited to:

- (1) Areas disproportionately affected by environmental pollution and other hazards that can lead to negative public health effects, exposure, or environmental degradation.

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<sup>20</sup> Public Utilities Code Sections 913.10 and 913.11; these reporting requirements originated from SB 350 (2015), which located them in Sections 454.55 and 454.56; SB 1222 (2016) subsequently relocated them to Sections 913.10 and 913.11.

(2) Areas with concentrations of people that are of low income, high unemployment, low levels of homeownership, high rent burden, sensitive populations, or low levels of educational attainment.

The CalEnviroScreen Tool utilizes a number of indicators to develop a composite “score,” which ranks a given census tract’s overall burden across the variety of indicators relative to all other census tracts’ scores. Indicators include both Pollution Burden indicators (exposure to ozone concentrations, particulate matter (PM) 2.5 concentrations, diesel PM emissions, drinking water contaminants, pesticide use, toxic releases from facilities, traffic density; and environmental effects of cleanup sites, groundwater threats, hazardous waste generators and facilities, impaired water bodies, and solid waste sites and facilities) and Population Characteristic indicators (higher pollution vulnerability due to asthma, cardiovascular disease, or low birth weight infants, educational attainment, housing burden, linguistic isolation, poverty, and unemployment).<sup>21</sup>

CalEPA, pursuant to Health and Safety Code Section 39711, defines disadvantaged communities as those census tracts scoring in the top 25 percent of census tracts statewide on the set of 20 different indicators in CalEnviroScreen. As part of its definition of disadvantaged communities, CalEPA also finds that an additional 22 census tracts that score in the highest five percent of CalEnviroScreen’s Pollution Burden indicator, but that do not have an overall CalEnviroScreen score in the top 25 percent because of unreliable socioeconomic or health data, are also defined as disadvantaged communities.

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<sup>21</sup> See website of the California Environmental Protection Agency, Office of Environmental Health Hazard Assessment, CalEnviroScreen Scoring & Modeling: <https://oehha.ca.gov/calenviroscreen/scoring-model>

As of the issue date of the proposed decision, the current version of the CalEnviroScreen Tool is CalEnviroScreen 3.0. In the event that CalEPA revises its methodology for identifying disadvantaged communities in the future, the revised methodology should be used for purposes of ongoing identification of disadvantaged communities.

It is worthwhile to distinguish the Commission's use of the term "disadvantaged communities" with respect to WE&T, which predates the above codified definition and serves the distinct purpose of articulating the Commission's Long Term Energy Efficiency Strategic Plan objectives for increasing participation from within minority, low-income and disadvantaged communities in the State's energy efficiency workforce.<sup>22</sup> The Strategic Plan does not specify a definition for "disadvantaged communities" with respect to this workforce goal; however, we are separately adopting metrics for trainings that reach disadvantaged workers, a definition for which the IOUs have developed as part of their proposed standard and modifiable contract terms, in Section 2.3 of this decision. For purposes of administering energy efficiency programs and maximizing the contribution of energy efficiency savings in disadvantaged communities, we follow CalEPA's method for identifying disadvantaged communities.

### **2.5.2. Definition of Hard-to-Reach Customers**

The Commission's Energy Efficiency Policy Manual defines hard-to-reach residential customers as "those customers who do not have easy access to

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<sup>22</sup> California Long Term Energy Efficiency Strategic Plan, at 78 (Workforce Education and Training Goal 2: "Ensure that minority, low income and disadvantaged communities fully participate in training and education programs at all levels of the DSM and the energy efficiency industry.")

program information or generally do not participate in energy efficiency programs due to a language, income, housing type, geographic, or home ownership (split incentives) barrier.” Hard-to-reach business customers also include factors such as business size and lease (split incentive) barriers.<sup>23</sup> As detailed in multiple parties’ comments, a modified definition of hard-to-reach in Resolution G-3497 gave rise to a dispute over which definition prevails, primarily for the purpose of determining whether the RENS’ business plans meet the approval criteria in D.12-11-015, including that RENS must “pilot activities in hard to reach markets, whether or not there is a current utility program that may overlap.”

In Resolution G-3497, the Commission provided the following clarification of hard-to-reach:

Specific criteria were developed by staff to be used in classifying a customer as hard-to-reach. Two criteria are considered sufficient if one of the criteria met is the geographic criteria defined below. There are common as well as separate criteria when defining hard-to-reach for residential versus small business customers. The barriers common to both include:

- Those customers who do not have easy access to program information or generally do not participate in energy efficiency programs due to a combination of language, business size, geographic, and lease (split incentive) barriers. These barriers to consider include:
  - Language – Primary language spoken is other than English, and/or

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<sup>23</sup> Energy Efficiency Policy Manual (Version 5, July 2013), accessible from the Commission’s energy efficiency webpage: <http://cpuc.ca.gov/egyefficiency/> .

- Geographic – Businesses or homes in areas other than the United States Office of Management and Budget Combined Statistical Areas of the San Francisco Bay Area, the Greater Los Angeles Area and the Greater Sacramento Area or the Office of Management and Budget metropolitan statistical areas of San Diego County.
- For small business added criteria to the above to consider:
  - Business Size – Less than ten employees and/or classified as Very Small (Customers whose annual electric demand is less than 20 kilowatt (kW), or whose annual gas consumption is less than 10,000 therm, or both), and/or
  - Leased or Rented Facilities – Investments in improvements to a facility rented or leased by a participating business customer
- For residential added criteria to the above to consider:
  - Income – Those customers who qualify for the California Alternative Rates for Energy (CARE) or the Family Electric Rate Assistance Program (FERA), and/or
  - Housing Type – Multi-family and Mobile Home Tenants (rent and lease)

The Policy Manual definition can be interpreted as requiring a customer need only meet one criterion to be considered hard-to-reach. The definition in Resolution G-3497 specifies that if a customer does not meet the geographic criterion (i.e., they are not located in one of the identified metropolitan statistical areas), they must meet a total of three criteria to be considered hard-to-reach; and if a customer meets the geographic criterion, they must meet one other criterion to be considered hard-to-reach.

PG&E relies on the definition that is contained in Resolution G-3497, which other parties (including the RENs and CCSF) contend was developed outside the public process and that PG&E applied the definition beyond its original intent.

Affirmation of the appropriate definition is needed in order to, among other things, determine the RENs' business plans' compliance with D.12-11-015 and to provide guidance on future REN program design.

The Commission has grappled with defining hard-to-reach, or the closely related and often interchangeably used term "underserved," since as early as the late 1990's.<sup>24</sup> The Commission's primary concern at that time was that utility programs were not making progress in expanding program reach into the customer segments that had historically not participated in ratepayer-funded energy efficiency programs at the level of their representation as ratepayers. The Commission also recognized that "underserved" or "hard-to-reach" are not static terms, and that a particular customer or market segment, once targeted for program participation, is no longer underserved relative to others that program administrators have yet to target. In the late 1990's and early 2000's, residential and small commercial customers were underserved relative to large businesses, which benefitted disproportionately from the utilities' energy efficiency programs. In the absence of program participation data, the Commission's ex ante review team analyzed available data in an effort to modify the definition so as to emphasize that hard-to-reach programs or activities should prioritize those customers who are likely the most underserved, and therefore presumably the most difficult to reach. The primary intent has always been to prioritize

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<sup>24</sup> See, e.g., D.00-07-017, at 79; and D.01-01-060 at 4, 9 and 29; and D.01-11-066, at 3, 6-7.

underserved customers; in the early 2000s “underserved” and “hard-to-reach” were understandably more interchangeable than they are now. With significantly expanded budgets it is reasonable to assume a smaller proportion of underserved ratepayers, but we have unfortunately continued to refer to them as hard-to-reach.

Some parties suggest we define hard-to-reach in terms of the barriers that implementers face in providing energy efficiency services to certain customer segments. For example, BayREN asserts “[c]ontractors doing business in urban areas contend with extreme traffic congestion, limited and expensive parking, and higher vendor costs and contractor wages, making customers in high density urban communities undeniably hard-to-reach.”<sup>25</sup> Further discussion of this issue also occurred in response to PG&E’s 2015 request for Efficiency Savings and Performance Incentive (ESPI) payments, wherein PG&E proposed to modify “hard-to-reach” as defined in Resolution G-3497, arguing “[i]f all San Francisco Bay Area residents were excluded from the HTR definition, a Chinese-speaking small business restaurant renting its facility in San Francisco’s Chinatown would not qualify, nor would a family-owned corner grocery store with less than ten employees and whose demand is less than 20 kW located in a disadvantaged neighborhood in Oakland. We assume this is not what was intended by the Commission resolution and suggest a revision to define customers who meet two other HTR criteria to be deemed HTR even though they may live in a non-HTR county.”<sup>26</sup> NRDC, on behalf of itself and ten other groups – including BayREN,

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<sup>25</sup> BayREN June 22, 2017 Comments, at 6.

<sup>26</sup> PG&E AL 3632-G/4705-E, submitted September 15, 2015, at 5-6.



SoCalREN, the Association of Monterey Bay Area Governments, and the Sierra Business Council – all submitted responses in support of PG&E’s proposal to revise the hard-to-reach definition. In Resolution G-3510, the Commission deemed PG&E’s proposal out of scope of the advice letter process and provided that Commission staff may address the issue in R.13-11-005.

There is sound policy basis for affirming the definition of hard-to-reach that is reflected in Resolution G-3497. As discussed above, the Commission’s intent has been that programs targeted at hard-to-reach customers should prioritize the most underserved customers or customer segments, because they are likely the *hardest* to reach. Certainly, residents of a multi-tenant building are harder to reach than single-family residents. But low-income residents of a multi-tenant building with limited English proficiency are, in all likelihood, even harder to reach. To the extent that REN activities may overlap with utility programs, it is reasonable with respect to prudent investment of limited ratepayer funds to limit such overlap to programs that target customers with the least likelihood of program information and access. BayREN and PG&E’s argument, that it may be reasonable to define hard-to-reach based on specific barriers that implementers face in engaging certain customers or customer segments, is well-taken, however, there is insufficient record in this proceeding to develop such an alternative at this time.

With one modification, discussed in the following section, the definition of hard-to-reach in Resolution G-3497 is the appropriate one for all purposes, including target setting / metrics tracking, and for determining the REN business plans’ compliance with D.12-11-015. We therefore evaluate the RENs’ business plans based on the hard-to-reach definition in Resolution G-3497, as modified in the following section, which has been well established since

December 2014, albeit not affirmed in an update to the Energy Efficiency Policy Manual.

Although we find some of the RENs' proposed activities are not sufficiently targeted at hard-to-reach customers or market segments, we will afford the RENs an opportunity to modify their planned activities intended for hard-to-reach customers for purposes of meeting the definition in Resolution G-3497, as modified in this decision. Staff has delegated authority in the ABAL process to approve, deny or modify funding for any REN activity if it fails to meet at least one of the criteria outlined in D.12-11-015.

This decision also does not disturb Resolution G-3510's provision that Commission staff may address this issue in R.13-11-005. If and when staff addresses this issue, parties advocating a modified definition must provide concrete data and analysis supporting their position. That proceeding is also the appropriate venue for parties to advocate a different basis for defining hard-to-reach, particularly as a distinct concept from underserved. Any such proposal must include supporting data on which parties and the Commission can deliberate.

### **2.5.3. Overlaps and Distinctions Between Disadvantaged Communities and Hard-to-Reach Customers**

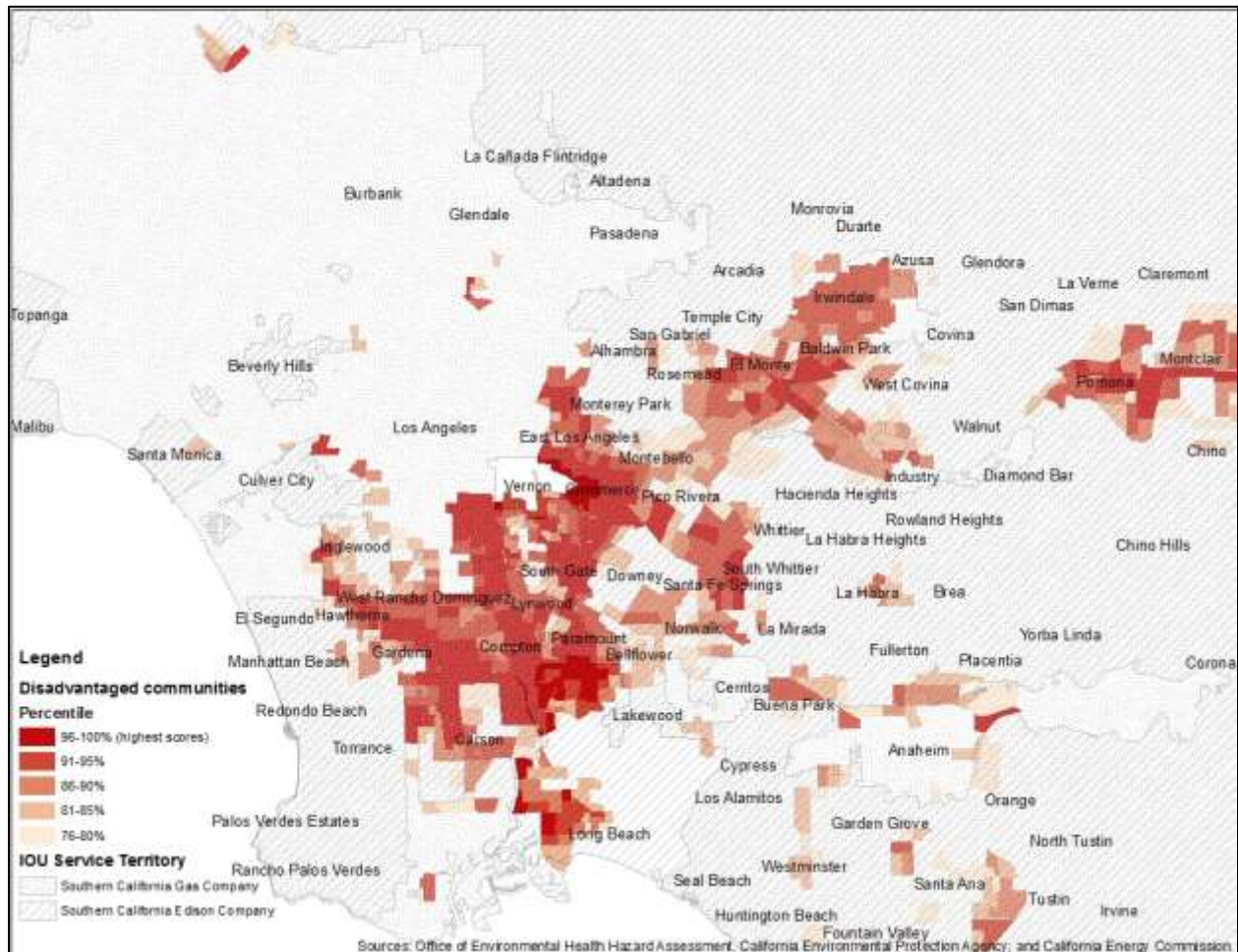
The socioeconomic characteristics of disadvantaged communities overlap considerably, but not perfectly, with Resolution G-3497's criteria for identifying hard-to-reach customers or market segments. A clear difference in the designation of disadvantaged communities is the Pollution Burden indicators that inform the CalEnviroScreen Tool, though even in that respect there are likely parallels beyond mere coincidence between customers considered hard-to-reach based (in part) on where they live, and residents of a disadvantaged community

that is so designated based (in part) on disproportionate exposure to diesel particulate matter, pesticide use, drinking water contaminants, and other pollution factors.

In response to comments on the proposed decision, we acknowledge the hard-to-reach definition in Resolution G-3497 may be overly narrow, although we maintain that the definition in the Policy Manual is overly broad. MCE offers a specific modification to Resolution G-3497, which is to include disadvantaged communities (as designated by CalEPA) in the geographic criteria for hard-to-reach customers. Given the overlap in socioeconomic characteristics of both classifications and their closely related policy objectives, we find it reasonable to adopt MCE's recommended modification.

For our purposes, it is important to maintain a distinction between these two classifications, even though they serve closely related purposes, in order to report on and include specific strategies for maximizing the contribution of energy efficiency savings in disadvantaged communities, pursuant to SB 350. Also, in many cases the two classifications may present different barriers to energy efficiency adoption. In SCE, SoCalGas and SoCalREN's overlapping service area, for instance, many disadvantaged communities are in urban, highly industrialized parts of Los Angeles County. The strategies for maximizing participation or uptake of energy efficiency measures in these communities will likely differ from those for customers in more rural and less densely populated areas of the State.

**Figure 1. Disadvantaged Communities in SCE, SoCalGas and SoCalREN Service Areas – Los Angeles County**



**2.5.4. Business Plan Strategies for Hard-to-Reach Customers and Disadvantaged Communities**

This section primarily addresses business plan strategies for maximizing the contribution of energy efficiency for customers in disadvantaged communities; given that most stakeholders first sought clarification of the definition of hard-to-reach customers, there was less discussion of specific strategies for serving those customers.

SB 350 required the CEC to conduct a study on barriers for low-income customers to energy efficiency and weatherization investments, including those in disadvantaged communities. The resulting “barriers study” identifies specific barriers that the energy efficiency PAs can address through their business plans, including but not limited to a lack of program integration among various clean energy offerings, and high transaction costs for customers with very limited time and resources. The business plans generally refer to the “barriers study” in identifying the strategies they intend to pursue with respect to maximizing energy efficiency savings in disadvantaged communities.

SoCalREN’s strategy for addressing barriers to energy efficiency in disadvantaged communities consists of incorporating distributed energy resource (DER) resources into one-stop project delivery; for hard-to-reach customers, SoCalREN identifies a number of activities including strategic engagement with hard-to-reach stakeholders and decision makers.<sup>27</sup> 3C-REN states its business plan seeks to address “the non-energy benefits that touch on disadvantaged communities’ needs.”<sup>28</sup> SDG&E states it will expand its Emerging Cities and San Diego Association of Governments (SANDAG) Energy Roadmap programs to disadvantaged communities.<sup>29</sup> SoCalGas proposes to first conduct a market study of disadvantaged communities to identify unique market characteristics, market barriers, and customer preferences and energy habits. In the commercial and public sectors, SoCalGas proposes to utilize its Intelligent Outreach strategy, which it describes as “cost efficient targeting of customers

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<sup>27</sup> SoCalREN June 22, 2017 Supplemental Information, at 15, 17-18.

<sup>28</sup> 3C-REN June 22, 2017 Comments, at 8.

<sup>29</sup> SDG&E business plan, at 122 and 204.

with perceived needs such as disadvantaged communities, small businesses, and non-English speaking customers.”<sup>30</sup> PG&E outlines a number of strategies in the commercial, residential, and agricultural sector chapters of its business plan, most notably with respect to coordinating its Energy Savings Assistance offerings with its business plan; PG&E also recommends we adopt a “locked in” ex ante net to gross (NTG) ratio of 0.85 for all programs and projects identified as serving disadvantaged communities, and use up to a 30-year maximum useful life for replaced and removed equipment in disadvantaged communities.<sup>31</sup> SCE’s business plan discusses a strategy to “leverage customer data to target core program coordination and outreach to rural and disadvantaged communities and relax certain program parameters that hinder rural and disadvantaged community participation.”<sup>32</sup> While not consistently called out as such, strategies aimed at addressing split incentive barriers, which is a major focus of the barriers study and the CEC’s resulting implementation efforts, should also help maximize the contribution of energy efficiency in disadvantaged communities when properly directed toward those communities.

Few parties comment on the adequacy of the business plans’ strategies for addressing the needs of either hard-to-reach customers or disadvantaged communities. NAESCO recommends the Commission order each PA to implement a new program for hard-to-reach and underserved ratepayers in manufactured homes.<sup>33</sup> TURN recommends that LEDs be promoted to

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<sup>30</sup> SoCalGas business plan, at 106 and 133; and SoCalGas June 22, 2017 Comments, at 21.

<sup>31</sup> PG&E June 22, 2017 Comments, at 50.

<sup>32</sup> SCE business plan, at 15.

<sup>33</sup> NAESCO June 22, 2017 Comments, at 14-15.

low-income customers in hard-to-reach markets.<sup>34</sup> Also, in its critique of PG&E's recommendation to apply an ex ante adder for energy efficiency programs or projects in disadvantaged communities, TURN asserts these adders are not appropriately tailored to the outcome of removing barriers to energy efficiency in disadvantaged communities.

We will not adopt PG&E's ex ante or maximum useful life recommendations for disadvantaged communities at this time, but we may consider them after an opportunity to evaluate specific programs or interventions. We note further that PG&E's revised sector-level metrics proposal incorrectly defines disadvantaged communities;<sup>35</sup> SDG&E's sector-level metrics proposal does not include specific targets but states it "is currently working to define hard to reach and disadvantaged communities and will incorporate upcoming Commission clarification of HTR."<sup>36</sup> In the compliance filing for program-level metrics discussed in Section 2.3 of this decision, the PAs must include metrics and associated targets for capturing energy savings based on the correct definitions of disadvantaged communities and hard-to-reach customers. We acknowledge and agree with NRDC's more general point that "*how* programs will better serve these customers will be determined by the third parties during the solicitation process in compliance with the new definition...IOUs could include targeted RFPs to help reach this population."<sup>37</sup> Another point made clear in the CEC's barriers study is that disadvantaged

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<sup>34</sup> TURN June 22, 2017 Comments, at 44.

<sup>35</sup> PG&E July 14, 2017 Response, Appendix 1, at 3.

<sup>36</sup> SDG&E July 14, 2017 Response, Attachment A, at 5.

<sup>37</sup> NRDC June 22, 2017 Comments, at 10.

communities face a variety of challenges, many of which may only be partially addressed by energy efficiency measures and/or workforce development efforts. We expect the PAs to coordinate their efforts with other clean energy opportunities to the greatest extent possible, and to conform their portfolios with the State's overall efforts toward maximizing the contribution of energy efficiency in disadvantaged communities. In this decision we direct program administrators to develop metrics for tracking progress toward energy savings among hard-to-reach customers and disadvantaged communities (as well as workforce training metrics for disadvantaged workers), and include them in their compliance filings. We also direct each PA to measure progress toward their identified interim milestones and targets for each metric in their annual reports. As part of this tracking activity, we also direct the PAs to assess the relative success of implementers' strategies, for purposes of identifying lessons learned and best practices for maximizing the contribution of energy efficiency in disadvantaged communities.

## **2.6. Cost Effectiveness, Reasonableness of Business Plan Budgets**

Public Utilities Code Section 454.5(b)(9)(C) requires that utilities shall first meet their unmet resource needs through all available energy efficiency and demand reduction resources that are cost-effective, reliable, and feasible. The Commission's current cost-effectiveness standard for the IOUs is reflected in D.12-11-015, which states "the dual test for overall portfolio cost effectiveness, taking into consideration passing both the TRC and PAC tests for each service territory and for the entire approved portfolio, including RENs, will continue to govern the CPUC's cost-effectiveness for the energy efficiency programs."

D.12-11-015 further specifies omitting the costs and benefits of the utilities' codes



and standards work from the calculation, as the historically high benefit-cost ratio of those activities serve as a “cushion” for the rest of the portfolio, and we continue to disallow costs and benefits from codes and standards work for both ex-ante and ex-post calculations at this time.

The Commission also requires CCAs’ portfolios to meet a cost-effectiveness standard. D.14-01-033 requires that a CCA’s portfolio meet a TRC of 1.0 for three years from the date we approved their proposal to “apply” or “elect” to administer conservation and/or energy efficiency programs, and thereafter meet the same cost-effectiveness standard as the IOUs. The Commission has not set a cost-effectiveness standard for RENs; we discuss that issue separately, in Section 4.1.

The “dual test” considers both the TRC test, which includes the costs to both program administrators and participants and the net lifecycle benefits to the utilities / all ratepayers in the form of avoided energy costs; and the PAC test, which considers the costs to the program administrator and the benefits to the utility / all ratepayers. PAC test estimates are in most cases higher than their corresponding TRC test estimates, since most programs involve some amount of participant costs.

In D.12-11-015 the Commission adopted a number of hedges against certain risks that the 2013-2014 portfolios would not achieve their forecasted TRC estimates. These hedges included: omitting codes and standards (C&S) advocacy costs and benefits and spillover effects; and setting a higher TRC threshold, of 1.25, as the basis for determining cost-effectiveness of the proposed

portfolios on an ex ante, or forecast, basis.<sup>38</sup> In D.14-10-046 the Commission removed the 1.25 threshold for 2015 portfolios, in recognition of the transition to a rolling portfolio framework. The Commission indicated, however, that it would return to a 1.25 threshold in subsequent years.

The PAs presented business plans under a general assumption that the Commission would rule on their proposals (i.e., to deny, adopt, or adopt with modifications) in time for the PAs to launch new programs beginning in 2018, and thus provided information on forecasted cost-effectiveness for 2018 through 2020 (MCE provided estimates for “Year 1” and “Year 2”). The Commission did not rule on the business plans before 2018, affording time for the submission of supplemental information by the PAs, including standardized budget details resulting from a meet-and-confer effort among ORA, TURN and the PAs, and further pleadings by all parties; the Commission also adopted a decision establishing the third party solicitation process in order to provide the PAs with an opportunity to commence solicitations as soon as feasible after the Commission disposes of the business plans. The July 25, 2017 ruling directed the PAs to submit their 2018 ABALs on September 1, 2017, consistent with the bus stop schedule adopted in D.15-10-028. The February 8, 2018 ruling consolidated the 2018 ABALs with this proceeding in order to consider the advice letters in the context of transitioning to the business plans.

### **2.6.1. Revisiting the Rolling Portfolio Framework**

A key issue, in our consideration of this first set of business plans under the rolling portfolio framework, was the business plans’ cost-effectiveness and

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<sup>38</sup> D.12-11-015 also specified omitting REN and CCA costs and benefits from the utilities’ TRC forecasts.

reasonableness of budgets. As context for that discussion, certain points from our decisions establishing the rolling portfolio framework (D.15-10-028 and D.16-08-019) are worth revisiting. We do this in part to address the dispute between CEE, ORA and NAESCO on the one hand, and the IOUs on the other, about the level of detail the PAs should have included as part of their business plan proposals. ORA, NAESCO, and CEE allege the IOUs have failed to provide sufficient detail in their proposed budgets to justify approval of their business plans. The IOUs counter with several arguments: first, that D.16-08-019 does not require the degree of budget detail that these parties seek, and such detail should be left to the ABAL process; and second, that any forecasts of utility expenditures prior to third party solicitations would be highly uncertain and subject to revision based on solicitation results, thus the purpose of such forecasts is questionable from the IOUs' perspectives.

The Commission and Commission staff shared parties' interest in better understanding the basis for PAs' budget projections, leading us to require the PAs to file supplemental budget information based on a meet-and-confer with ORA and TURN. This exercise, though it may be of limited use to our determination on the business plans, helps highlight the key issues that warrant attention as the PAs proceed to implement their business plans. It also compels us to reemphasize the key features of the rolling portfolio framework, which we discuss here.

In establishing the rolling portfolio framework, we put the PAs squarely in the position of serving as prudent managers of their own portfolios:

First, PAs, not the Coordinating Committee, are responsible for the content of what PAs file with the Commission (i.e., applications and advice letters) [footnote omitted]. PAs also bear responsibility for what PAs post to Commission-maintained web

sites pursuant to this decision (e.g., implementation plans). This means that PAs, not the Coordinating Committee, will have the final say in what PAs file and/or post with the Commission.<sup>39</sup>

The IOUs in particular will need to increasingly focus on running effective solicitations and evaluating the viability of third parties to perform the program design and delivery functions needed to achieve ambitious energy savings goals.

We expect the PAs to optimize their portfolios based on three high-level objectives: meeting or surpassing energy savings goals, cost-effectively, and within budget, as indicated by the triggers we identified for PAs to file revised business plans, which are:

1. A PA is unable to adjust its portfolio in response to goal, parameter, or other updates to:
  - a. meet savings goals,
  - b. stay within the budget parameters of the last-approved business plan, or
  - c. meet the Commission-established cost effectiveness (excluding Codes and Standards and spillover adjustments);
2. The Commission calls for a new application as a result of a decision in the policy track of the proceeding (or for any other reason);<sup>40</sup>

We are adopting guidance for reviewing annual funding levels and a minimum threshold for cost-effectiveness forecasts in ABALs, so the objective is

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<sup>39</sup> D.15-10-028, at 76.

