BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Concerning Energy
Efficiency Rolling Portfolios, Policies, Programs,
Evaluation, and Related Issues.

Rulemaking 13-11-005
(Filed November 14, 2013)

COMMENTS OF MARIN CLEAN ENERGY ON PROPOSED DECISION
PROVIDING GUIDANCE FOR INITIAL ENERGY EFFICIENCY
ROLLING PORTFOLIO BUSINESS PLAN FILINGS

Michael Callahan-Dudley
Regulatory Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6045
Facsimile: (415) 459-8095
E-Mail: mcallahan-dudley@mceCleanEnergy.org

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Recommendations Related to Existing Conditions Baselines:

1. The Commission should clarify that: (1) the evaluation of the 2017 and 2018 data will be focused on recommending improvements to the default policy; and (2) additional years of data will be evaluated to determine whether the default policy should be continued.

2. The Commission should limit the scope of the staff resolution on measure-level baseline rules to those measures not covered by the program level rules in the Proposed Decision and should extend the deadline for the staff resolution to June 2017.

Recommendations Related to Statewide Programs:

1. The Commission should clarify the decision-making process for statewide program design, cost-sharing, and attribution of savings.

2. The Commission should avoid a decision-making process for statewide programs that allows utility activities that would disadvantage CCAs.

3. The Commission should direct the California Energy Efficiency Coordinating Committee to regularly discuss the design, funding, and attribution of savings for statewide programs followed by the Commission providing a formal approval of a tier 2 advice letter filed by the lead administrator of the statewide program.

Recommendations Related to Evaluation, Measurement, and Verification:

1. Commission should require IOUs to transfer the entire approved annual EM&V budget to CCAs on January 15 each year.

2. The Proposed Decision should be modified to allow Energy Division to modify the default allocation if sufficient EM&V funds are not available.

3. The Commission should include an authorization in the Proposed Decision for MCE’s annual EM&V budget of $66,098 based on a gross up of programmatic budgets.

Other Recommendations:

1. The Commission should direct program administrators to reflect their solicitation strategies for all energy efficiency in their business plans.

2. The Commission should strike the language in the Proposed Decision that indicates only utilities are able to handle a portfolio management role with portfolios containing both solicitations and programmatic activities for energy efficiency.
3. The Commission should clarify that both the California Public Utilities Code and prior Commission decisions allow new CCA program administrators to propose a business plan on or after January 15, 2017.

4. The Commission should not require annual budget advice letters to be filed until the initial business plans are approved.
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COMMENTS OF MARIN CLEAN ENERGY ON PROPOSED DECISION PROVIDING GUIDANCE FOR INITIAL ENERGY EFFICIENCY ROLLING PORTFOLIO BUSINESS PLAN FILINGS


I. INTRODUCTION

MCE appreciates the opportunity to comment on a number of important issues in the Proposed Decision. MCE supports the default policy for an existing conditions baseline and provides recommendations to ensure it is adequately evaluated and developed on a timeline that acknowledges the business plan process. MCE provides comments to improve the decision-making process for statewide programs. MCE requests changes to the EM&V rules to allow flexibility and requests an EM&V budget based on a gross up of the programmatic expenditures. MCE makes several other recommendations to reflect all energy efficiency activities within business plans and refine language consistent with the California Public Utilities Code. These
recommendations are important to ensure a sound energy efficiency policy framework for all program administrators.

II. THE COMMISSION SHOULD COLLECT MORE THAN TWO YEARS OF DATA TO EVALUATE THE SUCCESS OF THE DEFAULT POLICY FOR AN EXISTING CONDITIONS BASELINE

MCE recommends the Commission clarify that it will evaluate more than two years’ worth of data before fundamentally reconsidering the default policy for an existing conditions baseline. The Proposed Decision adopts a default policy for an existing conditions baseline\(^1\) intended to enable additional projects to materialize.\(^2\) The Commission should evaluate data collected in 2017 and 2018 by 2020 to support demand forecasting and make policy recommendations.\(^3\) However, the decision is vague about whether the evaluation is intended to make recommendations concerning the continuation of the new default existing conditions policy. The Commission should clarify that: (1) the evaluation of the 2017 and 2018 data will be focused on recommending improvements to the default policy; and (2) additional years of data will be evaluated to determine whether the default policy should be continued. It is an error of fact to assume the significant programmatic and policy changes necessary to shift to existing conditions as the default baseline\(^4\) will produce the data necessary to evaluate the continuation of the policy by the end of 2018. The Commission should evaluate more information before reconsidering the validity of default policy.

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1 Proposed Decision at p. 30.
2 Proposed Decision at p. 31.
3 Proposed Decision at p. 31-32.
4 Some of these changes include: developing tools to measure metered-based savings (e.g. normalized metered energy consumption); designing appropriate incentives (D.14-10-046 at p. 52; Proposed Decision, Conclusion of Law 13 at p. 82); determining measure-level baseline rules (Proposed Decision, Ordering Paragraph 4); establishing new priorities and methods for evaluating the impacts of programs (Proposed Decision at p. 65-67); and adequately accounting for free ridership (Proposed Decision at p. 19).
III. THE COMMISSION SHOULD LIMIT THE INITIAL SCOPE OF THE MEASURE-LEVEL BASELINE RULES TO THOSE MEASURES NOT ADDRESSED IN THE PROPOSED DECISION

The Commission should limit the scope of the staff resolution on measure-level baseline rules to those measures not covered by the program level rules in the Proposed Decision. The Proposed Decision calls for staff to prepare a resolution articulating consensus recommendations on measure-level baseline rules by the end of 2016.\(^5\) However, this contradicts the statement in the Proposed Decision that “this decision represents the entirety of the guidance we expect the Commission to give prior to business plan submittal.”\(^6\) The additional guidance on measure-level baseline rules based on the staff resolution may impact the design of incentives, intervention strategies, and ultimately the content of business plans.

It would be an error of fact to assume program administrators can incorporate this information into their business plans between December 31, 2016 when the staff resolution is due\(^7\) and January 15, 2017 when business plans are due.\(^8\) Program administrators need adequate time to incorporate guidance into their business plans. Additionally, it would be an error of fact to assume that program administrators have adequate resources to develop consensus on comprehensive measure-level rules while simultaneously working to prepare business plans and solicit stakeholder feedback over the next four months. The Commission should allow more time to deliberate on measure-level baseline rules once the initial business plans are filed and approved. The Commission should limit the scope of the initial measure-level baseline recommendations to any measures that are not covered by the program-level rules in the Proposed Decision and should extend the deadline for the staff resolution to June 2017.

\(^5\) Proposed Decision at p. 44.
\(^6\) Proposed Decision at p. 77.
\(^7\) Proposed Decision at p. 44.
\(^8\) Proposed Decision at p. 78.
IV. THE COMMISSION SHOULD PROVIDE ADDITIONAL GUIDANCE ON THE DECISION-MAKING PROCESS FOR STATEWIDE PROGRAMS

The Commission should clarify the decision-making process for statewide program design, cost-sharing, and attribution of savings. The Commission provides a general definition for statewide programs in the Proposed Decision. However the Proposed Decision is vague about the decision-making process between the lead administrator and the other consulting administrators. Several elements of decision making for the statewide programs need to be clarified under the new definition. It is unclear how a consulting administrator may influence: (1) the design of statewide programs; (2) the share of budget and attribution of savings for the statewide programs among the lead and consulting administrators; and (3) ability to start new statewide programs or cease participation in statewide programs that are not effective. The language in the Proposed Decision could be interpreted to indicate that these decisions will be the result of collaboration among all administrators but does not clarify which entity is ultimately responsible for resolving differences. The Proposed Decision could also be interpreted to indicate that the lead administrator has complete authority over such decisions. This factual and legal ambiguity should be clarified in the decision so all administrators understand the decision-making process for statewide programs.

MCE urges the Commission to consider the decision making process in light of Senate Bill ("SB") 790 and the Commission’s CCA Code of Conduct Decision implementing that bill. In passing SB 790, the legislature found that due to the exercise of market power by electrical corporations, it is necessary to implement a code of conduct and associated rules to

9 Proposed Decision at p. 54-55.
10 “[I]t is important to have one entity in the role of lead administrator for each of the statewide programs, with consultation with the other administrators of other key aspects of the portfolio.” Proposed Decision at p. 49.
11 SB 790 (2011).
12 D.12-12-036.
facilitate the implementation of CCA programs to foster fair competition.\textsuperscript{13} The Commission decision establishing the code of conduct indicated the rules are intended to provide CCAs “the opportunity to compete on a fair and equal basis with other load serving entities, and to prevent investor-owned utilities from using their position or market power to undermine the development or operation of aggregators.”\textsuperscript{14} The code of conduct was “designed to foster fair competition by limiting utility activities that would disadvantage CCAs…”\textsuperscript{15} An electrical corporation in a role of lead administrator for a statewide program may be in a position to disadvantage CCAs and undermine the operation of CCA energy efficiency programs. For example, a lead administrator may preclude downstream rebates and associated energy savings for heating, ventilation, and air conditioning (“HVAC”) by providing statewide rebates at the upstream or midstream level.\textsuperscript{16} This would have the effect of removing any savings associated with technical assistance provided to support HVAC installations in downstream programs thereby reducing the cost-effectiveness of those downstream programs. Similarly, if the lead administrator is in the position of determining what cost and attribution share will go to consulting administrators or implementers, this could have the inappropriate effect of delegating oversight authority to the electrical corporation. The Commission should direct the California Energy Efficiency Coordinating Committee to regularly discuss the design, funding, and attribution of savings for statewide programs followed by the Commission approving a formal proposal via tier 2 advice letter filed by the lead administrator. The Commission should avoid a decision-making process for statewide programs that allows utility activities that would disadvantage CCAs.

\textsuperscript{13} SB 790, Sec. 2 (f)-(h).
\textsuperscript{14} D.12-12-036 at p. 2.
\textsuperscript{15} D.12-12-036 at p. 7.
\textsuperscript{16} Reply Comments of MCE to Ruling of Assigned Commissioner and Administrative Law Judge Seeking Input on Approaches for Statewide and Third-Party Programs at p. 3.
V. THE COMMISSION SHOULD REQUIRE SOLICITATIONS FOR ENERGY EFFICIENCY TO BE REFLECTED IN THE BUSINESS PLANS

The Commission should direct program administrators to reflect their solicitation strategies for all energy efficiency efforts in their business plans. The Proposed Decision acknowledged a tension between all-source solicitations and programmatic efforts. The Proposed Decision should address that tension by calling for administrators to include those solicitation strategies, even those ordered under different proceedings at the Commission, in their business plans. This is consistent with existing business plan guidance to discuss how strategies are coordinated with other demand-side options and may help utility administrators satisfy the general approach to Third Party Programs provided in the Proposed Decision. Inclusion of these strategies will help ensure a coordinated and transparent planning effort for energy efficiency spending and procurement. This will also create a single repository to facilitate Commission and stakeholder awareness of actual spending and associated energy efficiency activity and will begin to coordinate the demand and supply sides of energy efficiency and distributed energy resources procurement.

VI. THE COMMISSION SHOULD PROVIDE ADDITIONAL CLARITY TO THE PROCESS FOR TRANSFERRING EM&V FUNDS TO CCAS

The Commission should require Investor Owned Utilities (“IOUs”) to transfer the entire approved annual EM&V budget to CCAs on January 15 each year. The Proposed Decision requires the utility program administrators to handle fund transfers for EM&V work in the same...
manner that they handle program funds. This is intended not to disrupt IOU contractual arrangements with Regional Energy Networks (“RENs”) and CCAs that are fully functional already but not consistent. However, the rule is based on a factual error. As stated in MCE’s comments on the June 8th ruling in this proceeding, there is no functional process for CCAs to receive EM&V funds. If there are functional contractual arrangements with the RENs, the Proposed Decision can preserve them by simply providing the needed clarity specifically for CCAs. Additionally, EM&V funds are distinct from other program funds, and clarifying the process to transfer EM&V funds will not necessarily impact the transfers of other program funds.

The rule, as stated in the Proposed Decision, will result in an overly complex process that unnecessarily burdens Commission staff and program administrators. There are two manners in which CCAs currently receive program funds from IOUs depending on the type of funds (i.e. electric or gas). For electric funds, MCE receives quarterly payments based on the last approved budget. For gas funds, MCE was directed to enter into a contract with PG&E modeled after the existing contracts with the RENs. This contract requires MCE to invoice PG&E on a monthly basis for gas funds spent in the prior month. These invoices must be approved by Energy Division staff in order for PG&E to transfer the gas funds to MCE. The rule in the Proposed Decision would have the bizarre result of requiring separate processes for transferring electric and gas EM&V funds for a single EM&V study. The process would require Energy Division staff to unnecessarily approve transfers of gas funds that were already approved by the

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21 Proposed Decision, Conclusion of Law 55 at p. 87.
22 Proposed Decision at p. 71.
24 D.14-10-046, Ordering Paragraph 24 at p. 167-68.
25 D.14-10-046, Ordering Paragraph 26 at p. 168.
Commission when it approved the overall EM&V budget. It would also require MCE to advance its own operational revenues to cover EM&V expenses only to be reimbursed after the fact. The Commission should avoid this overly complex process, that unnecessarily burdens Commission staff and program administrators, and simply order IOUs to transfer the approved EM&V budget in whole on January 15 each year.

The Commission should authorize an EM&V budget for MCE based on a gross up of programmatic budgets. Through discussions with PG&E, MCE discerned one possible reason for difficulty in receiving EM&V funds for the 2013-2015 program years. MCE’s authorized budget is based entirely on programmatic expenditures (i.e. all non-EM&V expenditures). While it is the convention for program administrators to identify their programmatic expenditures and then gross up to include the EM&V funding, MCE’s authorized budget does not include a gross up of 4% for EM&V funding. Considering MCE’s most recently approved budget for programmatic expenditures is $1,586,347 a gross up to include EM&V would result in an overall annual budget of $1,652,445 as demonstrated in Table 1 below. The Commission should include an authorization for MCE to receive an EM&V budget based on a gross up of programmatic budgets in the Proposed Decision.

<table>
<thead>
<tr>
<th>Programmatic Expenditures</th>
<th>EM&amp;V Budget</th>
<th>Total Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>$1,586,347</td>
<td>$66,098</td>
<td>$1,652,445</td>
</tr>
<tr>
<td>96%</td>
<td>4%</td>
<td>100%</td>
</tr>
</tbody>
</table>

VII. A PROPORTIONATE BUDGET FOR EM&V IS INADEQUATE TO ADDRESS THE DIFFERENCES IN THE SIZE OF PROGRAM ADMINISTRATORS

The Commission should allow flexibility for smaller program administrators to access additional funds if needed for administrator-led EM&V activities. The Proposed Decision authorizes 4% of the portfolio to be used for EM&V with 40% of that funding divided

proportionately among program administrators based on total program budgets.\textsuperscript{27} As discussed in MCE’s comments to the June 8, 2016 ruling in this proceeding, smaller program administrators such as CCAs and RENs may have such small budgets that their proportional share will be insufficient to conduct market assessments, embed Measurement and Verification (“M&V”) into programs, and evaluate comprehensive programs.\textsuperscript{28} With an increasing emphasis on metered energy savings, subsequent impact evaluation efforts involve expensive statistical analyses such as randomized control trials. The Commission has currently authorized over $1 million for a study of one program utilizing such a method.\textsuperscript{29} At the current proposed funding levels, MCE’s share of the EM&V budget would amount to less then $40,000; this is insufficient to support the robust analyses contemplated for the new existing conditions baseline program designs. While MCE supports a default allocation as described in the Proposed Decision, the decision errs when it concludes that “this will ensure sufficient funds are available.”\textsuperscript{30} The Proposed Decision should allow Energy Division to modify the default allocation if sufficient funds are not available.

VIII. THE COMMISSION SHOULD ADDRESS LANGUAGE THAT IS NOT SUPPORTED BY EVIDENCE AND CONTRADICTS THE PUBLIC UTILITIES CODE

The Proposed Decision should remove an unsupported conclusion from dicta due to a lack of evidence and contradictions with the Public Utilities Code. The Proposed Decision notes that “[h]aving both programmatic and all-source solicitation options within one sector highlights

\textsuperscript{27} Proposed Decision at p. 68-70.
\textsuperscript{28} Comments of Marin Clean Energy to Administrative Law Judge’s Ruling Seeking Comment on Evaluation, Measurement, and Verification and Energy Savings Performance Incentive Issues at p. 3-5.
\textsuperscript{29} “Impact Evaluation of Comparative Energy Usage Report Programs,” DNVGL. The budget for this program is reported at $1,123,240 according to \url{http://eestats.cpuc.ca.gov/Views/PSRViewer.aspx} (August 4, 2016).
\textsuperscript{30} Proposed Decision at p. 70.
the importance of careful portfolio planning and solicitation rules. **No other entity besides the utility will be able to handle this portfolio design role.**31 The conclusion that only utilities are able to handle the portfolio design role is not supported by any reference to the record. It is also contradictory to sections 366.2 and 381.1 of the California Public Utilities Code. Section 366.2 assigns CCAs the sole responsibility for procurement activities on behalf of CCA customers.32 Section 381.1 grants CCAs authority to administer energy efficiency programs. The procurement role includes portfolio management which necessarily involves solicitation of resources, which may include energy efficiency. The programmatic role is similar to the role carried out by utilities. Taken together, CCAs have a statutory right to handle a design role over a portfolio that includes both all-source solicitations and programmatic options. The Commission should strike the sentence above that indicates only utilities are able to handle this role.

The Commission should clarify that the law allows new CCAs to propose a business plan on or after January 15, 2017. The Proposed Decision calls for MCE and any other CCA proposing a business plan to file on January 15, 2017.33 CCAs are eligible to apply to become program administrators under California law34 and the Commission has authorized new administrators to apply at any time.35 The Commission should amend Ordering Paragraph 2 to clarify that new CCAs can file on or after January 15, 2017. This change is required to ensure the Ordering Paragraph is consistent with the Public Utilities Code.

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31 Proposed Decision at p. 62 (**emphasis added**).
33 Proposed Decision, Conclusion of Law 2 at p. 88.
35 D.14-01-033, Ordering Paragraph 4 at p. 50-51.
IX. THE COMMISSION SHOULD START THE ANNUAL BUDGET ADVICE LETTER FILINGS ONCE BUSINESS PLANS ARE APPROVED

The Commission should not require annual budget advice letters to be filed until the initial business plans are approved. The Proposed Decision indicates that the annual budget advice letter filing is due on September 1, 2016. However, this direction is contrary to the decision that established the annual budget advice letter. That decision called for the annual budget advice letter to be “consistent with the last Commission-approved business plan.” The decision also indicated that the Commission may have to defer budget filings to 2017 depending on how long it takes the Commission to review and approve business plans. Considering no business plans will be filed until January 15, 2017, there will be no approved business plans on September 1, 2016. The Commission should remain consistent with D.15-10-028 and avoid the regulatory churn associated with processing an annual budget advice letter when no approved business plans exist.

MCE understands that Commission staff and program administrators are working diligently to prepare for the annual budget advice letter filing. This work should continue and the appropriate appendices and the online tool should be fully developed so that annual budget advice letters can use the system once the first business plans are approved.

X. CONCLUSION

MCE thanks Assigned Commission Peterman and Administrative Law Judge Fitch for their thoughtful consideration of these comments on the Proposed Decision.

36 Proposed Decision at p. 77.
37 D.15-10-028 at p. 59-63.
38 D.15-10-028 at p. 59.
39 D.15-10-028 at p. 61.
40 Proposed Decision at p. 78.
Respectfully submitted,

/s/ Michael Callahan-Dudley

Michael Callahan-Dudley  
Regulatory Counsel  
MARIN CLEAN ENERGY  
1125 Tamalpais Avenue  
San Rafael, CA 94901  
Telephone: (415) 464-6045  
Facsimile: (415) 459-8095  
E-Mail: mcallahan-dudley@mceCleanEnergy.org

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17. The Commission should continue to study the impact of baseline policy, especially the changes ordered in this decision. Staff should sponsor a study collecting 2017 and 2018 data, and return to us with recommendations for improving implementation before the start of 2020. Staff should sponsor a longer-term study to explore whether the baseline policy should be continued using data collected from 2017-2024.

31. The Commission should defer to a working group organized by staff or utilize the California Technical Forum to develop a list of measure-level baseline rules that will take effect after the first business plans are filed.

New Conclusion of Law 37b. The California Energy Efficiency Coordinating Committee should regularly discuss the design, funding, and attribution of savings for statewide programs followed by the Commission providing approval of a formal proposal via tier 2 advice letter filed by the lead administrator.

New Conclusion of Law 53.b. MCE should be allocated an annual EM&V budget based on a gross up of programmatic budgets.

54. EM&V budgets for non-IOU program administrators, including CCAs and RENs, should be allocated from among the 40 percent of the EM&V budget that goes to program administrators, on a proportional basis (based on each program administrator’s total program budget) within the utility service areas where the non-IOU administrators operate. Energy Division staff can modify the proportional budget allocation for EM&V funding via tier 2 advice letter when sufficient funds are not available.

55. The process to transfer EM&V funds from utility program administrators to non-IOU REN program administrators should be the same as used for regular program funds. The process for CCA program administrators should be to transfer the entire EM&V budget on January 15 each year.

New Conclusion of Law 63. While encouraged to file on January 15, 2017, new CCA program administrators can file a business plan after that date.

New Conclusion of Law 64. Annual Budget Advice Letters should be consistent with an approved business plan and should not be filed by a PA until their initial business plan is approved.

New Conclusion of Law 65. Program Administrators should reflect all of their solicitation strategies for energy efficiency in their business plans.
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Contracts Resulting From Its 2014 Energy Storage Request for Offers (ES RFO).

Application 15-12-003
(Filed December 1, 2015)

CONSOLIDATED

(U39E)

Application 15-12-004
(Filed December 1, 2015)

COMMENTS OF MARIN CLEAN ENERGY, SONOMA CLEAN POWER AUTHORITY, THE CITY OF LANCASTER AND THE COUNTY OF LOS ANGELES ON THE PROPOSED DECISION

C.C. Song
Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6018
Facsimile: (415) 459-8095
E-Mail: csong@mceCleanEnergy.org

Ty Tosdal
of Counsel
Braun Blasing McLaughlin & Smith, P.C.
915 L Street, Suite 1270
Sacramento, California 95814
Telephone: (858) 952-4016
E-mail: ty@tosdallaw.com
Counsel for the City of Lancaster and Sonoma Clean Power Authority

Steve Shupe
General Counsel
Sonoma Clean Power Authority
50 Santa Rosa Avenue, 5th Floor
Santa Rosa, CA 95404
Telephone: (707) 890-8485
Email: sshupe@sonomacleanpower.org

Howard Choy, General Manager
County of Los Angeles Office of Sustainability
1100 North Eastern Avenue
Los Angeles, CA 90063-3200
Telephone: (323) 267-2006
Email: HChoy@isd.lacounty.gov

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COMMENTS OF MARIN CLEAN ENERGY, SONOMA CLEAN POWER AUTHORITY, THE CITY OF LANCASTER AND THE COUNTY OF LOS ANGELES ON THE PROPOSED DECISION

Pursuant to Rule 14.3 of the California Public Utilities Commission (“Commission”) Rules of Practice and Procedure, Marin Clean Energy (“MCE”), Sonoma Clean Power Authority (“SCP”), the City of Lancaster (“Lancaster”), and the County of Los Angeles (“LA County”) (collectively, the “CCA Parties”) hereby submit these comments on the Proposed Decision (“PD”) in this proceeding issued on July 20, 2016. The CCA Parties remain concerned about cost recovery issues, particularly about the adoption of the Power Charge Indifference Adjustment (“PCIA”) and the fact that it fails to reflect the value of energy storage resources, as the Commission acknowledged in Decision (“D.”) 14-10-045.

The PCIA is a cost recovery mechanism that was designed for traditional generation resources. Without modification, it fails to capture the fair market value of energy storage resources. While the Proposed Decision makes an adjustment to the PCIA methodology to exclude energy storage charging costs, a change that the CCA Parties support, that
modification does not address the failure of the PCIA to capture the market value of storage. Accordingly, the CCA Parties propose the following:

- The PCIA methodology should be modified to include a Storage Adder, as the CCA Parties have advocated throughout this proceeding.
- Regardless, the Commission should exclude charging costs as proposed and adopt a credit or offset for ancillary services revenue.
- In addition, the CCA Parties support revisiting the PCIA methodology for energy storage resources when more data becomes available.
- Finally, the Commission should clarify that the delay on PCIA treatment until 2017 remains in force.

I. THE COMMISSION HAS RECOGNIZED THAT THE PCIA MUST BE MODIFIED FOR ENERGY STORAGE AND SHOULD RECONSIDER ADOPTION OF THE STORAGE ADDER

The Storage Adder proposed by the CCA Parties is designed to capture the fair market value of a nascent energy resource. As the PD explains, a critical component of the PCIA formula used for traditional generation resources is the Market Price Benchmark (“MPB”), and the difference between the MPB and the forecasted costs associated with the utility’s resource portfolio provides the indifference amount.\(^1\) As the Commission has recognized in previous rulings and decisions, a storage resource has capabilities and corresponding values that are

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The CCA Parties agree with the Commission’s assessment, which provides the basis for including a Storage Adder in the MPB to capture the current market value of the resource. The rationale behind the Storage Adder is that the present contract costs for storage are the best market price for the resource. The Storage Adder is derived from current IOU storage contracts and calculated annually based on the data submitted by the IOUs to the Energy Division. This approach is based on and analogous to the Green Adder adopted by the Commission to determine the market value of renewable contracts.

The Storage Adder would also ensure that contracts are not automatically above market from the day they become operational. The PCIA is intended to provide recovery for costs that are stranded when procurement costs are “unavoidable” and cannot be recovered through other means. But the IOU proposal to apply the PCIA without modification, which the PD adopts in large part, would result in costs that are subject to PCIA treatment as soon as the resource is operational under the contract. Cost recovery of this kind subjects CCA customers to inequitable treatment, and the Storage Adder should be adopted to provide relief from such costs.

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3 “A primary issue is that the existing market benchmark is not suited to determine the above market cost for energy storage projects. Because the energy storage program is in its nascent stages, there is insufficient data to develop appropriate market algorithms for this purpose.” (D. 14-10-045 at 45.)
4 D.11-12-018 at 113.
5 “Any additional costs of the electrical corporation recoverable in commission-approved rates, equal to the share of the electrical corporation's estimated net unavoidable electricity purchase contract costs attributable to the customer …” (Pub. Util. Code, § 366.2(f)(2)(italics added)
Furthermore, as the Commission has recognized that energy storage is not a generation resource.\(^6\) Therefore, energy storage should not be treated in the same manner as a generation resource for cost recovery purposes. A dedicated Storage Adder that modifies the MPB to reflect recent storage contracts would bring the benchmark closer to capturing the value of energy storage.

Unfortunately, the PD does not adopt the Storage Adder proposed by the CCA Parties for reasons that are not supported by the record. Contrary to the arguments advanced by the IOUs, procurement of energy storage resources for bundled customers does not benefit all customers alike. Accrual of benefits from energy storage is still an evolving picture, but each Load Serving Entity (“LSE”) including each CCA program, has its own energy storage obligations and is in the best position to procure generation resources for its customers.\(^7\)

TURN argued that the storage adder may contribute to scenario in which bundled customers are stuck with negative cash flows generated by the resources.\(^8\) But TURN did not explain how such a scenario would develop, or how likely it is that such an event would occur. Furthermore, TURN has not provided any evidence regarding a negative cash flow event and its possible effects. Without presenting factual evidence, such assertions are speculative and contribute nothing to the record.

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\(^6\) D. 14-10-045 at 31.
\(^7\) D. 14-10-045 at 26.
\(^8\) Opening Brief of The Utility Reform Network in Application 15-12-003 et al., May 25, 2016 at 2; Reply Brief of The Utility Reform Network in Application 15-12-003 et al., June 8, 2016, at 4-5.
II. ALTERNATIVELY, THE COMMISSION SHOULD MODIFY THE PCIA TO ACCOUNT FOR CHARGING COSTS AND ANCILLARY SERVICES

The CCA Parties believe that the adoption of a Storage Adder is the best way to capture the market value of storage, and that the PCIA methodology for energy storage resources should be modified accordingly. But regardless of whether the Commission adopts the storage adder at this time, the CCA Parties support eliminating charging costs, as the PD currently provides. The CCA Parties also support the adoption of a credit or offset for ancillary services revenue as part of a partially modified PCIA formula.

The PD rightly excludes charging costs from the PCIA methodology. The CCA Parties agree that the PCIA already reflects generation costs for power that the IOUs will procure and then use to charge energy storage resources. It follows that charging costs should not be counted a second time. The Commission should reject any IOU application or other proposal to include such costs in the PCIA calculation.

The PD should also include a credit or offset for ancillary services revenue. The IOUs are including the full costs of energy storage resources in the PCIA calculation, but the revenue that they obtain for ancillary services associated with these same resources is not reflected in the PCIA. The revenue is generated from the market established by the California Independent System Operator (“CAISO”) and potentially from other sources. Ancillary services revenue clearly has monetary value that should be incorporated into the PCIA calculation and shared among all the various customer groups that are subject to the charge, including CCA program customers, as a matter of equity and to reduce the overall impact.

9 “To reflect the charging costs as a storage cost would result in a double counting of this generation cost, effectively increasing the Indifference Amount beyond the actual costs incurred.” (PD at 23.)
The IOUs have stated that the use of energy storage resources to provide ancillary services is a reason that the Commission should approve their applications in this proceeding. PG&E has bargained with its developers for an assignment to the rights to ancillary services and to obtain any associated revenue.10 “PG&E is entitled to all of the energy discharged by the facility, ancillary services, capacity attributes, and any other products or services associated with the energy storage that may be defined by the CAISO or governmental authority.”11 There is little room for doubt that PG&E expects to obtain ancillary services revenue from the contracts that are part of the applications in this proceeding.

Such revenue is an important contributor to the value of energy storage, or else the IOUs would not have bargained for the rights to it and cited it as a reason to approve the contracts. With more distributed energy resources coming online, the market for ancillary services is anticipated to grow. CAISO, for example, recently increased the prices that it pays for ancillary services.12 While CCA customers will pay for resources that will be bid into the ancillary services market, unless the PCIA is modified, they will not receive the savings generated through ancillary services revenue. In the interest of fairness and to reduce cost impacts on CCA programs, the Commission should modify the PCIA formula to provide a credit or offset for any ancillary services revenue that is obtained for energy storage resources.

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11 PD at 9.
III. THE CCA PARTIES AGREE THAT THE PCIA METHODOLOGY SHOULD BE REVISITED WHEN MORE DATA IS AVAILABLE

The CCA Parties support revisiting the PCIA methodology in 2020, but that should not preclude the Commission from revisiting the PCIA beforehand if more data become available. The Commission has stated that the reason for waiting until 2020 is lack of information about the energy storage market. The energy storage market is still in its formative stages, and there are a limited number of contracts and other data points available. Nevertheless, while there may procedural reasons to delay review of the PCIA until 2020 because that is when another energy storage procurement cycle begins, the emergence of additional data before that time should compel a new assessment of the methodology.

Data collection should be a priority when the PCIA is ultimately revisited. The Commission may benefit from undertaking an information gathering process geared toward obtaining market data as part of a future energy storage proceeding. A potential avenue for obtaining relevant data is a third party index, similar to the index that is used for the Green Adder. All LSEs are gathering information through the contracting and operation of energy storage resources. When the PCIA is re-examined, such information should be made available to the Commission and the parties in a transparent manner.

IV. THE COMMISSION SHOULD CLARIFY THAT THE PROHIBITION ON PCIA TREATMENT UNTIL 2017 REMAINS IN FORCE

Regardless of any changes to the methodology, the Commission should clarify that time parameters for the PCIA established in previous decisions still apply to the contracts under consideration in this proceeding. D. 14-10-045 delayed cost recovery under the PCIA for energy storage resources.

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13 D. 14-10-045 at 89.
14 Decision Adopting Direct Access Reforms (D.11-12-018) at 17-25.
storage resources until 2017 at the soonest.\textsuperscript{15} This time limit should remain in force because there is no need for the IOUs recover costs any earlier.

V. CONCLUSION

The PCIA methodology does not reflect the market value of energy storage resources and must be modified to better capture the market. The CCA Parties urge the Commission to take the following steps:

• The PCIA methodology should be modified to include a storage adder, as the CCA Parties have advocated throughout this proceeding.

• Regardless, the Commission should exclude charging costs as proposed and adopt a credit or offset for ancillary services revenue.

• In addition, the CCA Parties support revisiting the PCIA methodology for energy storage resources when more data becomes available.

• Finally, the Commission should clarify that the delay on PCIA treatment until 2017.

\textsuperscript{15} “If PCIA treatment were implemented, the need for actual cost recovery will not occur, if at all, until at least 2017 or even later.” (D. 14-10-045 at 45.)
Respectfully submitted,

/s/ C.C. Song
C.C. Song
Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6018
Facsimile: (415) 459-8095
E-Mail: csong@mceCleanEnergy.org

/s/ Ty Tosdal
Ty Tosdal
of Counsel
Braun Blaising McLaughlin & Smith, P.C.
915 L Street, Suite 1270
Sacramento, California 95814
Telephone: (858) 952-4016
E-mail: ty@tosdallaw.com
Counsel for the City of Lancaster
and Sonoma Clean Power Authority

/s/ Steve Shupe
Steve Shupe
General Counsel
Sonoma Clean Power Authority
50 Santa Rosa Avenue, 5th Floor
Santa Rosa, CA 95404
Telephone: (707) 890-8485
Email: sshupe@sonomacleanpower.org

/s/ Howard Choy
Howard Choy, General Manager
County of Los Angeles Office of Sustainability
1100 North Eastern Avenue
Los Angeles, CA 90063-3200
Telephone: (323) 267-2006
Email: HChoy@isd.lacounty.gov

August 9, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Concerning Energy
Efficiency Rolling Portfolios, Policies, Programs,
Evaluation, and Related Issues.

Rulemaking 13-11-005
(Filed November 14, 2013)

NOTICE OF EX PARTE COMMUNICATION BY
MARIN CLEAN ENERGY

Catalina Murphy
Legal Assistant
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6014
Facsimile: (415) 459-8095
E-Mail: cmurphy@mceCleanEnergy.org

August 12, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA


NOTICE OF EX PARTE COMMUNICATION BY MARIN CLEAN ENERGY

Pursuant to Rule 8.4 of the Commission’s Rules of Practice and Procedure, Marin Clean Energy (“MCE”) hereby gives notice of the following ex parte communication. The communication was requested by the California Energy Commission (“CEC”) and occurred on August 12, 2016 at approximately 9:00am at the CEC offices. The communication was oral and written. Elizabeth Kelly, MCE General Counsel, served as a panelist to the Energy Commission Workshop Regarding Barriers of Low-Income and Disadvantaged Communities to Energy Efficiency and Renewable Energy (the “Workshop”). In connection with the Workshop, Ms. Kelly provided a summary of MCE’s energy efficiency, workforce and solar programs and a summary of MCE’s proposed low-income energy efficiency pilot before the CPUC which is included here as Attachment A.

Michael Colvin, Energy Advisor to Commissioner Sandoval, was in attendance for portions of the panel. The presentation lasted approximately two hours. There may have been other decision makers present via Webex but those participants are unknown.

During the presentation, panelist Elizabeth Kelly summarized MCE’s energy efficiency programs, workforce activities, solar offerings and low-income energy efficiency proposal (Low-Income Families and Tenants “LIFT” Pilot). Ms. Kelly’s summary was consistent with the written
one-page summary that was also distributed at the workshop and is attached here as Attachment A. Ms. Kelly addressed the barriers faced by low-income individuals for solar and energy efficiency, but did not advocate for any actions to be taken in pending CPUC proceedings.

Respectfully submitted,

/s/ Catalina Murphy

Catalina Murphy
Regulatory Assistant
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6014
Facsimile: (415) 459-8095
E-Mail: cmurphy@mceCleanEnergy.org

August 12, 2016
Attachment A
MCE’s Solutions to Barriers Faced by Low-Income and Disadvantaged Communities to Energy Efficiency and Renewable Energy

MCE provides our low-income and disadvantaged communities with a wide range of energy efficiency and solar offerings. In addition, our Low-Income Families and Tenants (LIFT) Program proposes increasing the number of services that we offer to these communities.

Existing MCE Energy Efficiency Offerings

MCE currently administers energy efficiency programs in four key areas: multifamily, single family, small commercial, and financing. Due to CPUC requirements, MCE’s current programs are limited to innovative offerings and areas not well served by other programs.

HIGHLIGHT: MCE’S MULTIFAMILY OFFERINGS

Since 2012, MCE has provided energy efficiency services to multifamily residences, which have included:

» Energy assessments
» Energy and water saving measures for tenant units
» Technical assistance

AS OF DECEMBER 31, 2015, MCE HAS:

<table>
<thead>
<tr>
<th>ACHIEVED</th>
<th>SAVED</th>
<th>AUDITED</th>
<th>DISTRIBUTED</th>
<th>PROVIDED</th>
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<td>389 MWH &amp; 53,277 THERMS</td>
<td>15 MILLION GALLONS OF WATER</td>
<td>627 MULTIFAMILY BUILDINGS</td>
<td>$427K+ IN REBATES</td>
<td>1,179 UNITS WITH ENERGY SAVING EQUIPMENT</td>
</tr>
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Existing MCE Renewable Energy Offerings

Available to Low-Income Customers

SOLAR INCENTIVES

MCE has allocated $80,000 in rebates for new residential solar installations and partners with Grid Alternatives to offer $800 rebates to low-income customers who install solar panels.

DISCOUNTED RATE

Low-income, CARE-eligible customers are able to receive the CARE discounted energy rate in full with MCE.

MORE RENEWABLES

All MCE customers receive 50% renewable energy by default. The following two MCE 100% renewable energy offerings are equally available to low-income customers and particularly benefit renters and others who are unable to place solar on their roofs.

» Deep Green: 100% renewable energy for an average premium of $5/month for residential customers.
» Local Sol: 100% locally produced solar energy at a rate that remains fixed for up to 20 years.
LOCAL JOBS WORKFORCE

2,400+ TOTAL CALIFORNIA JOBS
MCE’s commitment to community and the environment extends beyond supplying renewable power. MCE partners with local organizations and businesses to bring jobs home by investing in new community-based solar projects. MCE’s contracted power projects have supported more than 2,400 California jobs. MCE follows a Sustainable Workforce Policy, adopted by MCE’s Board of Directors.

SAN RAFAEL AIRPORT SOLAR PROJECT
As a model of business working to create local green jobs, Synapse Electric hired 20 workers, identified by the Marin City Community Development Corporation, a local job training program for low-income individuals, and CLP Resources, to install solar panels at the San Rafael Airport. The project was financed locally by the Bank of Marin and San Rafael businessman, Joe Shekou. San Rafael-based REP Energy designed the installation, REC Group manufactured 85% of the solar panels, and Power-One supplied all inverters. Both the solar panels and inverters were American-made.