<sup>40</sup> D.15-10-028, at 57 and Ordering Paragraph 2. The affected PA must file a business plan not less than one year prior to the end of funding. PAs may also file revised business plans whenever they choose to do so.

to maximize energy savings (at minimum, to meet energy savings goals) under these funding and cost-effectiveness constraints:

On funding authorization:

The decision on the business plans will not establish a particular amount for cost recovery (for IOUs) or for transfers from IOUs (for CCAs) or for contracting purposes (for RENs). It will establish a 'ballpark' figure for spending for the life of the business plan. The annual advice letter filings, not the business plans, will propose detailed budgets for cost recovery, transfer, and contracting purposes.

The goal is to give flexibility to PAs to adjust spending during the life of the business plan. Giving PAs this flexibility necessarily entails some discretion for staff in reviewing the annual advice letters. Hence those advice letters are properly Tier 2 rather than Tier 1...<sup>41</sup>

On cost-effectiveness:

Program administrators should still bring us an overall business plan portfolio that is cost-effective, but may also point out where risks to cost-effectiveness may be possible and leverage the implementation plans to propose program design and implementation alternatives to mitigate the challenges identified.<sup>42</sup>

Requiring the PAs to manage their portfolios, in order to satisfy these objectives, compels us to afford some flexibility with respect to how the PAs satisfy our requirements. We condition this flexibility on the PAs' adherence to Commission staff's and stakeholders' input, past Commission decisions, and the business plans (as adopted with modifications in this decision). The PAs will

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<sup>41</sup> D.15-10-028 at 55-56.

<sup>42</sup> D.16-08-019, at 91.

also need to conform their portfolios with future Commission guidance in the policy rulemaking:

The Commission will provide ongoing high-level strategic guidance via a ‘policy track’ in an EE proceeding. The policy track will run in parallel with more granular portfolio review activities.<sup>43</sup>

In this way, we intended to balance the requirement to assess reasonableness and consistency with Commission policy in the ABAL process, on the one hand, with flexibility for all stakeholders to work out the more technical details through the stakeholder collaborative process, on the other:

The annual review we contemplate here *should* be relatively ministerial. However, if a PA departs in significant ways from that PA’s most recent budget, the PA can expect a higher degree of scrutiny from Commission Staff, and possibly a suspension of the advice letter...<sup>44</sup>

Some parties emphasize the point that the annual review process should be ministerial, which we also prefer insofar as it both reflects and reinforces a collaborative stakeholder process. This condition, i.e., the need for collaboration, is absolutely essential:

The Coordinating Committee’s role is to advise the PAs. The Coordinating Committee therefore needs both stakeholder and PA participants, but PAs must not dominate Coordinating Committee proceedings. PAs must provide the Coordinating Committee with information in a form and on a timeline that allows for meaningful stakeholder input. In addition, PAs must be willing to take Coordinating Committee advice. If the Coordinating Committee becomes a “forum[] for the utilities to present decisions already

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<sup>43</sup> D.15-10-028, at 45.

<sup>44</sup> D.15-10-028, at 60-63.

made rather than to seek input in a collaborative manner,” [footnote omitted] rather than a source of useful input, then we will be back to the drawing board.<sup>45</sup>

In the hopefully rare event that issues reach an impasse, parties have a means to bring the issue to the Commission for formal resolution:

As part of the implementation plans, PAs are to provide (and keep current) PA-designed manuals and rules that provide guidance to customers and implementers with respect to program delivery, including measure and participant eligibility requirements. The manuals and rules must follow Commission policy and guidance as provided in past decisions and rulings, as well as guidance provided by CPUC Staff as a result of *ex ante* and *ex post* activities.

If (alleged) non-compliance with Commission/Commission Staff direction is identified in the implementation plans, manuals, and/or rules, the dispute resolution process we previously approved for *ex post* evaluation disputes in D.13-09-023 [footnote omitted] may be invoked. A party may file a “Motion for Implementation Plan Dispute Resolution” in this docket (R.13-11-005) or in the relevant PA’s most recent business plan application docket. This formal procedure may only be invoked after informal attempts to resolve disputes have been exhausted.<sup>46</sup>

We recognize that Coordinating Committee activities leading up to the PAs’ filing of their business plans may not have reflected the level of collaboration some stakeholders expected or desired, leading us to emphasize that our intent is for the PAs to work out most technical details informally with staff and stakeholders. In Section 8.2.1 of this decision we address whether and how collaboration in the Coordinating Committee process can improve. Part of

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<sup>45</sup> D.15-10-028, at 77.

<sup>46</sup> D.15-10-028, at 64-65.

our rationale for establishing a rolling portfolio framework was to facilitate a more stakeholder oriented approach – a departure from the more strictly formal and prescriptive approach to which parties were accustomed, and therefore requiring a greater degree of trust:

Whether a more stakeholder oriented approach to EE programs will work ultimately comes down to trust. No matter how many rules we promulgate, no matter how prescriptive Commission Staff and we are, ultimately this edifice will stand only if all concerned act in good faith towards a common goal of reduced energy use for a given level of activity.<sup>47</sup>

Against this backdrop, we consider cost-effectiveness of the 2018 ABALs and the 2018-2025 business plans.

### **2.6.2. 2018 Annual Budget Advice Letters**

The existing PAs' 2018 budget advice letters (submitted September 1, 2017) show non cost-effective or marginally cost-effective portfolio TRC estimates, which reflect the same energy efficiency goals and avoided cost assumptions as their business plans. On October 30, 2017, Energy Division directed the PAs to submit supplements that reflect the updated goals and interim greenhouse gas (GHG) adder adopted in 2017. Energy Division also advised that PAs may include alternative scenarios reflecting expanded programs with high cost-effectiveness, reduction or removal of programs with low cost-effectiveness, and/or portfolios that may exceed current budget limits.<sup>48</sup> The PAs' November

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<sup>47</sup> D.15-10-028, at 77-78.

<sup>48</sup> Energy Division's October 30, 2017 letter to the PAs notes that requests for budget authority beyond the amounts authorized in D.14-10-046 require Commission approval.



2017 supplemental submissions show improved TRC estimates but only SoCalGas's estimate exceeds 1.25.<sup>49</sup>

**Table 1. 2018 Energy Efficiency Portfolio Cost-Effectiveness Forecasts (without Codes and Standards) – 2018 Annual Budget Advice Letters**

PA	September 1, 2017 advice letters		November 2017 supplements	
	2018 Budget Request (millions)	TRC (w/out C&S)	2018 Budget Request (millions)	TRC (w/out C&S)
PG&E	\$400	0.86	[no change]	1.01
SoCalGas	\$83.7	1.05	\$104.1	1.37
SCE	\$299.6	1.00	[no change]	1.13
SDG&E	\$116.4	1.03	[no change]	1.09
MCE	\$1.59	0.57	[no change]	0.69
BayREN	\$16.7	0.2	[no change]	0.23
SoCalREN	\$21.7	0.4	[no change]	0.44

The November 2017 supplements (other than SoCalGas) also included alternative scenarios, pursuant to Energy Division's advice, to reflect different portfolio structures that might result in a minimum TRC of 1.25.

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<sup>49</sup> The IOUs and SoCalREN submitted their supplements on November 22, 2017; MCE and BayREN submitted their supplements on November 30, 2017,

**Table 2. 2018 Energy Efficiency Portfolio Cost-Effectiveness Scenarios  
(without Codes and Standards) – 2018 Annual Budget Advice Letter  
Supplements**

PA	Scenario 1/ baseline	Scenario 2	Scenario 3
PG&E	1.01	1.27	1.26
		Eliminate all non-resource programs and resource programs with a TRC less than 0.55.	Increase the NTG values to 0.85 for all measures with a NTG less than 0.85.
SCE	1.13	1.25	1.25
		Eliminate lowest impact programs. CFLs/A lamp LEDs remain.	Eliminate lowest impact programs. CFLs/A lamp LEDs removed.
SDG&E	1.09	1.16	1.37
		Eliminate all resource programs < 1.0	Eliminate all non-resource programs
MCE	0.69	NA <sup>50</sup>	[none]
		Business plan	
BayREN	0.23	0.27	0.32
		Shift funds from Res - Single Family to C&S, Commercial P4P/Financing	Target older Single Family homes for deeper savings; CodeCycle for Non-Res Lighting
SoCalREN	0.44	0.55	0.72
		Discontinue non cost-effective programs and shift funds from Single Family to Multi-family	Multi-family program with tiered incentives

<sup>50</sup> MCE's AL-25-E-A states "The expedited schedule for this advice letter did not provide sufficient time for MCE to update and finalize cost effectiveness inputs for its business plan. MCE expects, however, to have results for its cost effectiveness analyses in early 2018." MCE Advice Letter 25-E-A, at 7.

The extent to which the various scenarios reflect or are consistent with the PAs' business plans is obviously not uniform, but generally indicative of future challenges, i.e., the types of trade-offs the PAs may have to face, in achieving or improving cost-effectiveness. Given the non-cost-effective or marginally cost-effective forecasts reflected in the PAs' business plans – albeit reflective of now-outdated goals and avoided cost assumptions -- such budget optimization efforts may continue to be a necessary exercise.

By the time the Commission disposes of the 2018-2025 business plans (through this decision), the deadline for the next ABALs will only be several months ahead. In light of the marginally cost-effective TRCs in the 2018 ABALs -- other than SoCalGas's supplemental submission, which we address separately -- and in the interest of moving forward with the business plans and enabling the PAs to commence with third party solicitations as soon as practical, we reject the 2018 ABALs (except for SoCalGas) in favor of approving the business plans and associated funding levels for 2018. The IOU PAs must achieve cost-effective portfolios (i.e.,  $TRC > 1.0$ ) for this program year (2018) on an evaluated basis. As we discuss in Section 7, failure to achieve cost-effectiveness on an evaluated basis, in any program year, will affect a utility's ability to proceed with implementing its portfolio or gain approval of future annual budget requests.

#### **2.6.2.1. Disposition of SoCalGas's 2018 Annual Budget Advice Letter**

SoCalGas's Tier 3 supplement to its 2018 ABAL includes an incremental budget request of approximately \$20.4 million, for a total 2018 budget of \$104.1 million. Driving this incremental budget request, SoCalGas explains, is the significant increase to SoCalGas's energy savings goals resulting from our

adoption of 2018-2030 goals in D.17-09-025: SoCalGas's savings goals for 2018 increased by more than 50 percent, from 13.4 million net therms to 20.3 million net therms. SoCalGas further explains it intends to eliminate some programs with poor performance<sup>51</sup> and incorporate new programs consistent with the potential study on which D.17-09-025 is based. Specifically, SoCalGas's residential sector budget would increase by \$10 million to achieve an additional 1.8 million net therms, largely in behavioral programs; SoCalGas also intends to increase appliance rebates and direct install programs targeted at moderate income, hard to reach and disadvantaged communities. SoCalGas's industrial sector budget would increase by \$8.4 million to achieve an additional 4.1 million net therms, reflective of an increase in third party programs for mining customers and for small to medium customers to implement a comprehensive resource acquisition program. SoCalGas also proposes an additional \$1 million for its Commercial Energy Advisor Program, reflective of increased savings potential in the Building Operator Certification use category.

Combined with updated avoided cost assumptions (i.e., adoption of an interim greenhouse gas adder), these portfolio changes result in an increased TRC of 1.37, as opposed to 1.05 in SoCalGas's September 1, 2017 submission.

Given the significant increase in SoCalGas's savings goals, the proposed elimination of non-cost-effective programs and expansion of programs with higher savings potential, all contributing to a forecast portfolio TRC of 1.37, it is reasonable to approve SoCalGas's request for incremental budget authority for

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<sup>51</sup> SoCalGas intends to close the Commercial Recirculation Pump Control program, Energy Advantage Program for Small Business, and Clear Ice (ice rinks) due to declining or otherwise low cost-effectiveness; and to incorporate historic buildings into the Home Upgrade Program.

2018 with one exception, which is the Commercial Energy Advisor program. Since the CEDARS 2018 Budget Filling Detail Report\_V2 identifies the Commercial Energy Advisor as a *non-resource* program with zero projected savings, the extra funding would be due to converting this into a resource program. SoCalGas indicates the money would be used to enhance the program's development of methodologies. We are not convinced that the request for \$1.0 million to convert the non-resource program into a resource program is warranted. We will approve an increase in funding of \$19.4 million, which is all the funding requested except for the amount for the Commercial Energy Advisor program.

### **2.6.3. Business Plans**

The PA's business plans reflect portfolios that are tenuously cost-effective, as measured by the TRC test (omitting the contribution of codes and standards activities and spillover effects to portfolio cost-effectiveness). None of the portfolios' TRCs meet the 1.25 threshold that the Commission previously required for 2013-2014 portfolios.

**Table 3. 2018-2020 Energy Efficiency Portfolio Cost-Effectiveness Forecasts  
(without Codes and Standards) - Business Plans**

	TRC			PAC		
	2018	2019	2020	2018	2019	2020
<b>SCE</b>	1.00	1.05	1.10	1.29	1.35	1.42
<b>PG&amp;E</b>	1.03			1.27		
<b>SDG&amp;E</b>	1.02			1.19		
<b>SCG</b>	1.11			1.47		
<b>MCE</b>	1.13					
<b>BayREN<sup>52</sup></b>						
<b>SoCalREN<sup>53</sup></b>	1.01			1.23		
<b>3C-REN</b>	0.27	0.31	0.35	0.39	0.46	0.55

We reiterate that the portfolio TRC estimates in the PAs' business plans reflect now-outdated energy efficiency goals and avoided cost assumptions. The existing PAs' 2018 budget advice letters and supplemental submissions suggest that incorporation of the updated goals and interim GHG adder may improve the business plans' cost-effectiveness to a limited extent, although as demonstrated by SoCalGas's supplement, they may also imply a need for additional funding.

The key cost-effectiveness issue we must address, for purposes of determining whether to approve the business plans, is what cost-effectiveness standard (i.e., a TRC of 1.0 or 1.25, or a different standard) we utilize for assessing whether the business plans will generate cost-effective portfolios for each utility and among all the energy efficiency PAs.

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<sup>52</sup> BayREN's business plan does not include a portfolio TRC or PAC estimate.

<sup>53</sup> Does not include non-resource costs.

### **2.6.3.1. Positions of the Parties**

ORA and NAESCO recommend against approval of the proposed business plans, and instead advocate for the Commission to order updated and refiled business plans that include more favorable TRC estimates. The IOU PAs generally assert their business plans, as presented, are cost-effective pursuant to a 1.0 TRC standard, suggesting therefore that the Commission should evaluate the business plans based on a TRC of 1.0. PG&E, however, acknowledges that cost-effectiveness may continue to be a challenge and therefore recommends a number of changes to cost-effectiveness policy, which we address separately in Section 2.6.4.

The supplemental budget information submitted by the PAs, resulting from their meet-and-confer with ORA and TURN, may be useful for future tracking and reporting purposes but nearly all the PAs warn against heavy reliance on their current estimates, and that they will be able to provide more accurate forecasts following their first round of third party solicitations.

TURN acknowledges the substantial degree of uncertainty with which most of the PAs express their inability to forecast their costs beyond the first few years of the business plan timeframe. In this context of significant uncertainty, TURN recommends against reaching any definitive conclusion about the cost-effectiveness of the business plans, as filed, and instead focusing on providing specific guidance for the cost-effectiveness forecasts to be included in the PAs' ABAL submissions.<sup>54</sup> SDG&E agrees and suggests it would be

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<sup>54</sup> TURN June 22, 2017 Comments, at 2-6

reasonable to restore the 1.25 TRC threshold after solicitations are completed (based on the utilities' proposed solicitation schedules).

TURN further recommends we require the PAs to include updated budget information in their 2019 ABALs, using the supplemental budget templates filed on June 12, 2017, on the assumption that the PAs would at that time "know significantly more about portfolio composition and the cost impacts of the D.16-08-019 requirements."<sup>55</sup>

### **2.6.3.2. Discussion**

The fact that we previously held earlier portfolios to a higher cost-effectiveness standard (i.e., a TRC greater than or equal to 1.25) for approval reflected circumstances in which some programs forecasted dramatically high TRCs (e.g., greater than 6.0), but we were simultaneously concerned that actual performance did not track forecasts very well. In that context the Commission found it reasonable to adopt a number of hedges, including requiring an ex ante TRC greater than or equal to 1.25, to ensure that actual performance would generate a minimum TRC of 1.0. The circumstances under which we now consider the business plans are much changed, but similarly pose a high degree of uncertainty. We agree with TURN's suggested approach of reaching only a tentative conclusion regarding the business plans' cost-effectiveness. The IOUs have explained in their business plans and supplemental filings how they performed portfolio optimization in order to achieve an ex ante TRC above 1.0. Our adoption of the business plans rests largely on whether the business plans comply with past Commission direction, the merits of the strategies presented,

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<sup>55</sup> TURN June 22, 2017 Comments, at 7.



and the reasonableness of the PAs' approaches to developing their proposed budgets under a non-trivial amount of uncertainty regarding future staffing needs.

We acknowledge ORA and NAESCO's concerns with approving the business plans without first requiring the PAs to refile in order to demonstrate both greater certainty of future in-house staffing and budget projections and, resulting from that greater certainty, higher TRC estimates. However, if we further delayed ruling on the business plans in order to require this information, we would still face the fundamental question of whether and how much confidence we would put in such projections and whether it would be reasonable to hold the PAs accountable if they failed to meet those projections. We prefer to demand accountability in the form of requiring the PAs' ABALs to meet specific energy savings, cost-effectiveness and budget criteria. With our adoption of the third party solicitation process and the specific provisions therein intended to ensure robust solicitations, we find it reasonable to delay our expectation of more concrete and detailed forecasts of the PAs' in-house staffing and resource needs until after the PAs have conducted their first round of solicitations. However, we agree with the general position of ORA and NAESCO, that increasing reliance on third parties for program design and delivery should result in a decreasing need for in-house program staff and, therefore, decreasing budget forecasts on a long-term basis. To that end, we agree with TURN's further recommendation to require updated information in the format of the June 12, 2017 supplemental budget filings, for assessing PAs' administrative costs and for gaining greater certainty regarding long-term cost-effectiveness of their business plans. Given that the first solicitations likely will not occur until later this year

(2018), it is reasonable to require the PAs to include this information starting with their September 3, 2019 ABALs.

We are no doubt concerned that the TRC estimates reflected in both the 2018 ABALs (except SoCalGas's 2018 supplemental submission, which we address in the preceding section) and in the business plans are in most cases well below 1.25. In light of these low TRC estimates, the non-trivial amount of uncertainty regarding third-party programs and, relatedly, the IOUs re-orienting their focus toward prudent portfolio management, we intend to treat the first few program years (i.e., 2018 - 2022) as "ramp" or transition years, during which we will direct staff to evaluate the ABALs against a specific set of criteria, including most significantly that the portfolio forecast TRC must meet or exceed 1.0. We set this interim cost-effectiveness standard for the ramp years to enable continuity of energy efficiency activities and to allow third parties to develop and deliver new programs, which are central features of the rolling portfolio framework, while keeping sight of our key long-term objectives (meeting energy savings goals, cost-effectively, and within budget). We remain concerned about the gap between ex ante forecasts and evaluated results, as we previously acknowledged in D.15-10-028. However, multiple changes will be occurring at the same time, including a significant increase in program outsourcing and a new governance structure for statewide administration. Our fundamental intent with both these transitions is to achieve greater energy savings more efficiently, on the premises that (1) third parties will bring innovative strategies to bear on California's energy efficiency market, thereby achieving savings that would otherwise go untapped; and (2) statewide administration of certain programs could yield efficiency benefits in the form of standardized processes and seamless customer experience. Neither outcome is guaranteed, which is why we

should, and will, require an additional process to ensure the portfolios are cost-effective on an evaluated basis. We discuss the details of the ABAL review criteria, and additional review process, in Section 7 of this decision.

The gap between ex ante forecasts and evaluated results is an ongoing issue we may examine more closely as part of a comprehensive review of energy efficiency cost-effectiveness, in R.13-11-005. Ideally, evaluated results would track ex ante forecasts more closely and consistently, but we will not have such results for new third party programs until, at the earliest, 2021. Unless the Commission later decides otherwise, we will restore a 1.25 TRC cost-effectiveness standard beginning with the September 1, 2022 ABALs (i.e., for program year 2023 and beyond).

We also acknowledge the various calls for modifying cost-effectiveness policy, which would likely improve cost-effectiveness modeling results but for reasons discussed below, we do not adopt at this time. Irrespective of whether and when the Commission modifies cost-effectiveness policy, either for energy efficiency or for all distributed energy resources, all PAs must design their portfolios to achieve all feasible efficiencies and energy savings, consistent with their overall portfolio optimization efforts, in order to achieve an overall cost-effective portfolio. The PAs' ABALs must provide sufficient detail, and basis in their implementation plans, to demonstrate their business plans will be cost-effective during each year of implementation.

#### **2.6.4. Other Issues Regarding Cost-Effectiveness**

##### **2.6.4.1. Changes to Cost-Effectiveness Policy**

As we previously mentioned, some parties raise further issues or recommendations for modifying specific cost-effectiveness policies, which they contend are outdated or otherwise inapplicable to the rolling portfolio

framework. In particular, PG&E's business plan and 2018 ABAL include a number of recommendations for modifying cost-effectiveness policy:

- Excluding participant costs not associated with energy savings from TRC calculations.
- Excluding costs of non-resource programs for which benefits have not yet been quantified.
- Permitting energy efficiency measures with an effective useful life (EUL) longer than 20 years.
- Including codes and standards advocacy savings in program and portfolio cost-effectiveness calculations.
- Permitting PG&E to claim incremental finance savings
- Adopting ex ante "adders" for programs and projects in disadvantaged communities.
- Revisiting the process for adopting net-to-gross (NTG) estimates.<sup>56</sup>

CEDMC, NRDC, BayREN and SoCalREN also advocate a number of cost-effectiveness policy changes, suggesting a more extensive revision to reflect different and broader priorities such as workforce development, grid integration, and non-energy or societal benefits.<sup>57</sup>

ORA opposes consideration of the RENS' proposed Evaluation Benefits Framework as part of our evaluation of their business plans.

TURN supports consideration of PG&E's proposal to remove non-energy related participant costs from the TRC, but expresses concern with most of PG&E's other recommendations. For instance, regarding the proposal to permit

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<sup>56</sup> PG&E September 25, 2017 Comments, at 37 - 42.

<sup>57</sup> BayREN September 25, 2017 Comments, at 15-16.

an expected useful life (EUL) value up to 30 years, TURN notes the Commission in D.09-05-037 declined such a request due in large part to a lack of supporting empirical evidence. More generally, TURN urges that any consideration of changes to cost-effectiveness policy occur in the policy track (R.13-11-005 or its successor) rather than as part of our determination on the business plans.

SDG&E advocates, similar to PG&E, to include codes and standards savings in the TRC. SDG&E also agrees with TURN that the various recommendations for changing cost-effectiveness policy should be addressed in R.13-11-005.

We generally agree with TURN and SDG&E that this proceeding is not the appropriate venue for deciding major modifications to cost-effectiveness policy. Moreover, policy issues and recommendations such as those raised by parties require a much more robust record than we provided for in deliberations about approving the business plans. PG&E acknowledges, for instance, it “was not able to conclusively and comprehensively determine and verify all of the possible factors that contribute to low cost-effectiveness for specific programs and measures” in its 2018 budget advice letter supplement.<sup>58</sup> Such analysis is necessary to identify and determine the reasonableness of specific changes either to programs that improve their actual cost-effectiveness, or to cost-effectiveness policy that not only improves actual benefit-cost ratios, but that also improves the accuracy of the Commission’s cost-effectiveness estimates. For instance, a future consideration for cost-effectiveness policy may be to avoid the inclusion of pilot programs not on an annual evaluation cycle, such as a high opportunity

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<sup>58</sup> PG&E AL-3881-G-A/5137-E-A, at 11.

program or project (HOPP), in the portfolio cost-effectiveness calculation. Finally, we are more interested in seeing the PAs achieve greater savings and lower costs, consistent with our intent for the rolling portfolio framework, than in changing the rules in order to reach a finding that the portfolios are cost-effective. Such modifications may prove to have merit, but only after the PAs gain experience with implementing their business plans and are able to substantiate their positions with concrete program findings or evaluation results. This will invariably require more facts and examination thereof in order to reach a finding as to their reasonableness. 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.

#### **2.6.4.2. Administrative Costs**

D.09-09-047 established a cap on administrative costs (excluding third party and/or local government partnership budgets), of 10 percent of total energy efficiency budgets.<sup>59</sup> No parties propose modifications to this overall cap on administrative expenses in the context of the proposed business plans. However, NAESCO and ORA take issue with the large variance in administrative costs among the PAs, noting for instance the significant difference between PG&E and SCE's account representative full time equivalents (FTEs) despite their similar portfolio size. ORA suggests "[t]his raises the factual question of what customer acquisition costs actually are and what a reasonable

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<sup>59</sup> D.09-09-047, at 62 and Ordering Paragraph 13.

budget for customer acquisition would be even in the absence of the Commission's direction on third-party programs."<sup>60</sup>

NAESCO recommends we use the CEC's Proposition 39 program as a benchmark against which to evaluate PA administrative costs, at least for the portion that will be third party programs. NAESCO explains that, for an annual budget that is greater than any of the PAs, the CEC dedicates far fewer staff than either PG&E or SCE to administer Proposition 39 funds and conduct associated program administration duties. SCE and SDG&E argue against this recommendation, noting that administrative costs for specific programs depend on the type of program and delivery method and that the CEC's requirements differ sufficiently from the CPUC's that such a comparison is not justified.

We agree it likely does not make sense to evaluate administrative costs based on NAESCO's recommended benchmark; separately, however, we do intend in the near future to address administrative costs in the context of the accounting issues identified in the amended Scoping Memo of R.13-11-005. In D.15-10-028 the Commission recognized a lack of consistency in accounting practices across utilities, and stated our intent to address this issue following the issuance of the State Controller's Office report on PA accounting systems. We have yet to follow through on this important issue, but we have every intention to increase transparency and comparability of administrative costs among the PAs so that apparent inconsistencies such as those identified by NAESCO and ORA are mitigated and/or more easily explained. In particular, we remain interested in doing away with categories or classifications of certain funding

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<sup>60</sup> ORA June 29, 2017 Comments, at 5.

amounts as “committed” or “encumbered.” We take this opportunity to affirm that PAs must ensure their accounting and reporting policies and practices can accommodate any requirements the Commission may adopt in R.13-11-005 or its successor proceeding.

#### **2.6.4.3. Cost Recovery for Third Parties’ Use of Utilities’ Customer Support Personnel**

ORA points out that third parties may wish to utilize different customer acquisition techniques than those used by the IOU programs, and contends the IOUs should not assume that all third parties will necessarily use the IOUs’ customer acquisition resources. ORA recommends the Commission prohibit the utilities from charging customer support personnel expenses to their energy efficiency balancing accounts; instead, ORA asserts, the utilities should either seek recovery of such costs in general rate case (GRC) applications, or charge the use of utility account representatives to a non-tariff services arrangement, the costs of which would be included in the energy efficiency bids provided by third parties who opt to utilize utility account representatives. NAESCO supports ORA’s recommendation.

In response to ORA’s recommendation, the utilities assert a continuing need for their account representatives to interface with and provide assistance to customers, at least while they are undergoing the transition to a predominantly third party portfolio. PG&E indicates it “understands ORA’s concerns and is evaluating opportunities to find cost efficiencies during the transition to the third-party model,” and further agrees not to require third parties to use its customer-facing personnel “as long as third parties put forward reasonable and



cost-effective proposals to deliver this function.”<sup>61</sup> PG&E does not, however, support a prohibition on charging customer support personnel to their energy efficiency balancing accounts, citing earlier comments of some third party implementers in R.13-11-005 that using utility customer support personnel is more advantageous than an outsourced alternative. SCE agrees with and repeats PG&E’s arguments, but also acknowledges that “[a]s the transition process stabilizes, any reduction in the need for account representatives will be reflected in the Annual Budget Advice Letters.”<sup>62</sup> SDG&E believes its account representatives’ roles with respect to energy efficiency “should be largely unchanged,” based on its view that its account representatives are highly specialized in providing objective and independent advice. In that context, SDG&E asserts ORA’s recommendation “is contrary to assuring objective and independent advice, as [account representatives] would then be required to support specific third party program implementers to the exclusion of others.” SDG&E also contends that “[a]ny concern regarding the cost of this service is managed through the Commission’s Direct Implementation Non-Incentive cost target of 20% of portfolio budget.”<sup>63</sup>

Although we do not agree that use of a non-tariff agreement would necessarily result in biased advice, as SDG&E suggests, we acknowledge this is a possible outcome and are therefore hesitant to adopt ORA’s recommendation at this time. We share an interest in minimizing administrative costs, which the PAs state they are also mindful of, but there is insufficient information at this

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<sup>61</sup> PG&E October 13, 2017 Comments, at 3-5.