ENERGY EFFICIENCY JOBS FOR LOW-INCOME & DISADVANTAGED WORKERS
MCE has contracted more than $200,000 with RichmondBUILD, the Marin City Community Development Corporation, and Rising Sun Energy Center to train and provide workers to help implement energy upgrades for our energy efficiency programs. MCE is joining with Richmond Works on a new solar installation that will employ local residents under the Richmond Local Hire Ordinance.

MCE’s Low-Income Families and Tenants (LIFT) Proposal

LIFT MULTIFAMILY COMPONENTS
- Expanding on existing energy efficiency programs for income-qualified customers to provide additional incentives and achieve deeper energy savings.
- Using an alternative enrollment processes to reduce concerns related to privacy and immigration status.
- Creating opportunities for switching from natural gas combustion appliances to heat pumps in order to support cleaner and more efficient energy use.
- Delivering On-Bill Repayment options for financing energy efficiency improvements.

LIFT SINGLE-FAMILY COMPONENTS
- Launching a mobile platform-based behavioral program that encourages low and no cost changes to reduce energy use and save money.
- Depositing funds equal to twice the energy saved to reinforce the existing savings; these funds can be spent on additional energy savings investments.

FOR MORE INFORMATION, PLEASE CONTACT:
Elizabeth Kelly
MCE General Counsel
ekelly@mceCleanEnergy.org | (415) 464-6022
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA


Rulemaking 13-11-005  
(Filed November 14, 2013)

REPLY COMMENTS OF MARIN CLEAN ENERGY ON PROPOSED DECISION PROVIDING GUIDANCE FOR INITIAL ENERGY EFFICIENCY ROLLING PORTFOLIO BUSINESS PLAN FILINGS

Michael Callahan-Dudley  
Regulatory Counsel  
MARIN CLEAN ENERGY  
1125 Tamalpais Avenue  
San Rafael, CA 94901  
Telephone: (415) 464-6045  
Facsimile: (415) 459-8095  
E-Mail: mcallahan-dudley@mceCleanEnergy.org

August 15, 2016
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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Concerning Energy
Efficiency Rolling Portfolios, Policies, Programs,
Evaluation, and Related Issues.

Rulemaking 13-11-005
(Filed November 14, 2013)

REPLY COMMENTS OF MARIN CLEAN ENERGY ON PROPOSED DECISION
PROVIDING GUIDANCE FOR INITIAL ENERGY EFFICIENCY ROLLING
PORTFOLIO BUSINESS PLAN FILINGS


I. INTRODUCTION

These reply comments focus on ensuring non-utility program administrators are adequately reflected in the rules for portfolio design, statewide activities, and the third party definition. These reply comments also recommend sufficient time to designate statewide leads.

II. THE COMMISSION SHOULD RECOGNIZE THAT NON-UTILITY PROGRAM ADMINISTRATORS CAN PERFORM A PORTFOLIO DESIGN ROLE

The Commission should recognize that the California Public Utilities Code places Community Choice Aggregators (“CCAs”), in addition to utilities, in a portfolio design role. As discussed in MCE’s Opening Comments, Public Utility Code Sections 366.2 and 381.1 respectively provide CCAs authority over electricity procurement for their customers and

Reply Comments of Marin Clean Energy on Proposed Decision
authority to deliver energy efficiency programs. The Commission should reject Pacific Gas and Electric Company’s (“PG&E”) proposed finding of fact that repeats language from the Proposed Decision stating only utilities can perform a portfolio design role. The Commission should also disregard the comment made by Nexant that “among all EE stakeholders, only utilities can fully integrate EE with other demand side management….” The Public Utilities Code provides a role for CCAs to design portfolios that integrate distributed energy resources, programmatic energy efficiency, and solicitations. As part of this role, MCE maintains an integrated resources plan for procurement, including programmatic activities. The Commission should avoid references to the contrary as they represent factual and legal errors.

III. THE COMMISSION SHOULD NOT SUBJECT NON-UTILITY PROGRAM ADMINISTRATORS TO THE THIRD PARTY DEFINITION

The Commission should retain the original language in the Proposed Decision that does not apply the third party definition to non-utility program administrators. Southern California Edison Company (“SCE”) and Southern California Gas Company (“SoCalGas”) called for the definition to apply to all administrators. SCE claims nothing on the record supports different treatment and cites Commission Rule 14.3(c). SoCalGas claims that differing rules among administrators is both not allowed and creates an untenable constraint to an IOU managing their own portfolio which SoCalGas seems to believe includes non-utility administrators. However, these utilities’ arguments are availing.

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1 MCE Opening Comments at p. 9-10.
2 PG&E Opening Comments at p. 6.
3 Nexant Opening Comments at p. 2-3.
4 Proposed Decision at p. 58.
5 SCE Opening Comments at p. 5; SoCalGas Opening Comments at p. 8.
6 SCE Opening Comments at p. 5.
7 SoCalGas Opening Comments at p. 8.

Reply Comments of Marin Clean Energy on Proposed Decision
The record does include comments from parties to the May 24, 2016 ruling on statewide and third party programs that suggest the rules should apply differently to non-utilities.\(^8\) Further, Rule 14.3(c) does not support SCE’s argument; it simply describes the appropriate contents for comments on a Proposed Decision. The Commission has made it clear that “there may be particular instances where it is inappropriate for a rule developed in the context of IOU administration to apply to a CCA.”\(^9\) SoCalGas’ own citation\(^10\) appears to refute its claim that IOU portfolios would be untenable to manage given differing rules among administrators because Ordering Paragraph 2 of D.12-11-015 clarifies that CCAs and RENs are individually responsible to the Commission for program results. The Commission should disregard these arguments and retain the language that does not apply the third party definition to non-utility program administrators.

**IV. THE COMMISSION SHOULD ENSURE THE STATEWIDE PROGRAM LIST IS CONSISTENT WITH THE DEFINITION OF STATEWIDE PROGRAMS AND RELEVANT COMMISSION DECISIONS**

The statewide program list in the Proposed Decision should be clarified to remove any downstream activities and reflect the competitive solicitation for statewide marketing, education and outreach (“ME&O”). Several parties noted that downstream activities appear on the list of subprograms that were referenced as upstream and midstream activities in the Proposed Decision.\(^11\) Similarly, the University of California (“UC”) noted that the record does not contain sufficient information or support for including the UC/California State University partnership as a statewide subprogram.\(^12\) The Commission should follow the recommendations of SDG&E and SoCalGas and simply remove the downstream activities from the list of statewide subprograms.

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\(^8\) MCE Reply Comments to May 24 Ruling at p. 4-5.
\(^9\) D.14-01-033 at p. 32.
\(^10\) SoCalGas Opening Comments, FN 15 at p. 8 (citing D.12-11-015, Ordering Paragraph 2).
\(^11\) San Diego Gas and Electric Company (“SDG&E”) at p. 9; SoCalGas at p. 9; PG&E at p. 2.
\(^12\) UC Opening Comments at p. 2.
subprograms,\textsuperscript{13} including the government partnerships. Similarly, the Commission should adequately reflect the competitive solicitation for the statewide ME&O administrator as ordered in D.16-03-029\textsuperscript{14} in the Proposed Decision.

V. **THE COMMISSION SHOULD TRUE-UP BUDGETS FOR STATEWIDE ACTIVITIES BOTH PROSPECTIVELY AND RETROSPECTIVELY**

The Commission should provide fairness to ratepayers throughout California and order a true-up of statewide budgets both prospectively and retrospectively. The Office of Ratepayer Advocates ("ORA") called for a revision to the Proposed Decision that would require the statewide budget to be trued-up retroactively based on actual customer participation in each utility service area.\textsuperscript{15} MCE agrees that ratepayers should be treated fairly and recommends the Commission adopt this proposal with the slight modification that participation be measured, not by utility service area, but by program administrator service area to ensure fairness for CCA and REN customers.

VI. **PROGRAM ADMINISTRATORS SHOULD BE AFFORDED ADEQUATE TIME TO PROPOSE LEAD STATEWIDE ADMINISTRATORS FOR STAKEHOLDER DISCUSSION**

The Commission should allow adequate time for program administrators to come to consensus on the designations for statewide program leads. ORA recommended the Commission require a Tier 1 advice letter specifying the lead administrators for the statewide activities within 30 days of the decision.\textsuperscript{16} MCE supports stakeholder and Energy Division input into the selection of the statewide lead administrators. However, 30 days following the decision is insufficient time and the Commission should provide additional time for the program administrators to develop a proposal. Once a proposal has been made, Energy Division and the

\textsuperscript{13} SDG&E at p. 9; SoCalGas at p. 9.  
\textsuperscript{14} See Center for Sustainable Energy ("CSE") Opening Comments at p. 2-6.  
\textsuperscript{15} ORA Opening Comments at p. 5.  
\textsuperscript{16} ORA Opening Comments at p. 6.
stakeholders should provide input including recommending changes to the proposal in the Coordinating Committee process.

VII. THE COMMISSION SHOULD NOT EXCLUDE NON-UTILITY PROGRAM ADMINISTRATORS FROM LEADERSHIP ON STATEWIDE ACTIVITIES

The Commission should provide an opportunity for non-utility program administrators to provide statewide leadership. PG&E calls for criteria for statewide lead administrators to include past program performance and capacity to manage statewide programs. SDG&E calls for lead administrators to already have the capacity to handle larger programs and the creation of an IOU-Energy Division Steering Committee for statewide programs. The Commission should avoid biased criteria that favor pre-existing large administrators. Non-utility administrators are able to scale their operations to support a lead role as needed. The Commission should create a statewide steering committee to help administer those activities, but should not limit it to an IOU-Energy Division committee. The Commission should ensure all program administrators have an opportunity to provide statewide leadership as members of the steering committee.

VIII. CONCLUSION

MCE thanks Assigned Commissioner Peterman and Administrative Law Judge Fitch for their thoughtful consideration of these reply comments on the Proposed Decision.

Respectfully submitted,

/s/ Michael Callahan-Dudley
Michael Callahan-Dudley
Regulatory Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6045
E-Mail: mcallahan-dudley@mceCleanEnergy.org

August 15, 2016

17 PG&E Opening Comments at p. 3.
18 SDG&E Opening Comments at p. 6-7
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocations, and Rate Design. 
(U 39 E)

Application 16-06-013 
(Filed June 30, 2016)

RESPONSE OF MARIN CLEAN ENERGY

Jeremy Waen 
Senior Regulatory Analyst 
MARIN CLEAN ENERGY 
1125 Tamalpais Avenue 
San Rafael, CA 94901 
Telephone: (415) 464-6027 
Facsimile: (415) 459-8095 
E-Mail: jwaen@mceCleanEnergy.org

August 15, 2016
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Application of Pacific Gas and Electric
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Costs, Revenue Allocations, and Rate Design.
(U 39 E) Application 16-06-013
(Filed June 30, 2016)

RESPONSE OF MARIN CLEAN ENERGY

I.  INTRODUCTION

In accordance with Rule 2.6 of the California Public Utilities Commission
(“Commission”) Rules of Practice and Procedure, Marin Clean Energy (“MCE”), submits the
following Response to the APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY
(U 39 E) TO REVISE ITS ELECTRIC MARGINAL COSTS, REVENUE ALLOCATIONS,
AND RATE DESIGN, dated June 30, 2016 (“Application”). Though this Application was
presented to the Commission on June 30th it was not formally noticed until July 15th. As such this
Response is timely filed within the standard 30-day period beginning from when the Application
was first noticed which ends on August 15th. Though MCE supports some elements proposed
within the Application, MCE has serious concerns regarding other elements of the Application
where Pacific Gas and Electric Company (“PG&E”) proposes several significant rate design
changes what would impact many customers served by Community Choice Aggregators
(“CCAs”) within PG&E’s service territory. Moreover many of these rate design proposals appear
to run counter to the Commission’s and the State’s efforts to reduce greenhouse gas (“GHG”)
emissions. PG&E, like MCE, should encourage rather than oppose ratepayers’ efforts to reduce
their GHG emissions footprints.
II. **BACKGROUND**

MCE is the first operational CCA within California. Currently MCE is one of three operational CCAs within PG&E’s service territory, the other two being Sonoma Clean Power Authority (“SCPA”) and Clean Power San Francisco (“CPSF”). MCE currently provides electricity generation services to approximately 170,000 customer accounts within seventeen distinct communities.¹ MCE is underway with enrolling seven additional communities which will add approximately 80,000 more customer accounts bringing the total number of customer accounts served by MCE Clean Energy to upwards of 250,000.² Customers within these additional communities will begin receiving MCE’s electricity service in September. MCE’s customers receive generation services from MCE while continuing to receive transmission, distribution, billing and other services from PG&E. Because of this split in electricity service provisions, CCA customers are commonly referred to as “unbundled” electricity customers.

Though a CCA’s governing board has jurisprudential ratesetting authority for the CCA program, when the Commission authorizes an Investor-Owned Utility (“IOU”) such as PG&E to alter key components of its rate structures, such as (i) definitions of summer and winter seasons, (ii) definitions of Time-Of-Use (“TOU”) periods, and (iii) aspects of both fixed and volumetric components of specific rate schedules, common practice among CCAs is to alter their own rates to mirror the changes being implemented on the IOU’s side. Such mirroring of IOU rate structures by CCAs is primarily done to minimize risks for customer confusion that may result in

¹ Communities currently participating in MCE’s CCA include: the City of Belvedere, City of Benicia, Town of Corte Madera, City of El Cerrito, Town of Fairfax, City of Larkspur, City of Mill Valley, County of Marin, County of Napa, City of Novato, City of Richmond, Town of Ross, Town of San Anselmo, City of San Pablo, City of San Rafael, City of Sausalito, Town of Tiburon.
² MCE is currently going through the steps of enrolling the incorporated cities and towns within Napa County along with the Cities of Lafayette and Walnut Creek, both of which are located in Contra Costa County.
individual customers opting-out of CCA service. As such, many aspects of the Application relating to rate design are of material interest to MCE.

Additionally marginal cost and revenue allocation elements of PG&E’s Application are also of concern to MCE. As part of the Phase 2 process for PG&E’s General Rate Case (“GRC”), Revenue Cycle Service Fees are assessed for unbundled customers that continue to require certain services from PG&E, such as billing systems services. For CCAs these “Service Fees” provide a very material impact on the operational margins for CCA service because some of these fees are assessed on a per customer per month basis. In this Application, PG&E is proposing to significantly reduce these “Service Fees” for CCA customers. MCE is supportive of this section of PG&E’s proposal though more time is still required for further discovery and analysis prior to MCE being able to take a formal position on this matter.

III. MATTERS OF SUPPORT

A. CCA Service Fees (PG&E-02 – Appendix C)

As stated prior, a key area of interest for MCE within Phase 2 of PG&E’s GRC is the assessment of the “Service Fees” that are assigned to unbundled customers participating in CCA programs. Appendix C of PG&E’s Testimony PG&E-2 titled “Revenue Cycle Service Fees” details PG&E’s proposal for the adjustments to these fees during the instant GRC cycle. Based upon its initial review, MCE believes PG&E is proposing to significantly reduce these service fees due to significant growth in the number of ratepayers participating in CCA since the last GRC cycle. MCE is pleased to see PG&E’s proposal to lower these fees; nevertheless, MCE still reserves the right for further discovery and analysis to determine whether the costs that drive these fees are being properly assigned to CCA customers in the first place. MCE plans to explore
this area further, yet remains hopeful that it can formally support these service fee revisions as presented by PG&E.

**IV. MATTERS OF CONCERN**

A. Residential Rate Design (*PG&E-01 – Chapter 4*)

Though much of the significant changes to residential rate design are already occurring within Rulemaking 12-06-013, PG&E is seeking additional changes to its residential rate schedules through this Application as well. Among other changes sought, PG&E proposes (i) the creation of an optional demand charge based residential rate (“E-DMD”) and (ii) a significant redesign of its Electric Vehicle (“EV”) rate design. MCE has concerns with both.

1. **New Optional Demand Charge E-DMD Rate Design**

   First off, PG&E’s proposal to create a residential rate that involves demand charges is concerning because residential customers typically lack the knowledge and expertise to understand their risk exposure when participating in such complex rate schedules. With that said, MCE commends PG&E’s desire to create a new optional rate “to incent the installation of battery storage technology to allow solar electricity to be stored when it is plentiful and used when it is not.”

   MCE has also been exploring ways to encourage residential level onsite energy storage through rates and understands the complexity of the matter. Nevertheless MCE remains concerned with this rate proposal because it remains unclear as to whether unbundled CCA customers would be able to participate in such a rate. MCE plans to explore the matter of CCA customer participation within the E-DMD rate schedule further during the course of this proceeding.

1. **Electric Vehicle (EV) Rate Design**

   Similar to changes that are occurring in other residential rate schedules, PG&E is proposing to merge its existing EV rate schedules into a single new schedule that includes significant changes to the TOU seasonality, TOU periods, and rates applicable to electricity
usage under this schedule. By shortening the summer period AND shifting the partial-peak and off-peak hours AND reducing peak rates while increasing partial-peak and off-peak rates, PG&E’s proposal will make the EV rate significantly less appealing for EV owners and significantly more challenging to utilize in a low-cost manner.

EV electricity usage is influenced not only by price signals within rates but also by the scheduling constraints of the EV owners’ daily routines. When the pricing signals and the usage schedules overlap well, this provides an incentive for EV charging, but when these two factors do not coincide they create a disincentive instead. For example by pushing the start of off-peak period on the EV rates back to 1 AM, as PG&E proposes, EV owners would typically have anywhere from 5 to 7 hours of opportunity to charge their vehicle at off-peak rates before having to leave home and start their daily commute. While 5 to 7 hours of charging time may sound like a lot, a typical EV with approximately 80-90 miles of maximum range can take approximately 20 hours to fully charge depending upon factors such as (i) the onsite charging capabilities (i.e. level 1 vs. level 2), (ii) the overall size of the battery pack, (iii) the level of discharge in the battery pack when the charging starts, and (iv) the ambient temperature in which the car is charging.

Simply put PG&E’s requested changes to the residential EV rate schedule must be weighed against the practicality of the rate schedule for the end user. If the two do not overlap well, this EV rate would discourage EV adoption and usage rather than encourage it. MCE believes that PG&E, the Commission, and the State of California should all be operating in lock-step to continue encouraging the adoption and usage of EVs for climate, health, and local economic reasons. Failure to do so would be a reversal in policy direction and a significant step

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3 Such as a Chevrolet Spark EV or Nissan Leaf.
back from solving Climate Change. As such MCE questions the reasonableness of PG&E’s proposed changes to its residential EV rate schedule and recommends for PG&E to focus its efforts towards creating a new optional commercial EV rate schedule that would incentivize daytime workplace EV charging.

B. Small Light and Power Rate Design *(PG&E-01 – Chapter 5)*

PG&E is proposing significant changes to its non-residential rate schedules as well. One such change is its proposal to reduce the summer peak rate for the A-6 rate schedule from $0.55/kWh to $0.29/kWh while increasing partial-peak and off-peak rates by only $0.01/kWh. A 47% reduction to the peak rate component of a TOU rate that is heavily depended upon for the viability of non-residential distributed solar electricity generation is very concerning to MCE. This proposed rate change, similar to PG&E’s EV rate proposal, would create a strong signal against ratepayers attempts to lower their GHG emissions through the adoption of GHG-free distributed energy resources. MCE remains very concerned with this proposed change to the A-6 rate and MCE’s concern is made only stronger when considering this rate change alongside the other non-residential TOU rate changes that PG&E proposes later within the Application.