<sup>62</sup> SCE October 13, 2017 Comments, at 17-18.

<sup>63</sup> SDG&E October 13, 2017 Comments, at 7-11.

point to assess which model optimizes both cost and customer service. We wish to observe whether and to what extent third parties, when afforded the option, eschew the use of utility account representatives. We will require the utilities to, at minimum, make third parties' use of utility account representatives optional and to track the number and proportion of third parties that forego this option. The utilities should include this information in their annual reports.

### **3. Utility Business Plans**

This section addresses the IOU PAs' business plan filings. As with earlier sections of this decision, if particular items are not discussed that were included in the IOU filings, then those items should be considered approved. We discuss below only those items where the Commission needs to weigh in or give additional guidance.

#### **3.1. Statewide Programs**

D.16-08-019 laid out the basic structure of the requirements for statewide programs going forward. This section addresses additional guidance that is needed to ensure a successful rollout to this new model.

##### **3.1.1. Governance and Management of Statewide Programs**

The utilities jointly proposed that the governance for the statewide programs would be handled through a Program Council, comprised of all IOUs only, for each program area. Each Program Council would meet at least quarterly, or more frequently, if necessary. Decisions and management would be by consensus, with disputes settled by the Program Council or, if necessary, by the Commission.

As described by the IOUs, the lead IOU would have responsibility for:

- Program vision development, design/delivery, and intervention strategies (with input from the Program Council)
- Procurement, contract administration, and co-funding management from partner IOUs
- Implementer oversight
  - The lead IOU would have sole responsibility for implementer management, rewards, and any necessary corrective action
  - Lead IOU would review implementer performance and program performance on a quarterly basis
- Meeting savings goals and customer satisfaction levels
- Metrics development
- Reporting

The statewide implementer would have responsibility for developing the implementation plan and gathering stakeholder input from the CAEECC. The implementer would also gather data on performance indicators. SDG&E also specifically requested that the Commission confirm that these joint activities are consistent with state policy and actively supervised by the Commission, and therefore not in violation of anti-trust requirements, under the State Action Doctrine.

In general, we will not require the use of Program Councils. We agree with the responsibilities given to the lead statewide PA, and vest them with full authority, including assignment of personnel to manage the programs on behalf of the Commission.

While we encourage the lead PA to coordinate with its fellow PAs as necessary, the Program Council structure strikes us as overly bureaucratic in a manner that could result in substantial delays and difficulty handling day-to-day management of the programs. Thus, the lead PA is entrusted with full

responsibility to make any and all decisions associated with the design and implementation of the statewide program area to which they are assigned lead responsibility by this decision. The IOUs may, consistent with ORA's recommendations, utilize Program Councils or other joint meetings on a voluntary and consultative basis, but we will not require them or endorse them.

We are aware, however, that there could arise a rare circumstance in which a lead PA is taking a program in a direction either not supported by Commission direction or contrary to the interests of the other IOU PAs investing in the statewide program. In such cases, we will require that the other three IOU PAs all be in agreement and in opposition to an action of the lead PA. If that circumstance arises, one of the non-lead IOU PAs, on behalf of the other two, may file a motion in the relevant energy efficiency rulemaking proceeding seeking Commission resolution of the dispute. Should such a motion be filed, the lead IOU PA must cease the disputed action until the Commission addresses the motion.

We also agree with SDG&E that all of these statewide program administration activities fall under the State Action Doctrine defense to antitrust action. The two main requirements for this purpose are that the actions be in support of state policy that has been clearly articulated, and that the actions be under active supervision by the state. Since the statewide activities are clearly in support of state policy and actively supervised by, and a priority for, the Commission, these requirements are met. This is consistent with our prior findings in D.10-12-054. In addition, this conclusion applies regardless of the number of program administrators that are collaborating for purposes of effectuating the Commission's energy efficiency program policy, including coordination required among utilities with overlapping territories.

D.16-08-019 addressed the issue of allocation of savings credit for statewide programs based on budget contributed by each IOU PA. We clarify that this means that credit for energy savings generated will be based on funding contributed only, and not in relation to the geographic region in which the energy efficiency measure was sold or installed.

However, the Commission has not addressed any associated rewards under the ESPI structure that might accrue to the lead PA for handling a greater level of responsibility for statewide program implementation. Because ESPI changes are not within the scope of this proceeding, we do not further address this issue in this decision, but it may be taken up in the future in the appropriate energy efficiency rulemaking (R.13-11-005 or its successor).

### **3.1.2. SCE Statewide Policy Change Requests**

SCE, in its business plan, asked that the Commission specifically permit the following actions to occur:

- Give any PA the ability to opt out of statewide programs for cost-effectiveness or local reliability concerns.
- Give all PAs the ability to continue local pilot activities that would otherwise qualify for statewide administration but that are not yet ready for such statewide treatment.

We agree with the second request. In requiring certain program areas to be administered statewide, the Commission did not intend to prohibit testing or piloting of new ideas on a local or regional basis that could later be expanded into a statewide offering. Thus, as long as such local pilots do not directly compete with, or otherwise impede the progress of, any operational statewide programs, local pilots are permitted. In fact, that type of activity is generally encouraged, along with continuous evaluation of whether successful efforts of this type should be expanded.

We do not adopt SCE's first request, however, to allow any PA to opt out of the statewide programs for cost-effectiveness or reliability reasons. The purpose of a statewide approach is to ensure that there is uniformity of program offerings in as much of the state as possible. Allowing PAs to unilaterally opt out of statewide efforts would undermine that exact purpose. Thus, we will require that all IOU PAs fund all statewide programs.

This suggestion by SCE also leads us to become concerned about the potential for a PA to undermine the statewide programs substantially while still being in technical compliance with our requirements (e.g., a PA could maintain a nominal budget that is nowhere near its proportional share based on load served, while still undermining the total budget of the program). To prevent such an occurrence, we will require that each IOU PA contribute a budget to each statewide program area that is generally proportional to its load share, at a total level to be determined by the lead IOU for each statewide program area. If at any point an individual PA's contribution is found to deviate by more than plus or minus 20 percent from its proportional share, this will constitute an additional trigger for which the PA in question will be required to file a new business plan, justifying why it cannot continue to fund a statewide effort proportionately.

We also note that we expect that the number and types of programs that are classified as "statewide" will evolve over time, and we may need to define a process for PAs and stakeholders to make these types of portfolio changes. As discussed in Section 3.1.6, we will direct the IOU PAs to conduct an initial comprehensive "bottom up" review of statewide portfolio structures and composition within one year of the issuance of this decision. For now, we will vest the lead PA with the responsibility for suggesting and implementing

program modifications through the existing advice letter mechanisms or modified implementation plans.

### **3.1.3. Clarification of Statewide Budget Requirements**

PG&E, in its final comments on the business plan applications, seeks clarification on the 25 percent statewide budget requirement included in D.16-08-019. PG&E seeks to have the 25 percent calculated on its total program budget instead of its total portfolio budget. However, in its description of the concern, PG&E mentions removing the funding transferred to others, including BayREN, MCE, and the statewide ME&O effort. We agree that the funds for other administrators should be removed from the total utility portfolio calculation, of which the statewide requirement is 25 percent. However, other portfolio-related costs, such as overhead, EM&V, etc. are considered part of the individual PA portfolio budget and should not be removed from the calculation used to develop the statewide budgets of at least 25 percent.

SoCalGas, in its comments on the proposed decision, pointed out that we had not addressed its request to make its statewide funding requirement 15 percent of total portfolio budget, rather than the 25 percent required from other utilities, in recognition of the more limited set of measures and statewide approaches that it offers as a gas-only utility.<sup>64</sup> This is a reasonable request and we will adopt it.

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<sup>64</sup> See details contained in SoCalGas' business plan application, Appendix F, at 542-543.

### **3.1.4. Budget Mechanics**

On August 4, 2017, SDG&E filed a motion to establish balancing accounts to track funding for statewide programs. The establishment of balancing accounts would allow the utilities to track and manage the cost sharing among the statewide program lead administrators and the contributing PAs.

In its motion, SDG&E described the following approach:

These new interest-bearing balancing accounts will track (1) SDG&E's contribution to all the approved statewide programs; and (2) all the funds transferred from other PAs for programs that SDG&E will be administering on behalf of the all PAs.

SDG&E's contribution to the approved statewide programs will be funded through transfers of the authorized revenue requirement from the existing energy efficiency balancing accounts, which are the Electric Energy Efficiency Balancing Account (PEEEBA) for electric and the Post-2005 Gas Energy Efficiency Balancing Account (PGEEBA) for gas. The funding of the statewide programs for which SDG&E is the authorized lead program administrator will come from payments from the PAs for their portion of the statewide programs. These balancing accounts will also record expenses that will be incurred for SDG&E's administration of the statewide programs.

SDG&E further proposes that the annual true-up required by the Commission will be handled through an agreed-upon annual report that provides each PA with the status of their payments and their share of the interest for the programs administered by SDG&E. During the lifecycle of the program, SDG&E will work with each PA to ensure that there is adequate continuing funding for the statewide programs.

At the end of each statewide program, SDG&E will do a final true-up of each participating PA share and will either repay any remaining balance or request that the participating PA pay SDG&E for any outstanding costs. SDG&E's share of the program will be transferred back to its PEEEEBA and/or PGEEEEBA. The final disposition of these new statewide EE program balancing accounts will be addressed through a Tier 2 advice letter or appropriate Energy Efficiency proceeding.



No other party responded to SDG&E's motion. Thus, it is unclear if the other IOUs support SDG&E's approach or prefer a different structure. Thus, we will not adopt SDG&E's balancing account motion here, but instead will address this issue further, as necessary, in the energy efficiency rulemaking (R.13-11-005 or its successor). In the meantime, within 90 days of the issuance of this decision, all IOUs shall file a Tier 1 advice letter proposing a method for addressing cost-sharing for the statewide programs, to the extent additional authorization is needed, and providing justification for why current mechanisms are insufficient. One option may be the balancing account mechanism proposed by SDG&E in its August 4, 2017 motion, but ideally it would be preferable for all IOUs to choose the same method. Meanwhile, the IOUs shall continue to use their existing cost-sharing and balancing account mechanisms until further approvals from the Commission.

Regardless of the disposition with respect to balancing accounts for statewide program purposes, there will still need to be periodic true-up payments to reflect appropriate cost-sharing. To this end, we accept SDG&E's proposal to produce an agreed-upon annual report, as well as a final true-up report at the end of a statewide program or the end of the rolling portfolio cycle, whichever comes first.

Further, in order for the Commission to stay apprised of the general status of funding for the statewide programs, we direct the IOUs to include summary of key findings from the annual report in their respective annual energy efficiency portfolio reports to the Commission. Specifically, the summary of key findings should detail proportional funding amounts for each statewide program

area, and highlight any IOU cost-sharing discrepancies, with particular attention to the requirement for proportional budget contributions described above.

### **3.1.5. Downstream Pilots**

As directed in D.16-08-019, the IOUs proposed several downstream programs to be piloted on a statewide basis, as follows:

- Water/Wastewater pumping program for non-residential public sector customers (lead: SCE; annual budget \$5.3 million)
  - This program was originally launched out of SCE's IDEEA 365 solicitation process, piloted for approximately 18 months, and is now transitioning to a mainstream third party program.
- Workforce education, and training: Career and workforce readiness (lead: PG&E; annual budget \$1.7 million)
  - Career and workforce readiness to support organizations helping members of disadvantaged communities to enter the energy workforce. Collaborating with established training organizations that are preparing the incoming energy workforce, and increasing the capacity of the current workforce through technical upskill initiatives.
- Indoor Agriculture Program (lead: PG&E; budget: not yet specified)
  - This program would support growers in managing resources wisely and reducing electricity costs for agricultural customers. Aims to increase awareness among agricultural customers about behavioral opportunities to reduce energy use.
- Residential HVAC Quality Installation/Quality Maintenance (lead: SDG&E; annual budget: \$6.9 million)
  - This is a pay-for-performance program, building experience in offering residential quality installation programs, with SDG&E serving as the lead for the statewide residential HVAC quality installation program CALSPREE.

We appreciate the IOUs' initiative in proposing these downstream statewide programs and approve of them with one exception. PG&E's indoor agriculture program proposal is rejected. We are aware that PG&E itself desired to amend this program proposal and resubmit its business plan, a motion which was denied by the ALJs largely due to a desire not to restart the clock on processing of the business plans. But it is clear this program is not as well thought-out as some of the other proposals and it appears premature to be approved. Thus, PG&E shall not launch this program as a downstream statewide program at this time.

### **3.1.6. Lead PA Assignments**

Along with the proposed downstream programs listed above and the required statewide program areas taken from D.16-08-019, the IOUs proposed a sharing of lead administrator roles for the statewide programs in their business plans. Though requested by parties, including NAESCO, ORA, and TURN, and in response to the supplemental questions issued by ALJ ruling, the IOUs declined to give specific rationale for the assignment of lead administrator roles among the different IOUs. In general, it appears as though the process was opaque to stakeholders and not based on any particular set of criteria, other than general capacity to handle statewide programs and volunteering or nomination among utility peers.

We also note, similar to TURN, our disappointment that more analysis was not conducted along the lines of a "bottom up review" of the statewide programs listed in Ordering Paragraph 8 of D.16-08-019. Far from being exhaustive or determinative, that list was intended to be a starting point or a minimum level required to get the new statewide approach off the ground. The list of statewide programs from D.16-08-019 should not be the final list of statewide programs in

perpetuity. We fully expect that the portfolio, sector, and program approaches will evolve over the course of the business plan timeframe, and support efforts to identify potential improvements and refinements that can be made to selected approaches within the rolling portfolio.

We also agree with TURN that a comprehensive review of this structure should be undertaken by the PAs as soon as possible, covering not only the configuration of statewide programs, but also consideration of whether measures currently only promoted through downstream interventions should be included in statewide upstream and midstream programs. However, because of timing considerations, we will not require this “bottom up review” to occur prior to the launch of the business plans. We will, however, require the IOU PAs to conduct such a review and file any recommended changes to the statewide structure articulated in D.16-08-019 and in this decision, by no later than one year from the of this decision, in the available energy efficiency rulemaking. We should also note that some of this review may relate to the work that has been postponed, but that we expect will be getting underway in the energy efficiency rulemaking (R.13-11-005), related to market transformation.

With respect to the selection of the IOUs to be lead PAs in the various sectors for statewide programs, in general we find the assignments proposed in the business plans to be reasonable. There are, however, several exceptions, which we discuss further here.

Our first concern is with SCE taking the lead in the area of commercial new construction, given that they have previously proposed to meld lighting and the Savings by Design program together. This would appear to signify at least a diluted commitment, though we do allow for the possibility that the program could be changed or improved to be more successful.

In addition, our preference is that new construction statewide programs be managed by one lead PA overall, and not divided up separately for residential and commercial sectors. This is also partly because of the many synergies and similarities in new construction approaches and market actors, regardless of sector or fuel source. In addition, we note that PG&E is designated as the lead PA for codes and standards advocacy, which is also related to new construction expertise. For these reasons, we will assign PG&E as the lead PA for new construction programs.

We also note that there is one other area where the statewide program responsibilities were split by fuel, with gas emerging technologies to be administered by SoCalGas and electric by SCE. We would have preferred a single administrator here as well, and NAESCO also raised this concern in comments. However, if we were to make a change, it would logically be better to have a dual-fuel utility handle such responsibilities, and SDG&E and PG&E already have a larger number of programs assigned to them. Removing SoCalGas from a lead role here would also leave the utility with very little statewide program administration responsibility. So, for now we will leave the emerging technologies responsibilities as proposed by the IOU PAs in the business plans, and monitor how the process works particularly with respect to the fuel split in the emerging technologies area.

In summary, the final lead PA assignments will be as given in Table 3 and Table 4, for statewide program areas and downstream pilots, respectively.

**Table 3. Lead Program Administrator for Statewide Program Areas**

<b>Program Category</b>	<b>Original Subprograms</b>	<b>Combined?</b>	<b>New Sub/program</b>	<b>Lead IOU</b>
Midstream Plug Load & Appliance	No Change			SDG&E
HVAC	Upstream Residential	Combined	Upstream HVAC	SDG&E
	Upstream Commercial			
New Construction	Residential	No Change		PG&E
	Savings by Design (Commercial)	No Change		PG&E
New Finance Offerings	No Change			SoCalGas
Codes & Standards Advocacy	Building Codes	Combined	Codes & Stds Advocacy	PG&E
	Appliance Standards			
Lighting	Lighting Innovation	Combined	Lighting	SCE
	Primary Lighting			
	Lighting Market Transformation			
Emerging Tech	Tech Development	Combined (then split by fuel)	Gas	SoCalGas
	Tech Assessments		Electric	SCE
	Tech Introduction			
Workforce Education & Training	K-12 Connections	No Change		PG&E
Institutional Partnerships	University of California	Combined	UC/CSU/CC C	SCE
	California State University			
	State of California	Combined	DGS/DoC	PG&E
	Department of Corrections			

Program Category	Original Subprograms	Combined?	New Sub/program	Lead IOU
Foodservice Point of Sale Program				SoCalGas
Midstream Commercial Water Heating				SoCalGas

**Table 4. Lead Program Administrator for Statewide Downstream Pilot Programs**

Program	Lead IOU
HVAC Quality Installation/Quality Maintenance (QI/QM)	SDG&E
Water/Wastewater Pumping Program	SCE
Career and Workforce Readiness	PG&E

These statewide lead PA assignments are expected to remain in place through the end of this first business plan period (i.e., through 2025) until or unless new business plans are filed by one or more PA with proposals for new or different statewide leads.

### **3.2. Third Party Requirements**

The Commission has addressed portfolio requirements for programs designed and implemented by third parties in D.16-08-019 and more recently D.18-01-004. We clarify that the third party requirements contained in both of those decisions apply to the business plans of the IOUs approved in this decision.

In addition, SDG&E requested a one-year delay in the requirements for compliance with the schedule articulated in D.18-01-004, based on the fact that third party solicitations will not begin until later this year. D.18-01-004 stated that “beginning in 2019, the D.16-08-019 definition of third party should be fully in effect.” We clarify now that the requirement is that 25 percent of each IOU PA’s 2020 annual forecasted budget must be under contract to a third party by

the definition in D.16-08-019 by December 31, 2019. All other deadline requirements in D.18-01-004 are still in effect.

### **3.3. SCE-Only Issues**

#### **3.3.1. LED Rebates for Exterior Lighting**

CalSLA urges the commission to extend LED rebates for streetlights to 2025, and approve SCE's proposed \$11.3 M for LED rebates.<sup>65</sup> SCE agrees, and includes Energy Division's memo regarding modifying workpapers as Appendix B to their final reply comments. SCE states it will review and address any follow-up to Energy Division. We will approve SCE's proposed budget for street light incentives and encourage SCE to follow Energy Division's recommendations. We also note here that we do not generally determine what level of incentives to provide for each specific type of energy efficiency activity (or technology); rather, it is incumbent on program administrators to make those determinations as appropriate based on forecasted energy savings through the database for energy efficiency resources (DEER) and workpaper review process. We continue to recognize the availability of energy savings, and therefore potential for incentives to be offered, for delivery of street light measures via the early retirement measure application type and encourage program administrators to undertake thorough review of all existing outdoor lighting workpapers and make necessary modifications to capture those savings.

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<sup>65</sup> CalSLA September 25, 2017 Comments, at 1-4.



#### **4. REN Business Plans**

##### **4.1. Generic Issues**

##### **4.1.1. REN Portfolios' Cost-Effectiveness**

The Scoping Memo invited comments on whether the Commission should apply cost-effectiveness thresholds to REN portfolios, either now or in the future, and if so how such thresholds should be implemented.

SCE, SDG&E and SoCalGas agree that cost-effectiveness thresholds should apply consistently across all PAs. MCE does not agree, arguing that the restrictions the Commission placed on the types of pilots/programs the RENs could administer “make it difficult – if not impossible – to achieve cost-effectiveness on a portfolio level. The Commission recognized this tension when it created the RENs.”<sup>66</sup>

PG&E acknowledges that the “unique mandate” applicable to RENs’ activities “may require unique cost-effectiveness requirements for REN activities.”<sup>67</sup> PG&E supports consistent use of the same metrics across PAs, for tracking purposes, and suggests the TRCs of specific IOU programs may serve as the baseline for comparing the TRCs of REN programs that are designed and administered similar to those IOU programs. ORA similarly suggests that, for the RENs’ resource programs, “[a] REN should be able to demonstrate that they are at least as effective as other actors’ resource programs, which would mean that a REN should have a comparable or superior TRC and PAC to those of the other PAs serving the same territory.”<sup>68</sup>

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<sup>66</sup> MCE June 22, 2017 Comments, at 2.

<sup>67</sup> PG&E June 22, 2017 Comments, at 51-52.

<sup>68</sup> ORA June 22, 2017 Comments, at 14.

With our renewed emphasis that RENs should focus on filling gaps, piloting different or unique approaches that have potential to scale, and/or targeting hard-to-reach customers, we do not find it reasonable to impose a minimum cost-effectiveness threshold for REN proposals. As we have maintained in the past, the more limited scope of activities we authorize RENs to undertake, which results in a much lower ability to diversify their portfolios (relative to the IOUs), argues against holding them to a particular cost-effectiveness standard.

To be clear, we remain interested in seeing RENs provide value (or the promise of value), and this serves as a key criterion against which we evaluate their proposals and will assess their performance going forward, particularly in tracking business plan metrics and assessing PAs' progress in meeting their designated targets. We decline to consider the proposed Benefits Evaluation Framework, as we prefer to use the same cost-effectiveness methodology for all PAs even if we do not hold the RENs to a particular standard. We also remain interested in seeing improving TRC estimates over the long run, therefore we retain our requirement for RENs to include cost-effectiveness statements in their ABALs.

#### **4.1.2. Standard of Review**

The Commission first approved budgets for BayREN and SoCalREN in D.12-11-015, which directed the RENs to undertake:

- Activities that utilities cannot or do not intend to undertake;
- Pilot activities for which there is no current utility program offering and where there is potential for scalability to a broader geographic reach, if successful; and
- Pilot activities in hard-to-reach markets, whether or not there is a current utility program that may overlap.

In D.16-08-019 the Commission further specified that “REN programs, and therefore administrative expenses, will only be funded to the extent that they are determined by the Commission to provide value (or the promise of value) to ratepayers in terms of energy savings and/or market transformation results for energy efficiency.”<sup>69</sup> RENs should “be involved in programs where they have special expertise or relationships with customers that other administrators (including utilities and potential statewide administrators) or local government partnerships do not.”<sup>70</sup> Although the Commission declined to set a TRC threshold or other particular cost-effectiveness standard that the RENs’ portfolios must meet, it encouraged the RENs “to manage their programs with an eye toward long-term cost-effectiveness.”<sup>71</sup>

Our intent, as outlined above, is for the RENs to really focus on filling gaps (i.e., not duplicating the utilities’ activities), and adding value based on their unique expertise and relationships with local stakeholders; where they may duplicate utility offerings, as described in Section 2.5.2, is limited to the hardest-to-reach customers or customer segments. This conflicted, however, to some extent with D.16-08-019’s direction for PAs to present high-level sector strategies and leave program-level details to implementation plans. Specifically, the IOUs allege certain proposed REN programs / activities duplicate existing or planned utility offerings, to which the RENs counter with further details of their proposals in order to demonstrate how they differ from the utilities’ proposed activities. The RENs also assert they shared drafts of their business plans and

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<sup>69</sup> D.16-08-019, at 71.

<sup>70</sup> D.16-08-019, at 11-12.

<sup>71</sup> *Ibid.*

afforded other PAs an opportunity to raise any concerns regarding overlap or duplication.

Since we have determined not to require the RENs to meet a specific cost-effectiveness standard, we find it reasonable to require a formal assurance that the RENs will implement their business plans pursuant to D.12-11-015 and D.16-08-019; IOU PAs' active involvement in this formal assurance is integral to ensuring this is a balanced process. Specifically, we will require the PAs (RENs, IOUs and CCA) to develop a joint cooperation memo to demonstrate how they will avoid or minimize duplication for programs that address a common sector (e.g., residential or commercial) but pursue different activities, pilots that are intended to test new or different delivery models for scalability, and/or programs that otherwise exhibit a high likelihood of overlap or duplication and are not targeted at hard-to-reach customers. For such programs, each PA must explicitly identify and discuss how its activities are complementary and not duplicative of other PAs' planned activities. Staff will utilize these memos in their reviews of the PAs' ABALs, and may disapprove funding for specific activities or programs that do not conform with the memos, or more broadly with D.12-11-015 and D.16-08-019. We discuss the details of these required submissions in Section 7.

The IOUs further allege BayREN and SoCalREN's business plans represent an expansion of their previously authorized activities, which the IOUs generally oppose, at least until the Commission has completed its review of REN performance thus far. PG&E also recommends the Commission not consider new or expanded RENs until after PG&E completes all third-party solicitations, as this would "ensure the RENs are truly filling gaps in PG&E's offerings, and that PG&E is not constrained from meeting its statutorily-mandated energy

savings goals.”<sup>72</sup> In D.16-08-019 we stated “there is no guarantee that existing or new RENs will continue to be approved for funding by the Commission for future new activities, though existing approved activities may have ongoing funding that was previously approved. Instead, we will consider REN program proposals ... alongside proposals from the other program administrators during the rolling portfolio business plan process.”<sup>73</sup> We find we are in much the same situation as in 2016, having not reached a definitive determination on BayREN and SoCalREN’s success as REN pilots,<sup>74</sup> therefore we are on one hand inclined to allow BayREN and SoCalREN to continue existing activities but on the other hand more wary in our consideration of new activities and/or significantly expanded budgets.<sup>75</sup> Again relying on the REN criteria we laid out in D.12-11-015 and D.16-08-019, we find it reasonable to defer consideration of certain substantially new or expanded activities or budgets in this decision. We discuss those details and other concerns raised by parties in the following sections.

We take this opportunity to confirm our intention to evaluate the RENs’ impact and overall success before the end of this business plan period and potentially as soon as 2021, when we expect to have a complete set of evaluations on which to gauge the RENs’ success. Although we approve the RENs’ 2018-2025 business plans (with modifications as discussed below), we reserve

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<sup>72</sup> PG&E September 25, 2017 Comments, at 33.

<sup>73</sup> D.16-08-019, at 10-11.

<sup>74</sup> D.16-08-019, at 10.

<sup>75</sup> Programs that are currently offered and for which the proposed budgets remained largely the same include BayREN and SoCalREN’s residential and financing programs, BayREN’s codes and standards and SoCalREN’s public sector programs.

judgment on whether we will continue to authorize REN programs and budgets based on future evaluations, including those that will be completed during this business plan period.

#### **4.2. BayREN**

BayREN's business plan anticipates a funding level in 2025 that is nearly twice as much as its currently authorized annual funding. Much of this increase results from a significant increase of funding and scope in the commercial sector, and to a lesser extent the public sector.

PG&E opposes BayREN's proposed commercial and public sector activities, alleging they duplicate programs or activities that PG&E currently offers or intends to undertake, and further that they are not geared towards hard-to-reach customers, therefore they do not meet our approval criteria. In response, BayREN alleges bad faith by PG&E, recounting numerous instances in which it afforded both MCE and PG&E an opportunity to preview its business plan and to voice any concerns of potential overlap. Notwithstanding this allegation, BayREN asserts its proposals are not duplicative, and further that PG&E lacks the agility to effectively deal with smaller customers, including residential, small commercial building owners and tenants or local government agencies.

ORA contends BayREN's Water Bill Savings program lacks support in terms of either the proposed budget increase from \$361,146 in 2017 to \$1,051,000 in 2018 or the energy savings that would justify the nearly twofold increase.<sup>76</sup> In response, BayREN explains its intention to enroll a far greater number of water

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<sup>76</sup> ORA June 22, 2017 Comments, at 7-8.

utilities in its Regional Water Bill Savings Program (i.e., forty as opposed to the three currently served), and a more consistent approach than the more customized nature of program design that has characterized the current partnerships.

Consistent with our discussion in Section 4.1.2, we will approve BayREN’s business plan to the extent it proposes to continue existing activities and complies with D.12-11-015 and D.16-08-019. Although we do not require RENS’ portfolios to meet a particular cost-effectiveness standard, we are concerned with BayREN’s apparent failure to provide a portfolio-level estimate (TRC, PAC or otherwise) of its business plan’s cost-effectiveness, though we note their 2018 ABAL includes a portfolio TRC estimate (0.2) and, in response to our request for supplemental information, BayREN provided the following estimates for its resource activities, by sector:

	TRC	PAC
Residential	0.56	1.25
Commercial	1.02	1.67

Further, with our affirmation of how we define hard-to-reach, we intend to pay closer attention to whether BayREN is targeting the hardest-to-reach customers for activities that overlap or are significantly similar to PG&E’s. Combined with our direction in Section 7 for PAs to submit a joint cooperation memo, we expect BayREN and PG&E to describe in detail how their proposed activities will not overlap except with respect to hard-to-reach customers.

We do not anticipate BayREN’s multi-family residential activities will overlap with PG&E’s, as currently designed. BayREN’s multi-family program, according to BayREN, provides a “middle of the road” path and maintains a

cross-referral agreement with PG&E to avoid duplication. However, we will monitor BayREN’s multi-family program through the joint cooperation memo with PG&E to ensure that the effort is not duplicative of PG&E and /or is targeting a hard-to-reach market. We are less clear about whether BayREN’s commercial offerings, including a pay for performance program for small and medium businesses and Co-Pay Financing, will overlap with PG&E’s commercial sector activities. Further, we are not certain the fairly drastic increases in budget for either the commercial or public sectors are warranted, given our preference to first evaluate the success of their existing activities. We have modified BayREN’s proposed budget consistent with our determination to defer consideration of new or expanded activities or budgets.

**Table 5. Approved Funding Levels for BayREN 2018-2025 Business Plan, in thousands**

	Residential	Commercial	Public	C&S	Water/ Energy Nexus	Admin	EM& V	Total
2018	\$16,537	\$1,692	\$-	\$1,788	\$1,051	\$1,298	\$373	\$22,738
2019	\$16,595	\$2,772	\$-	\$1,918	\$944	\$1,328	\$393	\$23,950
2020	\$16,707	\$3,326	\$-	\$1,983	\$831	\$1,365	\$404	\$24,615
2021	\$15,170	\$3,581	\$-	\$1,954	\$824	\$1,306	\$381	\$23,216
2022	\$15,084	\$4,005	\$-	\$2,096	\$811	\$1,335	\$389	\$23,720
2023	\$15,279	\$4,539	\$-	\$2,166	\$842	\$1,376	\$403	\$24,605
2024	\$14,924	\$4,842	\$-	\$2,136	\$941	\$1,382	\$404	\$24,629
2025	\$15,134	\$5,240	\$-	\$2,291	\$996	\$1,424	\$418	\$25, 503

### 4.3. SoCalREN

SoCalREN’s business plan proposes a modestly expanded budget with a significant shift from the residential to the public sector and cross-cutting (codes and standards, workforce education and training) activities. SoCalREN proposes to discontinue Flex Path Incentives, acknowledging that “[s]trong impact in the



Single Family Residential market has largely eluded PAs, who have struggled to reconcile process-heavy offerings with a process-adverse market.”<sup>77</sup> In place of Flex Path Incentives, SoCalREN proposes to focus on marketing, education, outreach and customer support to access residential Property-Assessed Clean Energy (PACE) Program funding. SoCalREN also proposes funding for Codes and Standards, specifically on compliance training and local reach codes, and workforce education and training.

The main parties that take issue with SoCalREN’s business plan are SCE and SoCalGas, the two utilities in whose service territory SoCalREN operates. In its response to SoCalREN’s business plan, SCE identifies a number of SoCalREN’s programs or activities as duplicative of current SCE offerings, including energy benchmarking and monitoring; engaging public agencies; partnering with supply chain stakeholders; regional energy master plans; tools for Codes and Standards stakeholders; model energy codes, standards and policies; and WE&T infrastructure and partnerships and skills training.<sup>78</sup> SoCalGas similarly takes issue with SoCalREN’s proposals for Codes & Standards, WE&T, and Finance, asserting those proposals would duplicate work that SoCalGas already does.<sup>79</sup>

SoCalREN’s reply to SoCalGas and SCE’s responses explains that SoCalREN has designed its activities to fill gaps and be complementary to the utilities’ offerings, for instance SoCalREN’s proposed Codes & Standards activities will start with a needs assessment to identify gaps in existing utility

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<sup>77</sup> SoCalREN September 25, 2017 Comments, at 25.

<sup>78</sup> SCE March 3, 2017 Response, at 3-6.

<sup>79</sup> SoCalGas March 3, 2017 Response, at 7-10.

services, and its stated intention to “steer C&S community members first toward resources and tools provided by” the utilities before assessing members’ needs and its ability to meet those needs. SoCalREN also explains that some alleged overlaps are not overlaps at all since their purpose is distinct from the purpose of the utility’s offering, for instance SoCalREN’s Energy Atlas database, which is intended in part to support regional master planning, as opposed to SCE’s Enhanced Energy Advisor Tool, which SCE states “provides customer access to their historical monthly usage data and comparisons to demonstrate the importance of energy efficiency.”<sup>80</sup>

SoCalGas and SCE raise additional concerns with SoCalREN’s business plan. Most significantly, SoCalGas asserts SoCalREN’s PACE proposal faces a significant risk of free-ridership, since contractors are not currently relying on incentives to sell PACE projects. SoCalREN counters that its proposal is aimed at otherwise missed opportunities to “sell up to higher levels of efficiency and more comprehensive projects.”<sup>81</sup> We will allow SoCalREN to pilot this approach, though we share SoCalGas’s concern and expect SoCalREN to collect and track data that help attribute (higher) energy savings to this program design. Also, as this proposed program is meant to serve the same population and contribute to the same original goal as the continued Home Upgrade/Advanced Home Upgrade programs, we expect SoCalREN to align this program with D.12-11-015’s guidelines for those programs, i.e., to include at least three qualifying measures, to use a tiered incentive structure, to support the energy

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<sup>80</sup> SCE March 3, 2017 Response, at 3.

<sup>81</sup> SoCalREN March 10, 2017 Reply, at 8.

efficiency loading order, and to support appropriate combustion safety testing protocols.<sup>82</sup>

SCE and SoCalGas also raise concerns with the possible use of energy efficiency funds for non-energy efficiency activities, and SCE recommends we require SoCalREN to identify funding sources for non-energy efficiency activities.<sup>83</sup> SoCalREN points out that, as fiscal agents for SoCalREN's authorized budget, the utilities are well positioned to review SoCalREN's expenditures and activities at a detailed level to ensure prudent use of ratepayer funds, before they proceed to reimburse SoCalREN for its submitted expenses.<sup>84</sup> We will continue to rely on SCE and SoCalGas to serve as responsible fiscal agents for SoCalREN.

While SoCalREN's overall budget request reflects an annual two percent increase, which we agree is generally modest, we are concerned with the proposed new WE&T and Codes & Standards activities, particularly given savings forecasts that appear somewhat optimistic and our adoption of a statewide Codes & Standards program. We will approve SoCalREN's budget request with several modifications – to remove funding for new WE&T and C&S, and to adjust SoCalREN's 2018 budget for Public sector activities to reflect a more moderate ramping of activity -- as shown in the below table.

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<sup>82</sup> D.12-11-015, at 24-25.

<sup>83</sup> SCE March 3, 2017 Response, at 7.

<sup>84</sup> SoCalREN September 25, 2017 Comments, at 34.

**Table 6. Approved Funding Levels for SoCalREN 2018-2025 Business Plan, in thousands**

	Residential	Public	C&S	Financing	WE&T	Total
2018	\$6,540	\$9,815	\$-	\$2,180	\$-258	\$18,793
2019	\$6,671	\$11,563	\$-	\$2,224	\$-284	\$20,742
2020	\$6,804	\$11,794	\$-	\$2,268	\$-312	\$21,188,
2021	\$6,940	\$12,030	\$-	\$2,313	\$-343	\$21,626
2022	\$7,079	\$12,270	\$-	\$2,360	\$-378	\$22,087
2023	\$7,221	\$12,516	\$-	\$2,407	\$-416	\$22,560
2024	\$7,365	\$12,766	\$-	\$2,455	\$-457	\$23,043
2025	\$7,512	\$13,022	\$-	\$2,504	\$-503	\$23,541

SoCalGas and SCE also point out that SoCalREN’s budget request only shows cost-effectiveness for resource programs;<sup>85</sup> we confirm that all PAs should include cost-effectiveness estimates of their entire portfolios, and SoCalREN must include this information in its ABAL submissions.

#### **4.4. 3C-REN**

3C-REN proposes formation of a new REN to serve the counties of San Luis Obispo, Santa Barbara and Ventura.

3C-REN characterizes its business plan as “new program design that will generate meaningful and measurable results for targeted stakeholders with a focus on moderate-income residents. 3C-REN’s intention is to develop improved programs that enhance services, cost savings, energy savings, and other benefits to increase participation while continuing to improve overall cost-effectiveness.”<sup>86</sup>

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<sup>85</sup> SoCalREN June 22, 2017 Comments, at 11, footnote 12.

<sup>86</sup> 3C-REN September 25, 2017 Comments, at 9.

3C-REN proposes a number of activities to serve customers in its service area, including direct install, financing, code compliance and assistance to building departments of participating counties and cities, and local workforce training and diversification.

A key component of 3C-REN's proposal is to apply lessons learned from the emPower Central Coast (emPower) program, a home upgrade and financing program started in 2011 under the American Recovery and Reinvestment Act and jointly funded by PG&E, SCE and SoCalGas since 2014. The primary modification 3C-REN proposes is to include financing for projects that do not receive Home Upgrade or other IOU incentives, which 3C-REN asserts limits participation in the program. Another major element of 3C-REN's approach is a direct install program for moderate income households and customers in rural areas. 3C-REN explains that "33 percent of the Tri-Counties population has household incomes between \$50,000 and \$100,000, which is just above the eligibility for low-income programs and below the typical level of service for mainstream utility programs."<sup>87</sup>

PG&E and SoCalGas recommend against approval of 3C-REN's business plan, asserting certain elements are duplicative of current utility offerings and further that evaluation of the current emPower program was pending at the time of deliberation over the business plans.<sup>88</sup> That evaluation has since been completed, however its study objective is not precisely to determine whether emPower was successful but rather "to gain a foundational understanding of the

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<sup>87</sup> 3C-REN business plan, at 27.

<sup>88</sup> SoCalGas March 3, 2017 response to 3C-REN business plan, at 6.

value of financing programs in achieving or increasing energy savings from whole home retrofits.”<sup>89</sup> In comments to the proposed decision, 3C-REN confirms it does not intend to continue emPower financing or otherwise offer its own financing program, but rather to promote all financing options available,<sup>90</sup> including the California Hub for Energy Efficiency Financing (CHEEF) and PACE programs as well as other local financing providers, all of which offer solutions not tied to Home Upgrade or other IOU incentives.

PG&E highlights the fact that it currently offers a Moderate Income Direct Install (MIDI) program through its LGPs, therefore 3C-REN’s residential direct install proposal would duplicate PG&E’s offering. PG&E acknowledges, however, “there is room for improvement in its administration of energy efficiency in 3C-REN’s proposed service area, and that there are difficulties associated with coordinating efforts among three utilities,” and therefore commits to “improving delivery of its existing offerings in the 3C-REN service area moving forward, and encourage third parties to consider this for future program proposals.”<sup>91</sup> 3C-REN counters, however, that none of the LGPs operating within its service area serve residential customers.

We acknowledge 3C-REN has proposed a suite of programs or activities that are designed to work in a holistic manner, however we also see the potential for unnecessary duplication and/or insufficient focus on hard-to-reach customers in certain areas, namely financing and the residential sector-focused

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<sup>89</sup> Regional Finance Program Attribution and Cost-effectiveness Study: Final Report, Opinion Dynamics, December 22, 2017.

<sup>90</sup> 3C-REN April 24, 2018 comments, at 3.

<sup>91</sup> PG&E September 25, 2017 Comments, at 31-32.

activities. In general we find the most value in 3C-REN's proposed workforce education and training program and code compliance program, given their distance from the IOUs' training centers that serve code officials, builders and architects. We will approve these components of 3C-REN's proposal, though we acknowledge there will still need to be some degree of coordination between 3C-REN's activities and the IOU-led statewide programs discussed in Section 3.1 of this decision. For instance, certain training activities such as development of online training materials for contractors may be more appropriately implemented in the context of statewide administration; to that end, 3C-REN's implementation plans and ABALs should specifically reference any relevant statewide programs and activities and demonstrate how its proposed activities for the upcoming year will complement and not duplicate those statewide activities.

With respect to PG&E's MIDI program and its expressed intention to better serve 3C-REN's service area, we remind all PAs of our conclusion in D.18-01-004 that "as much informal communication and coordination among the PAs as possible is encouraged...we will require utility PAs to include a contract term that requires third parties to coordinate with other PAs in the same geographic area."<sup>92</sup> To the greatest extent feasible, PG&E must enable 3C-REN and other relevant PAs to have significant input in developing the request for abstracts (RFA)/request for proposals (RFP) for PG&E's MIDI program.

We also acknowledge that 3C-REN's residential direct install proposal identifies a general intent to focus its efforts on Spanish-speaking residents of its

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<sup>92</sup> D.18-01-004, at 48.

service area. To the extent 3C-REN wishes to pilot a more targeted program to either Spanish-speaking customers or to non-single family households, 3C-REN may submit an implementation plan and request funding for such a proposal. Staff will have discretion to approve or modify such a request, based on the potential for such a pilot to result in measurable energy savings tied to intended participants.

3C-REN's business plan does not break out its proposed budget into the various activities it proposes, therefore we are unable to approve a specific funding amount based on our partial approval. Further, given this is a new REN and will need some amount of start-up time and effort, we are concerned with 3C-REN's as yet unproven ability to effectively operate as a REN. We will conditionally approve its business plan, subject to the modifications discussed in this section, and on the condition that 3C-REN submit a revised budget in its 2019 budget advice letter to reflect only (1) its workforce education and training and code compliance activities, and (2) to the extent it intends to focus on Spanish-speaking and/or multi-family customers, a residential direct install program. As with all PAs, each year's ABAL will need to show progress toward meeting key performance metric targets.

## **5. MCE Business Plan**

MCE, at this time, is the only CCA that has presented a business plan for Commission consideration. MCE has applied to administer its energy efficiency portfolio under the provisions of Public Utilities Code Section 381.1(a)-(d). As such, MCE is subject to the Commission's cost-effectiveness requirements and other oversight of its proposed energy efficiency business plan portfolio.

MCE proposes a set of programs for commission consideration, as well as to become the single point of contact (SPOC) for customers within its service



area. In addition, MCE proposes to take on the role of “downstream liaison” for other program offerings within its geographic area, asking that the Commission require other PAs to coordinate its program offerings through MCE, in order to minimize overlap and duplication. Along with this, MCE requests attribution of energy savings associated with all of the programs it coordinates within its territory, including statewide and regional programs run by other PAs.

Finally, MCE makes some specific requests with respect to the way they contract with PG&E to provide natural gas energy efficiency programs alongside their electric offerings. In particular, MCE proposes that the gas contract mirror the electric funding mechanism, where funding is transferred quarterly in advance of program expenditures, instead of billed after the fact.

### **5.1. Sector Level Proposals**

MCE proposed a total of approximately \$9 million in expenditures in the first year, ramping up to around \$11 million annually in middle years, and then settling at around \$10 million annually in later years, in the following sectors:

- Residential, single family
- Residential, multi-family
- Commercial
- Industrial
- Agricultural
- Workforce, education, and training

MCE did not propose program activities in the public sector, for codes and standards, or in the emerging technologies area.

MCE also estimated its cost-effectiveness of programs during the first two years at a 1.22 TRC, 1.25 PAC, with improvement in later years.

Overall, we find MCE's proposal thorough and thoughtful. Their program ideas are well-considered and innovative, and they propose logical metrics and a small administrative structure to minimize costs.

The chief issue area with MCE's plan, as they acknowledge, is the potential for overlap with PG&E's considerably larger set of program offerings. Because the business plans are presented at the level of sector strategies, by design, it is difficult to tell from the information presented by PG&E and MCE where there may be program overlap, resulting in confusion or duplication.

In general, because of the growth of CCAs, these issues of program overlap and appropriate role for the IOUs and the CCAs are ones the Commission is going to have to grapple with and devise strategies for in the coming years. MCE is the pioneer in this area, and we are mindful that their work may set a precedent or example for other CCAs to follow. However, we are reluctant to set general policy on these matters in this application proceeding designed to evaluate specific business plan proposals. We anticipate needing to take a closer look at how to coordinate and design seamless integration of CCA and IOU energy efficiency portfolios in the future in an ongoing rulemaking proceeding. But for now, we will evaluate MCE's proposals on their individual merits relative to the offerings of PG&E and, to some extent, BayREN.

We will also require MCE, similar to the RENs, to prepare a joint cooperation memorandum (discussed further below in Section 7.1) with PG&E summarizing the areas of potential overlap in their portfolios and the manner in which they will coordinate and collaborate during the business plan period.

With this in mind, we are entirely comfortable with MCE's proposal in the residential sector, because they have already been running programs similar to those they propose and have developed a track record. It is also the case that the

majority of their service area consists of residential and small commercial customers; thus, it makes logical sense for MCE to focus in these areas.

MCE's proposals for the commercial, industrial, and agricultural sectors, are also reasonable and should be approved.

In the industrial sector, MCE proposed a strategic energy management style approach. They also propose some other ideas, such as peer advisory groups. In general, a number of these activities are similar to PG&E's, so we will require MCE and PG&E to detail how they will coordinate in their joint cooperation memorandum.

Finally, MCE proposed to conduct workforce, education, and training activities. While there is the potential for overlap and redundancy here, too, this is an area where we need innovative and thoughtful approaches to improve our results. Thus, we intend to allow MCE to give their activities a try and will ask them to coordinate with PG&E to ensure duplication is minimized and unique approaches are designed, or at least unique populations served.

In summary, Table 7 below includes the approved budgets for MCE over the approved business plan period.

**Table 7. Approved Funding Levels for MCE 2018-2025 Business Plan, in \$thousands**

	Residential: Single Family	Residential: Multi-family	Commer- cial	Industrial	Agricul- tural	WE&T	EM&V	Total
2018	\$2,348	\$2,252	\$1,522	\$1,112	\$810	\$160	\$328	\$8,532
2019	\$2,348	\$2,252	\$1,522	\$1,112	\$810	\$160	\$328	\$8,532
2020	\$3,009	\$3,336	\$3,123	\$1,028	\$1,111	\$320	\$477	\$12,404
2021	\$3,009	\$3,336	\$3,123	\$1,028	\$1,111	\$320	\$477	\$12,404
2022	\$2,626	\$2,811	\$2,765	\$1,014	\$1,039	\$320	\$423	\$10,998
2023	\$2,626	\$2,811	\$2,765	\$1,014	\$1,039	\$320	\$423	\$10,998
2024	\$2,626	\$2,811	\$2,765	\$1,014	\$1,039	\$320	\$423	\$10,998
2025	\$2,414	\$2,513	\$3,082	\$1,005	\$1,118	\$320	\$418	\$10,870
Total	\$21,006	\$22,122	\$20,667	\$8,327	\$8,007	\$2,240	\$3,297	\$85,736

## **5.2. Single Point of Contact**

As part of its business plan filing, MCE proposes to act as the single point of contact (SPOC) for many of its program offerings to individual customers. MCE describes this as a sort of “concierge” service where the MCE representative would be a one-stop-shop for information about all energy efficiency programs and incentives available to the customer for a particular project or activity.

Although MCE’s business plan describes the SPOC service as non-exclusive, in that they would provide information to customers about programs that are offered by all PAs and/or third parties available to the customer, it is not totally clear what the Commission’s endorsement of this concept would really mean. While it is clear that MCE would step forward to provide information about all offerings, would the other PAs be prohibited from having contact with customers separately? Would the other administrators be required to refer customers to the MCE SPOC?

To the extent that MCE’s proposal is designed to make the customer experience of participating in an energy efficiency program user-friendly and seamless, we endorse it. However, we do not do so to the exclusion of the role of other PAs. Customers may need or want multiple sources of information about energy efficiency offerings, and thus we decline to give MCE an exclusive role as SPOC in their geographic area. We do, however, approve MCE’s budget request to serve in this capacity and encourage coordination between PG&E, BayREN, and MCE to avoid duplication of marketing and outreach funding and activities for customers in MCE’s geographic service area. Again, this should be detailed in a joint memo of cooperation between MCE and PG&E.

### **5.3. Downstream Liaison Proposal**

Beyond the SPOC proposal, MCE also included in its business plan the concept that it be assigned as the “downstream liaison” for all programs in its geographic service area. As with the SPOC proposal, it is not entirely clear what this would mean in a practical sense. As described by MCE, it would give them power to cancel program offerings of other PAs in its service area if the offerings conflicted with programs that MCE was running on a downstream basis. MCE acknowledges that it would not seek to cancel any upstream or statewide programs available to its customers and offered by other administrators.

But the definition of upstream and downstream is conceptual and not precise, and we are reluctant to give one administrator power over the program offerings of another administrator in the absence of Commission oversight. Acting as SPOC to customers serves a purpose to assist customers, whereas this downstream liaison proposal appears to be aimed at disputes between PAs or at least their program offerings.

We understand MCE’s expressed frustration at less-than-successful efforts to coordinate with PG&E in the past on program offerings, but that does not necessarily justify an exclusive role such as the one MCE suggests.

Further, MCE is suggesting that, in order to help improve their portfolio cost-effectiveness ratio, among other benefits, that they be attributed the energy savings associated with the upstream and statewide programs being offered in their territories, and allow the IOUs to earn shareholder incentives for better cooperation and coordination with the CCAs.

Since energy savings goals are set on the basis of each IOU service territory, it is not clear what purpose would be served by attributing energy savings to MCE for programs run by other administrators, except for the

cost-effectiveness improvement to their portfolio, as noted. However, since we have already indicated flexibility on MCE's portfolio cost-effectiveness in light of changes we are suggesting and delays in program implementation, we are not convinced that savings attribution should be modified in the manner suggested by MCE. This may be yet another issue with which the Commission will need to grapple in the energy efficiency rulemaking, as more CCAs begin to become energy efficiency PAs. But for purposes of this proceeding and MCE's business plan, we will not approve the downstream liaison proposal at this time.

#### **5.4. Natural Gas Contractual Issues**

In MCE's business plan, they address an issue related to the mechanics with which MCE is granted natural gas energy efficiency funding, as previously authorized by the Commission in D.14-10-046 and D.15-10-028. MCE requests that its natural gas budget be treated similarly to its electric budget, which involves quarterly transfers of its annual budget in advance of program expenditures, rather than monthly billing after expenditure, as is done now in the case of natural gas funds.

We agree with MCE that this is a sensible mechanism that is working for the electricity funding and should be replicated for the natural gas funding. This finding does not modify any other requirement related to natural gas funding for MCE.

#### **5.5. Automatic Budget Increases for Expansion to New Communities**

MCE proposes that the Commission establish a process for budget augmentation consistent with CCA expansion into new communities. MCE represents that adding new customers will not necessarily involve fundamental changes to the approaches articulated in its business plan. Under current rules, if

MCE wanted to increase its budget, it would need to file a new business plan. MCE requests, instead, to file a Tier 2 advice letter requesting additional funding if it is not associated with any change in business plan strategies, but rather simply an increase in customer base. MCE proposes a threshold of budget increases of 50 percent for triggering a new business plan; beneath that threshold only a Tier 2 advice letter would be required.

We decline to adopt this suggestion by MCE. Because of the rapid expansion of not only MCE, but also many other CCAs recently, the Commission may need to develop a framework for addressing these sorts of issues in the future. We decline to make large budget increases relatively automatic, and conclude that rapid expansion of territories could involve different customer bases, potentially necessitating different sectoral strategies. Therefore, the Commission will still require MCE to file an updated business plan if it wishes to exceed the budget caps adopted by this decision.

#### **5.6. MCE Budget Advice Letter Consolidation**

Currently, MCE files an advice letter on December 1 of each calendar to delineate any unspent funds, including estimated from the calendar year that is not yet complete. Then, as a PA, MCE will also file a business plan ABAL on September 1 of every year. MCE requests that those advice letters be consolidated, reducing administrative costs and confusion. We agree with this request and will allow MCE to consolidate its unspent budget advice submission previously required to be filed on December 1 with its ABAL submission.

#### **6. LGSEC Proposal**

LGSEC proposes to serve as statewide administrator for LGPs, each of which is currently run by one of the IOU PAs. In advancing its proposal, LGSEC points out a number of challenges that LGPs currently face, including

inconsistent data access and contracting schedules and terms, among others. To address these challenges, LGSEC proposes several key activities: transition LGPs from a mixture of resource and non-resource programs to all non-resource programs; standardize LGP contracts; and develop a statewide energy usage database akin to The University of California at Los Angeles' (UCLA's) Energy Atlas (for Los Angeles County).

### **6.1. Positions of the Parties**

CCSF, NRDC, RHTR, and all four IOUs oppose LGSEC's proposal for statewide administration of local government partnerships. Most of these parties assert that LGSEC's proposed activities are unnecessary and could potentially disrupt the functioning of existing LGPs. CCSF, for instance, argues that statewide administration may have unintended negative consequences, specifically in reducing flexibility and the ability to serve a broad range of customers. RHTR takes particular issue with the proposal to designate all LGP programs as non-resource, asserting that local governments' ability to determine the mix between resource and non-resource activities is essential.<sup>93</sup> The IOUs assert they have already initiated efforts to begin increased alignment for the implementation of LGPs across the state, including development of more consistent LGP contracts. Responding specifically to the proposal to only offer non-resource programs or services, PG&E asserts "a bifurcated approach that requires two applications - one to an IOU for resource programs and another to a Statewide Administrator for non-resource programs - has the potential to create additional barriers to local governments' participation in energy efficiency

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<sup>93</sup> RHTR March 3, 2017 Protest, at 5.



solutions.”<sup>94</sup> NRDC does not oppose LGSEC’s proposal but recommends the Commission defer consideration of the proposal until after the program administrators transition their portfolios to the predominantly third party and statewide administration framework.<sup>95</sup>

LGSEC argues, in response to these critiques, that it intends to honor existing LGPs and “if successful, continue them where they are located today (so long as the utilities continue to honor their current agreements, renew them into the future while continuing to staff them appropriately)...”<sup>96</sup> LGSEC further asserts it has no intent either to remove local governments’ autonomy, or to remove the utilities from their current support activities for LGPs, but aims exclusively at administrative activities and developing technical support capabilities not currently available statewide.

## **6.2. Disposition**

We are wary of adding an administrative layer on top of the overall LGP structure, particularly since the value of LGSEC’s proposal, and thus its likelihood of success, depends in large part on the number or proportion of LGPs that would participate in both the data collection and the contract standardization efforts. For the proposed activity of standardizing contract terms and conditions, many LGPs may desire to maintain their existing contracts (i.e., seek to extend them rather than execute new contracts based on standardized terms and conditions as proposed by LGSEC), or to adopt the more consistent formats that the IOUs state they will develop. We support LGSEC’s

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<sup>94</sup> PG&E March 3, 2017 Response to LGSEC, at 4.

<sup>95</sup> NRDC March 3, 2017 Response, at 19.

<sup>96</sup> SoCalREN March 10, 2017 Reply, at 36.

statement that it would honor those agreements; we do not find it reasonable to restrict LGP partners' ability to choose which contract format best serves their needs. This means, however, the more LGP partners that eschew LGSEC's standardized terms and conditions, the less practical value they have even if, objectively, they could be very beneficial.

We are also concerned with LGSEC's proposal to convert all LGP activities from their current mix of resource and non-resource to entirely non-resource activities, as many LGPs are indeed focused on reaching specific energy savings goals and there is value in enabling those partners to credit their efforts towards reaching those goals. In this respect, we are persuaded by PG&E's argument against requiring LGPs to apply to two different administrators if they wish to pursue both resource and non-resource activities.

For the above reasons, we will not adopt LGSEC's proposal for statewide administration of local government partnerships.