C. Economic Development Rates *(PG&E-01 – Chapter 11)*

PG&E is also proposing to extend its offering of both “Standard and Enhanced” Economic Development Rate (“EDR”) tariffs to December 31, 2020. MCE was not supportive of the last EDR tariff extension and revision request made by PG&E within Application 12-03-001, and MCE remains oppositional to the EDR tariff. MCE does not believe there is adequate evidence presented by PG&E for both *why* the EDR tariff continues to be needed and *what* economic benefit can be clearly and directly attributed to the existence of the EDR tariff. What is certain about the EDR tariff is that it creates a subsidy between ratepayers. MCE questions whether the subsidy created by the EDR tariff is both reasonable and necessary given the
significant changes in the State’s economic conditions and policy objectives since this matter was last considered before the Commission. MCE is not supportive of extending the EDR tariff.

D. Optimal Non-Residential TOU Period Analysis (PG&E-02 – Chapter 12)

Finally, and likely most concerning, PG&E proposes to drastically change the TOU seasons, TOU periods, and week day vs. weekend applicability of TOU factors for ALL non-residential TOU rate schedules. While TOU rates are gradually being adjusted on the Residential side by the Commission, such transitions are already proving to be very challenging for the Commission and IOUs to implement over the multi-year glide path established for adopting these changes. PG&E’s proposal to change the non-residential rate schedules in a similar manner but over a much quicker timeframe will only further strain the Commission and PG&E’s resources while creating further risk for customer confusion. Such customer confusion creates increased risk for customers to opt-out of CCA service due to frustration with changing rates and billing amounts. As such MCE is not supportive of these proposed changes to non-residential TOU rate periods.

Furthermore, such dramatic changes to non-residential TOU rates will further discourage localized efforts to reduce GHG emissions through the adoption and usage of GHG-free distributed energy resources. For example rooftop solar installed on non-residential facilities will suddenly have a much longer payback period because 1) the summer season will be two months shorter, 2) the peak periods will have shifted from “noon to 6 PM” to “5 PM to 10 PM,” and 3) if they happen to be on the A-6 rate schedule their peak rate will be decreased by 47% as discussed in an earlier section. Such changes will undoubtedly impact local efforts by schools, municipal governments, and businesses to lower their GHG footprint through generating onsite GHG-free electricity. Here too the Commission must weigh and balance PG&E’s rate proposals against the State’s goals to reduce GHG emissions and address Climate Change. As such MCE does not
support PG&E’s proposal to significantly alter the TOU factors for all of its non-residential rate schedules.

V. RULE 2.6(D) COMPLIANCE

A. Proposed Category

The instant proceeding is appropriately categorized at “ratesetting.”

B. Need for Hearing

Due to the complex nature of the marginal cost, revenue allocation, and rate design matters presented by PG&E within this Application and the additional complexity of evaluating the factual impacts of these proposals on CCAs and CCA customers, MCE believes evidentiary hearings will be necessary. The factual record will need to be explored in detail to determine the accuracy and reasonableness of PG&E’s numerous proposals.

C. Issues to Be Considered

If the Commission continues to consider PG&E’s proposal as currently presented, then the Commission should closely evaluate and weigh the appropriateness of these numerous requested changes against State mandate to reduce statewide GHG emissions and facilitate the formation and operational success of CCA programs.

D. Proposed Schedule

No revisions to the proposed schedule are presented at this time.
VI. SERVICE LIST

Filings and other communications to this proceeding should be served on the following individuals:

MCE Regulatory  
MARIN CLEAN ENERGY  
1125 Tamalpais Avenue  
San Rafael, CA  94901  
Telephone: (415) 464-6010  
Facsimile: (415) 459-8095  
E-Mail: regulatory@mceCleanEnergy.org

Jeremy Waen  
Senior Regulatory Analyst  
MARIN CLEAN ENERGY  
1125 Tamalpais Avenue  
San Rafael, CA  94901  
Telephone: (415) 464-6027  
Facsimile: (415) 459-8095  
E-Mail: jwaen@mceCleanEnergy.org

VII. CONCLUSION

MCE thanks Commissioner Carla Peterman and Assigned Administrative Law Judge Jeanne McKinney for their thoughtful consideration of this response and the issues detailed herein.

Respectfully submitted,

/s/ Jeremy Waen

Jeremy Waen  
Senior Regulatory Analyst  
MARIN CLEAN ENERGY  
1125 Tamalpais Avenue  
San Rafael, CA  94901  
Telephone: (415) 464-6027  
Facsimile: (415) 459-8095  
E-Mail: jwaen@mceCleanEnergy.org

August 15, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Contracts Resulting From Its 2014 Energy Storage Request for Offers (ES RFO).

Application 15-12-003
(Filed December 1, 2015)

CONSOLIDATED


Application 15-12-004
(Filed December 1, 2015)

REPLY COMMENTS OF MARIN CLEAN ENERGY, SONOMA CLEAN POWER, THE CITY OF LANCASTER AND THE COUNTY OF LOS ANGELES ON THE PROPOSED DECISION

C.C. Song
Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6018
Facsimile: (415) 459-8095
E-Mail: c.song@mceCleanEnergy.org

Ty Tosdal
of Counsel
Braun Blaising McLaughlin & Smith, P.C.
915 L Street, Suite 1270
Sacramento, California 95814
Telephone: (858) 952-4016
E-mail: ty@tosdallaw.com
Counsel for the City of Lancaster and Sonoma Clean Power

Steve Shupe
General Counsel
Sonoma Clean Power
50 Santa Rosa Avenue, 5th Floor
Santa Rosa, CA 95404
Telephone: (707) 890-8485
Email: sshupe@sonomacleanpower.org

Howard Choy, General Manager
County of Los Angeles Office of Sustainability
1100 North Eastern Avenue
Los Angeles, CA 90063-3200
Telephone: (323) 267-2006
Email: HChoy@isd.lacounty.gov

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Contracts Resulting From Its 2014 Energy Storage Request for Offers (ES RFO).

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Application 15-12-004
(Filed December 1, 2015)

REPLY COMMENTS OF MARIN CLEAN ENERGY, SONOMA CLEAN POWER, THE CITY OF LANCASTER AND THE COUNTY OF LOS ANGELES ON THE PROPOSED DECISION

Pursuant to Rule 14.3 of the California Public Utilities Commission (“Commission”) Rules of Practice and Procedure, Marin Clean Energy (“MCE”), Sonoma Clean Power (“SCP”), the City of Lancaster (“Lancaster”), and the County of Los Angeles (“LA County”) (collectively, the “CCA Parties”) hereby submit these reply comments on the Proposed Decision (“PD”) in this proceeding issued on July 20, 2016.

The CCA Parties are deeply concerned with Pacific Gas & Electric Company’s (“PG&E”) treatment of charging costs in its Energy Storage Agreements (“ESAs”) and with Southern California Edison Company’s (“SCE”) treatment of charging costs generally. The positions that PG&E and SCE have taken on charging costs run counter to the guidance provided by the Commission and would inevitably result in double payments by unbundled ratepayers. The CCA Parties urge the Commission to affirm the position taken in the PD and
direct PG&E to exclude the charging costs from its Power Charge Indifference Adjustment (“PCIA”) calculation.

I. PG&E SHOULD BE DIRECTED TO EXCLUDE THE CHARGING COSTS FROM THE PCIA

The Commission should direct PG&E to exclude the charging costs in its ESAs from the PCIA to prevent double payments by unbundled customers. As stated in the PD, the charging cost can potentially be reflected twice, once as a storage cost, and again as a cost of generation.¹ As PG&E’s ESAs are currently structured, the charging costs would be reflected both as a storage cost and a generation cost. Therefore, PG&E should exclude the charging costs from the PCIA.

PG&E did not provide sufficient evidence in its comments on PD that the charging costs in its ESAs are not reflected as part of the cost of generation resource procurement. In its comments on PD, PG&E claimed that “the charging energy for a storage resource comes from the California Independent System Operator (CAISO) wholesale energy markets,” and that ESA counterparty will not pay PG&E for the charging costs.² It is unclear that PG&E will always use spot market purchases to supply the energy for storage resources. Since these ESAs are part of PG&E’s energy obligation, the facility charging needs can be fulfilled by a variety of PG&E’s standard practices, including its long term procurement contracts. Unless PG&E can provide evidence that these facilities will solely rely on sport market energy purchases, charging costs should be excluded from PCIA to avoid double counting.

Additionally, PG&E is entitled to all the ancillary services associated with the facility,³ and can generate revenue to offset the charging costs. Since an energy storage resource has the

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¹ PD at page 23.
² Comments of PG&E at page 8.
³ PG&E Exhibit 1 at page 3-1.
unique ability to discharge energy when the market price is high, and store energy when the market price is not as favorable, the facility itself should not result in incremental load. This ability will likely lead to instances where the charging costs can be offset by the revenue. Therefore, the Commission should either direct PG&E to exclude the charging costs from the PCIA, or provide a PCIA offset to ensure that unbundled customers will receive some of the benefits for which they have paid. This is consistent with existing statute, which prevents departing load customers from being subjected to cost increases resulting from resources that were not incurred on their behalf.4

II. SCE SHOULD ALSO BE INSTRUCTED TO EXCLUDE CHARGING COSTS FOR ALL ENERGY STORAGE PROJECTS WHOSE COSTS ARE RECOVERED THROUGH THE PCIA

SCE attempts to reinterpret the Commission’s guidance on charging costs by stating that it only applies to “hybrid” projects. The Commission clearly states in the PD that the “Joint IOU Protocol should be modified to remove the costs associated with charging the storage resource from the Indifference Amount calculation and instead should just reflect the purchase costs … unless the charging power costs have not already been reflected in utility generation costs.”5 To include charging costs in the PCIA calculation would amount to double counting and burden unbundled customers.6 This rule should be interpreted in a straightforward manner to exclude the recovery of charging costs from the PCIA for energy storage projects. There may be exceptions, and to the extent charging costs are not captured in generation costs that are already passed on to customers, the Commission can evaluate them on a case by case basis.

4 Public Utilities Code Section 365.2.
5 PD at page 23.
6 PD at page 23.
SCE ignores the bright line rule established in the PD. While vague on details, SCE argues that the Commission is not actually modifying the Joint IOU Protocol, and that the exclusion of charging costs only applies to projects where storage is paired with generation.\(^7\) The implication of SCE’s argument is that charging costs should otherwise be included in the PCIA. The plain language of the PD, however, does not support SCE’s interpretation.

The Commission’s direction in the PD explicitly modifies the Joint IOU Protocol by excluding charging costs. The Joint IOU Protocol proposed to include the “forecasted cost of “fuel” (electricity purchased to charge resources) in the Total Portfolio Costs component of the Total Portfolio Indifference Calculation for each vintage year beginning in the year the resource commitment is made.”\(^8\) The Commission’s direction the PD is directly contrary to the Joint IOU Protocol in that regard. The Commission should retain the modification language, otherwise SCE and the other IOUs may insist in future applications that no modification has been made.

Furthermore, the issue of double counting, as it relates to the PCIA, is not limited to hybrid projects, as SCE suggests. As the Commission recognizes in the PD, double counting occurs when an IOU recovers the charging costs of an energy storage resource and recovers those same costs through generation resources. That is possible whether a project is “hybrid” or not. Accordingly, SCE and the other IOUs should be directed to exclude charging costs from the PCIA calculation as the Commission has directed.

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\(^7\) “SCE agrees that this scenario can exist when an energy storage device is integrated with a solar facility (i.e. a “hybrid”), for example, where the solar facility’s generation charges the storage device.” Comments of SCE at page 3.

\(^8\) Joint IOU Protocol at page 1.
III. CONCLUSION

The CCA Parties thank Commissioner Peterman and Assigned Administrative Law Judge Cooke for their thoughtful consideration of these Reply Comments on the PD.

Respectfully submitted,

/s/ C.C. Song

C.C. Song
Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6018
Facsimile: (415) 459-8095
E-Mail: csong@mceCleanEnergy.org

/s/ Ty Tosdal

Ty Tosdal
of Counsel
Braun Blaising McLaughlin & Smith, P.C.
915 L Street, Suite 1270
Sacramento, California 95814
Telephone: (858) 952-4016
E-mail: ty@tosdallaw.com
Counsel for the City of Lancaster and Sonoma Clean Power

/s/ Steve Shupe

Steve Shupe
General Counsel
Sonoma Clean Power
50 Santa Rosa Avenue, 5th Floor
Santa Rosa, CA 95404
Telephone: (707) 890-8485
Email: sshupe@sonomacleanpower.org

/s/ Howard Choy

Howard Choy, General Manager
County of Los Angeles Office of Sustainability
1100 North Eastern Avenue
Los Angeles, CA 90063-3200
Telephone: (323) 267-2006
Email: HChoy@isd.lacounty.gov

August 15, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company
(U 39-E) for Authorization to Procure Energy
Storage Systems During the 2016-2017 Biennial
Procurement Period Pursuant to Decision 13-10-
040.  

Application of Southern California Edison
Company (U 338-E) for Approval of Its 2016
Energy Storage Procurement Plan.  

Application of San Diego Gas & Electric Company
(U 902 M) for Approval of Energy Storage
Procurement Framework and Program As Required
by Decision 13-10-040.  

Application 16-03-001  
(Filed March 1, 2016)  

Application 16-03-002  
(Filed March 1, 2016)  

Application 16-03-003  
(Filed March 1, 2016)

COMMENTS OF COMMUNITY CHOICE AGGREGATION PARTIES
ON THE PROPOSED DECISION APPROVING STORAGE PROCUREMENT
FRAMEWORK FOR THE 2016 BIENNIAL PROCUREMENT PERIOD

C.C. Song  
Regulatory Analyst  
MARIN CLEAN ENERGY  
1125 Tamalpais Avenue  
San Rafael, CA  94901  
Telephone: (415) 464-6018  
Facsimile: (415) 459-8095  
E-Mail: csong@mceCleanEnergy.org

Ty Tosdal  
Of Counsel  
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.  
915 L Street, Suite 1480  
Sacramento, California 95814  
Telephone: (916) 682-9702  
FAX: (916) 563-8855  
E-mail: ty@tosdallaw.com

August 18, 2016  
Counsel for Sonoma County Power Authority and the City of Lancaster
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BEFORE THE PUBLIC UTILITIES COMMISSION
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Application of Pacific Gas and Electric Company (U 39-E) for Authorization to Procure Energy Storage Systems During the 2016-2017 Biennial Procurement Period Pursuant to Decision 13-10-040. Application 16-03-001 (Filed March 1, 2016)

Application of Southern California Edison Company (U 338-E) for Approval of Its 2016 Energy Storage Procurement Plan. Application 16-03-002 (Filed March 1, 2016)

Application of San Diego Gas & Electric Company (U 902 M) for Approval of Energy Storage Procurement Framework and Program As Required by Decision 13-10-040. Application 16-03-003 (Filed March 1, 2016)

COMMENTS OF COMMUNITY CHOICE AGGREGATION PARTIES ON THE PROPOSED DECISION APPROVING STORAGE PROCUREMENT FRAMEWORK FOR THE 2016 BIENNIAL PROCUREMENT PERIOD

Pursuant to Rule 14.3 of the Rules of Practice and Procedure of the Public Utilities Commission of the State of California ("Commission"), Marin Clean Energy ("MCE"), Sonoma Clean Power ("SCP"), and the City of Lancaster ("Lancaster") hereby jointly file comments as the Community Choice Aggregation ("CCA") Parties on the Proposed Decision Approving Storage Procurement Framework for the 2016 Biennial Procurement Period ("PD"). The comments of the CCA Parties focus on the proposed counting methodology for Self-Generation Incentive Program ("SGIP") funded storage projects.
I. THE PROPOSED SGIP-FUNDED PROJECTS ACCOUNTING METHOD DOES NOT ADEQUATELY CONSIDER POTENTIAL CHANGES IN CCA SERVICE AREAS

The CCA Parties appreciate the Commission’s effort to specify the accounting and verification for SGIP-funded projects. However, the proposed method would not adequately assist CCAs in accurately accounting for SGIP-funded projects in their service areas. If a CCA expands its service area, or if a new CCA forms after the applications and Advice Letter have already been filed, such CCA would not be able to track SGIP-funded energy installations in its service area.

Because the biennial procurement application cycles and Advice Letters do not have the flexibility to reflect the change of the equipment host’s generation service provider, CCAs’ ability to meet their energy storage procurement requirements would be impacted. Under present reporting requirements, there may be a significant lag time between the project coming online and being eligible to count toward CCA storage targets. The delay would put CCA programs at a disadvantage in knowing the present status of their compliance with the targets and unnecessarily complicate procurement efforts.

The CCA Parties provide clarifications on its joint accounting proposal with the Alliance for Retail Energy Markets (“AReM”), and the Direct Access Customer Coalition (“DACC”). The CCA Parties urge the Commission to update the format of the existing SGIP Weekly Projects report to reflect vital information that can assist the CCAs in accounting for SGIP-funded projects.

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1 PD at page 12. The Commission directs “the utilities to provide a breakout of SGIP-funded energy storage installations by bundled, CCA, and Direct Access customers as part of future biennial procurement contract approval applications. In instances where a utility does not submit an application for approval of its storage contracts (for example, when energy storage contracts are being procured through a Local Capacity Requirement RFO), the utility should file a Tier 1 Advice Letter containing the breakout of SGIP-funded installations, served on parties to the current energy storage rulemaking (R.15-03-011), or any successor to the rulemaking.”
II. THE COMMISSION SHOULD DIRECT THE ENERGY DIVISION TO UPDATE THE EXISTING SGIP DATABASE TO REFLECT THE APPROPRIATE LSES

The CCA Parties respectfully request the Commission to direct the Energy Division and the SGIP Program Administrators to modify the existing SGIP Weekly Projects report as described below. The modifications should provide crucial information to help all LSEs accurately account for SGIP-funded projects in their service areas that are online after D.16-01-032.²

The Commission’s website currently publishes an SGIP Weekly Projects report, which contains information on each SGIP project’s equipment type, rated capacity, location, electric utility, and interconnection date.³ To help all LSEs account for SGIP-funded projects procured by their customers, the SGIP Program Administrators should update the electric utility column to precisely indicate the equipment host’s generation service provider. Alternatively, a column can be added to indicate whether the customer is served by an IOU, a CCA, or an Energy Service Provider (“ESP”). Separately, a column should be added to indicate when the project is online, so the LSEs know when to count the credit toward their procurement targets.

This approach provides CCAs and ESPs the ability to regularly track whether there are newly online SGIP-funded projects in their service areas and allows existing CCAs to adjustment their storage procurement plans accordingly. If the Commission finds the frequency of weekly updates too onerous, monthly updates can still assist CCAs in accounting for SGIP-funded projects. As long as this report is updated regularly, new CCAs will also be able to identify online SGIP-funded storage projects without having to rely on the biennial application cycles.

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² Id.
III. CONCLUSION

The CCA Parties thank the Commission, Commissioner Peterman, and Administrative Law Judge Cooke for their attention to these comments on the PD.

Respectfully Submitted,

/s/ C.C. Song
C.C. Song
Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6018
Facsimile: (415) 459-8095
E-Mail: csong@mceCleanEnergy.org

/s/ Ty Tosdal
Ty Tosdal
Scott Blaising
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, California 95814
Telephone: (916) 682-9702
FAX: (916) 563-8855
E-mail: blaising@braunlegal.com

Counsel for Sonoma Clean Power Authority and the City of Lancaster

August 18, 2016
Appendix A

The CCA Parties’ Proposed Changes to Ordering Paragraphs of the Proposed Decision

Conclusions of Law

5. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must provide a breakout of Self-Generation Incentive Program-funded energy storage installations by bundled, Community Choice Aggregators, and Direct Access customers as part of future biennial procurement contract approval applications. If a utility does not submit a storage specific application for approval of its storage contracts, the utility must file a Tier 1 Advice Letter containing the breakout of Self-Generation Incentive Program-funded installations, and serve it on parties to the energy storage rulemaking (Rulemaking15-03-011), or its successor in the SGIP Weekly Projects report.
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Create a
Consistent Regulatory Framework for the
Guidance, Planning, and Evaluation of Integrated
Distributed Energy Resources.  

Rulemaking 14-10-003
(Filed October 2, 2014)

OPENING COMMENTS OF MARIN CLEAN ENERGY
ON THE COMPETITIVE SOLICITATION FRAMEWORK WORKING GROUP
FINAL REPORT

C.C. Song
Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6018
Facsimile: (415) 459-8095
E-Mail: csong@mceCleanEnergy.org

August 22, 2016
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OPENING COMMENTS OF MARIN CLEAN ENERGY
ON THE COMPETITIVE SOLICITATION FRAMEWORK WORKING GROUP
FINAL REPORT

I. INTRODUCTION


MCE appreciates the coordination committee’s hard work. MCE’s comments primarily focus on the role of non-Investor Owned Utility (“IOU”) Load Serving Entities (“LSEs”) in providing Distributed Energy Resource (“DER”) services in the competitive solicitation framework. MCE also offers limited comments on incrementality and double-counting issues.
II. **TREATMENT OF NON-IOU LSES**

A. **CCAs Should Be Able to Bid into the IOUs’ Distribution Service Competitive Solicitation Process**

MCE agrees with the recommendation that CCAs should be “eligible to provide non-wire DER services as other market participants.”\(^1\) As such, CCAs would be subject to the same eligibility requirements as other market participants, including demonstrating their ability to deliver DER products and services. If awarded the bids, CCAs would receive the same sets of data that are available to market participants.

As implementation issues arise, MCE supports the recommendation to overcome these obstacles by building off successful negotiations on a case-by-case basis.\(^2\) The IOUs and CCAs have developed procedures to address current implementation challenges with the participation of the CPUC to ensure their customers will continue to have seamless experiences with their LSEs and distribution service providers. MCE also looks forward to working with Pacific Gas and Electric Company (“PG&E”) in implementing its Commission-approved Electric Vehicles (“EV”) program, which will allow IOUs and CCAs to identify collaboration opportunities and implementation challenges.

B. **Several Claims about CCAs in Appendix 7 Are Erroneous and Should Not Be Assigned Weight in Commission’s Decision**

There are several erroneous claims made about CCAs in the report, and the Commission should not assign these claims any weight in its decision to accept the report into its record. Some of the issues raised in Appendix 7 on page 90, such as the CCA Code of Conduct, should not be re-litigated as the Commission has already closed the proceeding. Several issues are clearly out of

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\(^1\) Final Report at page 56.

\(^2\) Final Report at page 56.
the scope of competitive distribution deferral solicitations, and should be addressed in other proceedings. Additionally, if CCAs are allowed to bid into the solicitations, CCAs should not be subject to any special treatments that are not applicable to other market participants. Due to these reasons, Appendix 7 on page 90 should not become part of the Commission’s official record.

First, the IDER proceeding is not the right venue to re-litigate the application and interpretation of the CCA Code of Conduct. The CCA Code of Conduct does not prevent the IOUs from providing DER services to customers in CCA service areas, as long as the marketing campaign does not affect CCA services.3 Once the IOUs have selected winners to deploy DERs for distribution deferral purposes, these programs are expected to follow the rules defined in Decision ("D.") 12-12-036.4

Second, some of the issues raised are out of the scope of the current proceeding, and should be addressed in appropriate proceedings. Issues related to load forecasting, program design, and data streamlining are being addressed in the Distribution Resources Planning ("DRP") proceeding. Challenges related to creating and implementing Integrated Resources Plans ("IRP") should be raised in the IRP proceeding. These issues are clearly beyond the scope of the Working Group, which is developing fundamental rules that guide competitive solicitations for distribution deferral products and services.5

Lastly, as market participants, CCAs should be subject to the same eligibility requirements as all market participants. This would include submitting pro forma contracts, developing financially sound bids to aggregate resources to meet reliability needs, and conducting customer

3 Code of Conduct and Expedited Complaint Procedure. Rules 8.1(9), 8.1(18), and 8.1(19).
4 D.12-12-036, Attachment 1.
5 Administrative Law Judge’s Ruling Establishing a Working Group to Develop the Competitive Solicitation Framework ("Ruling") at pages 2-3.
outreach to maximize participation and minimize confusion. Without meeting the needs of these solicitations, CCAs are subject to penalties and fines, just like other market participants. The Commission should not attempt to create a separate set of rules for CCAs to bid into these solicitations, which would have anti-competitive impacts.

Because the issues raised in Appendix 7 on page 90 are out of scope, erroneous, or confusing, the Commission should not accept this part of the report into the official record.

**C. The “Enhanced” Proposal 2 Violates Existing Statute and Should Be Rejected**

The proposal to form an umbrella entity between IOUs and CCAs is deeply flawed, and should not be assigned weight by the Commission. The proposal would undermine CCAs’ procurement autonomy, and should be rejected by the Commission.

The proposal asks the Commission to authorize CCAs and IOUs to form a partnership that would streamline the implementation of California environmental policies, not limited to IRP and achieving Energy Efficiency (“EE”) goals. The proposal states that if CCAs choose not to form partnerships with the IOUs and their “report metrics to show performance relating to state objectives including DER proliferation in CCA territories to be sub-optimal in ex-post evaluations, the Commission should consider mandating the formation of a partnership in such cases.”

The proposal undermines CCAs’ procurement autonomy as enabled by Section 366.2(a)(5) of the Public Utilities Code. CCAs have the independent authority to develop procurement plans that are in accordance to state policy goals, and are subject to penalties if such goals are not met.

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6 Final Report at page 57.
7 Final Report at page 58.
8 “A community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator’s customers, except where other generation procurement arrangements are expressly authorized by statute.”
The Commission does not have the jurisdictional authority to force CCAs into such partnerships, and thus should reject the proposal from the official record.

III. THE GUIDING PRINCIPLES FOR IDENTIFYING INCREMENTALITY NEED TO BE FURTHER DEFINED

MCE recommends that the Commission provide additional time and formal commenting opportunities in a future phase of the IDER proceeding to allow parties to form concrete proposals that can identify incrementality. While the Final Report offered basic principles and frameworks to solve double-counting and payment problems, it did not provide concrete definitions and solutions. Several elements of these principles and frameworks need greater clarity, and warrant further discussions to develop actual methodologies that can effectively resolve double-counting issues.

One of the guiding principles recommended by the Final Report is establishing “reasonable planning assumptions.”\(^9\) The Final Report does not define what reasonable planning assumptions would be, and these may change if the state adopts new policy goals. Although these assumptions would be informed by the DER growth scenarios and forecasts developed in Track 3 of the DRP proceeding, it is unclear how the growth scenario analysis developed in the DRP proceeding would lead to concrete reasonable planning assumptions for competitive solicitations.

To reduce market uncertainty and spur DER adoption to meet reliability needs, the Commission should provide at least another 6 to 8 weeks for parties to revisit the guiding principles and develop concrete proposals. This phase can occur after Track 3 of the DRP proceeding has reached significant milestones in developing DER growth scenarios and forecast methodology.


MCE Comments on Final Cost-Effectiveness Working Group Report
IV. CONCLUSION

MCE thanks Assigned Commissioner Florio and Assigned Administrative Law Judge Hymes for the opportunity to provide these comments on the Final Report.

Respectfully submitted,

/s/ C.C. Song

C.C. Song
Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6018
Facsimile: (415) 459-8095
E-Mail: csong@mceCleanEnergy.org

August 22, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA


Rulemaking 14-08-013
(Filed August 14, 2014)

And Related Matters.

Application 15-07-002
Application 15-07-003
Application 15-07-006

(NOT CONSOLIDATED)

In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.

Application 15-07-005
(Filed July 1, 2015)

And Related Matters.

Application No. 15-07-007
Application No. 15-07-008

COMMENTS OF MARIN CLEAN ENERGY
ON THE ASSIGNED COMMISSIONER’S RULING ON TRACK 3 ISSUES

C.C. Song
Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6018
Facsimile: (415) 459-8095
E-Mail: csong@mceCleanEnergy.org

August 22, 2016
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III. Conclusion .............................................................................................................................. 3
COMMENTS OF MARIN CLEAN ENERGY
ON THE ASSIGNED COMMISSIONER’S RULING ON TRACK 3 ISSUES

I. INTRODUCTION

Pursuant to the directions set forth in the Assigned Commissioner’s Ruling on Track 3 Issues (“Ruling”) issued on August 9, 2016, Marin Clean Energy (“MCE”) respectfully submits the following comments on the Ruling. MCE’s comments respond only to question 1 in the Ruling.

MCE was the first operational Community Choice Aggregator (“CCA”) in California, and its mission is to address climate change by reducing energy related greenhouse gas emissions. MCE currently serves approximately 175,000 customer accounts in Marin County, unincorporated
Napa County, and the cities of Richmond, San Pablo, El Cerrito, and Benicia. MCE will begin serving cities and towns of Napa County and cities of Walnut Creek and Lafayette in Contra Costa County in 2016. The inclusion of these communities will increase MCE’s total customer accounts to approximately 255,000.

As a Load-Serving Entity ("LSE"), MCE has several local programs aimed at increasing the adoption of Distributed Energy Resources ("DER"). MCE currently annually administers $1.2 million in ratepayer funded energy efficiency (EE) programs, focusing on hard to reach customer segments. MCE supports local renewable energy development through its Feed-in Tariff ("FIT") program, which purchases energy from 2 MW of local rooftop solar, with another 10 MW currently under construction. MCE has collaborated with many third-party technology providers to administer pilot projects to help facilitate market deployment. These projects include Electric Vehicles ("EV"), Demand Response ("DR"), and Energy Storage ("ES"). Besides achieving the goal of reducing energy related greenhouse gas emissions, MCE also has an interest in deploying DERs in a manner that would reduce or defer grid upgrade needs to facilitate the integration of local renewable energy and to benefit ratepayers.

II. RESPONSE OF MCE

A. Question 1: Should items 3, 8, 9, 15, 18, 20, 21, and 22 from the list in the Scoping Memo be grouped into the three sub-tracks described above? Should any other items from the Scoping Memo list be included in one of the three sub-tracks?

MCE encourages the Commission to include the role of CCAs in sub-track 1, which addresses topics related to Distributed Energy Resources ("DER") adoption and distribution load forecasting. Because the Competitive Solicitation Framework Working Group ("CSFWG") only narrowly addressed CCAs’ ability to bid into Investor Owned Utilities’ ("IOUs") Requests for
Offers (“RFOs”) for distribution deferral services, the Commission should not exclude the role of CCAs from the scope of Track 3. As more municipalities consider either joining existing CCAs or forming new CCAs, IOUs’ DER growth scenarios and forecast analyses need to consider DERs deployed by CCAs.

As the Commission has acknowledged, the CSFWG’s final report recommended that CCAs should have the ability to participate in the IOUs’ solicitation process for distribution deferral DER products and services. Therefore, if CCAs determine that it is financially feasible for them to administer DER products and services, they can choose to enter into the solicitation process as a third-party market participant.

However, this recommendation does not address how the IOUs should integrate CCAs and other local government agencies’ DER deployment efforts in their distributed resources planning. Because it is unclear if the IOUs consider the DER programs of CCAs and other local agencies in the development of their distributed resources planning, sub-track 1 should address this policy issue. Sub-track 1 should aim to provide guidance to ensure that the IOUs’ distributed resources planning will maximize the utilization of existing local DER programs and services administered by CCAs and other local government agencies.

III. CONCLUSION

MCE thanks Assigned Commissioner Picker, Assigned Administrative Law Judge Mason, and Assigned Administrative Law Judge Allen for the opportunity to provide these comments on the Ruling.

_____________________

1 Ruling at page 5.

MCE Comments on Ruling on Track 3 Issues
Respectfully submitted,

/s/ C.C. Song

C.C. Song
Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6018
Facsimile: (415) 459-8095
E-Mail: csong@mceCleanEnergy.org

August 22, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of the Application of Marin Clean Energy for Approval of the 2016 Energy Efficiency Business Plan.

Application 15-10-014
(Filed October 27, 2015)

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Respectfully submitted,

/s/ Martha Serianz

Martha Serianz
LEGAL OPERATIONS MANAGER
MARIN CLEAN ENERGY
1125 Tamalpais Ave.
San Rafael, CA 94901
Telephone: (415) 464-6043
Facsimile: (415) 459-8095
E-Mail: mserinz@mceCleanEnergy.org

August 23, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of the Application of Marin Clean Energy for Approval of the 2016 Energy Efficiency Business Plan.  

Application 15-10-014  
(Filed October 27, 2015)

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the Commission’s Rules of Practice and Procedure, Marin Clean Energy (“MCE”) hereby gives notice of the following *ex parte* communication. The communication was held in-person on August 23, 2016 at the California Public Utilities Commission offices in San Francisco, CA at 11:56 AM and lasted approximately 2 minutes. The meeting was initiated by Marin Clean Energy and included Beckie Menten, MCE Director of Customer Programs, Michael Callahan-Dudley, MCE Regulatory Counsel, Jennifer Kalafut, Advisor to Commissioner Peterman, and David Gamson, Advisor to Commissioner Peterman. Mr. Gamson participated in the meeting by telephone.

The communication included a discussion on utilizing a single point of contact approach to serving customers as MCE has proposed in the general energy efficiency programs including MCE's business plan filing that launched A.1510-014.
Respectfully submitted,

/s/ Martha Serianz

Martha Serianz
LEGAL OPERATIONS MANAGER
MARIN CLEAN ENERGY
1125 Tamalpais Ave.
San Rafael, CA 94901
Telephone: (415) 464-6043
Facsimile: (415) 459-8095
E-Mail: mserinz@mceCleanEnergy.org

August 23, 2016

Rulemaking 13-11-005
(Filed November 14, 2013)

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Respectfully submitted,

/s/ Martha Serianz

Martha Serianz
LEGAL OPERATIONS MANAGER
MARIN CLEAN ENERGY
1125 Tamalpais Ave.
San Rafael, CA 94901
Telephone: (415) 464-6043
Facsimile: (415) 459-8095
E-Mail: mserinz@mceCleanEnergy.org

August 23, 2016

Marin Clean Energy Ex Parte Notice
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA


MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the Commission’s Rules of Practice and Procedure, Marin Clean Energy (“MCE”) hereby gives notice of the following ex parte communication. The communication was held in-person on August 23, 2016 at the California Public Utilities Commission offices in San Francisco, CA at 11:56 AM and lasted approximately 2 minutes. The meeting was initiated by Marin Clean Energy and included Beckie Menten, MCE Director of Customer Programs, Michael Callahan-Dudley, MCE Regulatory Counsel, Jennifer Kalafut, Advisor to Commissioner Peterman, and David Gamson, Advisor to Commissioner Peterman. Mr. Gamson participated in the meeting by telephone.

The communication included a discussion on utilizing a single point of contact approach to serving customers as MCE has proposed in the general energy efficiency programs including MCE's business plan filing that launched A.1510-014.
Respectfully submitted,

/s/ Martha Serianz

Martha Serianz
LEGAL OPERATIONS MANAGER
MARIN CLEAN ENERGY
1125 Tamalpais Ave.
San Rafael, CA 94901
Telephone: (415) 464-6043
Facsimile: (415) 459-8095
E-Mail: mserinz@mceCleanEnergy.org

August 23, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison
Company (U338E) for Approval of its Energy
Savings Assistance and California Alternate Rates
for Energy Programs and Budgets for Program

And Related Matters.

Application 14-11-007
(Filed November 18, 2014)

Application 14-11-009
Application 14-11-010
Application 14-11-011

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Martha Serianz
Legal Operations Manager
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6043
Facsimile: (415) 459-8095
E-Mail: mserianz@mceCleanEnergy.org

August 23, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison
Company (U338E) for Approval of its Energy
Savings Assistance and California Alternate Rates
for Energy Programs and Budgets for Program

And Related Matters.

<table>
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<td>(Filed November 18, 2014)</td>
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MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the Commission’s Rules of Practice and Procedure, Marin Clean Energy (“MCE”) hereby gives notice of the following *ex parte* communication. The communication was held in-person on August 23, 2016 at the California Public Utilities Commission offices in San Francisco, CA at 11:30 AM and lasted approximately 28 minutes. The meeting was initiated by Marin Clean Energy and included Beckie Menten, MCE Director of Customer Programs, Michael Callahan-Dudley, MCE Regulatory Counsel, Jennifer Kalafut, Advisor to Commissioner Peterman, and David Gamson, Advisor to Commissioner Peterman. Mr. Gamson was present for the meeting by telephone. Additionally, Mr. Callahan-Dudley sent an email to Mr. Gamson with an informational handout attached prior to the start of the in-person meeting. The email and attachment are included in Attachment A of this Notice. Mr. Callahan-Dudley also sent a follow-up email to both Mr. Gamson and Ms. Kalafut after the meeting which also included an informational handout. This email and informational handout are included in Attachment B of this Notice.
At the beginning of the meeting, Ms. Menten provided Ms. Kalafut with the same one pager emailed to Advisor Gamson. Ms. Menten expressed support for the alternate proposed decision. Ms. Menten highlighted several beneficial components of the alternate decision including policy changes and authorization for MCE to deliver energy efficiency to low-income communities supported by Energy Savings Assistance Program (ESAP). Ms. Menten discussed the benefits of streamlining the delivery of programs to customers including the general energy efficiency programs and ESAP, as proposed in MCE's Low-Income Families and Tenants (LIFT) pilot proposal that the alternate proposed decision approves, with modifications. Ms. Menten also identified that the streamlined delivery an important component of the single point of contact model included in the alternate proposed decision and in MCE’s general energy efficiency programs. Mr. Callahan-Dudley also described that the alternate proposed decision provides MCE with authority to request ESAP funding in the future.

Ms. Menten highlighted several policy changes in the alternate proposed decision. The alternate proposed decision removes the modified three-measure minimum rule, allows for ESAP funding for common area measures, and removes prohibition against serving a customer that has been served in the past ten years. Ms. Menten noted that MCE supported these policy changes leading up to the issuance of the proposed decisions.

Ms. Menten also noted that the alternate proposed decision's requirement that all ESAP customers also be enrolled in a dynamic rate or demand response program provides an opportunity for demand response enabled central heat pump water heaters.
Respectfully submitted,

/s/ Martha Serianz

Martha Serianz  
Legal Operations Manager  
MARIN CLEAN ENERGY  
1125 Tamalpais Avenue  
San Rafael, CA 94901  
Telephone: (415) 464-6043  
Facsimile: (415) 459-8095  
E-Mail: mserianz@mceCleanEnergy.org

August 23, 2016
ATTACHMENT A
From: Michael Callahan-Dudley <mcallahan-dudley@mcecleanenergy.org>
Date: Tue, Aug 23, 2016 at 11:26 AM
Subject: Fwd: LIFT/Low-Income 1 Pager
To: "Gamson, David M." <david.gamson@cpuc.ca.gov>

David,

The attached PDF will be shared during our meeting today. Jennifer just joined us.

Best,

Mike
MCE provides our low-income and disadvantaged communities with a wide range of energy efficiency and solar offerings. In addition, our Low-Income Families and Tenants (LIFT) Program proposes increasing the number of services that we offer to these communities.

**MCE’s Solutions to Barriers Faced by Low-Income and Disadvantaged Communities to Energy Efficiency and Renewable Energy**

MCE currently administers energy efficiency programs in four key areas: multifamily, single family, small commercial, and financing. Due to CPUC requirements, MCE’s current programs are limited to innovative offerings and areas not well served by other programs.