To be clear, our denial of LGSEC's proposal is not an ipso facto endorsement of the IOUs' performance in administering their LGP partnerships. The IOUs acknowledge and agree with LGSEC's characterization of the challenges facing LGP programs, and state their commitment to addressing these challenges. We are also aware that many LGP programs / partnerships have fairly low TRCs, and could thus be at risk of termination as a result of the stringent portfolio cost-effectiveness requirements we adopt in this decision. We urge the IOUs to work with LGP partners to find workable solutions for both improving LGP programs' cost-effectiveness (to the extent they are not cost-effective) and meeting LGP partners' needs, particularly where meeting those needs would also improve their cost-effectiveness. This relates to both the need for data sharing, as highlighted by multiple parties and most notably by

LGSEC and the RENs, and providing contract terms that align with local governments' budgeting, legal, etc. constraints.

In addition, we acknowledge two issues LGSEC sought to remedy, and specific strategies that LGSEC proposed for addressing those issues. First, LGSEC notes that "Rural and Hard-to-Reach Communities are under-served due to higher costs, more diverse circumstances and lack of institutional capacity."<sup>97</sup> We agree with this assessment, and believe increasing and streamlining support of the LGPs is an effective and essential component in serving hard-to-reach and disadvantaged communities. We therefore direct the IOUs to adopt the following intervention strategies as originally proposed in LGSEC's business plan: quantify co-benefits and local economic benefits of LGPs in hard-to-reach and disadvantaged communities; and support local governments' efforts to increase local capacity to conduct energy efficiency activities. Second, LGSEC notes "inconsistent management, assessment & reporting of LGPs across and within IOU service territories."<sup>98</sup> We urge the program administrators to collaborate amongst themselves and with local governments to implement either the associated strategies proposed in LGSEC's business plan or their own.

Finally, we acknowledge comments submitted by 3C-REN, BayREN, and LGSEC in response to the proposed decision, indicating support for statewide deployment of the Energy Atlas, which LGSEC had proposed as part of their business plan on behalf of the Local Government Commission (LGC). BayREN and SoCalREN recommend implementation through a local government, as

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<sup>97</sup> LGSEC business plan, at 18.

<sup>98</sup> LGSEC business plan, at 21.

opposed to an IOU, and LGSEC proposes a budget be allocated for LGC to coordinate this effort. The Commission previously considered a similar proposal in R.08-12-009, to develop a statewide data center, but declined to adopt this proposal.<sup>99</sup> At that time, the Commission acknowledged “the importance of exploring the value of a dedicated energy data center in the future to increase access to data while developing reasonable protections on customer privacy,” and we continue to see value in such a project. We recognize there is broader interest in developing and implementing an energy data center, or Energy Atlas as proposed by LGSEC. Rather than select the specific entity to implement a statewide Energy Atlas in this decision, we will order the IOUs to select a statewide lead specifically to oversee the deployment of the Energy Atlas, and to solicit a third party implementer to coordinate with local governments and utilities, facilitate onboarding new participating LGP partners, perform continuous quality control on the data sets, educate users in both data submission and analysis, develop new features within the Energy Atlas, and advocate for broader and deeper usage of the tool.

## **7. Guidance for Submission and Staff Review of Annual Budget Advice Letters**

As we discussed in Section 2.6, we will require the IOUs’ ABALs to demonstrate a portfolio TRC greater than or equal to 1.0. Here we discuss further guidance for PAs in submitting ABALs and for staff in reviewing the PAs’ ABALs.

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<sup>99</sup> In particular, the Energy Atlas would fit use cases 1, 2, and 3 discussed in D.14-05-016.

### 7.1. Joint Cooperation Memos

As discussed in Sections 4 and 5, we will require the PAs to submit joint memoranda of cooperation between energy efficiency program administrators with overlapping service areas, or “joint cooperation memos” (i.e., one memo each between PG&E and BayREN; among SCE, SoCalGas and SoCalREN; among PG&E, SCE, SoCalGas and 3C-REN; and between PG&E and MCE). The joint cooperation memos between IOUs and RENs must include the following details:

- RENs must include a summary of the programs they intend to run; if **the IOU(s) who shares territory with a REN offers a similar program**, the IOU(s) must also provide the same summary of their program. The summary for each PA’s program must include eligible measures, budgets, and target audiences. The RENs and IOUs must describe how they will offer their corresponding portfolios and avoid duplication.
- RENs must also include a discussion section for each program, summarizing how the program meets at least one of the criteria outlined in D.12-11-015, i.e., aimed at hard-to-reach customers (which can overlap with an IOU offering); programs that IOUs do not offer; and pilots not offered by IOUs but with the possibility of scaling.

The joint cooperation memo between PG&E and MCE must include:

- A summary of the programs MCE intends to run and **if PG&E offers a similar program**, PG&E must also provide the same summary of their program. The summary for each program must include eligible measures, budgets, and target audiences. Each PA must detail their role, including items such as:
  - 1) As the single point of contact, will MCE be the only customer-facing **PA in their territory for all programs, or will they be the single point** of contact just for their program;
  - 2) how each PA will work with the other so that customers are informed of all the options available to them and not steered simply to their own programs, but are also aware of alternative programs; and

- 3) how each PA will ensure customers are also aware of the other's programs, where that PA does not have a similar offering.

Staff approval of the joint cooperation memos will be a prerequisite for staff to consider the PAs' ABALs for the relevant program year. Specifically, if the PAs are unable to agree in submitting the joint cooperation memos, or if staff finds the joint cooperation memos lack sufficient detail for reviewing the ABAL submissions, staff will hold the PAs' ABALs in suspension until all deficiencies are cured.

We will require the PAs to submit annual joint cooperation memos to detail how the different PAs plan to cooperate or make changes to programs that may overlap in the upcoming program year. The initial joint cooperation memos, for program year 2019, must be submitted via Tier 2 advice letters no later than August 1, 2018, to afford staff adequate time for reviewing these documents ahead of the ABALs. For subsequent program years (i.e., starting with the September 3, 2019 ABALs), PAs with overlapping service areas must submit updated joint cooperation memos via a Tier 2 advice letter no later than June 15, prior to submitting their ABALs.

## **7.2. Required Components of Annual Budget Advice Letters**

Updates are necessary for the ABAL review process and the information filed by program administrators in their respective ABALs.

Annual budget advice letter submissions consist of two parts that are submitted at the same time: (1) the letter (document) and (2) companion information (e.g., database submissions) uploaded to the Commission's California Energy Data and Reporting System (CEDARS). All information currently submitted in the ABAL, such as prior year and requested budget(s),

will continue to be included in future submissions and the format of the information uploaded to CEDARS will not change. However, in order to streamline ABAL review and ensure a homogenous presentation of requested information, we will direct staff to develop templates and further guidance as needed for the ABAL submissions, beginning no later than June 1, 2018. In developing these templates and associated guidance, staff shall seek and incorporate program administrator input as much as possible.

Future ABALs will be based on the staff-developed template and present the information listed below in order to facilitate stakeholder and staff review and draw attention to portfolio cost-effectiveness and energy savings trends and the potential need to reevaluate current strategies and/or redouble efforts in certain areas.

Beginning with the ABALs due on September 4, 2018, the following information must be provided in each ABAL:

- **Cost Effectiveness** -Forecasted, claimed and evaluated cost-effectiveness information will facilitate staff review of the PA portfolios and illustrate trends within certain sectors and/or programs that highlight areas in need of improvement or programs that are performing “as intended.” Staff will use this information in the “verification of PA claim (see Section 7.3 – Criteria for Approving Annual Budget Advice Letters)” to determine whether it is reasonable to conclude the forecast will be achieved.
- **Forecast TRC and PAC** of each program and of each sector for the relevant program year (i.e., the year for which the PA is requesting budget authorization)
- **Claimed TRC and PAC** of each program and of each sector from the two most recent years for which data is available
- **Evaluated TRC and PAC** of each program and of each sector from the two most recent years for which data is available

- **Table of Forecast, Claimed and Evaluated TRC and PAC** at the portfolio level going back to the beginning of the Rolling Portfolio, i.e., 2016, or the earliest subsequent program year.<sup>100</sup>
- **Budget** – Information regarding historic portfolio, sector, and program-level budget requests and actual expenditures over the life of the business plan will facilitate staff review and understanding of how and where the program administrators are targeting ratepayer dollars, in concert with TRC and energy savings information. Providing this information along-side cost-effectiveness, energy savings and sector-level metrics reporting will help identify sectors and programs that may or may not be performing as intended. Staff will also “measure” requested budgets against the annual funding amount, for the relevant program year, in the PA’s business plan pursuant to the review criteria (see Section 7.3).
  - **Budget**: portfolio total, and broken out by sector and by program, for the relevant program year (i.e., the program year for which the PA is requesting budget authorization)
  - **Authorized budgets** for each program and for each sector for the two most recent years
  - **Actual expenditures** for each program and for each sector for the two most recent years
  - **Table of authorized budgets and actual expenditures** at the portfolio level for each program year beginning with the first year of the Rolling Portfolio, i.e., 2016.<sup>101</sup>
  - **Table of budget forecasts and annual budget caps in business plan for the relevant program year** (i.e., the program year for which the PA is requesting budget authorization) and each future year of the approved business

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<sup>100</sup> There will be a two- or three-year time lag between when forecast data and evaluated TRC data become available to report; evaluated TRC data for 2016 will not be available due to a gap in EM&V contracts.

<sup>101</sup> There will be a time lag between when forecast and actual data become available to report.



plan period. Section 7.2.1 discusses a true-up budget advice letter which, if approved, should be reflected in this budget table.

- **Budget details required for ESPI and UAFCB Audit purposes:** A breakdown of total program budget by category, including but not limited to:
  - Administrative costs
  - Direct implementation-incentives and rebates
  - Direct implementation non-incentives
  - IOUs administered marketing, education, and outreach
  - EM&V
  - On Bill Financing (program and revolving loan pool).
- **Energy Savings -** Information regarding forecasted, claimed and evaluated energy savings over the life of the Rolling Portfolio will facilitate staff review and understanding of both portfolio and program performance, based on energy savings, and whether and how well program administrators' energy savings forecasts align with savings attributable to energy efficiency program intervention(s) and at what cost. An energy efficiency expert will use this information in staff's "verification of PA claim" (see Section 7.3) to determine whether it is reasonable to conclude the forecast will be achieved.
  - **Forecast energy savings and goals** of each program for the program year for which the PA is requesting budget authorization
  - **Claimed energy savings** of each program and of the total portfolio, from each of the prior program years going back to the beginning of the Rolling Portfolio
  - **Evaluated energy savings** from the most recent evaluated program year

- **Table showing forecast, claimed and evaluated energy savings compared to goals** at the portfolio level going back to the beginning of the Rolling Portfolio, i.e., 2016.<sup>102</sup>
- **Table showing greenhouse gas savings forecasts, actuals, and goals.**
- **Sector-level Metrics** - Sector-level metrics are intended to serve as indicators of performance. Metrics, and their associated baselines, targets, and reports of progress against metrics, allow for mid-course assessments of performance to-date and facilitate program modifications, if needed. Information on sector-level metrics, which may be an appendix to the budget advice letter,<sup>103</sup> will complement energy savings, budget and cost-effectiveness information as staff reviews portfolio and program performance to date, and will provide insight on whether it is reasonable to conclude the cost-effectiveness and energy savings forecasts will be achieved.
  - **Measured progress to date** for each of the sector-level metrics since January 2016 or the beginning of the sector / program implementation, whichever is earlier.
- **Program and portfolio descriptive information for ABALs**

The ABALs must contain information regarding cost-effectiveness, budgets, energy savings, and portfolio progress as measured by sector-level metrics, as discussed above. We will also require the PAs to include a discussion of proposed program and portfolio changes, to facilitate Commission staff and stakeholder review of the ABAL submissions and understanding of future portfolio considerations and composition. Our purpose for requiring this

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<sup>102</sup> There will be a two- or three-year time lag between forecast and evaluated TRC data; there will be a gap in TRC data for 2016 due to a gap in EM&V contracts.

<sup>103</sup> This issue may be resolved in the larger advice letter template discussion between Commission staff and PAs.

information is for the program administrators to demonstrate their ability to analyze and optimize their portfolios, and to make that analysis and decision-making process transparent to stakeholders; this is how the Commission and stakeholders may gain confidence in the program administrators' portfolio management skills and capacity. There will be minimal to no review/oversight by staff of the provided information, but the information must be included.

Specifically, such a discussion should be structured to include:

- 1) Discussion of proposed program changes
  - A summary of program realignments and program modifications, including:
    - Changes made to reduce or remove unnecessary duplication; changes to better align with programs offered by other PAs; and new programs.
    - For programs the PA proposes to significantly expand or reduce (i.e., more than 40 percent change in funding): a reason for these changes, and specifically what changes are being made, e.g., changes to design, incentive levels, eligible measures, and/or eligibility requirements, etc.
    - For programs a PA proposes to terminate: discussion of whether the PA expects the program's cost-effectiveness to improve over time, or whether previous evaluations show the program is consistently not meeting expected energy savings.
    - For programs that are not cost-effective and that a PA proposes to continue: whether the PA expects that the program's cost-effectiveness will improve over time, and if so, what is the basis for this expectation, i.e., what specific factors would lead to improved cost-effectiveness and which of those factors the PA can control or influence.

- Reassessed or altered strategies (budget reductions, retired measures, etc.) and/or general approaches to improve cost-effectiveness.
- 2) Discussion of proposed portfolio changes
- Portfolio optimization - this section would describe at a high level any changes to the portfolio to optimize cost-effectiveness and/or achieve savings goals, and how those changes fit into the overall portfolio strategy. The narrative would likely flow from the “foundation” of program-level discussion and trade-offs, and the effect any proposed changes may have on the portfolio.
- 3) Any ABAL that includes a forecast portfolio TRC between 1.0 and 1.25 during the 2019-2022 ramp years should include:
- An explanation of why the PA is not proposing a portfolio that meets a 1.25 TRC;
  - Why the PA is confident that it will meet the evaluated 1.0 TRC for that year; and
  - How the PA intends to lower costs or increase savings going forward.
- 4) Any ABAL that includes forecasted energy savings that are lower than Commission established annual savings goals<sup>104</sup> should include:
- Discussion or explanation for how the PA will ensure achievement of the overall savings goals, within the overall budget, during the business plan period (i.e., through 2025).

### **7.2.1. Updating for 2018-2030 Goals and Interim GHG Adder, Subsequent Updates**

The September 4, 2018 ABALs will serve as the true-up budget ALs we previously anticipated the PAs would submit following Commission disposition

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<sup>104</sup> The most recently adopted energy savings goals are reflected in D.17-09-025.

of the business plans. The PAs should use the Cost Effectiveness Tool (CET) version that is effective as of August 1, 2018. The PAs must update their portfolios and budgets to reflect the 2018-2030 goals, interim GHG adder, and other relevant factors to provide a more accurate forecast of their expected annual funding levels. These revised annual funding levels, to the extent they differ from a PA's business plan, will take the place of the annual funding levels in the PA's business plan for purposes of staff's ABAL review process and criteria. With the exception of SoCalGas, as discussed in Section 2.6.2.1, the overall funding amount, i.e., the sum of the revised annual funding levels through 2025, must not exceed the overall funding amount in the PA's business plan. SoCalGas' overall funding amount must not exceed the overall funding amount in its business plan by more than \$135.8 million, which is \$19.4 million annually for program years 2019 through 2025.

For subsequent ABALs, PAs should continue to identify cost savings and revise their annual funding levels downward, as necessary, to provide more transparency and reflect more accurate assumptions as they progress with business plan implementation. Again, the overall funding amount of any such revisions must not exceed the overall funding amount in a program administrator's 2018-2025 business plan (as modified in this decision) for the corresponding timeframe.

We expect revisions that follow the 2019 ABALs, if any, to reflect downward adjustments based on the PAs improving their forecasts of in-house staffing needs with each solicitation, and realizing administrative efficiencies through the statewide administration framework. The business plan triggers remain in effect, that is, if a PA is unable to achieve the Commission's most

current adopted goals cost-effectively and within the budget parameters of their approved business plan, that PA must file a new business plan.<sup>105</sup>

### **7.2.2. Guidance on Data Submissions**

While reviewing the ESPI and budget advice letters in 2016 and 2017, Commission staff discovered several data discrepancies between the IOUs' monthly and quarterly claims, annual true-up submissions (final official program tracking data), the ABALs and the ESPI annual advice letter. These discrepancies create challenges for the Commission's review, verification, reconciliation and data analysis processes. It also creates unnecessary delays in the Commission's approval process of the utilities' submissions, including but not limited to the budget and ESPI advice letters.

To avoid data discrepancy across various submissions, the IOUs must use their final official program year tracking data as the basis for all their submissions that include data associated with that specific program year. This change will be effective beginning with this program year (2018).

The IOUs may not make any changes to the data after the final submission, save for the following provision: if an IOU discovers any errors in the data after the final tracking data is submitted, then the IOU must update its tracking data in CEDARS and notify the Energy Efficiency Branch Program Manager; the Utility Audit, Finance and Compliance Branch Program Manager; and all parties to the active energy efficiency proceeding (i.e., R.13-11-005 or its successor) of any such changes. The IOU must list the changes and the reason(s) for such

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<sup>105</sup> D.15-10-028, Ordering Paragraph 2.

changes in its notification. The IOU must then use the updated dataset in the respective regulatory filings going forward.

The IOUs must also conform their submissions to the data requirements and formats directed by Commission staff via annual guidelines or the monthly/ quarterly/ annual filing templates.

### **7.3. Criteria for Approving Annual Budget Advice Letters**

As we discussed in the previous section, the PAs will need to update their budget assumptions in their September 4, 2018 ABALs (for program year 2019), consistent with D.17-09-025 (adopting 2018-2030 energy efficiency goals) and D.17-08-022 (adopting interim greenhouse gas adder). We acknowledge this update may result in revisions to the annual funding levels included in the business plans; to the extent a PA revises its annual funding levels as a result of updating its budget assumptions pursuant to D.17-09-025 and D.17-08-022, staff shall use those revised annual amounts for reviewing the 2019 and subsequent ABALs. Again, the total amount of these revised estimates, for this business plan period (2018-2025), must not exceed the total amount of the forecast budget (for the same years) included in the business plans. The overall amount of funding through 2025, as reflected in the business plans, essentially serves as a cap on PAs' total spending for this business plan period. In adopting such a cap on overall spending, we find it reasonable to afford staff discretion to dispose of a PA's portfolio budget request that exceeds the corresponding annual funding amount included in its business plan (as modified by this decision), plus unspent funds from previous years in the business plan period, through the ABAL review process.

We direct staff to evaluate the ABALs pursuant to the following **ABAL approval criteria**:

- **IOU PAs' and MCE's portfolios**
  - PA claims requiring staff verification:
    - Forecasted TRC must meet or exceed 1.25 in the ABAL, except during program years 2019 – 2022, when the forecasted TRC must meet or exceed 1.0. Verification shall include review of actual evaluated TRC for two previous years and analysis of provided program/ portfolio information so an energy efficiency expert would reasonably conclude the forecast will be achieved; and
    - The IOUs' forecasted energy savings goals must meet or exceed Commission established savings goals for each IOU;<sup>106</sup> MCE's forecasted energy savings goals must meet or exceed the annual energy savings targets included in its business plan. Verification shall include review of: prior year actual energy savings, prior years' forecasts, sector-level metrics, and analysis of provided program/portfolio information so an energy efficiency expert would reasonably conclude the forecast will be achieved.
  - Forecasted budget must not exceed the PA's annual budget in the approved business plans, or (if applicable) the revised annual budget in the PA's September 4, 2018 ABAL, for the program year for which the ABAL requests budget authority.

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<sup>106</sup> Goals are established through goals and potentials studies and are based on what is practical and possible in the energy efficiency sector to meet state energy efficiency goals. The Integrated Resource Plan process, an approach for system optimization, refines energy efficiency goals along-side other procured resources, to optimize for reaching state goals, such as decarbonization, in affordable way. This requires Commission staff to work on a Common Resource Valuation Method, which is intended to reconcile the various valuation methods currently used to choose which resources to procure.



- Standard of review for staff disposition of the ABALs does not include review of program administrators' decisions on reducing, cancelling, expanding or adding individual programs or program areas.
- **REN PAs' portfolios**
  - Forecasted budget must not exceed the annual budget in the approved business plan, or (if applicable) the revised annual budget in the PA's September 4, 2018 ABAL, for the program year for which the ABAL requests budget authority, plus any unspent funds from previous years in the business plan period, by more than 20 percent; and PA claim requiring staff verification: Forecasted energy savings goals must meet or exceed the annual energy savings targets included in the PA's business plan. Verification shall include review of: prior year actual energy savings, sector-level metrics, and analysis of provided program/portfolio information so an energy efficiency expert would reasonably conclude the forecast will be achieved.
  - Standard of review for staff disposition of the ABALs does not include review of program administrators' decisions on reducing, cancelling, expanding or adding individual programs or program areas.

#### **7.4. Review Process for "Ramp" or Transition Period**

We consider the first few years of this business plan period (2018-2022) as ramp years in the context of third party solicitations, setting up the statewide administration framework, and affording the PAs an opportunity to improve portfolio cost-effectiveness.

The Commission can call for a re-submitted ABAL from any PA as a result of a decision in the policy track (R.13-11-005 or its successor), new data based on evaluation results or PA savings claims, or for any other reason.

If a PA's ABAL submitted for program year 2019 (September 4, 2018) through program year 2022 (September 1, 2021) meets the ABAL review criteria,

staff will approve that PA's ABAL. If a PA's ABAL submitted for program year 2019 (September 4, 2018) through program year 2022 (September 1, 2021) fails the ABAL review criteria, then staff will reject that PA's ABAL and direct the PA to hold a workshop to explain why it failed to meet the approval criteria; the main purpose of this workshop would be to provide transparency of the challenges in meeting the criteria and potentially to aid the PA in revising its business plan. Pursuant to D.15-10-028, the PA will need to file a revised business plan for Commission approval.

Given that we are requiring a portfolio forecast TRC of 1.0 during the ramp years (program years 2019 - 2022), combined with the uncertainty that the business plan portfolios will achieve a 1.0 TRC on an evaluated basis, we find it reasonable and necessary to require an additional process for PAs that propose a portfolio forecast TRC that meets or exceeds 1.0 but does not meet or exceed 1.25:

- Within 45 days after staff's approval of its ABAL, the PA must hold a workshop for stakeholders, to explain why its forecasted TRC does not meet or exceed 1.25, and propose how it will transition to a TRC forecast of 1.25 during the ramp years. The PA must describe how it intends to achieve a portfolio TRC that meets or exceeds 1.0 on an evaluated basis, and a forecast TRC of at least 1.25 by program year 2023; this may include implementation of recommendations not adopted in this decision but that could result in cost savings, including ORA's recommendations regarding cost recovery for third party implementers' use of utility account representatives. As part of this process, the PA should identify any programs it intends to discontinue or modify due to consistently poor or declining cost-effectiveness results, and how the PA is communicating this intention to those programs' beneficiaries. The PA must provide notice of the workshop to the service list of R.13-11-005 or its successor, no later than 30 days prior to the workshop date.
- Within 15 days after the workshop, the PA must produce a report summarizing the workshop, which will include the PA's

proposal for meeting/exceeding a 1.0 TRC on an evaluated basis and transitioning to a TRC forecast of 1.25 during the ramp years, and stakeholder comments from the workshop. The PA must file and serve the report in R.13-11-005 or its successor proceeding. The workshop should not focus on modifying energy efficiency cost-effectiveness policy, though the workshop report may include recommendations, to be considered in R.13-11-005 or its successor proceeding, to better align the statutory requirement regarding cost-effectiveness with the Commission's other energy efficiency policy goals.

- Within 20 days of the PA sending the workshop report to the service list(s), parties may file comments (in R.13-11-005 or its successor proceeding) on the PA's portfolio composition, the workshop report, and how the PA proposes to achieve an evaluated portfolio TRC greater than or equal to 1.0 and transition toward a forecast portfolio TRC greater than or equal to 1.25.
- The PA must review the stakeholder feedback and develop a draft framework or proposal for making portfolio improvements to ensure the portfolio is on track to meeting the ABAL review criteria in future program years (i.e., a forecast TRC of at least 1.25 by program year 2023).
- The PA must consult the new energy efficiency procurement review group (PRG) and present its proposal to meet the ABAL review criteria in future program years (i.e., a forecast TRC of at least 1.25 by program year 2023).
- The PA's ABAL for the following program year must include updated information per the required advice letter content discussed in Section 7.2, along with an updated implementation plan describing in greater detail how the PA will address the portfolio challenges that caused it to propose a portfolio forecast TRC below 1.25.
- If, based on evaluated savings results for program year 2019, a PA's portfolio TRC does not meet or exceed 1.0, the Commission may require the PA to file a revised business plan for Commission approval. Further, the Commission may apply

additional repercussions, which we have yet to develop but we discuss some possible options below.

Our purpose for this process is not to dwell on failures but rather to move portfolios back into cost-effectiveness and toward energy savings. Further, in response to comments on the proposed decision, we extend the duration of the ramp years in part to allow time for a thoughtful and transparent examination of cost-effectiveness policy during the ramping years for purposes of equitable treatment of programs, prior to obligating the PAs to cut programs with low TRCs, to allow for a more gradual and rational phasing out of programs that do not align with cost-effectiveness and/or other policy objectives. We will also require the PAs to share and present their draft ABALs at a CAEECC meeting prior to the September submission deadline, so that stakeholders have an opportunity to review and provide feedback that should inform the PAs' ABAL submissions. During the ramping period the PA can continue administration of its programs and operate within Commission rules for implementing its portfolio, including making program modifications, shifting funds, submitting advice letters to cancel programs or seeking additional funds for successful programs, etc. Notwithstanding that provision for continuity, however, we find it necessary to establish effective penalties for the potential scenario in which a PA's ABAL for program years starting in 2023 is rejected. We intend to consider options for such penalties as soon as practicable in R.13-11-005 or its successor. Such options may include: withholding ESPI payments for portfolios that are not cost-effective; increased oversight and CPUC-directed cancelling of programs with low TRCs; shifting costs for non-cost-effective programs from ratepayers to PAs (i.e., ratepayers only pay for the part(s) of a portfolio that is/are cost-effective).

## **8. Next Steps**

### **8.1. Timeframe for Portfolio Launch**

The PAs should commence with implementing their business plans as soon as practicable following the issue date of this decision. To summarize, in this decision we are directing the PAs to submit:

1. Within 60 days of the issue date of this decision: compliance filings that include the final set of business plan metrics;
2. On or before August 1, 2018: joint cooperation memos via Tier 2 advice letters;
3. On or before September 4, 2018: ABALs for program year 2019; and
4. Within 120 days of the issue date of this decision: implementation plans posted as required in D.15-10-028.

We are also directing staff to develop ABAL templates through a collaborative process with PA staff, and we are further requiring the IOUs to submit documents to staff that describe their strategies for meeting third party implementers' data access needs. Finally, the PAs will also be preparing to launch third party solicitations. To that end, we intend to rule on the motion ordered in D.18-01-004, for proposed standard and modifiable contract terms, as soon as practicable. We expect to close this proceeding after the Commission disposes of the motion proposing standard contract terms.

### **8.2. Future Modifications to the Rolling Portfolio Process**

#### **8.2.1. Collaboration in the CAEECC Process**

As we acknowledged earlier in this decision, the CAEECC process has at times been contentious and stakeholder discussions leading up to the PAs' filing of their business plans may not have been as collaborative as D.15-10-028 envisioned. We direct the CAEECC facilitator to provide an assessment of

collaboration in the CAEECC process, including PAs' responsiveness to stakeholder input and all stakeholders' (including the program administrators) flexibility in reaching outcomes that are mutually agreeable. The facilitator may also make specific recommendations for process or structural modifications that would facilitate collaboration in the CAEECC process. NRDC, in its role as co-chair of the CAEECC, shall file and serve the facilitator's report in R.13-11-005 or its successor no later than March 31, 2019. Based on the facilitator's assessment, we may consider whether to direct the CAEECC to implement modifications to its structure and/or process, including whether to report on CAEECC efficacy at the end of each year in advance of the advice letter that includes the next year's proposed budget.