**HIGHLIGHT: MCE’S MULTIFAMILY OFFERINGS**

Since 2012, MCE has provided energy efficiency services to multifamily residences, which have included:

- Energy assessments
- Energy and water saving measures for tenant units
- Technical assistance

**AS OF DECEMBER 31, 2015, MCE HAS:**

- Achieved 389 MWH & 53,277 THERMS of energy savings
- Saved 15 MILLION gallons of water
- Audited 627 MULTIFAMILY BUILDINGS
- Distributed $427K+ in rebates
- Provided 1,179 UNITS WITH ENERGY SAVING EQUIPMENT

**Existing MCE Renewable Energy Offerings Available to Low-Income Customers**

**SOLAR INCENTIVES**

MCE has allocated $80,000 in rebates for new residential solar installations and partners with Grid Alternatives to offer $800 rebates to low-income customers who install solar panels.

**DISCOUNTED RATE**

Low-income, CARE-eligible customers are able to receive the CARE discounted energy rate in full with MCE.

**MORE RENEWABLES**

All MCE customers receive 50% renewable energy by default. The following two MCE 100% renewable energy offerings are equally available to low-income customers and particularly benefit renters and others who are unable to place solar on their roofs.

- Deep Green: 100% renewable energy for an average premium of $5/month for residential customers.
- Local Sol: 100% locally produced solar energy at a rate that remains fixed for up to 20 years.
LOCAL JOBS WORKFORCE

2,400+ TOTAL CALIFORNIA JOBS
MCE’s commitment to community and the environment extends beyond supplying renewable power. MCE partners with local organizations and businesses to bring jobs home by investing in new community-based solar projects. MCE’s contracted power projects have supported more than 2,400 California jobs. MCE follows a Sustainable Workforce Policy, adopted by MCE’s Board of Directors.

SAN RAFAEL AIRPORT SOLAR PROJECT
As a model of business working to create local green jobs, Synapse Electric hired 20 workers, identified by the Marin City Community Development Corporation, a local job training program for low-income individuals, and CLP Resources, to install solar panels at the San Rafael Airport. The project was financed locally by the Bank of Marin and San Rafael businessman, Joe Shekou. San Rafael–based REP Energy designed the installation, REC Group manufactured 85% of the solar panels, and Power–One supplied all inverters. Both the solar panels and inverters were American–made.

ENERGY EFFICIENCY JOBS FOR LOW–INCOME & DISADVANTAGED WORKERS
MCE has contracted more than $200,000 with RichmondBUILD, the Marin City Community Development Corporation, and Rising Sun Energy Center to train and provide workers to help implement energy upgrades for our energy efficiency programs. MCE is joining with Richmond Works on a new solar installation that will employ local residents under the Richmond Local Hire Ordinance.

MCE’s Low–Income Families and Tenants (LIFT) Proposal

LIFT MULTIFAMILY COMPONENTS
- Expanding on existing energy efficiency programs for income–qualified customers to provide additional incentives and achieve deeper energy savings.
- Using an alternative enrollment processes to reduce concerns related to privacy and immigration status.
- Creating opportunities for switching from natural gas combustion appliances to heat pumps in order to support cleaner and more efficient energy use.
- Delivering On–Bill Repayment options for financing energy efficiency improvements.

LIFT SINGLE–FAMILY COMPONENTS
- Launching a mobile platform–based behavioral program that encourages low and no cost changes to reduce energy use and save money.
- Depositing funds equal to twice the energy saved to reinforce the existing savings; these funds can be spent on additional energy savings investments.
ATTACHMENT B
Dear Advisor Kalafut and Advisor Gamson,

Thank you for taking the time to meet with us today. I have attached the one pager that describes the measures and budget for MCE’s Low-Income Families and Tenants (LIFT) pilot proposal. Keep in mind both the PD and the APD remove some elements of the pilot (e.g. heat pumps and energy education workshops) and reduce the budget to $2.5 million over two years. Please feel free to reach out if you have any questions.

Best,

Michael Callahan-Dudley | 415.464.6045
Regulatory Counsel
MCE
1125 Tamalpais Avenue
San Rafael, CA 94901

Follow MCE!
MCE’s Low-Income Families and Tenants (LIFT) Program

MCE proposed the LIFT program to better serve income qualified single-family and multifamily homes that do not participate in existing programs for a variety of reasons. The program will leverage existing energy efficiency programs, facilitate the installation of heat pumps where they are safe and cost-effective, develop mobile platforms of information for low-income individuals, and provide a matching savings program and subsidized financing for energy efficiency investments.

### LIFT Budget, Targets, and Savings Summary

<table>
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<tr>
<th>Sector</th>
<th>Proposed Budget (ESAP)</th>
<th>kWh</th>
<th>Therms</th>
<th>Units</th>
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<tbody>
<tr>
<td>Multifamily</td>
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<td>568,105</td>
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<tr>
<td>Single-family</td>
<td>$846,324</td>
<td>23,831</td>
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<td>300</td>
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<tr>
<td>Total</td>
<td>$4,616,682</td>
<td>595,275</td>
<td>26,202</td>
<td>2,770</td>
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### Multifamily Performance Metrics

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<tr>
<th>Tenants to Receive Education</th>
<th>1,500</th>
<th>Participants Receiving ’Alerts’</th>
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<tr>
<td>Heat Pumps Installed</td>
<td>370</td>
<td>Homes Provided with Education</td>
<td>150</td>
</tr>
<tr>
<td>Properties Referred to MASH²</td>
<td>15</td>
<td>Homes Referred to SASH³</td>
<td>100</td>
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<tr>
<td>Properties Enrolled in Financing</td>
<td>15</td>
<td>Properties Enrolled in Financing</td>
<td>45</td>
</tr>
</tbody>
</table>

### LIFT Single-Family Components:

- Expanding on existing energy efficiency programs for income qualified customers to provide additional incentives and achieve deeper energy savings.
- Using an alternative enrollment processes to reduce concerns related to privacy and immigration status.
- Creating opportunities for fuel switching away from natural gas combustion appliances to heat pumps to support cleaner and more efficient energy use while resolving health and safety concerns.
- Providing accessible On-Bill Repayment options for financing energy efficiency improvements.

### LIFT Single-Family Components:

- Launching a mobile platform based behavioral program that encourages low and no cost changes to reduce energy use and save money.
- Depositing funds equal to twice the energy saved to reinforce the existing savings; these funds can be spent on additional energy savings investments.
- Providing accessible On-Bill Repayment options for financing energy efficiency improvements.

---

1 The budget for the LIFT program will funded from the Energy Savings Assistance Programs.
2 Multifamily Affordable Solar Homes program.
3 Single-Family Affordable Solar Homes program.
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison
Company (U338E) for Approval of its Energy
Savings Assistance and California Alternate Rates
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And Related Matters.

Application 14-11-007
(Filed November 18, 2014)

Application 14-11-009
Application 14-11-010
Application 14-11-011

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Martha Serianz
Legal Operations Manager
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6043
Facsimile: (415) 459-8095
E-Mail: mserianz@mceCleanEnergy.org

August 25, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of its Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for Program Years 2015-2017.

And Related Matters.

Application 14-11-007
(Filed November 18, 2014)

Application 14-11-009
Application 14-11-010
Application 14-11-011

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the Commission’s Rules of Practice and Procedure, Marin Clean Energy (“MCE”) hereby gives notice of the following ex parte communication. The communication was held in-person on August 25, 2016 at the California Public Utilities Commission offices in San Francisco, CA at 2:30 PM and lasted approximately 20 minutes. The meeting was initiated by Marin Clean Energy and included Beckie Menten, MCE Director of Customer Programs, Michael Callahan-Dudley, MCE Regulatory Counsel, and Sepideh Khosrowjah, Advisor to Commissioner Florio. Ms. Menten also provided two written informational hand-outs that are included in Attachment A of this Notice.

At the beginning of the meeting, Ms. Menten expressed support for the alternate proposed decision. Ms. Menten highlighted several beneficial components of the alternate decision including policy changes and authorization for MCE to deliver energy efficiency to low-income communities supported through the Energy Savings Assistance Program (ESAP) activity. Ms. Menten discussed the benefits of streamlining the delivery of programs to, as
proposed in MCE's Low-Income Families and Tenants (LIFT) pilot proposal that the alternate proposed decision approves, with modifications. Mr. Callahan-Dudley also described that the alternate proposed decision provides MCE with authority to request ESAP funding in the future and suggested that the authority be provided to Community Choice Aggregators generally.

Ms. Menten highlighted several policy changes in the alternate proposed decision. The alternate proposed decision removes the modified three-measure minimum rule, allows for ESAP funding for common area measures, alternative eligibility criteria, and removes prohibition against serving a customer that has been served in the past ten years. Ms. Menten noted that MCE supported these policy changes leading up to the issuance of the proposed decisions.

Respectfully submitted,

/s/ Martha Serianz

Martha Serianz
Legal Operations Manager
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6043
Facsimile: (415) 459-8095
E-Mail: mserianz@mceCleanEnergy.org

August 25, 2016
ATTACHMENT A
BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of its Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for Program Years 2015-2017.

And Related Matters.

Application 14-11-007
(Filed November 18, 2014)

Application 14-11-009
Application 14-11-010
Application 14-11-011

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Martha Serianz
Legal Operations Manager
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6043
Facsimile: (415) 459-8095
E-Mail: mserianz@mceCleanEnergy.org

August 26, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison
Company (U338E) for Approval of its Energy
Savings Assistance and California Alternate Rates
for Energy Programs and Budgets for Program

And Related Matters.

Application 14-11-007
(Filed November 18, 2014)

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Application 14-11-010
Application 14-11-011

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the Commission’s Rules of Practice and Procedure, Marin Clean
Energy (“MCE”) hereby gives notice of the following ex parte communication. The
communication was held in-person on August 26, 2016 at the California Public Utilities
Commission offices in San Francisco, CA at 1:36 PM and lasted approximately 24 minutes. The
meeting was initiated by Marin Clean Energy and included Beckie Menten, MCE Director of
Customer Programs, and Scott Murtishaw, Advisor to President Picker. Ms. Menten also provided
two written informational hand-outs that are included in Attachment A of this Notice.

At the beginning of the meeting, Ms. Menten expressed support for the alternate proposed
decision. Ms. Menten highlighted several beneficial components of the alternate decision including
policy changes and authorization for MCE to deliver energy efficiency to low-income
communities supported by Energy Savings Assistance Program (ESAP). Ms. Menten discussed
the benefits of streamlining the delivery of programs to customers including the general energy
efficiency programs and ESAP, as proposed in MCE's Low-Income Families and Tenants (LIFT)
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Respectfully submitted,

/s/ Martha Serianz

Martha Serianz
Legal Operations Manager
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6043
Facsimile: (415) 459-8095
E-Mail: mserianz@mceCleanEnergy.org

August 26, 2016
ATTACHMENT A
MCE’s Solutions to Barriers Faced by Low-Income and Disadvantaged Communities to Energy Efficiency and Renewable Energy

MCE provides our low-income and disadvantaged communities with a wide range of energy efficiency and solar offerings. In addition, our Low-Income Families and Tenants (LIFT) Program proposes increasing the number of services that we offer to these communities.

Existing MCE Energy Efficiency Offerings

MCE currently administers energy efficiency programs in four key areas: multifamily, single family, small commercial, and financing. Due to CPUC requirements, MCE’s current programs are limited to innovative offerings and areas not well served by other programs.

HIGHLIGHT: MCE’S MULTIFAMILY OFFERINGS

Since 2012, MCE has provided energy efficiency services to multifamily residences, which have included:

» Energy assessments
» Energy and water saving measures for tenant units
» Technical assistance

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2,400+ TOTAL CALIFORNIA JOBS
MCE’s commitment to community and the environment extends beyond supplying renewable power. MCE partners with local organizations and businesses to bring jobs home by investing in new community-based solar projects. MCE’s contracted power projects have supported more than 2,400 California jobs. MCE follows a Sustainable Workforce Policy, adopted by MCE’s Board of Directors.

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As a model of business working to create local green jobs, Synapse Electric hired 20 workers, identified by the Marin City Community Development Corporation, a local job training program for low-income individuals, and CLP Resources, to install solar panels at the San Rafael Airport. The project was financed locally by the Bank of Marin and San Rafael businessman, Joe Shekou. San Rafael–based REP Energy designed the installation, REC Group manufactured 85% of the solar panels, and Power-One supplied all inverters. Both the solar panels and inverters were American-made.

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MCE’s Low-Income Families and Tenants (LIFT) Proposal

**LIFT MULTIFAMILY COMPONENTS**
- Expanding on existing energy efficiency programs for income-qualified customers to provide additional incentives and achieve deeper energy savings.
- Using an alternative enrollment processes to reduce concerns related to privacy and immigration status.
- Creating opportunities for switching from natural gas combustion appliances to heat pumps in order to support cleaner and more efficient energy use.
- Delivering On-Bill Repayment options for financing energy efficiency improvements.

**LIFT SINGLE–FAMILY COMPONENTS**
- Launching a mobile platform–based behavioral program that encourages low and no cost changes to reduce energy use and save money.
- Depositing funds equal to twice the energy saved to reinforce the existing savings; these funds can be spent on additional energy savings investments.

FOR MORE INFORMATION, PLEASE CONTACT:
Beckie Menten
Director of Customer Programs
bmenten@mceCleanEnergy.org | (415) 464-6034
MCE’s Low-Income Families and Tenants (LIFT) Program

MCE proposed the LIFT program to better serve income qualified single-family and multifamily homes that do not participate in existing programs for a variety of reasons. The program will leverage existing energy efficiency programs, facilitate the installation of heat pumps where they are safe and cost-effective, develop mobile platforms of information for low-income individuals, and provide a matching savings program and subsidized financing for energy efficiency investments.

### LIFT Budget, Targets, and Savings Summary

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---

1 The budget for the LIFT program will funded from the Energy Savings Assistance Programs.
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3 Single-Family Affordable Solar Homes program.
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company
for Approval of the Retirement of Diablo Canyon
Power Plant, Implementation of the Joint Proposal,
and Recovery of Associated Costs Through
Proposed Ratemaking Mechanisms

Application 16-08-006
(August 11, 2016)

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Martha Serianz
Legal Operations Manager
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1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6043
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E-Mail: mserianz@mceCleanEnergy.org

August 29, 2016
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MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the Commission’s Rules of Practice and Procedure, Marin Clean Energy ("MCE") hereby gives notice of the following ex parte communication. The communication was initiated by MCE and occurred on August 24, 2016 at approximately 12:30 PM at the California Public Utilities Commission offices. The communication was between Dawn Weisz, MCE Executive Director, Jeremy Waen, MCE Senior Regulatory Analyst, and Rachel Peterson, Advisor to Commissioner Randolph and lasted approximately 30 minutes.

The communication included a discussion of MCE’s concerns with the Application recently submitted by the Pacific Gas and Electric (“PG&E”) Company regarding its proposal to decommission the Diablo Canyon Nuclear Power Plant (“DCPP”). MCE’s representatives voiced their strong support for the closure of DCPP and the Application’s stated intent to replace DCPP generation with greenhouse gas (“GHG”) -free electricity generation and energy efficiency (“EE”); however, MCE’s representatives also voiced their strong reservations regarding both the Application’s request for procurement authorization without a formal needs assessment and the unprecedented request for “on-behalf-of” cost and benefit sharing of the replacement power that would extend to CCA customers. Additionally MCE’s representatives also called into question
how the EE procurement described in tranches 1 and 2 of the proposal would risk circumventing existing proceedings at the CPUC to evaluate the future administration of EE programs. Lastly MCE’s representatives stressed the importance for the Commission to respect and preserve the procurement autonomy of CCAs by not allowing PG&E to impose new forms of “on behalf of” procurement CCAs and CCA customers.

Respectfully submitted,

/s/ Martha Serianz

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At the beginning of the meeting, Ms. Menten expressed support for the alternate proposed decision. Ms. Menten highlighted several beneficial components of the alternate decision including policy changes and authorization for MCE to deliver energy efficiency to low-income communities supported by Energy Savings Assistance Program (ESAP). Ms. Menten discussed the benefits of streamlining the delivery of programs to customers including

MCE Notice of Ex Parte Communication
the general energy efficiency programs and ESAP, as proposed in MCE’s Low-Income Families and Tenants (LIFT) pilot proposal that the alternate proposed decision approves, with modifications. Ms. Menten also identified that the changes proposed in the APD reflect recommendations from stakeholders who have been working on these issues for many years, whereas the PD largely reflects status quo.

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Mr. Callahan-Dudley stated that MCE supports the alternate Proposed Decision and that it supports MCE applying for future funding and that all CCAs should have the same opportunities. MCE also asked about the implications of requesting ESAP participants to participate in DR programs or dynamic pricing tariffs.

Respectfully submitted,

/s/ Martha Serianz

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ASSISTANCE (ESA) PROGRAM APPLICATIONS

Michael Callahan
Regulatory Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6045
Facsimile: (415) 459-8095
E-Mail: mcallahan@mceCleanEnergy.org

September 6, 2016
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SUMMARY OF RECOMMENDATIONS

Recommendations for Successful Program Administration

1. The Proposed Decision ("PD") and Alternate Proposed Decision ("APD") should be modified to include heat pumps as a measure in the Low-Income Families and Tenants ("LIFT") pilot.

2. The PD and APD should be modified to authorize Marin Clean Energy ("MCE") to provide energy education workshops both in coordination with the Community Help and Awareness of Natural Gas and Electricity Services ("CHANGES") program and in partnership with additional CBOs throughout MCE’s service area as part of the LIFT pilot.

3. The PD and APD should be modified to fully fund MCE’s two-year budget of $4,616,682 for the LIFT pilot to serve customers in 2017-2018.

4. The PD and APD should direct PG&E to transfer MCE’s annualized Energy Savings Assistance ("ESA") Program budget on January 15 each year.

Recommendations to Ensure Factual Accuracy

1. The PD and APD should eliminate language that indicates MCE lacks administrative capabilities to administer the full LIFT pilot.

2. The single point of contact ("SPOC") efforts should endeavor for simultaneous program offerings.

Elements of the APD Recommended for Incorporation into the PD

1. The PD should be modified to approve the LIFT pilot subject to additional details provided in a Tier 2 advice letter.

2. The PD should clarify that MCE is not limited to a single two-year pilot, but should have authority to request ESA Program funds following the pilot.

3. The PD should be modified to incorporate the policy changes embodied in the APD including changes to: (1) the modified 3-measure minimum rule; (2) the go back rule; (3) the measure caps; (4) and ESA Program funding for common area measures.
COMBINED COMMENTS OF MARIN CLEAN ENERGY
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I. INTRODUCTION

MCE is the first operating Community Choice Aggregator (“CCA”) in California and started serving customers with electricity service in 2010. By 2014, MCE was serving the entirety of Marin County and the City of Richmond. In 2015, the cities of Benicia, El Cerrito, San Pablo, and unincorporated Napa County joined MCE, representing approximately 30% more
customer accounts compared to 2014. This year, MCE is enrolling the cities of Calistoga, St. Helena, Napa, American Canyon, and Yountville, Lafayette, and Walnut Creek, representing approximately 40% more customer accounts compared to 2015. By 2017, MCE will be serving approximately 250,000 customer accounts.

MCE’s mission includes addressing climate change by reducing greenhouse gas (“GHG”) emissions through renewable energy supply and energy efficiency.1 MCE is a program administrator of general energy efficiency programs,2 including a multifamily program that has provided upgrades to over 1,000 tenant units to date. In 2015, over 77% of those multifamily properties MCE served were income-qualified. The Commission increased MCE’s energy efficiency program budget 30% to account for the new communities that joined in 2015.3 In 2015, MCE also requested authorization to administer the Low-Income Families and Tenants (“LIFT”) pilot supported with Energy Savings Assistance (“ESA”) Program funds to provide additional support for income-qualified customers.4 As MCE grows, it will strive to deliver comprehensive and high-quality energy efficiency programs to all of its customers.