### **8.2.2. SCE Recommendations for Process Modifications**

Given the rolling portfolio framework is still a relatively new approach, we acknowledge the frustration voiced by several parties in assessing the reasonableness of the business plans, given our direction to present high-level sector strategies and budgets. SCE agrees with ORA and TURN that parties should have an opportunity to examine proposed budgets in greater detail, and proposes we modify the rolling portfolio framework to enable a more in-depth formal review of proposed budgets and activities. TURN expresses support for consideration of SCE's proposal within the policy track (R.13-11-005 or its successor).<sup>107</sup>

SCE's recommendations reflect a thoughtful consideration of the overall process and we acknowledge its critiques of the current framework. The

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<sup>107</sup> TURN September 25, 2017 Comments, at 5.

Commission envisioned that stakeholder engagement in program specifics would occur in the informal CAEECC process and we remain, at this time, interested in seeing that approach develop into a viable model for collaboration, portfolio oversight and strategic planning. Further, we anticipate a fair amount of uncertainty will be reduced with each round of solicitations, and as the new statewide administration framework is implemented. We will allow for updated budgets and other information at key junctures to enable assessment of whether the portfolios are meeting our objectives, and issue further guidance as needed. While we do not commit to considering SCE's proposal at this time, we by no means rule out the potential need to revisit our framework based on future unknown circumstances.

## **9. Miscellaneous/Other Issues**

### **9.1. ORA Allegations Regarding SoCalGas Codes and Standards-Related Conduct**

ORA's final comments on the business plans include serious allegations regarding SoCalGas's conduct with respect to codes and standards advocacy activities. Specifically, ORA cites the following as evidence of SoCalGas's misconduct:

SoCalGas's opposition to the US Department of Energy's (DOE) proposed new efficiency standards for residential furnaces. ORA includes, as an attachment to its final comments, internal emails among SoCalGas managers discussing the potential for the proposed standards to raise the cost of some gas furnaces and thereby encourage fuel switching away from natural gas. ORA also includes SoCalGas's filings in the Department of Energy's (DOE) rulemaking, wherein SoCalGas identified flawed cost assumptions, inputs, and methods and argued that the proposed standard was essentially not needed. ORA further

highlights that, when all the other IOUs and the CEC requested that DOE maintain and strengthen energy efficiency policies, “SoCalGas instead used the opportunity to request that the federal government reverse previously adopted or pending standards such as the 2015 furnace rule.”<sup>108</sup>

SoCalGas’s use of ratepayer-funded studies to support its position against proposed standards. ORA includes internal emails from SoCalGas discussing a study, commissioned by SoCalGas, that “replicates” an earlier analysis conducted by the same consultant for the American Gas Association and American Public Gas Association in opposition to the DOE’s proposed furnace rule. ORA asserts these emails suggest “a coordinated effort by [the American Gas Association] and SoCalGas to undermine the furnace standard.”<sup>109</sup>

SoCalGas’s purportedly bad faith engagement with the other IOUs in joint codes and standards efforts. ORA details several situations in which SoCalGas appears to have frustrated the other IOUs’ efforts to advance higher standards, including backing out of drafting a joint letter just one day before the response deadline to a 2017 DOE request for information (despite having decided a week earlier that they would not sign on); ORA further alleges that SoCalGas required PG&E to fire its principal codes and standards employee as a condition of PG&E becoming the statewide lead for codes and standards.

ORA requests the following remedies: first, that we prohibit SoCalGas from playing any role in codes and standards advocacy in this upcoming business plan period other than transferring ratepayer funds to the statewide

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<sup>108</sup> ORA September 25, 2017 Comments, at 7-8.

<sup>109</sup> *Ibid.*, at 9.



lead; and second, that we order SoCalGas to return shareholder incentives awarded for codes and standards advocacy, and “other relief as may be appropriate and requested.”<sup>110</sup>

In response to ORA’s allegations, SoCalGas denies any wrongdoing, outlining the various codes and standards activities it has undertaken; asserting its conduct was in accordance with the approved Statewide Program Implementation Plan for codes and standards advocacy; and arguing for a continued role in statewide codes and standards advocacy activities.<sup>111</sup> Also, PG&E denies that it agreed to dismiss any PG&E employee in order to become the statewide lead for codes and standards; PG&E confirms, however, that it agreed to “assign a different employee the task of serving as the lead contact for the statewide codes and standards program.”<sup>112</sup>

SoCalGas acknowledges it communicated with industry organizations and consultants, but points out it “is certainly not the only IOU that engages industry experts and consultants when evaluating energy efficiency rules, regulations, or measures...nothing produced by ORA, including internal company emails, shows that SoCalGas’s concerns about the Furnace Rule were inconsistent with its public comments.”<sup>113</sup> SoCalGas does not, however, address ORA’s more

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<sup>110</sup> ORA September 25, 2017 Comments, at 15-16.

<sup>111</sup> Concurrent with its October 13, 2017 (final reply) comments, SoCalGas filed a motion to strike the portions of ORA’s final comments that alleged misconduct, asserting these allegations were false and misleading. We denied that motion because we are considering ORA’s allegations only as related to our interest, in this proceeding, in adopting a statewide administration framework that will advance the State’s ambitious energy savings goals.

<sup>112</sup> PG&E October 13, 2017 Comments, at 5.

<sup>113</sup> SoCalGas October 13, 2017 Comments, at 4.

substantive argument regarding the use of ratepayer funds in support of a policy position against more stringent standards. Indeed, SoCalGas confirms it did not, in some instances, support more stringent standards, but asserts its lack of support was justified given the concerns it laid out, e.g., the proposed furnace standards had flawed assumptions and would disproportionately impact low-income customers.

The issues before us are whether a utility is prohibited from using ratepayer funds to conduct any activity that does not result in adoption of more stringent codes and standards and, relatedly, whether any circumstances warrant an exception to this prohibition. We have reviewed Commission policies and past decisions and find no such explicit prohibition. Consequently, we also have no rules or guidance for determining whether and under what circumstances a utility may be ‘justified’ in arguing against more stringent codes and standards, which is the basis on which SoCalGas would have us dismiss ORA’s allegations.

We do find, however, our initial authorization of energy efficiency funding for codes and standards advocacy makes clear our intent for those funds:

“[u]sing ratepayer dollars to work towards adoption of higher appliance and building standards may be one of the most cost-effective ways to tap the savings potential for EE and procure least-cost energy resources on behalf of all ratepayers.”<sup>114</sup> ORA provides evidence of instances in which SoCalGas has not worked towards adoption of higher standards, using ratepayer funds, which SoCalGas concedes – albeit on, SoCalGas argues, reasonable bases, which again

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<sup>114</sup> D.05-09-043, at 6.

we have no established guidance for evaluating and determining such asserted reasonableness.

We see no reason to now consider what constitutes a reasonable basis for taking a position other than in support of more stringent standards, given our intent for such activities has been clear since we first authorized energy efficiency funding for those activities. By this decision, we are establishing a governance structure for the statewide programs that minimizes potential for any one IOU program administrator to obstruct those efforts. Additionally, we make clear that the designated lead for a statewide program should have flexibility to determine the most appropriate individual in its organization to manage those activities.

We are nevertheless convinced that there is a potential for SoCalGas to misuse ratepayer funds authorized for codes and standards advocacy, such that we find it reasonable to limit SoCalGas's involvement in codes and standards advocacy as ORA recommends. SoCalGas shall have no role in statewide codes and standards advocacy other than to transfer funds to the statewide codes and standards lead for program implementation.

As the scope of this proceeding is limited to consideration of the 2018 - 2025 business plans, ORA's request for sanctions for alleged past misconduct is ill-placed. We decline to consider this particular request in this proceeding; however, ORA may file a motion renewing its request for sanctions in R.13-11-005 or its successor. We may also need to address the appropriateness of ESPI payments for a program in which an IOU is prohibited from taking part, except with funding. This is also an issue more appropriate for R.13-11-005 or its successor.

## 10. Comments on Proposed Decision

The proposed decision of ALJs Fitch and Kao in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on April 24, 2018 by 3C-REN, Association of Monterey Bay Area Governments (AMBAG), BayREN, Bosch, CCSF, California Energy Efficiency Alliance, CEE, CLEAResult, CodeCycle, East Bay Energy Watch, Efficiency Council, Institute of Heating and Air Conditioning Industries (IHACI), LGSEC, MCE, Nest Labs, Inc. (Nest), NRDC, ORA, PG&E, RHTR, Rising Sun Energy Center (Rising Sun), SBUA, SCE, SoCalGas, SDG&E, SoCalREN, TURN, and Verified.<sup>115</sup> Reply comments were filed on April 30, 2018 by AMBAG, BayREN, California Community Choice Association, California Municipal Utilities Association, City/County Association of Governments of San Mateo County, CCSF, CEE, Center for Sustainable Energy, CodeCycle, Efficiency Council, GreenFan, Greenlining, MCE, Nest, NRDC, ORA, PG&E, RHTR, Rising Sun, SCE, SDG&E, SoCalGas, SoCalREN, TURN, University of California, and Verified. We have modified the proposed decision to reflect specific recommended modifications for clarification and/or consistency. Here, we describe and address the most significant comments to the proposed decision.

Most but not all commenting parties recommend the Commission remove the requirement that the IOUs' ABALs, beginning with the September 4, 2018 ABALs, include a forecast portfolio TRC that meets or exceeds 1.25. These

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<sup>115</sup> Verified sought and received permission to serve and file late comments; Verified served and filed opening comments to the proposed decision on April 25, 2018.

parties offer a range of alternatives, including requiring a forecast portfolio PAC of 1.25 and requiring a lower forecast portfolio TRC, of 1.0. In support of lowering or altering the required portfolio cost-effectiveness forecast, parties generally assert that the PAs will not be able to simultaneously satisfy the numerous requirements outlined in both the proposed decision and in D.18-01-004, and design portfolios that will meet a forecast TRC of 1.25, especially in light of the barely or non-cost-effective portfolio TRCs included in the most recent ABALs. Related to their opposition to the 1.25 TRC standard, many of the PAs also recommend either rejecting or modifying the probation process outlined in the proposed decision, asserting it is unnecessary or unduly burdensome.

We acknowledge the tension created by requiring a higher portfolio TRC and our various directions or indications that PAs focus on hard-to-reach customers, disadvantaged communities, and improving LGP partnerships. We make clear that it is up to the PAs to set their own targets with respect to serving hard-to-reach residential customers, nevertheless we recognize the practical implication that setting a higher standard for cost-effectiveness will necessarily limit plans to focus on presumably more costly customer segments or programs. We are not convinced, however, that programs or activities targeting these segments will necessarily be non-cost-effective. The same is true, even more so, for programs targeted at customer segments that may be underserved but do not meet the criteria in Resolution G-3497 (as modified in this decision), such as PG&E's middle income direct install program. On the one hand, as stated in the proposed decision, we remain committed to affording the PAs considerable flexibility in managing their portfolios, including discontinuing programs on the basis of anticipated or consistently poor cost-effectiveness. On the other hand, however, we find it reasonable to allow time for a thoughtful examination of

energy efficiency cost-effectiveness policy as it relates to the Commission's other energy efficiency policy goals, particularly in light of issues such as CCSF's assertion that PG&E imposed administrative costs constituting 30 percent of the San Francisco Energy Watch LGP budget. NRDC expresses support for "a transparent and smooth transition, perhaps through discussions at the CAEECC, on what the role of local governments should be and how their programs should be designed to meet the multiple needs of the evolving portfolio."<sup>116</sup> We encourage stakeholders to engage in such discussions through the CAEECC, and make explicit our intention to examine cost-effectiveness issues during the ramp years so that program-level cost-effectiveness estimates are as accurate and transparent as possible, for the express purpose of ensuring equitable treatment of programs in the context of our statutory mandate to fund cost-effective energy efficiency portfolios.

Separately, given that the portfolios will be transitioning from predominantly PA-administered to predominantly third party-administered over the next several years, we anticipate that the most recent ABALs should be decreasingly indicative of future ABALs. Specifically, we anticipate third party implementers will deliver savings more cost-efficiently than has been the case with PA-administered programs; similarly, their evaluated savings should also be closer to forecast estimates than has been the case with the current portfolios. We will not be able to determine this, however, until we have evaluated results for 2019 programs – likely not until 2022. We prefer to maintain the requirement to meet or exceed a portfolio forecast TRC of 1.25 but, in agreement with

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<sup>116</sup> NRDC April 30, 2018 comments, at 7.

comments asserting we should afford more time and flexibility for new programs and/or new third party implementers to develop cost-effective programs, modify the cost-effectiveness standard during the ramp years (program years 2019 - 2022) to a TRC of 1.0 to provide additional time and flexibility and clarity on the process for approval of annual budgets. Though we provide this additional time and flexibility, we require assurance through a public process for PAs who forecast a TRC greater than or equal to 1.0 but less than 1.25 to demonstrate how they will manage their portfolios through the ramp or transition period to ultimately achieve cost-effective portfolios on an evaluated basis.

Multiple parties advocate against the proposed decision's determination to define hard-to-reach customers based on the criteria specified in Resolution G-3497, and instead recommend the Commission either adopt the definition in the Energy Efficiency Policy Manual (version 5) and/or defer a decision on this issue to the energy efficiency policy rulemaking proceeding. We continue to believe the definition in the Policy Manual is overly broad but are sympathetic to arguments that the criteria specified in Resolution G-3497 may be unnecessarily narrow. MCE offers a modification, to include disadvantaged communities as an additional geographic criterion, to Resolution G-3497,<sup>117</sup> which we find reasonable based on the fact that, as the proposed decision acknowledges, the objectives associated with each of these classifications are very closely related (i.e., serving disadvantaged communities and serving underserved customers). We have revised Section 2.5 to reflect adoption of

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<sup>117</sup> MCE April 24, 2018 comments, at 13.

MCE's proposed modification to the hard-to-reach criteria included in Resolution G-3497.

SoCalGas highlights the fact that the proposed decision approves its request for supplemental budget authority for 2018, but is silent on whether SoCalGas may also increase its overall budget for this business plan period, and requests the Commission authorize SoCalGas to increase the subsequent annual funding levels in its business plan by the same amount of additional funding authorized for 2018 (\$19.4 million).<sup>118</sup> We find this request is reasonable and have modified Sections 2.6 and 7.2 to grant SoCalGas's request to increase its overall budget by \$135.8 million, or \$19.4 million annually for program years 2019 through 2025.

3C-REN requests budget authority in this decision for 2018 activities associated with developing implementation plans, a joint cooperation memo and ABAL. PG&E opposes such budget authorization, stating the request is premature since the proposed decision "only conditionally approves 3C-REN's Business Plan, subject to an approved 2019 ABAL."<sup>119</sup> Separately, we note the Commission did not authorize funding for either BayREN or SoCalREN to support activities prior to authorizing them to serve as RENs. We agree with PG&E that 3C-REN's request is premature and will not approve its request.

BayREN, CCSF and SoCalREN emphasize that the proposed joint cooperation memos, as described in the proposed decision, are unfairly biased against the non-IOU PAs. We make clear here our intention for the joint

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<sup>118</sup> SoCalGas April 24, 2018 comments, at 13-14.

<sup>119</sup> PG&E April 30, 2018 comments, at 4.



cooperation memo requirements to apply to all PAs equally; any indication to the contrary was an unfortunate oversight. MCE recommends some specific modifications to the proposed joint cooperation memo requirements to make clear those requirements apply equally to non-IOU PAs and IOU PAs, which we agree with and have incorporated in this decision.

LGSEC and several other parties take issue with the proposed decision's rejection of LGSEC's proposed statewide expansion of the current Energy Atlas and the related indication that the utilities are the appropriate entities to develop a statewide energy use database. We have modified the proposed decision to direct the utilities to select a lead to oversee development of a statewide energy use database by a third party implementer.

SoCalGas recommends the Commission strike the entire portion of the proposed decision addressing ORA's allegations against SoCalGas with respect to codes and standards advocacy, asserting the determination to exclude SoCalGas from all future codes and standards activities is arbitrary and discriminatory. Nothing in SoCalGas's comments persuades us to modify this determination, but it is worthwhile to address and clarify the proposed decision to the extent it is unclear that we are not prohibiting SoCalGas from advocating against or in favor of codes and standards, on whatever basis SoCalGas determines is reasonable, which SoCalGas also acknowledges.<sup>120</sup> We are prohibiting SoCalGas from *using ratepayer funds* to conduct codes and standards advocacy, which we find reasonable based on the Commission's clear policy intent for such funds and on evidence submitted by ORA of SoCalGas's past

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<sup>120</sup> SoCalGas April 24, 2018 Comments, at footnote 44.

contravention of that policy intent. Our determination, therefore, is not arbitrary but based in both policy and fact. Additionally, SoCalGas characterizes the proposed decision's determination as a penalty, which it is not. As the proposed decision explicitly states, we decline to consider a penalty for SoCalGas's past conduct but instead limit their future involvement in statewide codes and standards advocacy as a precautionary measure.

A number of parties, including SBUA, CodeCycle, BayREN, SoCalREN, and all IOUs, commented that 60 days may not be enough time to finalize the metrics required in this decision. However, there appeared to be some misunderstanding about which metrics were required to be finalized. The text of the decision has been modified to clarify that the only metrics or indicators required to be finalized within 60 days are the portfolio-level and sector-level metrics and indicators included in Attachment A to this decision. Other metrics or indicators submitted by the program administrators in their business plans should be included in their annual reports but are not required to be submitted within 60 days. We also clarify that any modifications proposed to metrics in the future should be included in the annual budget advice letter filings.

Both the Council and ORA recommended in their comments that the Commission should make explicit that the third-party solicitation requirements articulated in D.16-08-019 apply to the business plans approved in this decision. This is our intention, and we have made changes to this decision to clarify these requirements. In addition, SDG&E, in its comments on the decision as well as in previous comments, sought a delay in the schedule for compliance with the D.16-08-019 requirements for percentage of the total portfolio to be third party designed and implemented. Specifically, SDG&E requested until the end of 2019

to have 25 percent of their portfolio budget under contract to third parties. We have made this modification as well.

Several parties, including PG&E, BayREN, CLEAResult, and SCE, commented on the required process for implementation plans in this decision, seeking clarification about whether existing PIPs are required to be converted into implementation plans, and whether a stakeholder process is required for existing programs. We have clarified in this order that a stakeholder process is not required for pre-existing programs. In addition, PIPs are grandfathered and do not need to be converted into new implementation plans; however they should be posted alongside the new implementation plans to allow a complete picture of all PA programs in one place.

Numerous parties commented on the guidance included in the proposed decision with respect to design of customer incentives. NRDC, Nest, CLEAResult, the Council, and the IOUs all argued that these guidelines were too restrictive to be applied in all instances. In addition, the IOUs, Ecology Action, RHTR, Sun Energy Center, and Verified also argued that the guidance with respect to LED incentives is contrary to baseline policy from AB 802. We have modified the language associated with customer incentive guidance to specify that it is intended as an articulation of “best practices” but not mandatory to be applied in all programs or circumstances.

Related to customer incentives, TURN’s comments requested that we specify a deadline when CFL incentives are no longer authorized, which we have now included as December 31, 2018.

Numerous parties commented on the workforce quality standards that would have been mandated in the proposed decision for HVAC and lighting projects, requesting that those standards not be mandatory in all instances,

including the Council, CLEAResult, Ecology Action, IHACI, Nest, BayREN, SoCalGas, and SDG&E. CEE and ORA supported the standards as written. PG&E, SCE, and NRDC did not object to the standards. Most of the other parties were concerned that the standards, if mandated across the board, are unworkable or premature. Nest, for example, points out that an outcome that requires a journeyman to install a Nest thermostat in order to collect a program rebate is nonsensical. IHACI argued that the Commission does not have the authority to set workforce requirements. CLEAResult offered different workforce requirements for adoption that reflect recommendations of the Western HVAC Performance Alliance. The Council offered the most practical near-term approach, noting that D.18-01-004 required that this issue be addressed in the proposed third party contract terms and conditions, which have already been filed and are under consideration separately in this proceeding. We choose to take that recommendation, though will also consider the applicability not only to the third party contracts but also to the portfolio as a whole.

The Commission has demonstrated interest in this topic for some time, with past inquiries that resulted in a study about utility energy efficiency programs and impact on workforce issues.<sup>121</sup> CEE also provided timely information on this topic in the course of the proceeding, while other parties did not provide a thorough response to CEE proposals until in comments to the original proposed decision.

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<sup>121</sup> See study from the Don Vial Center for Labor Research and Education at UC Berkeley, available at: <http://laborcenter.berkeley.edu/workforce-issues-and-energy-efficiency-programs-a-plan-for-californias-utilities/>

While the Commission is interested in considering application of some workforce standards as suggested in the original proposed decision, it appears from parties' comments that there may be reasonable application of some workforce standard requirements for some types of programs or projects, but not necessarily all projects across the board. For example, the Commission could consider applicability of the standards with midstream and downstream program approaches, but those definitions are not always uniform. It also would be helpful to have further clarification regarding who qualifies under the proposed HVAC standards (for example, are there both union and non-union apprentice programs, and does the journeyman definition include both experienced union and non-union workers?)

We remain interested in adopting the standards that were outlined in the proposed decision, but would like to hear from parties about any need to fine tune their structure and applicability to be most successful in implementation. We also would like more detailed information about the interactions of such standards with other workforce initiatives of other California agencies, including the building and appliance standards and the licensing requirements for those activities. Finally, we could benefit from clearer information about the costs and benefits of such standards, as well as the availability of workers who already meet the standards, and what is necessary for additional workers to meet the standards. These are considerations that were not possible to handle in enough detail in the context of consideration of revisions to this decision, which addresses numerous other details of the energy efficiency business plans.

Thus, we intend to provide for further development of options for implementation of workforce quality standards in this proceeding, both as part

of consideration of the third party contract terms and conditions as articulated in D.18-01-004, as well as for potential application to the portfolio as a whole.

We anticipate issuing a ruling shortly seeking further input from parties on the appropriate application of the workforce quality standards, with the potential for going beyond the flexible terms proposed thus far by the IOUs as part of the modifiable third party contract terms and conditions. We intend to consider this input before approving the third-party contract terms and conditions, so any appropriate standards may be included in the contract terms and conditions.

While these issues are complex, we are committed to starting somewhere with the other workforce provisions in this decision and making additional progress in this area. Some of the other workforce metrics and provisions for disadvantaged workers in this decision represent our best progress to date in these areas, and we will continue to refine our efforts during the business plan period.

CEE's comments also included a number of clarifications to the sections of the decision addressing job access for disadvantaged workers and WE&T metrics/indicators. We have made several changes to the conclusions and ordering paragraphs herein to address these comments.

MCE's comments argued that there was an inherent contradiction in the treatment of MCE's portfolio in the proposed decision, steering MCE toward addressing the needs of smaller customers while holding them to the same standards for cost-effectiveness as other PAs. We agree and have modified MCE's budget and portfolio approval discussion accordingly. This decision no longer restricts the types of customers that MCE may serve with its portfolio in any sector.

SoCalGas, in its comments, pointed out that it was assigned as the statewide financing lead for the pilot programs in D.17-03-026, which was after the business plan were filed proposing PG&E as the statewide lead. This was an oversight in drafting of this decision, and it has now been modified to show SoCalGas as the statewide financing lead. In addition, the two midstream programs proposed as statewide, foodservice point-of-sale rebates and midstream commercial water heating, have both been added to the list of statewide programs, to be led by SoCalGas. Finally, SoCalGas' request that its statewide funding requirement be reduced to 15 percent instead of the 25 percent required from the other utilities, in recognition of its more limited measure offerings not including large electric areas such as lighting, is also approved in the revised language of this decision.

Bosch's comments on the proposed decision generally support the provisions for energy efficiency and demand response integration, but offer clarifications to allow for an incentive "add-on" for customer participation in a demand response program after an energy efficiency retrofit. In addition, their comments suggest that the technologies offered in these programs be agnostic as to whether they are alternative current or direct current. We agree and have made these clarifications. CEA also offered some clarifications on the importance of emphasizing lighting controls in commercial buildings, which we have included, as well as a summary of their position on the staff energy efficiency and demand response integration proposal, which was inadvertently omitted from the proposed decision.

CodeCycle's comments addressed a number of aspects of the codes and standards programs. In particular, part of their comments seemed to interpret some language with respect to compliance improvement programs to be singling

out those activities for differential treatment. We have clarified that the language applies to the entire portfolio, and was not intended as specific to code compliance programs.

## **11. Assignment of Proceeding**

Carla J. Peterman is the assigned Commissioner and Julie A. Fitch and Valerie U. Kao are the co-assigned ALJs in this proceeding.

### **Findings of Fact**

1. The 2018-2025 business plans are sufficiently flexible to accommodate future goal updates and other policy guidance for this business plan period (2018-2025). However, pursuant to D.15-10-028, PAs are able to re-file their business plans, as needed, to update their sector strategies and overall budget, in order to accommodate future updates to energy savings goals.
2. D.15-10-028 included requirements and expectations for the process for the development and posting of implementation plans. The process includes an opportunity for stakeholder input.
3. An increase in installations of demand response-capable building controls is necessary to align achievement of energy efficiency, demand response, and greenhouse gas reduction goals.
4. CFL measures no longer provide the most technologically advanced, customer friendly, or energy savings advantages compared to LED technologies.
5. The majority of streetlights in California are not utilizing LED technologies today. The Legislature has encouraged the conversion of streetlights through requirements to encourage conversion.
6. Metrics and indicators at the portfolio and sector levels will help the program administrators, stakeholders, and the Commission to assess progress



towards long-term goals, including, but not limited to, sustainable energy savings.

7. The PAs proposed, in the business plans, a number of sector-level metrics with specific targets. Some of the proposed metrics are more appropriate as indicators, where there is no established target, but progress is still tracked.

8. The Commission should require all program administrators to track metrics and indicators at the portfolio and sector levels to track business plan progress and report these data in the annual reports. The minimum sector-level metrics and indicators for all PAs are those included in Attachment A to this decision, which may be modified in the compliance filings required within 60 days of this decision.

9. Commission staff proposed a reasonable set of activities for limited integration of energy efficiency and demand response, for purposes of adding benefits for very little incremental cost, and to assist with customer acceptance of time-varying rate structures currently being implemented.

10. SB 350 requires the Commission to report specific strategies for, and an update on, progress toward maximizing the contribution of energy efficiency savings in disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code.

11. CalEPA, pursuant to Health and Safety Code Section 39711, defines disadvantaged communities as those census tracts scoring in the top 25 percent of census tracts statewide on the set of 20 different indicators in CalEnviroScreen. As part of its definition of disadvantaged communities, CalEPA also finds that an additional 22 census tracts that score in the highest five percent of CalEnviroScreen's Pollution Burden indicator, but that do not have an overall

CalEnviroScreen score in the top 25 percent because of unreliable socioeconomic or health data, are also defined as disadvantaged communities.

12. The current version of the CalEnviroScreen Tool is CalEnviroScreen 3.0.

13. The Commission's original purpose for targeting hard-to-reach customers for energy efficiency investments was to prioritize underserved customers. With significantly expanded budgets it is reasonable to assume a smaller proportion of underserved ratepayers. There is considerable overlap, however, in the socioeconomic characteristics and policy objectives for disadvantaged communities and hard-to-reach customers.

14. For purposes of administering energy efficiency programs, hard-to-reach customers are defined pursuant to the criteria identified in Resolution G-3497, with one modification. Specifically:

Specific criteria were developed by staff to be used in classifying a customer as hard-to-reach. Two criteria are considered sufficient if one of the criteria met is the geographic criteria defined below.

There are common as well as separate criteria when defining hard-to-reach for residential versus small business customers. The barriers common to both include:

- Those customers who do not have easy access to program information or generally do not participate in energy efficiency programs due to a combination of language, business size, geographic, and lease (split incentive) barriers. These barriers to consider include:
  - Language - Primary language spoken is other than English, and/or
  - Geographic -
    - Businesses or homes in areas other than the United States Office of Management and Budget Combined Statistical Areas of the San Francisco Bay Area, the Greater Los Angeles Area and the Greater Sacramento Area or the

Office of Management and Budget metropolitan statistical areas of San Diego County.

- Businesses or homes in disadvantaged communities, as identified by CalEPA pursuant to Health and Safety Code Section 39711.
- For small business added criteria to the above to consider:
  - Business Size – Less than ten employees and/or classified as Very Small (Customers whose annual electric demand is less than 20 kilowatts, or whose annual gas consumption is less than 10,000 therm, or both), and/or
  - Leased or Rented Facilities – Investments in improvements to a facility rented or leased by a participating business customer
- For residential added criteria to the above to consider:
  - Income – Those customers who qualify for the California Alternative Rates for Energy (CARE) or the Family Electric Rate Assistance Program (FERA), and/or
  - Housing Type – Multi-family and Mobile Home Tenants (rent and lease).

15. PG&E's revised metrics proposal incorrectly defines disadvantaged communities for the purpose of maximizing the contribution of energy efficiency in disadvantaged communities.

16. D.15-10-028, establishing the rolling portfolio framework, provides that the energy efficiency program administrators must optimize their portfolios based on three high-level objectives: achieving or surpassing energy savings goals, cost-effectively, and within budget.

17. D.15-10-028 required the PAs to provide for meaningful stakeholder input into the business plans; the success of the rolling portfolio framework requires ongoing collaboration among all stakeholders (including the PAs).

18. Public Utilities Code Section 454.5(b)(9)(C) requires that utilities shall first meet their unmet resource needs through all available energy efficiency and demand reduction resources that are cost-effective, reliable, and feasible.

19. D.12-11-015 requires “the dual test for overall portfolio cost effectiveness, taking into consideration passing both the TRC and PAC tests for each service territory and for the entire approved portfolio, including RENs, will continue to govern the CPUC’s cost-effectiveness for the energy efficiency programs.”

D.12-11-015 further specifies (a) omitting the costs and benefits of the IOUs’ codes and standards advocacy work and spillover effects, and (b) setting a higher TRC threshold, of 1.25, as the basis for determining cost-effectiveness of the proposed portfolios on an ex ante, or forecast, basis. This decision does not modify these requirements.

20. D.12-11-015 set a higher TRC threshold, of 1.25, as a hedge against uncertainty that portfolio TRCs would not meet or exceed 1.0 on an evaluated basis.

21. D.14-10-046 removed the 1.25 TRC threshold for 2015 portfolios, in recognition of the transition to a rolling portfolio framework, but stated the Commission would return to a 1.25 TRC threshold in subsequent years.

22. D.14-01-033 requires that a CCA’s portfolio meet a TRC of 1.0 for three years from the date we approved their proposal to “apply” or “elect” to administer conservation and/or energy efficiency programs, and thereafter meet the same cost-effectiveness standard as the IOUs.

23. The Commission has not required RENs’ portfolio TRCs to meet a specific standard.

24. PG&E, SDG&E and SCE’s 2018 ABALs (including supplemental submissions) include portfolio TRCs that do not meet or exceed 1.25.

25. MCE's 2018 ABAL includes a portfolio TRC of 0.69.

26. PG&E, SDG&E, SCE and MCE's 2018 ABALs are either not cost-effective according to D.12-11-015, or only marginally cost-effective according to D.14-10-046.

27. The deadline for the next ABALs is less than five months after the Commission disposes of the 2018-2025 business plans (through this decision).

28. The 2018 ABALs -- other than SoCalGas's supplemental submission -- included non-cost-effective or marginally cost-effective portfolios.

29. SoCalGas's supplemental submission to its 2018 ABAL includes a portfolio TRC that exceeds 1.25. SoCalGas requests incremental budget authority of approximately \$20.4 million, beyond its annual funding level of \$83.6 million authorized in D.14-10-046.

30. SoCalGas's energy savings goals increased by more than 50 percent, from 13.4 million net therms to 20.3 million net therms, as a result of the Commission's adoption of 2018-2030 goals in D.17-09-025.

31. SoCalGas's supplemental submission to its 2018 ABAL proposes eliminating programs with poor cost-effectiveness and expanding programs with higher savings potential.

32. The Commercial Energy Advisor program is a non-resource program with zero projected savings. SoCalGas's supplemental submission includes \$1.0 million to convert the Commercial Energy Advisor program from non-resource to resource. There is not sufficient evidence to find that this specific request would be efficacious.

33. The 2018-2025 business plans include portfolio TRCs that do not meet or exceed 1.25.

34. The portfolio TRC estimates in the 2018-2025 business plans are based on outdated energy efficiency goals and avoided cost assumptions.

35. The PAs' budget forecasts, including the supplemental budget filings submitted on June 12, 2017, reflect a non-trivial amount of uncertainty related to third party solicitations.

36. Requiring the PAs to submit further budget projections, prior to commencing the third party solicitation process, will not significantly increase our confidence in the certainty of those projections.

37. Increasing reliance on third parties for program design and delivery should result in a decreasing need for in-house program staff and, therefore, decreasing budget forecasts on a long-term basis.

38. Periodic updates to the supplemental budget filings resulting from the PAs' meet-and-confer with ORA and TURN will improve assessment of administrative costs and increase certainty regarding long-term cost-effectiveness of the business plans.

39. The first third party solicitations will not occur until after the Commission disposes of the 2018-2025 business plans.

40. The requirements of D.16-08-019 and D.18-01-004 are in effect and apply to the IOU business plans approved in this decision.

41. Statewide administration of certain programs should yield efficiencies in the form of standardized processes and seamless customer experience.

42. A "bottom up" review of statewide program areas has been proposed in the past and should be conducted to reexamine the design of the statewide program structure.

43. We remain concerned about the gap between ex ante, or forecast, cost-effectiveness estimates and evaluated results.

44. Recommendations for major modifications to cost-effectiveness policy are not within scope of this proceeding.

45. D.15-10-028 acknowledged a lack of consistency in accounting practices across utilities, and stated the Commission's intent to address this issue following the issuance of the State Controller's Office report on PA accounting systems.

46. There is insufficient information to assess whether and under what circumstances third parties' use of utility account representatives optimizes cost and customer service, relative to third parties' opting not to use utility account representatives.

47. D.16-08-019 set out the basic structure for statewide programs to be implemented in the business plans.

48. The IOU business plans proposed to give responsibility to the lead PA for each statewide program area for all of the following:

- a. Program vision development, design/delivery, and intervention strategies;
- b. Procurement, contract administration, and co-funding management from partner IOUs;
- c. Implementer oversight;
- d. Sole responsibility for implementer management, rewards, and any necessary corrective action;
- e. Reviewing implementer performance and program performance on a quarterly basis;
- f. Meeting savings goals and customer satisfaction levels;
- g. Metrics development; and
- h. Reporting.

49. D.16-08-019 requires each IOU PA to devote at least 25 percent of its energy efficiency portfolio budget to statewide activities. SoCalGas' request to make its requirement 15 percent due to the more limited measures in its portfolio is reasonable.

50. The IOU PAs will need a mechanism such as the balancing account proposed by SDG&E in its August 4, 2017 motion to track funding for statewide programs.

51. D.12-11-015 directs RENs to undertake:

- Activities that utilities cannot or do not intend to undertake;
- Pilot activities for which there is no current utility program offering and where there is potential for scalability to a broader geographic reach, if successful;
- Pilot activities in hard-to-reach markets, whether or not there is a current utility program that may overlap.

52. D.16-08-019 provides further that "REN programs, and therefore administrative expenses, will only be funded to the extent that they are determined by the Commission to provide value (or the promise of value) to ratepayers in terms of energy savings and/or market transformation results for energy efficiency;" and encouraged the RENs "to manage their programs with an eye toward long-term cost-effectiveness."

53. D.16-08-019 directed the PAs to present high-level sector strategies in their business plans, which did not align well with our need to verify that the RENs' business plans comply with D.12-11-015.

54. RENs' activities may only overlap with utility PAs' activities when those activities are targeted at hard-to-reach customers.



55. A joint cooperation memo among PAs that share a common service area will help ensure those PAs' proposed activities will complement and not duplicate each other, and that RENS otherwise comply with D.12-11-015.

56. The Commission has not completed its review of BayREN and SoCalREN's success as REN pilots.

57. We intend to evaluate the RENS' impact and overall success before the end of this business plan period.

58. BayREN's business plan proposes significant increases in funding and scope of its energy efficiency activities in the commercial and public sectors.

59. BayREN's business plan did not include a portfolio-level TRC or PAC estimate.

60. SoCalREN's business plan proposes continued WE&T and new codes and standards activities.

61. SoCalREN's business plan only includes cost-effectiveness estimates for resource programs.

62. 3C-REN's proposed direct install activities may duplicate existing services and/or IOU activities.

63. 3C-REN's proposed activities for WE&T and code compliance have value in terms of the significant distance of its service area to the IOUs' training centers.

64. 3C-REN's business plan does not break out its proposed budget into the various activities or programs it proposes to implement.

65. MCE proposed a full portfolio of activities for all sectors within its geographic area, including several areas that overlap with existing programs of other program administrators.

66. MCE has experience implementing programs for the residential sector and has a greater proportion of small commercial and agricultural customers within its geographic area, but also has significant load in the commercial, industrial, and agricultural sectors.

67. MCE has previously been granted access to natural gas energy efficiency funding where natural gas savings are coincident with its electric energy efficiency activities. Utilizing the same funding transfer mechanism for natural gas funding as for electricity funding will minimize administrative transaction costs.

68. MCE's business plan seeks automatic budget increases associated with expansion of its service to new communities, when the budget increase is not associated with any change in business plan strategies.

69. MCE has previously been required to file an advice letter each December 1 detailing unspent and projected unspent funds from the previous calendar year. MCE should be allowed to consolidate this advice letter submission with the September 1 annual advice letter submission on its energy efficiency annual budgets.

70. LGSEC's proposal to standardize contract terms and conditions for LGPs has value to the extent that negotiated terms and conditions can be added in individual agreements to address individual project scope and local government requirements. The IOUs say they will develop more consistent LGP contracts.

71. LGSEC's proposal to convert all LGP activities to entirely non-resource activities could conflict with some LGPs' focus on reaching specific energy savings goals.

72. Increasing and streamlining support of the LGPs is an effective an essential component in serving hard-to-reach and disadvantaged communities. The

LGSEC business plan includes quantification of co-benefits and local economic benefits as well as local capacity building and greater financial support for higher service cost regions as effective intervention strategies in rural, hard-to-reach and disadvantaged communities.

73. LGSEC's proposal to broaden usage of the Energy Atlas statewide is aligned with the State's goals to improve data access and support local governments in achieving and monitoring energy savings.

74. A core feature of the rolling portfolio framework is to provide for continuity while also ensuring the energy efficiency portfolios will achieve the State's energy efficiency goals cost-effectively and within authorized budgets.

75. Discrepancies between the IOUs' monthly and quarterly claims, annual true-up submissions, ABALs and the ESPI annual advice letter create challenges for the Commission's review, verification, reconciliation and data analysis processes. Discrepancies also create unnecessary delays in the Commission's approval process of the utilities' submissions, including but not limited to the budget and ESPI advice letters.

76. Commission rules allow the transfer of customer data as long as confidentiality is maintained.

77. Evidence shows that SoCalGas has not worked towards adoption of more stringent codes and standards.

78. Commission policy does not explicitly prohibit PAs from using ratepayer funds, intended for codes and standards advocacy, to engage in any activity that does not result in adoption of more stringent codes and standards. However, the Commission's intent for the use of such funds is articulated in D.05-09-043, which states "[u]sing ratepayer dollars to work towards adoption of higher appliance and building standards may be one of the most cost-effective ways to

tap the savings potential for EE and procure least-cost energy resources on behalf of all ratepayers.”

79. Requests for sanctions against alleged past misconduct in codes and standards advocacy are not within the scope of this proceeding. Such requests, as well as consideration of ESPI reward modifications based on the statewide administration structure adopted in this decision, are within scope of R.13-11-005 or its successor.

### **Conclusions of Law**

1. The Commission should require preparation of implementation plans as outlined in D.15-10-028, with an associated stakeholder input process that utilizes the CAEECC and/ or separate PA-hosted workshops.

2. Implementation plans for new programs and PIPs for currently-available programs should be required to be posted within 120 days of the issuance of this decision. For third-party programs for which solicitations are forthcoming, implementation plans should be posted within 60 days of contract execution, or within 60 days of Commission approval if the contract is required by the terms of D.18-01-004 to be reviewed by the Commission.

3. The following guidance with respect to design of incentives to be paid to customers or implementers should be considered “best practices” and both program administrators and third parties should strive for consistency with these guidelines within the business plan period, but these are not mandatory:

- a. Incentives should generally be calculated on a net lifecycle savings basis, not a first-year savings basis, to support and align with achievement of portfolio net lifecycle savings goals.
- b. Incentives should generally be tiered to promote increasing degrees of efficiency above code, particularly when an existing

- conditions baseline is used and when the direct install delivery channel is used.
- c. Incentives should generally be strategically targeted at commercially available products that offer higher and highest degrees of efficiency and quality, not at all above-code high efficiency products.
  - d. Incentive structure should take into consideration the variation in barriers to efficiency upgrades faced by different customer segments, instead of being set uniformly for a measure class.
  - e. For performance based programs, payment of customer and contractor incentives should tie, in significant part (50 percent or more), to independently verified savings performance estimated on a 12 month post-implementation period for capital projects and 24 months, if the project includes behavioral, retrocommissioning, or operational savings, for projects with savings measured with normalized metered energy consumption approaches.
4. The Commission should prohibit payment of incentives for CFL measures as part of the business plans after December 31, 2018, guidance which should be reflected in the implementation plans and annual budget advice letter for 2019.
  5. The Commission should encourage bulk early replacement of street lighting and require the PAs to continue to offer rebates for those projects.
  6. Program administrators should be required to do all of the following to improve performance on workforce, education, and training:
    - a. Expand/initiate partnerships with entities that do job placement;
    - b. Require placement experience for any new partners in the workforce, education, and training programs and new solicitations;
    - c. Require “first source” hiring from a pool of qualified candidates, before looking more broadly, beginning with self-certification in the beginning; and

- d. Facilitate job connections, by working with implementers and contractor partners, and utilizing energy centers. Utility program administrators should require third party program designers and implementers to report on how they are adhering to this guidance in their implementation plans.

7. The Commission should require all program administrators to track metrics and indicators at the portfolio and sector levels to track business plan progress. The minimum sector-level metrics are those included in Attachment A to this decision. PAs should make proposals for new or modifications to existing metrics in the future in their annual budget advice letters.

8. 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.

9. The Commission should require the program administrators to take into account general policy principles for integration of energy efficiency and demand response, including the following:

- a. Help customers save on their energy bill by shifting HVAC use away from peak pricing periods (e.g., pre-cooling or pre-heating strategies in insulated buildings) through automated response to TOU rates, and where there is customer interest, critical peak pricing events;
- b. Ensure there is no incremental measure or transaction cost for a building to participate in a demand response program after an energy efficiency retrofit by installing automated and communicating demand response control technologies as part of energy efficiency retrofits, or design and commissioning of new construction;
- c. Capitalize on “co-benefits,” where the same technologies or device upgrades that enable demand response (e.g., smart thermostats, building energy management systems or lighting controls), produce other benefits by allowing a building to operate more efficiently and can be reflected as reduced upfront

costs for adding demand response capability to energy efficiency controls. In addition, minimize duplication of outreach, marketing, site visits, etc. and associated costs, both to PAs and participants, through integrated programs.

10. Each IOU PA should set aside a minimum annual amount of \$1 million for the residential sector and a load-share-proportional amount of \$20 million for the commercial sector from each IOU PA's IDSM budget to test and deploy integration strategies, which may test multiple program design and customer incentive approaches, as well as multiple technology types, with emphasis on demand-response-capable control technologies.

11. The requirements of D.16-08-019 and D.18-01-004 with respect to third-party solicitations should apply to the business plans approved in this decision, including Ordering Paragraphs 10 through 13 of D.16-08-019.

12. The compliance deadline for achieving at least 25 percent of an IOU PA's portfolio being designed and implemented by third parties should be extended such that at least 25 percent of the forecast budget for 2020 will be designated for third parties. All other deadlines in D.18-01-004 should remain in effect.

13. The lead PA for each statewide program area should have sole responsibility for all of the following:

- a. Program vision development, design/delivery, and intervention strategies;
- b. Procurement, contract administration, and co-funding management from partner IOUs;
- c. Implementer oversight;
- d. Implementer management, rewards, and any necessary corrective action;
- e. Review of implementer performance and program performance on a quarterly basis;

- f. Meeting savings goals and customer satisfaction levels;
- g. Metrics development; and
- h. Reporting.

14. The lead PA for each statewide program may consult with the other non-lead IOUs through Program Councils voluntarily, as proposed in the business plans, but should not be required to institute such a structure for every statewide program area.

15. In the event that a dispute arises among IOUs about the design or implementation of a statewide program area, and all non-lead IOUs are in agreement in opposition to the lead PA, one of the non-lead PAs should be empowered to file a motion in the relevant energy efficiency rulemaking asking the Commission to resolve the dispute.

16. IOU actions to administer statewide programs on behalf of the other IOUs, under Commission direction, fall under the State Action Doctrine defense to anti-trust action, consistent with our prior findings in D.10-12-054.

17. All PAs should have the ability to continue local pilot activities that would otherwise qualify for statewide administration but that are not yet ready for such statewide treatment, provided that such local pilots or programs do not compete with, or otherwise impede the progress or activities of, operational statewide programs.

18. IOU PAs should not have the option to opt out of statewide programs for cost-effectiveness or local reliability concerns. IOUs should be required to fund statewide programs at levels within 20 percent of their proportional share based on load, unless specifically approved by the Commission for a deviation by means of a new business plan filing containing justification for why the statewide program cannot be funded at the required level.



19. The IOU PAs should develop an agreed-upon annual report to facilitate ongoing statewide program funding-level management, as suggested by SDG&E. A summary of key findings from this annual report should be included in each IOU's annual energy efficiency portfolio report to the Commission. The summary should detail proportional funding amounts for each statewide program, and highlight any cost-sharing discrepancies or issues, with particular attention to the proportional funding share requirements.

20. The 25 percent requirement for statewide funding articulated in D.16-08-019 should be calculated as a proportion of the IOU's total portfolio budget, including EM&V, but excluding funding allocated to other program administrators.

21. SoCalGas should be required to fund statewide programs at a minimum level of 15 percent of its total portfolio budget, including EM&V, but excluding funding allocated to other program administrators.

22. The Commission should require all IOU PAs to propose a mechanism to track funding for statewide programs, including funding flows from other IOUs, in a Tier 1 advice letter within 90 days of the issuance of this decision. SDG&E's proposed balancing account mechanism in its August 4, 2017 motion is one option.

23. The downstream programs proposed to be piloted on a statewide basis in the utility business plans should be approved, with the exception of PG&E's proposal for an indoor agricultural program, which should not be launched statewide at this time.

24. A bottom-up, comprehensive review of the statewide program structure and composition should be completed and the results filed in the energy

efficiency rulemaking (R.13-11-005 or its successor) within one year of the issuance of this decision.

25. The Commission should assign the statewide lead administrators as given in Table 3 and Table 4 of this decision. Lead PAs should remain in place through the end of the business plan period unless and until the business plans are updated.

26. For purposes of administering energy efficiency programs, we should follow CalEPA's method for identifying disadvantaged communities. In the event that CalEPA revises its methodology for identifying disadvantaged communities in the future, the revised methodology should be used for the purposes of ongoing identification of disadvantaged communities.

27. Programs targeted at hard-to-reach customers should prioritize the most underserved customers or customer segments, because they are likely the hardest to reach. There is considerable overlap in the policy objectives for disadvantaged communities and hard-to-reach customers. The definition of hard-to-reach should reflect this overlap by including disadvantaged communities, as identified by CalEPA, as an additional criterion for meeting the geographic component of the hard-to-reach definition.

28. To the extent that REN activities may overlap with utility programs, it is reasonable with respect to prudent investment of limited ratepayer funds to limit such overlap to programs that target customers with the least likelihood of program information and access.

29. The energy efficiency program administrators should include targets for capturing energy savings in their compliance filings for program-level metrics, based on the correct definitions of disadvantaged communities and hard-to-reach customers.

30. To fulfill reporting requirements pursuant to SB 350, we should require the program administrators to assess the relative success of implementers' strategies with respect to maximizing the contribution of energy efficiency in disadvantaged communities, for purposes of identifying lessons learned and best practices.

31. In the interest of moving forward with the business plans and enabling the PAs to commence with third party solicitations as soon as practical, we should not approve the 2018 ABALs (except for SoCalGas) and should instead approve the business plans and associated funding levels for 2018.

32. We should approve SoCalGas's 2018 ABAL, except for \$1.0 million requested for the Commercial Energy Advisor program, as well as its incremental budget request for years 2018-2025.

33. We should not reach a definitive conclusion about the cost-effectiveness of the business plans, but instead provide specific guidance for the cost-effectiveness forecasts of the ABALs to be submitted during this business plan period.

34. The program administrators should periodically update their business plan budgets, including the supplemental budget filings, in order to provide greater certainty regarding long-term cost-effectiveness of their business plans.

35. It is reasonable to require the PAs to include updated budget information, including the supplemental budget filings, starting with their September 3, 2019 ABALs.

36. We should require the IOUs' ABALs to include forecasted portfolio TRCs that meet or exceed 1.25, except for program years 2019 - 2022 (ramp years), during which the IOUs' ABALs should include forecasted portfolio TRCs that meet or exceed 1.0.

37. An additional process, for IOUs whose ABALs include forecasted portfolio TRCs that meet or exceed 1.0 but do not meet or exceed 1.25 during the program years 2019-2022 (ramp years), is necessary to provide for continuity and align PAs' interests with our overall objectives of meeting or exceeding energy savings goals, cost-effectively, and within budget.

38. Recommendations for major modifications to cost-effectiveness policy should not be addressed in this proceeding.

39. Recommendations for major modifications to cost-effectiveness policy should cite to specific evaluation studies and/or program data supporting such recommendations, in R.13-11-005 or its successor.

40. The program administrators should ensure their accounting and reporting policies and practices can accommodate any requirements the Commission may adopt in Rulemaking 13-11-005 or its successor proceeding.

41. We should consider third party models that minimize administrative costs.

42. We should enable third parties to choose whether to use utility account representatives.

43. The IOUs should track the number and proportion of third parties that forego the option of using utility account representatives. The utilities should include this information in their annual reports.

44. We should use the same cost-effectiveness methodology for all PAs, regardless of whether and what cost-effectiveness standards we require for a particular type of PA.

45. RENs should include portfolio cost-effectiveness statements in their ABALs.

46. We should require RENs to demonstrate that their business plan activities meet the criteria established in D.12-11-015.

47. We should require the IOUs and RENs to develop joint cooperation memos to demonstrate and describe how they will coordinate and not duplicate activities, except with respect to hard-to-reach customers.

48. It is reasonable to permit BayREN and SoCalREN to continue their existing energy efficiency activities.

49. It is reasonable to defer consideration of certain substantially new or expanded REN activities or budgets until the Commission completes its review of BayREN and SoCalREN's success as REN pilots.

50. We should consider whether to continue to authorize REN programs and budgets based on evaluations of RENs' impact and success and will assess REN performance going forward with an emphasis on tracking business plan metrics and assessing REN progress in meeting their designated targets.

51. We should not authorize BayREN's proposed budgets for the commercial and public sectors at this time.

52. We should not authorize SoCalREN's proposed budgets for the codes and standards activities at this time.

53. 3C-REN's implementation plans and ABALs should specifically reference any relevant statewide programs and activities and demonstrate how its proposed activities for the upcoming year will complement and not duplicate those statewide activities.

54. We should authorize 3C-REN's proposed business plan activities for residential direct install programs that target hard-to-reach customers.

55. We should not approve 3C-REN's budget as shown in its business plan.

56. We should permit 3C-REN to submit a 2019 ABAL to request budget authority for its proposed workforce education and training and code compliance activities. We should also permit 3C-REN to request budget

authority for a residential direct install program, if 3C-REN demonstrates that program will target hard-to-reach customers.

57. Staff should have discretion to approve, deny, or modify RENs' budget requests, based on D.12-11-015 and D.16-08-019, through the ABAL process.

58. MCE's proposed program portfolio should be approved.

59. MCE should be authorized to act as the non-exclusive single point of contact on behalf of customers within its geographic area, providing concierge-type services for customers desiring to participate in energy efficiency programs of various program administrators with available offerings.

60. MCE should not be assigned as the downstream liaison for all programs in its geographic area, and should not be allowed to veto or cancel programs of other program administrators.

61. MCE should not be given credit for the energy savings achieved by other program administrators operating programs in its geographic area.

62. MCE should be granted access to natural gas funding in the same manner as it receives electricity funding for its related energy efficiency activities. That is, natural gas funding should be transferred in quarterly increments in advance of program expenditures.

63. MCE should not be granted automatic budget increases when it expands service to new communities. Instead, MCE should file a new business plan if it wishes to exceed the budget caps included in this decision.

64. It is not reasonable to require LGPs to apply to two different administrators if they wish to pursue both resource and non-resource activities.

65. We should not adopt LGSEC's proposal for statewide administration of LGPs at this time.

66. The IOUs should work with LGP partners to improve LGP programs' cost-effectiveness and to meet LGP partners' needs with respect to data sharing and contract terms that align with local governments' budgeting, legal, etc. constraints.

67. The IOUs should collaborate amongst themselves to streamline and standardize common LGP contract terms and conditions and identify those that should be modifiable.

68. The Commission should require utility PAs to submit for consideration and approval standard and modifiable contract terms and conditions for LGPs. This contract should be considered in this proceeding, or, if closed, R.13-11-005 or its successor.

69. The IOUs should quantify co-benefits and local economic benefits of LGPs in hard-to-reach and disadvantaged communities; and support local governments' efforts to increase local capacity to conduct energy efficiency activities.

70. LGSEC's proposal to expand UCLA's Energy Atlas to statewide use should be implemented. The Commission should oversee a competitive solicitation by a lead program administrator for a third party to develop and deploy the Energy Atlas on a statewide basis.

71. To avoid data discrepancy across various submissions, the IOUs should use their final official program year tracking data as the basis for all their submissions that include data associated with that specific program year.

72. We should require that, to the extent a program administrator revises its annual funding levels through the ABAL process, the overall amount (through 2025) must not exceed the overall amount (for the same years) included in the business plans, as modified by this decision.

73. In setting a cap on the overall amount of funding through 2025, it is reasonable to afford staff discretion to dispose of a program administrator's portfolio budget request that exceeds the corresponding annual funding amount included in its business plan, plus unspent funds from previous years in the business plan period, through the ABAL review process.

74. If a program administrator's ABAL fails the approval criteria during the 2019 through 2022 program years, staff should reject the ABAL and direct the program administrator to hold a workshop to explain why it failed to meet the ABAL approval criteria. Pursuant to D.15-10-028, the program administrator will need to file a revised business plan for Commission approval.

75. In providing program administrators an opportunity to administer their business plan portfolios during program years 2019-2022 (ramp years), if their forecast TRC does not meet or exceed 1.25, it is reasonable for the Commission to consider establishing effective penalties for the potential scenario in which a program administrator's portfolio TRC does not meet or exceed 1.0 on an evaluated basis beginning with program year 2019, or the Commission rejects a program administrator's ABAL for program years starting in 2023.

76. We should limit SoCalGas's involvement in codes and standards advocacy during this business plan period.

77. The designated lead for a statewide program should have flexibility to determine the most appropriate individual(s) in its organization to manage those activities.



**O R D E R**

**IT IS ORDERED** that:

1. For purposes of this decision, the term “program administrator” includes the following entities: Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company, San Diego Gas & Electric Company, the Bay Area Regional Energy Network, the Southern California Regional Energy Network, the Tri-County Regional Energy Network, and Marin Clean Energy.

2. As directed in Decision 15-10-028, the program administrators shall host a forum for stakeholder input on implementation plan development for new programs either through the California Energy Efficiency Coordinating Committee or another workshop hosted by the program administrators following the issuance of this decision.

3. Implementation plans associated with the business plans adopted in this decision, as well as program implementation plans for pre-existing programs still in operation, shall be posted within 120 days of the issuance of this decision. For third party programs that are part of the solicitation process adopted in Decision 18-01-004, implementation plans shall be posted no later than 60 days following contract execution or, for contracts where Commission approval is required, 60 days following Commission approval.

4. The third party requirements of Decision (D.) 16-08-019 and D.18-01-004 are required to be applied to the business plans of the investor-owned utilities approved in this decision. All utility program administrators shall have at least 25 percent of their 2020 program year forecast budgets under contract for programs designed and implemented by third parties by no later than

December 19, 2019. All other deadlines in D.18-01-004 remain in effect.

Implementation plans associated with the business plans adopted in this decision shall demonstrate compliance with Ordering Paragraphs 10, 11, and 12 of D.16-08-019.

5. Program administrators shall discontinue payment of incentives as part of the business plan energy efficiency program for compact fluorescent lighting no later than December 31, 2018. This prohibition shall also be reflected in the implementation plans, as well as in the annual budget advice letter filing for 2019.