II. MCE FAVORS THE ADOPTION OF THE APD OVER THE PD, THOUGH BOTH REQUIRE MODIFICATIONS

As currently drafted, the APD should be adopted in lieu of the PD due to several elements of the APD that will enhance ESA Program delivery for low-income customers. These

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1 “Our mission is to address climate change by reducing energy related greenhouse gas emissions through renewable energy supply and energy efficiency at stable and competitive rates for customers while providing local economic and workforce benefits.” https://www.mcecleanenergy.org/about-us/.
2 See e.g. D.14-10-046.
3 D.16-05-004.
include: (1) approving MCE’s LIFT pilot;\(^5\) (2) providing MCE authority to request ESA Program funding in the future;\(^6\) and (3) making several policy changes to the ESA Programs. These policy changes include: (1) elimination of the go back rule;\(^7\) (2) lifting measure caps;\(^8\) (3) eliminating the modified three measure minimum rule;\(^9\) (4) allowing ESA Programs to fund common area measures;\(^10\) and (5) changes to eligibility criteria for multifamily buildings.\(^11\) Adopting the APD over the PD will achieve a greater ESA Program saturation in low income households to help meet state goals.

The APD and PD both require modifications to ensure that MCE is able to successfully administer ESA Program funding and to avoid factual errors.

III. THE PD AND APD SHOULD BE MODIFIED TO ENABLE MCE TO SUCCESSFULLY ADMINISTER ESA PROGRAM FUNDING

A. The PD and APD should be Modified to Include the Heat Pump Component of MCE’s LIFT Pilot

The PD and APD should be modified to include heat pumps as measures in the LIFT pilot to: (1) gather additional data from installed heat pumps to understand the costs and benefits, including the capacity to provide space heating and cooling; (2) explore the potential to leverage energy efficiency to provide demand response (“DR”) with heat pumps; and (3) support state goals in reducing GHG emissions.

The PD and APD should allow MCE to include heat pumps as a measure in the LIFT pilot to gather additional data about installed heat pumps. The PD and APD remove heat pumps

\(^{-5}\) APD at p. 383.
\(^{-6}\) APD at p. 383.
\(^{-7}\) APD at p. 60-63.
\(^{-8}\) APD at p. 115-17.
\(^{-9}\) APD at p. 72-79.
\(^{-10}\) APD at p. 179-89.
\(^{-11}\) APD at p. 189-90.
from the LIFT pilot, stating that the proposed analysis of would be duplicative of pending Commission research on heat pumps.\(^{12}\) The PD and APD also state that all fuel switching measures need to pass the 3-prong fuel switching test.\(^{13}\) The LIFT pilot should be able to provide heat pumps as fuel-switching measures when they pass the 3-prong test. Additionally, the referenced Commission study appears to be nearly one year overdue\(^{14}\) and has been reduced in scope to only examine heat pump water heater technology.\(^{15}\) The final research plan indicates that DNV GL will use models for the costs of ownership for heat pumps and competing technologies rather than relying on performance data of installed technologies.\(^{16}\) The LIFT pilot will provide valuable additional data by using installed measures, as opposed to models of cost estimates, to understand the actual costs and benefits of heat pump installations in both water heating and space heating and cooling capacities. The LIFT pilot provides an opportunity to more fully examine heat pumps and provide valuable data to supplement the Commission study. Additionally, providing data on the performance of heat pump technology in the field, as opposed to relying on modeling estimates, can help provide more information to assess whether these technologies are ripe for installation across the broader ESAP portfolio. The PD and APD

\(^{12}\) PD at p. 318-19; APD at p. 379-80. 
\(^{13}\) PD at p. 318; APD at p. 379.


should authorize MCE to provide heat pumps where they can provide insights to supplement the Commission study or where these technologies comply with the 3-prong test.

As discussed at the all party meeting on August 31 in this proceeding, leveraging energy efficiency to deploy demand response may help achieve numerous state goals. MCE highlights the opportunity for heat pump technology to integrate DR, and help achieve the policy goals of the APD. MCE supports the goal of integrating demand response program delivery into energy efficiency deployment. If done on a voluntary basis, this represents a good ‘no regrets’ policy that minimizes ratepayer costs associated with program delivery and ensures better success at recruitment for residential DR programs. The heat pump component of the LIFT pilot should be permitted to help support the deployment of DR.

The PD and APD should not exclude heat pumps from MCE’s LIFT pilot due to the potential for heat pumps to achieve state goals. Senate Bill (“SB”) 32 calls for a significant reduction of GHG emissions by 2030.17 SB 350 calls for 50% of electricity in California to be renewable resources.18 AB 2672 (2014) requires the Commission to investigate economically feasible options for providing affordable access to low energy options in disadvantaged communities that currently lack access to natural gas pipeline infrastructure.19 Heat pumps are a powerful tool to reduce GHG emissions because they can switch customers from a natural gas fuel source to increasingly GHG-free electricity. Additionally, these technologies offer a high efficiency replacement to existing electric resistance equipment. Replacing an inefficient HVAC or water heater system with a higher efficiency natural gas based system will provide incremental energy savings, but will commit California’s ratepayers to decades of infrastructure

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17 Senate Bill 32 (2016, pending Governor’s signature) (requires 40% reduction in GHG emissions compared with 1990 levels by 2030).
19 Assembly Bill 2672 (2014).
that relies on fossil fuels.\(^{20}\) Heat pumps can operate on a non-carbon based fuel source for building conditioning and water heating. The PD and APD should authorize heat pump installations as an eligible measure in MCE’s LIFT pilot to support state goals to reduce GHG emissions, integrate renewable energy, and explore high efficiency measures for disadvantaged communities that lack access to natural gas infrastructure.

**B. The PD and APD should be Modified to Authorize Energy Education Workshops as a Component of the LIFT Pilot**

The PD and APD should allow MCE to provide energy education workshops to educate customers about energy management technologies and increase enrollment in ESA Programs. The PD and APD both characterize MCE’s proposed energy education as duplicative of the Community Help and Awareness of Natural Gas and Electricity Services (“CHANGES”) program.\(^{21}\) In Decision 15-12-047, the Commission noted that additional community-based organizations (“CBOs”) are needed so that services can be provided statewide\(^ {22}\) and attached a report containing the list of CBOs that participate.\(^ {23}\) Only one of the CBOs listed is within MCE’s service area. It is factually inconsistent to conclude that MCE’s energy education workshops are duplicative of the CHANGES activities when considering the Commission’s stated need for more CBOs to deliver the CHANGES program and the lack of CBOs delivering CHANGES in MCE’s service area. The Commission should allow MCE to provide energy education workshops both in coordination with CHANGES and in partnership with additional CBOs throughout MCE’s service area.

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\(^{20}\) Many natural gas heating systems have life expectancies of 15 years or longer.
\(^{21}\) PD at p. 319; APD at p. 380.
\(^{22}\) D.15-12-047 at p. 33.
\(^{23}\) D.15-12-047, Attachment B at p. 24-25.
The PD and APD should recognize the MCE’s proposed energy education workshops will lead to energy savings due to enrolling attendees in the ESA Program and providing education on Energy Management Technologies. Both the PD and APD state that past energy education workshops did not result in immediate energy savings.\(^{24}\) The PD and APD also note the requirement of Assembly Bill (“AB”) 793 to provide education on energy management technologies.\(^{25}\) MCE’s workshops will likely achieve energy savings because MCE will attempt to enroll attendees in the LIFT pilot including installation of measures.\(^{26}\) MCE’s workshops will also follow the AB 793 direction to provide education on energy management technologies, including assistance gaining access to the single family mobile platform and web-based tools.\(^{27}\) The workshops can also provide information about dynamic pricing programs and DR programs. The PD and APD should support MCE’s energy education workshops because they will lead to savings, provide education as directed in AB 793, and may be leveraged for DR program delivery.

C. The PD and APD should be Modified to Authorize MCE’s Originally Requested Budget

The PD and APD should be modified to fully fund MCE’s budget for the LIFT pilot. Both the PD and APD limit MCE’s two year pilot budget apparently due to removal of elements from the program.\(^{28}\) The proposed decisions are correct that MCE cancelled its Single-Family

\(^{24}\) PD at p. 319; APD at p. 380.
\(^{25}\) PD at p. 255; APD at p. 310-11.
\(^{26}\) Opening Brief of Marin Clean Energy at p. 24.
\(^{28}\) See \textit{i.e.} PD at p. 321 (“We direct MCE to refile this pilot proposal with commensurate budget, incorporating the changes and recommendations mentioned herein….“); APD at p. 383 (“We approve $2.5 million for MCE’s pilot, adjusting downwards from the $4.6 million requested.”).
On-Bill Repayment (“OBR”) Program.\(^{29}\) However, the Single-Family OBR program was a small component of the overall LIFT budget. MCE based its requested budgets on an achievable target of units treated and MCE has experienced significant growth since the pilot was filed in 2015.\(^{30}\) Thus, MCE proposes to divert funds requested for OBR program elements to Multifamily sector for the treatment of additional units (Table 1). MCE provided discussion related to the heat pumps and energy education workshops in Sections III.A and III.B above. MCE provides Table 1 below to clarify the budget associated with the pilot sectors based on the removal of the SF OBR program. A significant reduction of the proposed LIFT budget will limit the number of units that can be treated under the MCE LIFT pilot. The PD and APD should authorize the budget from Table 1 to ensure MCE is able to successfully deploy the pilot.

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\(^{29}\) PD at p. 319; APD at p. 380-81.

\(^{30}\) As discussed in Section I above, MCE’s service area increased to include approximately 40% more customer accounts in 2016.

\(^{31}\) The budget for the LIFT program will be funded with ESA Program funding. The budget years have been shifted to account for the time between the LIFT pilot proposal and the issuance of the PA and APD. MCE has provided a proposed Ordering Paragraph (“OP”) in Appendix A to incorporate this shift.
D. The PD and APD should be Modified to Provide Clarity for the ESA Program Budget Transfer

The PD and APD should adopt a similar budget transfer process for MCE’s ESA Program budget as is used for the general energy efficiency program evaluation, measurement, and verification (“EM&V”) budget. The PD and APD currently do not provide a process for MCE to receive authorized ESA Program funds. As with the ESA Program, the investor-owned utilities (“IOUs”) perform revenue collection for the general energy efficiency program funds. The most recent decision from the general energy efficiency rulemaking directs IOUs to transfer the approved EM&V budget to CCAs on January 15 every year.\footnote{D.16-08-019, OP 16 at p. 112.} This budget transfer process is needed to ensure that IOUs have clarity on the timing and amount of the budget transfer to MCE. There should be a similar process for MCE to receive annualized budget transfers of ESA Program funds.\footnote{In the case of the LIFT pilot, a two year pilot, the annualized budget would mean half the budget would be transferred to MCE in 2016 and the second half in 2017.} This process should take place on January 15 each year. The PD and APD should incorporate this process to ensure MCE is able to receive any authorized budget without further Commission action.

IV. THE PD AND APD SHOULD BE MODIFIED TO AVOID FACTUAL ERRORS

A. The PD and APD should be Modified to Eliminate the Reference to MCE Lacking Administrative Capabilities to Serve Low-Income Customers

The PD and APD should eliminate language that indicates MCE lacks administrative capabilities to administer the full LIFT pilot. Both proposed decisions state that “[w]ith no previous experience in administering the ESA Program, we think it is reasonable for MCE to demonstrate its administrative capabilities on a more limited pilot scale, before approval of such

\[32\] D.16-08-019, OP 16 at p. 112.
\[33\] In the case of the LIFT pilot, a two year pilot, the annualized budget would mean half the budget would be transferred to MCE in 2016 and the second half in 2017.
a large package of measures.”34 While it is correct that MCE has not administered an ESA Program, MCE has demonstrated sufficient administrative capabilities to administer the scope of activities provided in Table 1 of section III.C above. The MCE budget and targets were based on an achievable reach goal given what MCE has accomplished to date. The MCE multifamily energy efficiency program has provided upgrades to over 1,000 tenant units to date, in 2015 over 77% of these properties were income-qualified. MCE carried out these upgrades as a Commission-authorized energy efficiency program administrator in the same sense that IOUs are administrators35 and consistent with Commission direction for program administrators. This track record demonstrates MCE has the administrative capabilities to administer the scope of LIFT pilot activities requested in Section III above. The PD and APD should eliminate the reference to the need for MCE to demonstrate administrative capabilities to administer the full LIFT pilot.

B. The PD and APD should Clarify that the SPOC Includes Simultaneous and Streamlined Program Offerings

The PD and APD should clarify and include direction that the SPOC should strive for simultaneous delivery of programs. The PD and APD discuss the SPOC as a way to leverage multiple program offerings and eliminate barriers that create silos between programs.36 However, neither provides the foundational direction for a SPOC model to strive for simultaneous delivery of programs. Without this clarification, the SPOC approach could remain largely relegated to referrals and eliminating discrete barriers to create streamlined program administration without working toward the more meaningful goal of streamlined program delivery. As stated in MCE’s testimony, MCE works in partnership with water agencies to

34 PD at p. 318; APD at p. 379.
35 D.14-01-033 at p. 9.
36 PD at p. 147, 156-57; APD at p. 182, 185-187, 194-95.
provide toilet replacements. MCE consolidates the toilet replacements and direct install of energy efficiency measures in the same visit to the home which reduces costs and improves program delivery for the customer. The PD and APD should include language to clarify that the SPOC efforts should endeavor to streamline the delivery of program offerings to be simultaneous.

V. THE PD SHOULD BE MODIFIED TO INCORPORATE ASPECTS OF THE APD

A. The PD should be Modified to Approve MCE’s LIFT Pilot

The PD should approve the LIFT pilot subject to additional details provided in a Tier 2 advice letter. The PD generally supports the LIFT pilot but directs MCE to file a petition for modification for approval of the LIFT pilot containing additional details about the budget, pilot eligibility, the behavioral tool, the income verification process, and additional metrics. The APD approved the pilot and calls for additional details in a Tier 2 advice letter. A petition for modification requires a subsequent decision of the Commission. The scope of the additional details called for in the PD does not warrant a second review by the full Commission. This process is resource intensive for stakeholders and the Commission. Commission staff is better suited to review the additional pilot details through the Tier 2 advice letter process to ensure the LIFT pilot is consistent with the final Commission decision. The PD should authorize the full scope and budget for the LIFT pilot consistent with the discussion in Section III of these comments. The PD should be modified to approve the LIFT pilot subject to additional details provided in a Tier 2 advice letter.

37 LIFT Proposal at p. 19.
38 PD at p. 318-22.
39 APD at p. 383.
B. The PD should be Clarified to Provide MCE Authority to Request ESA Program Funding in the Future

The PD should be clarified to provide MCE with authority to request ESA Program funding in the future. The APD appropriately clarifies that MCE may apply for ESAP funding in the future. The PD indicates it is appropriate for MCE to receive funding for the LIFT pilot, provided the additional details are adequate. The PD providing only a single discrete opportunity for ESA Program funding would be arbitrary. The PD should clarify that MCE is not limited to a single two-year pilot, but should have authority to request ESAP funds following the pilot.

C. The PD should Include Several Policy Changes that are Necessary to Ensure ESA Programs are Capable of Achieving California’s Goals

The APD makes several policy changes that will help ESA Programs save energy and reduce GHG emissions. California has statutory goals to significantly increase energy efficiency\(^{40}\) and reduce GHG emissions.\(^{41}\) The Commission itself has adopted goals to offer low income program services to the entire eligible population by 2020.\(^{42}\) The ESA Programs need to adapt their policies to remove barriers to participation and better conform to these legislative mandates. The APD makes changes to eligibility criteria for multifamily buildings that will achieve a greater ESA Program saturation in low income households to help meet state goals.\(^{43}\) The APD eliminates the go back rule,\(^{44}\) measure caps,\(^{45}\) the modified three measure minimum rule,\(^{46}\) and allows ESA Programs to fund common area measures.\(^{47}\) The PD acknowledges issues with the

\(^{40}\) SB 350 (2015) (calls for a doubling of energy efficiency).
\(^{41}\) SB 32 (2016, pending Governor’s signature) (requires 40% reduction in GHG emissions compared with 1990 levels by 2030).
\(^{42}\) Long Term Energy Efficiency Strategic Plan, Commission (2011) at p.6.
\(^{43}\) APD at p. 189-90.
\(^{44}\) APD at p. 60-63.
\(^{45}\) APD at p. 115-17.
\(^{46}\) APD at p. 72-79.
\(^{47}\) APD at p. 179-89.
go back rule,\textsuperscript{48} measure caps,\textsuperscript{49} achieving savings in the multifamily setting,\textsuperscript{50} and the limited but real impact of the modified three measure minimum rule.\textsuperscript{51} However, the PD prolongs the status quo by deferring resolution of these issues. This deferral is contrary to the intent of state statutes because it will hinder the ability of the Commission to meet California’s energy savings and GHG emissions targets. The PD should be modified to incorporate the policy changes embodied in the APD.

\textbf{VI. CONCLUSION}

MCE respectfully requests the recommended changes above to approve the full LIFT pilot, provide MCE an opportunity to successfully deliver ESA Programs, and improve the ESA Program policies to help achieve state goals for reducing GHG emissions and increasing energy efficiency. MCE thanks Commissioner Sandoval and Administrative Law Judge Colbert for their thoughtful consideration of these comments.

Respectfully submitted,

\textit{/s/ Michael Callahan}

Michael Callahan  
Regulatory Counsel  
MARIN CLEAN ENERGY  
1125 Tamalpais Avenue  
San Rafael, CA 94901  
Telephone: (415) 464-6045  
Facsimile: (415) 459-8095  
E-Mail: mcallahan@mceCleanEnergy.org

September 6, 2016

\textsuperscript{48} PD at p. 40.  
\textsuperscript{49} PD at p. 88-89.  
\textsuperscript{50} PD at p. 147-48.  
\textsuperscript{51} PD at p. 51 (1%-3% of homes approached were precluded by the rule).
APPENDIX A
PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF LAW

Findings of Fact

New PD Finding of Fact 89; New APD Finding of Fact 92. *The single point of contact (“SPOC”) efforts include simultaneous program offerings when appropriate.*

Conclusions of Law

Amended PD Conclusion of Law 196; Amended APD Conclusion of Law 200. MCE’s proposed heat pump installation measures in its LIFT Pilot proposal should be *denied* and the education workshops component of the LIFT Pilot should also be *denied*.

Amended PD Conclusion of Law 197; Amended APD Conclusion of Law 201. *It is reasonable to fund MCE’s LIFT pilot subject to additional details being approved by Commission staff in a Tier 2 advice letter consistent with this decision.*

New PD Conclusion of Law 201; New APD Conclusion of Law 206. *As with the ESA Program, the IOUs perform revenue collection for the general energy efficiency funds.*

New PD Conclusion of Law 202; New APD Conclusion of Law 207. *The SPOC efforts should include simultaneous program offerings when appropriate.*

New PD Conclusion of Law 203; New APD Conclusion of Law 208. *MCE may seek additional funding for future program years after the completion of its pilot via a Tier 3 Advice Letter if it is within this program cycle or via the Application process if it is the next program cycle.*

Proposed Ordering Paragraphs

New PD Ordering Paragraph 197; Amended APD Ordering Paragraph 145. *Marin Clean Energy’s LIFT Proposal pilot is approved, in full. The total budget authorized for the pilot is $4,616,682. To implement the pilot, Marin Clean Energy shall file Tier 2 Advice Letter with the Commission’s Energy Division regarding the additional information discussed in this decision to serve customers in 2017-2018. PG&E shall transfer the annualized budget of $2,308,341 to MCE on January 15 each year, starting in 2017.*
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Distributed Energy Resources.