6. The utility program administrators shall continue to offer rebates for bulk streetlighting conversion and replacement projects to light emitting diode technology.

7. Program administrators, to improve performance in the areas of workforce, education, and training, shall do all of the following:

- a. Expand/initiate partnerships with entities that do job placement;
- b. Require placement experience for any new partners in the workforce, education, and training programs and new solicitations;
- c. Require “first source” hiring from a pool of qualified candidates, before looking more broadly, beginning with self-certification; and
- d. Facilitate job connections, by working with implementers and contractor partners, and utilizing energy centers.

8. Utility program administrators shall require third party implementation plans to address how they are addressing the items listed in Ordering Paragraph 7 of this decision.

9. All program administrators shall track progress toward the metrics and indicators included in Attachment A of this decision. Program administrators

shall work with Commission staff to finalize those metrics, targets, and indicators and file an updated set of final metrics within 60 days of the issuance of this decision. Program administrators may also track additional metrics and indicators, including those included in their business plans. Progress toward all metrics and indicators shall be included in the annual reports of all program administrators. Commission staff is authorized to develop reporting templates, frequency, and instructions and develop a review strategy incorporating input from the California Energy Efficiency Coordinating Committee. New or modified metrics or indicators in the future shall be proposed in annual budget advice letter filings.

10. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall set aside a minimum annual amount from each of their integrated demand side management budgets to test and deploy strategies for integration of energy efficiency and demand response as further directed in this decision, as follows: at least \$1 million for the residential sector and a load-share-proportional amount of \$20 million for the commercial sector.

11. The program administrators' compliance filings for business plan metrics must include metrics and targets for capturing energy savings based on the correct definitions of disadvantaged communities and hard-to-reach customers, as defined in this decision. The program administrators must also assess the relative success of implementers' strategies, for purposes of identifying lessons learned and best practices for maximizing the contribution of energy efficiency in disadvantaged communities. These assessments shall be included in the program administrators' annual reports.

12. We reject the 2018 annual budget advice letters of Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Marin Clean Energy, Bay Area Regional Energy Network and Southern California Regional Energy Network. Instead, we adopt the business plans (as modified by this decision) and associated funding levels for 2018.

13. The investor owned utilities must achieve cost-effective portfolios (that is, the portfolio Total Resource Cost result must meet or exceed 1.0) for this program year (2018), and future program years, on an evaluated basis.

14. We approve the 2018 annual budget advice letter of Southern California Gas Company, except for \$1.0 million requested for the Commercial Energy Advisor program, as well as the incremental budget request of \$135.8 million (\$19.4 million annually) for years 2019 through 2025.

15. The program administrators must ensure their accounting and reporting policies and practices can accommodate any requirements the Commission may adopt in Rulemaking 13-11-005 or its successor proceeding.

16. The investor-owned utilities shall make third parties' use of utility account representatives optional, neither requiring third parties to use utility account representatives nor preventing utility account representatives from assisting third party programs.

17. The investor owned utilities must track the number and proportion of third parties that forego the option of using utility account representatives. The utilities must include this information in their annual reports.

18. The lead program administrator for each statewide program area shall have sole responsibility for all of the following:

- a. Program vision development, design/delivery, and intervention strategies;

- b. Procurement, contract administration, and co-funding management from partner program administrators;
- c. Implementer oversight;
- d. Implementer management, rewards, and any necessary corrective action;
- e. Review of implementer performance and program performance on a quarterly basis;
- f. Meeting savings goals and customer satisfaction levels;
- g. Metrics development; and
- h. Reporting.

19. In the event that a dispute arises among program administrators about the design or implementation of a statewide program area, and all non-lead utility program administrators are in agreement in opposition to the lead program administrator, one of the non-lead program administrators shall file a motion in the relevant energy efficiency rulemaking asking the Commission to resolve the dispute.

20. Utility program administrator actions to coordinate program delivery and administer statewide programs on behalf of the other utilities, under Commission direction, fall under the State Action Doctrine defense to anti-trust action, consistent with our prior findings in Decision 10-12-054.

21. All program administrators shall have the ability to continue local pilot activities that would otherwise qualify for statewide administration according to the terms of Decision 16-08-019 but that are not yet ready for such statewide treatment, provided that such local pilots or programs do not compete with, or otherwise impede the progress or activities or operational statewide programs.

22. Utility program administrators shall not opt out of funding statewide programs. All utility program administrators shall fund statewide programs at

levels consistent with their proportional share based on load, unless specifically approved by the Commission for a deviation by means of a new business plan filing containing justification for why the statewide program cannot be funded at the required level.

23. The 25 percent requirement for statewide funding articulated in D.16-08-019 shall be calculated as a proportion of the utility program administrator's total portfolio budget, including evaluation, measurement, and verification funding, but excluding funding allocated to other program administrators for other (non-statewide) programs. The percentage requirement for statewide program funding for the Southern California Gas Company shall be reduced to 15 percent, but remain 25 percent for the other utility program administrators consistent with D.16-08-019.

24. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, and Southern California Gas Company may file Tier 1 advice letters within 90 days of the issuance of this decision to propose a mechanism for shared funding of statewide programs, justifying why the current cost-sharing arrangements are insufficient, if applicable. They shall also develop an agreed-upon annual report to facilitate ongoing statewide program funding-level management. A summary of key findings from this report shall be included in each utility's annual energy efficiency portfolio report to the Commission, detailing proportional funding amounts for each statewide program and any cost-sharing discrepancies or issues, with particular attention to the proportional funding requirements.

25. The following downstream programs are required to be piloted on a statewide basis: water/wastewater pumping for non-residential public sector customers; workforce, education, and training (career and workforce readiness);

and residential heating, ventilation, and air conditioning quality installation/quality maintenance.

26. The statewide program areas shall be led by the program administrators given in Table 3 and Table 4 of this decision.

27. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, and Southern California Gas Company shall jointly conduct a bottom-up assessment of the structure and composition of the statewide program areas and offerings and file and serve the results of this assessment and its associated recommendations in the open energy efficiency rulemaking no later than one year from the issuance of this decision.

28. We approve the 2018-2025 business plan of the Bay Area Regional Energy Network, as modified pursuant to Section 4.2 of this decision.

29. We approve the 2018-2025 business plan of the Southern California Regional Energy Network, as modified pursuant to Section 4.3 of this decision.

30. The investor owned utilities must work with Local Government Partnership partners to improve cost-effectiveness and to meet the local governments' needs with respect to data sharing and contract terms that align with local government budgeting, legal, and other constraints; quantify co-benefits and local economic benefits of Local Government Partnerships in hard-to-reach and disadvantaged communities; and support local governments' efforts to increase local capacity to conduct energy efficiency activities.

31. The investor-owned utilities must, within 90 days of the issuance of this decision, select one company from among them to file a motion in this proceeding for approval of a standard contract for local government partnerships, with standard terms and conditions that address the items a, b, c, and d below, with placeholder terms for other modifiable terms:

- a. Contract term/length;
- b. Budget and payment schedule and terms, both to local governments and participating utility customers (for incentive payments);
- c. Dispute resolution process;
- d. Termination process;
- e. Data collection and access provisions;
- f. Progress and evaluation metrics;
- g. Evaluation, measurement, and verification requirements; and
- h. Method for calculating co-benefits and economic development benefits of programs in disadvantaged communities and/or for hard-to-reach customers.

32. As part of their local government and public sector implementation plans, the utility program administrators shall select among themselves a lead to oversee statewide deployment of the Energy Atlas and competitively solicit a third party to implement the deployment, maintain data quality, consistency and security, continue development of the Energy Atlas' capabilities, and encourage and support local governments that choose to participate. Commission staff is authorized to oversee the procurement process and implementation of the Energy Atlas statewide deployment and ongoing management. The utility program administrators shall allocate up to \$2 million to expand the Energy Atlas, and include annual Energy Atlas management and maintenance costs in their annual budget advice letters proportionally according to relevant energy efficiency program budgets.

33. The sector-level program proposals of Marin Clean Energy are approved, with budgets as given in Table 7 of this decision.



34. Marin Clean Energy is authorized to serve as a non-exclusive single point of contact to refer customers within its geographic area to its own energy efficiency programs as well as those offered by other program administrators.

35. The Marin Clean Energy proposal to serve as a downstream liaison for all programs within its geographic area is denied.

36. Pacific Gas and Electric Company shall transfer natural gas energy efficiency funding authorized for use by Marin Clean Energy in quarterly increments in advance of program expenditures.

37. Marin Clean Energy shall consolidate its advice letter submission detailing unspent funds, previously required each December 1, with its annual budget advice letter submission, each September 1.

38. The energy efficiency program administrators must submit annual joint memoranda of cooperation between energy efficiency program administrators with overlapping service areas, or "joint cooperation memos" (i.e., one memo each between Pacific Gas and Electric Company and the Bay Area Regional Energy Network; among Southern California Edison Company, Southern California Gas Company and the Southern California Regional Energy Network; among Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company and the Tri-County Regional Energy Network, for which Southern California Gas Company will be the utility and fiscal lead; and between Pacific Gas and Electric Company and Marin Clean Energy). The required contents of these joint cooperation memos are included in Section 7.1 of this decision. Both utility program administrators and non-utility program administrators shall (1) summarize all the programs they intend to run and indicate which programs may overlap; (2) describe how each will work with the other so that customers are informed of all options and not steered simply to

their own programs; and (3) describe how each will ensure customers are also aware of the others' programs, where that administrator does not have a similar offering. The program administrators must submit their first annual joint cooperation memos for approval via Tier 2 advice letters no later than August 1, 2018. The program administrators must include subsequent annual joint cooperation memos via Tier 2 advice letters no later than June 15, prior to submitting their annual budget advice letters.

39. Staff approval of the joint cooperation memos is a prerequisite for approval of the program administrators' annual budget advice letters for the relevant program year, for each year of this business plan period.

40. Staff is authorized to develop templates and further guidance as needed for the annual budget advice letter (ABAL) submissions, beginning no later than June 1, 2018. Staff shall seek and incorporate program administrator input for these templates and associated guidance as much as possible. Program administrators must use the staff-developed templates for future ABAL submissions unless and until staff updates or otherwise amends these templates.

41. Beginning with the annual budget advice letters due on September 4, 2018, the program administrators must include the information identified in Section 7.2 of this decision.

42. The program administrators must each share and present a draft of their annual budget advice letters, for program year 2019, at a meeting of the California Energy Efficiency Coordinating Committee prior to the September 4, 2018 submission deadline.

43. The program administrators' September 4, 2018 annual budget advice letters must include updated business plan budgets to reflect the 2018-2030 goals adopted in Decision 17-09-025 and interim greenhouse gas adder adopted in

Decision 17-08-022, and other relevant factors to provide a more accurate forecast of expected annual funding levels. The overall funding amount, that is, the sum of the revised annual funding levels through 2025, must not exceed the overall funding amount in a program administrator's 2018-2025 business plan (as modified in this decision, including incremental budget authority for Southern California Gas Company as specified in Ordering Paragraph 14) for the corresponding timeframe (2019-2025).

44. Beginning with the annual budget advice letters due on September 3, 2019, the program administrators must include updated budget estimates in the same format as the supplemental budget information filed in this proceeding on June 12, 2017.

45. If a program administrator revises its annual funding levels in annual budget advice letters after September 4, 2018, the overall funding amount must not exceed the overall funding amount in that program administrator's 2018-2025 business plan (as modified in this decision) for the corresponding timeframe (the year for which the program administrator requests budget authorization, through 2025).

46. The investor owned utilities must use their final official program year tracking data as the basis for all their submissions that include data associated with that specific program year, beginning with this program year (2018). The investor owned utilities may not make any changes to the data after final submission, except as specified in Section 7.2.2 of this decision.

47. The investor owned utilities must conform their submissions to the data requirements and formats directed by Commission staff via annual guidelines or the monthly/ quarterly/ annual filing templates.

48. To the extent a program administrator revises its annual funding levels as a result of updating its budget assumptions pursuant to Decision 17-09-025 and Decision 17-08-022, staff is authorized to use those revised annual amounts for reviewing the 2019 and subsequent annual budget advice letters.

49. Staff is authorized to evaluate the annual budget advice letters pursuant to the approval criteria identified in Section 7.3 of this decision.

50. Staff shall have discretion to dispose of a program administrator's portfolio budget request that exceeds the corresponding annual funding amount included in its business plan (as modified by this decision), through the annual budget advice letter review process.

51. Staff is authorized to dispose of a program administrator's annual budget advice letter for program years 2019-2022 pursuant to the process described in Section 7.4 of this decision.

52. The California Energy Efficiency Coordinating Committee (CAEECC) facilitator shall provide an assessment of collaboration in the CAEECC process, including program administrators' responsiveness to stakeholder input and all stakeholders' (including the program administrators) flexibility in reaching outcomes that are mutually agreeable. The facilitator may also make specific recommendations for process or structural modifications that would facilitate collaboration in the CAEECC process. The Natural Resources Defense Council, in its role as co-chair of the CAEECC, shall file and serve the facilitator's report in Rulemaking 13-11-005 or its successor no later than March 31, 2019.

53. Southern California Gas Company is prohibited from participating in statewide codes and standards advocacy activities, other than to transfer ratepayer funds to the statewide lead for codes and standards, during this business plan period.

54. This proceeding, for consolidated Applications 17-01-013, 17-01-014, 17-01-015, 17-01-016 and 17-01-017, remains open for consideration of the

proposed contract terms associated with third party solicitations.

This order is effective today.

Dated May 31, 2018, at San Francisco, California.

MICHAEL PICKER

President

CARLA J. PETERMAN

LIANE M. RANDOLPH

MARTHA GUZMAN ACEVES

CLIFFORD RECHTSCHAFFEN

Commissioners

# **Attachment A**

**Attachment A.**

**Adopted Common Metrics for Energy Efficiency Business Plans**

**Overall Portfolio Level**

<b>Common Problem</b>	<b>Final Common Metric or Indicator</b>	<b>Category: Metric or Indicator</b>
Capturing energy Savings	First year annual and lifecycle ex-ante (pre-evaluation) gas, electric, and demand savings (gross and net)	Metric
Disadvantaged Communities	First year annual and lifecycle ex-ante (pre-evaluation) gas, electric, and demand savings (gross and net) in disadvantaged communities	Metric
Hard-to-Reach Markets	First year annual and lifecycle ex-ante (pre-evaluation) gas, electric, and demand savings (gross and net) in hard-to-reach markets	Metric
Cost per unit saved	Levelized cost of energy efficiency per kWh, therm and kW (use both TRC and PAC)	Metric

**Residential – Single Family**

<b>Common Problem</b>	<b>Final Common Metric or Indicator</b>	<b>Category: Metric or Indicator</b>
Capturing energy Savings	First year annual and lifecycle ex-ante (pre-evaluation) gas, electric, and demand savings (gross and net) for Single Family Customers	Metric
Greenhouse Gas Emissions	Greenhouse gasses (MT CO <sub>2</sub> eq) Net kWh savings, reported on an annual basis	Metric



<b>Common Problem</b>	<b>Final Common Metric or Indicator</b>	<b>Category: Metric or Indicator</b>
Depth of interventions	Average savings per participant in both opt-in and opt-out programs (broken down by downstream, midstream and upstream, as feasible)	Metric
Penetration of energy efficiency programs in the eligible market	Percent of participation relative to eligible population  Percent of participation in disadvantaged communities  Percent of participation by customers defined as "hard-to-reach"	Metrics
Cost per unit saved	Levelized cost of energy efficiency per kWh, therm and kW (use both TRC and PAC)	Metric
Energy intensity	Average energy use intensity of single family homes (average usage per household – not adjusted)	Indicator

**Residential – Multi Family**

<b>Common Problem</b>	<b>Final Common Metric or Indicator</b>	<b>Category: Metric or Indicator</b>
Capturing energy Savings	First year annual and lifecycle ex-ante (pre-evaluation) gas, electric, and demand savings (gross and net) for multifamily customers (in-unit, common area, and master metered accounts)	Metric
Greenhouse Gas Emissions	Greenhouse gasses (MT CO <sub>2</sub> eq) Net kWh savings, reported on an annual basis	Metric

Common Problem	Final Common Metric or Indicator	Category: Metric or Indicator
Depth of interventions	Average savings per participant Savings per project (property)  Energy savings (kWh, kw, therms) per project (building)  Energy savings (kWh, kw, therms) per square foot	Metrics
Penetration of energy efficiency programs in the eligible market	Percent of participation relative to eligible population (by unit, and property)  Percent of square feet of eligible population participating (by property)  Percent of participation in disadvantaged communities  Percent of participation by customers defined as "hard-to-reach"	Metrics
Penetration of benchmarking in the eligible market	Percent of benchmarked multi-family properties relative to the eligible population  Percent of benchmarking by properties defined as "hard-to-reach"	Metrics
Cost per unit saved	Levelized cost of energy efficiency per kWh, therm and kW (use both TRC and PAC)	Metric
Energy intensity	Average energy use intensity of multifamily buildings (average usage per square foot – not adjusted and Average energy use intensity of multifamily units, including in-unit accounts)	Indicator

**Commercial**

<b>Common Problem</b>	<b>Final Common Metric or Indicator</b>	<b>Category: Metric or Indicator</b>
Capturing energy savings	<p>First year annual and lifecycle ex-ante (pre-evaluation) gas, electric, and demand savings (gross and net)</p> <p>First year annual and lifecycle ex-ante (pre-evaluation) gas, electric, and demand savings (gross and net) as a percentage of overall sectoral usage</p>	Metrics
Greenhouse gas emissions	Greenhouse gasses (MT CO <sub>2</sub> eq) Net kWh savings, reported on an annual basis	Metric
Depth of interventions	Energy savings (gross kWh, therms) as a fraction of total project consumption.	Metric
Penetration of energy efficiency programs in the eligible market	<p>Percent of participation relative to eligible population for small, medium, and large customers</p> <p>Percent of square feet of eligible population</p> <p>Percent of participation by customers defined as "hard-to-reach"</p>	Metrics
Penetration of benchmarking in the eligible market	<p>Percent of benchmarked customers relative to eligible population for small, medium, and large customers</p> <p>Percent of benchmarked square feet of eligible population</p> <p>Percent of benchmarking by customers defined as "hard-to-reach"</p>	Metrics
Cost per unit saved	Levelized cost of energy efficiency per kWh, therm and kW (use both TRC and PAC)	Metric

Common Problem	Final Common Metric or Indicator	Category: Metric or Indicator
Use of whole building metered data to estimate savings	Fraction of total projects utilizing Normalized Metered Energy Consumption (NMEC) to estimate savings  Fraction of total savings (gross kWh and therm) derived from NMEC analysis	Indicators
Program Satisfaction	Improvement in customer satisfaction  Improvement in trade ally satisfaction	Indicator
Investment in energy efficiency	Fraction of total investments made by ratepayers and private capital	Indicator

**Public**

Common Problem	Final Common Metric or Indicator	Category: Metric or Indicator
Capturing energy savings	First year annual and lifecycle ex-ante (pre-evaluation) gas, electric, and demand savings (gross and net) across Public Sector programs	Metric
Greenhouse Gas Emissions	Greenhouse gasses (MT CO <sub>2</sub> eq) based on net lifecycle kWh and Therms savings, reported on an annual basis, incorporating average fuel/technology mix	Metric
Depth of interventions	Average percent energy savings (kWh, kw, therms) per project building or facility  Average annual energy savings (kWh, kw, therms) per project building floor plan area  Average annual energy savings (kWh, kW therms) per annual flow through project water/wastewater facilities	Indicators

Common Problem	Final Common Metric or Indicator	Category: Metric or Indicator
Penetration of energy efficiency programs and benchmarking in the eligible market	Percent of Public Sector accounts participating in programs	Metric
	Percent of estimated floorplan area (i.e., ft <sup>2</sup> ) of all Public Sector buildings participating in building projects—estimate within +/-15% of sector-wide building area, +/-5% of project building area	Indicator
	Percent of Public Sector water/wastewater flow (i.e., annual average Million Gallons per Day) enrolled in non-building water/wastewater programs—estimate within +/-20% of flow through eligible facilities (treatment facilities pumping stations), +/-10% of flow through project facilities	Indicator
Cost per unit saved	Levelized cost of energy efficiency per kWh, therm and kW (use both TRC and PAC)	Metric
Investment in energy efficiency	Total program-backed financing distributed to Public Sector customers requiring repayment (i.e., loans, OBF)	Indicator
Energy intensity	Average energy use intensity of all Public Sector buildings	Metric
	Percent of Public Sector buildings with current benchmark	Metric
	Percent of floorplan area of all Public Sector buildings with current benchmark	Indicator

**Industrial**

<b>Common Problem</b>	<b>Final Common Metric or Indicator</b>	<b>Category: Metric or Indicator</b>
Capturing energy savings	First year annualized and lifecycle ex-ante (pre-evaluation) gas, electric, and demand savings (gross and net) in industrial sector	Metric
Greenhouse Gas Emissions	Greenhouse gasses (MT CO <sub>2</sub> eq) Net kWh savings, reported on an annual basis	Metric
Penetration of energy efficiency programs and diversity of participants	Percent of participation relative to eligible population for small, medium and large customers	Metric
New participation	Percent of customers participating that have not received an incentive for the past three years, annually, by small, medium and large customer categories	Indicator
Cost per unit saved	Levelized cost of energy efficiency per kWh, therm and KW (use both TRC and PAC)	Metric
Baseline/consumption reduction	Reduction in consumption (proposed by SCE and SDG&E)	Metric

**Agricultural**

<b>Common Problem</b>	<b>Final Common Metric or Indicator</b>	<b>Category: Metric or Indicator</b>
Capturing energy savings	First year and lifecycle ex ante (pre-evaluation) annualized gas, electric, and demand savings in agriculture sector, gross and net	Metric
Greenhouse Gas Emissions	Greenhouse gasses (MT CO <sub>2</sub> eq) Net kWh savings, reported on an annual basis	Metric
Penetration of energy efficiency	Percent of participation relative to eligible population for small, medium and large customers	Metric
Cost per unit saved	Levelized cost of energy efficiency per kWh, therm and kW (use both TRC and PAC)	Metric

**Codes and Standards**

<b>Common Problem</b>	<b>Final Common Metric or Indicator</b>	<b>Category: Metric or Indicator</b>
Capturing energy savings (for any resource program or resource subcomponent of a traditionally non-resource program that begins measuring energy and demand reduction benefits)	Net Energy Savings: GWH, M Therms and MW (demand)	Metric
Activity in advocating for building codes (T-24) tied to adoption in CA	Number of measures supported by CASE studies in rulemaking cycle (current work)  Number of measures adopted by CEC in rulemaking cycle (indicator of past work)	Metrics
Activity in advocating for appliance, lighting and equipment standards tied to adoption in CA	Number of T-20 measures supported by CASE studies in rulemaking cycle (current work)  Number of measures adopted by CEC in current year	Metrics
Activity in advocating for codes and standards tied to adoption at the federal level	Number of federal standards adopted for which a utility advocated (IOUs to list advocated activities)  Percent of federal standards adopted for which a utility advocated (# IOU supported/ # DOE adopted)	Metrics



Common Problem	Final Common Metric or Indicator	Category: Metric or Indicator
Local government participation and success in adoption of reach codes	The number of local government Reach Codes implemented (this is a joint IOU and REN effort)	Metric
Compliance Improvement	<p><b><u>For IOUs:</u></b> Number of training activities (classes, webinars) held, number of market actors participants by segment (e.g., building officials, builders, architects, etc.) and the total size (number) of the target audience by sector.</p>	Metric
	Increase in code compliance knowledge pre/post training.	Metric
	<p><b><u>For the RENs:</u></b> The percentage increase in closed permits for building projects triggering energy code compliance within participating jurisdictions</p>	Metric
	<p><b><u>Also for RENs:</u></b> Number and percent of jurisdictions with staff participating in an Energy Policy Forum</p>	Indicator
	Number and percent of jurisdictions receiving Energy Policy technical assistance.	Indicator
Buildings receiving enhanced code compliance support and delivering compliance data to program evaluators	Indicator	

**Work force Education and Training**

<b>Common Problem</b>	<b>Final Common Metric or Indicator</b>	<b>Category: Metric or Indicator</b>
Expanding WE&T Reach via Collaborations	Number of partnerships by sector (complete “partnership” defined by curriculum developed jointly + agreement)	Metric
Penetration of training	Number of participants by sector  Percent of participation relative to eligible target population for curriculum	Metric  Metric
Diversity of participants	Percent of disadvantaged participants trained (ID by zip code)  Percent of incentive dollars spent on measures verified to have been installed by contractors with a demonstrated commitment to provide career pathways to disadvantaged workers  Number of energy efficiency projects related to the WE&T training on which a participant has been employed for 12 months after receiving the training	Metric  Metric  Indicator

**Emerging Technologies Metrics**

<b>Common Problem</b>	<b>Final Common Metric or Indicator</b>	<b>Category: Metric or Indicator</b>
Need to track Technology Priority Map (TPM) development	ETP-M1: 6* TPMs (gas and electric combined) initiated within the first 3 years (including 1 Technology-focused Pilot TPM identifying market barriers for a diverse range of high-impact technologies through studies, and subsequently breaking down identified barriers via cooperative projects initiated in coordination with WE&T, ME&O, and other relevant IOU programs)  * This number will be updated once all third party contracts have been awarded.	Metric
Need to track TPM updating activity	ETP-M2: 3 TPMs updated within the first 3 years	Metric
Need to project activity	ETP-M3: 183* projects initiated within the first 3 years  *This averages 61 projects per year; this number will be updated once all third party contracts have been awarded.	Metric
Need to track event activity	ETP-M4: Host 15 outreach events with technology developers with products <1 year from commercialization within the first 3 years, including new technology vendors, manufacturers, and entrepreneurs.	Metric
Need to track event activity	ETP-M5: Host 6 outreach events with technology developers with products <5 years from commercialization within the first 3 years, including new technology vendors, manufacturers, and entrepreneurs.	Metric

<b>Common Problem</b>	<b>Final Common Metric or Indicator</b>	<b>Category: Metric or Indicator</b>
Need to track Technology-focused Pilot (TFP) TPM efforts	ETP-M7: 3* Technology-focused Pilots initiated as part of the TFP TPM within the first 3 years  *This number may be updated according to the results of the TPM development working group process	Metric
ETP is not utilizing other programs to confront barriers to market penetration	ETP-M6: 2* projects initiated with cooperation from other internal IOU programs associated with each Technology-focused Pilot  *This number may be updated according to the results of the TPM development working group process	Metric

**Emerging Technology Tracking (Reporting)**

<b>Common Problem</b>	<b>Final Common Metric or Indicator</b>	<b>Category: Metric or Indicator</b>
Savings are not being tracked	<p>ETP-T1: Prior year: % of new measures added to the portfolio that were previously ETP technologies</p> <p>ETP-T2: Prior Year: # of new measures added to the portfolio that were previously ETP technologies</p> <p>ETP-T3: Prior year: % of new codes or standards that were previously ETP technologies</p> <p>ETP-T4: Prior Year: # of new codes and standards that were previously ETP technologies</p>	Metrics
Savings are not being tracked	ETP-T5: Savings of measures currently in the portfolio that were supported by ETP, added since 2009. Ex-ante with gross and net for all measures, with ex-post where available	Metric
Input from other groups is not being tracked	<ul style="list-style-type: none"> <li>• ETP-T6: Number of ETCC project ideas submitted outside of TPM process by source. [Note: Categories of sources (e.g. PA, national lab, manufacturer, technology incubator, etc.) will be developed collaboratively with ED, and self-reported by submitter.] Project source also labeled in the ETP database.</li> <li>• ETP-T7: Number of TPM project ideas by source, if available [Note: Categories of sources (e.g. PA, national lab, manufacturer, technology incubator, etc.) will be developed collaboratively, and attributed by ETP based on ETP's expert judgment.] Project source also labeled in the ETP database.</li> </ul>	Metrics

<b>Common Problem</b>	<b>Final Common Metric or Indicator</b>	<b>Category: Metric or Indicator</b>
Output from ETP is not explicitly aligned with long-term goals	ETP-T8: Mapping of ETP projects and technologies aligned with specific statewide goals, with specificity as to what aspect of each goal it is fulfilling. For example: "4 ETP projects are aligned with statewide ZNE-readiness" in addition to "a list of ETP projects aligned with ZNE-readiness are as follows:" Goals will also be labeled in the ETP database. A list of eligible goals will be developed collaboratively with ED.	Metric

(End of Attachment A)