Rulemaking 14-10-003
(Filed October 2, 2014)

COMMENTS OF MARIN CLEAN ENERGY
ON THE AMENDED SCOPING MEMO AND RULING OF ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE

C.C. Song
Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6018
Facsimile: (415) 459-8095
E-Mail: csong@mceCleanEnergy.org

September 15, 2016
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BEFORE THE PUBLIC UTILITIES COMMISSION 
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COMMENTS OF MARIN CLEAN ENERGY 
ON THE AMENDED SCOPING MEMO AND RULING OF ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE

I. INTRODUCTION

Pursuant to the directions set forth in the Amended Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge (“Ruling”) issued on September 1, 2016, Marin Clean Energy (“MCE”) respectfully submits the following comments. MCE’s comments respond to Question 3 and Question 5 provided in the Ruling. Additionally, MCE asks the Commission to clarify the procedural schedule for this proceeding.

II. RESPONSES OF MCE

A. Question 3: Does the attached proposal appropriately balance the need to execute the pilot on a reasonable schedule and provide adequate oversight of implied cost to ratepayers?

The Commission should ensure that the generation, distribution, and transmission benefits of procured resources are appropriately quantified, and cost recovery for the pilot should be conducted proportional to the benefits. This will ensure that no costs are shifted to Direct Access (“DA”) and Community Choice Aggregation (“CCA”) customers. In producing the Post Evaluation Report, the Independent Professional Engineer (“IPE”) should be directed to provide a
detailed analysis to demonstrate the benefits incurred in each function, as well as financial impacts on bundled and unbundled customers.

Unbundled customers paying for generation attributes will inappropriately subsidize bundled customers’ generation service. While procured resources will produce distribution and transmission benefits, and all ratepayers should pay for those benefits, the generation benefits incurred by the procured resources should be solely borne by bundled customers. Unbundled customers, including CCA and DA customers, may not experience generation benefits produced by the IOU-procured resources, and should not be required to pay the costs associated with those generation benefits. If the IOUs are able to recover costs associated with generation benefits from unbundled customers, the pilot would unfairly impact unbundled ratepayers.

In the Pilot Evaluation Report, the IPE should address whether the procured Distributed Energy Resources (“DERs”) have provided generation benefits in addition to transmission and distribution benefits. The IOUs should identify the functions that the procured resources performed, quantify the benefits the resources provided, and apportion the benefits by generation, distribution, and transmission functions. Cost recovery for these resources will then be conducted based on the proportion of benefits received by each function. This analysis will ensure that unbundled customers do not unfairly subsidize generation benefits that are solely received by bundled customers, such as reduced generation rates.

1 Public Utilities Code 707(a)(4)(A). The statute directs the Commission to “incorporate rules that the Commission finds to be necessary or convenient in order to facilitate the development of community choice aggregation programs, to foster fair competition, and to protect cross-subsidization paid by ratepayers.”  
2 Ruling at page 12.
B. Question 5: Are there changes to the attached proposal that you see as essential and without which you would not support adoption of the proposal?

MCE cannot support the pilot without the adoption of a clearly defined performance-based ratemaking regime, where the incentive can only be recovered if the DERs procured meet pre-determined success criteria. The Commission should also provide post-pilot workshops and formal comment opportunities to allow parties to examine the results of the pilots, and identify improvements needed in future DER procurement efforts.

MCE has previously expressed its support for a performance-based ratemaking regime, where the deployed distribution assets would have to meet performance metrics set by the Commission before the IOUs can recover the costs of the projects and the shareholder incentive.3 While the Ruling stated that an incentive can only be claimed when “the DERs procured were successful in avoiding or deferring an otherwise planned utility expenditure,” 4 the definition of “success” remains unclear.

The Commission should initiate a process to establish goals and metrics that these pilots must meet in order to recover costs from any ratepayers and to receive shareholder incentives. Besides examining whether procured DERs can maintain the distribution grid, the pilot should also aim to facilitate DER market innovation and transformation. As MCE expressed in its comments filed on May 9th, 2016, market transformation milestones should be incorporated into the performance metrics and goals, 5 as part of the pre-determined success criteria. This is intended to motivate the IOUs to support the distribution grid in a cost-effective manner, while appropriately valuing DERs.

3 MCE Comments on Joint Ruling Requesting Responses at page 3.
4 Ruling at page 13.
5 MCE Comments on Joint Ruling Requesting Responses at page 3.
Second, in addition to requiring the IOUs to file a Pilot Evaluation Report, the Commission should schedule workshops and establish formal comment periods for parties to provide feedback. This process will serve to develop a formal procedural record that can inform the review in the Energy Resource Recovery Account (“ERRA”) compliance application. Through workshops and comments, the Commission can also determine whether future pilots are needed to further study and refine resource procurement methodologies.

III. THE COMMISSION SHOULD PROVIDE PROCEDURAL CLARIFICATIONS ON THE FUTURE PHASES OF THIS PROCEEDING

MCE respectfully requests the Commission to provide procedural clarifications on the future phases of this proceeding. The Ruling indicated that “the remaining issues from the two phases of this proceeding are hereby combined into one phase” for the purpose of efficient determination of issues that are within the scope of this proceeding. It is unclear whether there will be future phases to this proceeding to determine issues that have previously been mentioned by a previous scoping ruling, but have not yet been addressed in this phase of the proceeding.

Specifically, in the Joint Assigned Commissioner and Administrative Law Judge Ruling and Scoping Memo (“Scoping Memo”) issued on February 26, 2016, the Commission indicated that the future role of the IOUs in the ownership of DERs may be addressed. While the future role of the IOUs does not fit within the scope of the proposed pilot, the Commission should not limit the sourcing mechanisms and IOU ownership of DERs to what is proposed in the pilot.

MCE urges the Commission to examine the utilities’ role and other business models that can incentivize the deployment of DERs. As the Commission indicated in Decision (“D.”) 15-09-

6 Ruling at page 13.
7 Ruling at page 3.
8 Scoping Memo at pages 7 and 8.
022, the overarching goal for the proceeding is to deploy DERs to optimize customer and grid benefits, while enabling California to achieve its climate policy goals.\(^9\) While providing an incentive to IOUs may result in greater DER deployment and grid benefits, there are other mechanisms and models that the Commission should consider to optimize customer and grid benefits.\(^{10}\) MCE respectfully requests the Commission to examine other mechanisms that can optimize the deployment of DERs, including programs, tariffs, and other business models.

IV. CONCLUSION

MCE thanks Assigned Commissioner Florio and Assigned Administrative Law Judge Hymes for the opportunity to provide these comments on the Ruling.

Respectfully submitted,

/s/ C.C. Song

C.C. Song
Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6018
Facsimile: (415) 459-8095
E-Mail: csong@mceCleanEnergy.org

September 15, 2016

\(^9\) D. 15-09-022 at page 28.
\(^{10}\) Other mechanisms could include the Distribution System Operator (“DSO”) model supported by MCE and the Southern California Regional Energy Network (“SoCalREN”). More details can be found in MCE Comments on Joint Ruling Requesting Responses at page 4 and the Comments of SoCalREN at page 5.
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA


PROTEST OF MARIN CLEAN ENERGY TO THE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY SEEKING AUTHORITY TO PROCURE REPLACEMENT POWER FOR THE RETIREMENT OF DIABLO CANYON POWER PLANT AND IMPOSE THE RESULTING COSTS ONTO ALL RATEPAYERS

Jeremy Waen
Senior Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6027
Facsimile: (415) 459-8095
E-Mail: jwaen@mceCleanEnergy.org

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA


PROTEST OF MARIN CLEAN ENERGY TO THE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY SEEKING AUTHORITY TO PROCURE REPLACEMENT POWER FOR THE RETIREMENT OF DIABLO CANYON POWER PLANT AND IMPOSE THE RESULTING COSTS ONTO ALL RATEPAYERS

I. INTRODUCTION


MCE generally supports the retirement of the Diablo Canyon Power Plant (“Diablo Canyon”) as well as PG&E’s commitment to replace Diablo Canyon’s generation with greenhouse-gas (“GHG”) free resources. However, MCE strongly opposes PG&E’s Application for two main reasons: (1) it circumvents existing Commission processes for both energy efficiency (“EE”) and electric resource procurement; and (2) it is a thinly-veiled, unlawful attack against the procurement autonomy of the Community Choice Aggregators (“CCAs”) operating and emerging throughout PG&E’s service territory.
Pursuant to established Commission rules and precedent, this Application proceeding is not the appropriate venue for the Commission to consider or authorize procurement to replace Diablo Canyon, particularly given the immense size and scope of PG&E’s requested procurement and the impact it will have on the entire state. In fact, the Commission already has at least two ongoing proceedings in which it is considering these very same issues: the Integrated Resources Plan (“IRP”) proceeding, Rulemaking (“R.”) 16-02-007; and the EE Business Plan & Rolling Portfolio proceeding, R.13-11-005. PG&E has offered no credible explanation for why the replacement of Diablo Canyon cannot be addressed in the existing IRP and EE proceedings.

PG&E’s proposal would also unlawfully force CCAs to bear the costs of PG&E’s unilateral procurement decisions, which would foist enormous costs onto CCAs, artificially inflate the costs of CCA service when compared to PG&E’s bundled service, and significantly hinder CCAs’ ability to independently procure resources on behalf of their own customers. CCAs are already making procurement decisions that far exceed the targets PG&E proposes for both GHG-free and Renewables Portfolio Standard (“RPS”) procurement, and their customers are already paying the costs related to such CCA procurement. CCA customers also pay a fair and proportionate amount of the costs needed to decommission Diablo Canyon through existing, non-bypassable nuclear decommissioning charges that the Legislature has expressly authorized through statute. Accordingly, the Commission should not allow PG&E to use Diablo Canyon as an excuse to effectively reclaim full control over electric procurement in Northern California or create an entirely new non-bypassable charge without the Legislature’s approval.

PG&E’s proposal would also create an unfair advantage for PG&E in energy efficiency because it proposes to circumvent the Commission’s established rules – including rules related to cost effectiveness – applicable to all other energy efficiency administrators including MCE. If
the Commission were to consider EE program issues within the scope of this proceeding, it could undermine the Commission’s efforts in the ongoing EE proceeding and potentially exclude EE stakeholders that do not have the time and resources to participate in numerous proceedings.

For the foregoing reasons, MCE respectfully requests that the Commission limit the scope of this proceeding to consideration of PG&E’s requests related to the safety and environmental impacts of the closure of Diablo Canyon, employment and property tax issues, and accounting issues (i.e. Issues 6-13 in Section VI.D.3 of the Application).\(^1\) MCE further requests that the Commission expressly exclude all procurement and cost allocation issues from the scope of this proceeding (i.e. Issues 1-5 in Section VI.D.3 of the Application),\(^2\) and direct that such issues be considered within the scope of the Commission’s existing proceedings, including the IRP and EE proceedings.

II. BACKGROUND ON MCE AND CCAS

MCE is the first operational CCA within California. MCE is one of three operational CCAs within PG&E’s service territory, the other two being Sonoma Clean Power Authority and Clean Power San Francisco. Peninsula Clean Energy and Silicon Valley Clean Energy will also soon begin service in PG&E’s service territory. MCE currently provides electric generation services to approximately 250,000 customer accounts within twenty-four distinct communities

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\(^1\) See Application, at 17-18

\(^2\) Id.
across four counties, amounting to approximately 500 megawatts (“MW”) of peak demand.³ MCE’s customers receive generation services from MCE while continuing to receive transmission, distribution, billing and other services from PG&E. Because of this split in electricity service provisions, CCA customers are commonly referred to as “unbundled” electricity customers.

CCAs procure electric supply resources through long-term power purchase agreements to ensure: (i) stability in customers’ rates, (ii) in-state and local economic benefit, and (iii) steady market signals to encourage the continued development of RPS and GHG-free electric resources. CCAs have consistently met or exceeded state procurement mandates, and MCE continues to outpace the state’s Investor Owned Utilities (“IOUs”) in pursuing cleaner procurement portfolios. In 2015, MCE’s Governing Board directed MCE to provide its customers with a default Light Green electricity product containing 80% RPS-eligible and 95% GHG-free electricity by 2025. Since its launch, MCE has also been directed by its Governing Board to not procure electricity from nuclear generation.

The primary factor inhibiting MCE’s ability to achieve its ambitious procurement goals sooner than 2025 is the continued expansion of non-bypassable charges, such as the Power Charge Indifference Adjustment (“PCIA”) and the Cost Allocation Mechanism (“CAM”), that MCE’s customers are continuing to be forced to pay. PG&E’s Application seeks to unlawfully change the non-bypassable charge framework at the Commission by creating a new charge.

³ Communities currently participating in MCE’s CCA include: the City of American Canyon, City of Belvedere, City of Benicia, City of Calistoga, Town of Corte Madera, City of El Cerrito, Town of Fairfax, City of Lafayette, City of Larkspur, City of Mill Valley, County of Marin, City of Napa, County of Napa, City of Novato, City of Richmond, Town of Ross, City of Saint Helena, Town of San Anselmo, City of San Pablo, City of San Rafael, City of Sausalito, Town of Tiburon, City of Walnut Creek, and City of Yountville.
PG&E refers to as the Clean Energy Charge, which would create dramatic further impediments for MCE and other CCAs to cost-effectively procure renewable and GHG-free electricity on behalf of their customers.

For these reasons as well as the general concerns MCE raises throughout this Protest relating to the impact PG&E’s Application could have on MCE’s customers, MCE requests that it be granted party status in this proceeding.

III. BACKGROUND ON DIABLO CANYON POWER PLANT

Diablo Canyon has been highly controversial since before it even started generating electricity, in part because of construction errors that resulted in significant additional costs. Numerous complicating factors for Diablo Canyon have also arisen during the course of its operation, including the discovery of numerous seismic fault lines near the plant and staggering-high estimates for maintenance costs that would be necessary for Diablo Canyon to comply with the state’s Once Through Cooling mandate.

California’s electricity supply and demand profiles have shifted dramatically due to the continuing adoption of renewable electricity generation and distributed energy resources, making an inflexible massive baseload resource like Diablo Canyon less useful for meeting the needs of

4 See http://www.energy-net.org/01NUKE/DIABLO1.HTM
5 Note In particular the Shoreline fault line was discovered in 2008 which is a “few hundred feet” away from coastline on which Diablo Canyon is situated. See http://www.sfgate.com/news/article/PG-E-USGS-disagree-on-Diablo-Canyon-fault-danger-2354326.php
6 Note A study by Bechtel estimated implementing Once Through Cooling at Diablo Canyon could costs as much as $13.3 Billion. See Bechtel Alternative Cooling Technologies Report (Bechtel Report) issued September 2014 cited within PG&E’s Workpaper 004 supporting Table 2-6.
PG&E’s bundled electricity portfolio.\textsuperscript{7,8} All of these factors have rightly compelled PG&E to retire Diablo Canyon.

IV. GROUNDS FOR PROTEST

A. The Commission Should Focus on the Safety, Economic, and Environmental Impacts Related to the Closure of Diablo Canyon

PG&E’s proposed scope for this proceeding is excessively broad and fails to address core issues related to the closure of the facility. Instead of focusing on the steps it will take to ensure that Diablo Canyon’s retirement will not result in adverse safety, economic, and environmental impacts for California’s ratepayers, PG&E’s Application focuses on the various ways in which PG&E proposes to make other entities such as CCAs subsidize its proposed future procurement. Including procurement and cost allocation issues within the scope of this proceeding would distract the Commission from the critical safety, economic, environmental issues related to the closure of Diablo Canyon.

B. Preauthorization for Replacement of Procurement is Inappropriate for an Application Proceeding

PG&E’s Application includes an audacious and unprecedented request for authority to: (i) procure as much as 5,000 GWh of replacement electricity generation through EE, GHG-free, and RPS resources “on behalf of” its own bundled customer as well as CCAs and other load serving entities, and (ii) allocate the costs of its unilateral procurement decisions onto all of the customers in its service territory, including those customers who have chosen to take service

\textsuperscript{7} See Chapters 2 of PG&E’s Testimony wherein PG&E highlights how the continued adoption of EE and Distributed Generation, such as rooftop solar, are reducing overall demand for PG&E’s bundled electricity.

\textsuperscript{8} See Chapter 3 of PG&E’s Testimony wherein PG&E states that the continued operation of Diablo Canyon would result in as much as 35,000 GWh of renewable generation curtailment due to Diablo Canyon’s inflexibility (3-8 and 3-9).
from alternate providers such as CCAs. The Commission should view this request for what it really is—a power grab by PG&E that is meant to counteract the increasing penetration and success of community choice aggregation in PG&E’s service territory.

The Commission already has at least two ongoing rulemakings to address procurement of EE and GHG-free resources: (1) the EE program deployment proceeding, R.13-11-005; (2) the IRP Proceeding, R.16-02-007. Both of these detailed and complex multi-stakeholder processes are already underway. Any parallel consideration of PG&E’s procurement requests within this proceeding would risk undermining the Commission’s EE and IRP efforts, and also potentially exclude stakeholders that do not have the time or resources to actively participate in multiple proceedings. Moreover, given the size and scope of PG&E’s requested Diablo Canyon-related procurement authorizations, the Commission will undoubtedly have to consider such requests in connection with its new holistic IRP planning process.

C. PG&E’s Proposal to Foist Non-Bypassable Charges on CCAs for Bundled Procurement is Unlawful and Inappropriate

Section 366.2 of the Public Utilities Code mandates that CCAs “shall be solely responsible for all generation procurement activities on behalf of [their] customers, except where other generation procurement arrangements are expressly authorized by statute.”9 Likewise, Section 380 directs the Commission to “maximize the ability of community choice aggregators to determine the generation resources used to serve their customers.”10 CCAs are also obligated to meet certain procurement requirements that are overseen by the Commission due to specific

9 California Public Utilities ("P.U.") Code Section 366.2(a)(5).
10 P.U. Code Section 380(b)(5).
statutorily defined requirements, such as RPS,\textsuperscript{11} Resource Adequacy,\textsuperscript{12} and Energy Storage.\textsuperscript{13} Additionally, CCAs are empowered by statute to self-provide resources to meet any renewable energy integration costs they may be deemed responsible for by the Commission.\textsuperscript{14}

The only exclusions to CCA self-procurement that have been authorized by statutes are non-bypassable charges, such as the PCIA and CAM, which spread the costs of IOU procurement and other activities onto CCAs’ customers. These non-bypassable charges are problematic for a number of reasons and the CCAs will continue to address such problems in the appropriate forums. For the purposes of this Application, however, it is entirely unlawful and inappropriate for PG&E to propose that the Commission authorize an entirely new non-bypassable charge – the so-called “Clean Energy Charge” – so that PG&E can pass the costs of its own procurement onto non-bundled customers in its service territory. As set forth above, Section 366.3 of the Public Utilities Code expressly requires that any new non-bypassable charges be authorized by the Legislature through statute, not created by the decree of the very entity (i.e. PG&E) that would stand to benefit most from the existence of such a charge.

PG&E seeks unprecedented and unlawful changes to how non-bypassable charges, and specifically “on behalf of” procurement, is applied to IOU resource procurement. If the Commission wishes to entertain PG&E’s requests for substantial changes to the present framework and balance of non-bypassable charges, it is imperative that the Commission address the issue in a separate, properly-noticed rulemaking dedicated to evaluating the comprehensive

\textsuperscript{11} P.U. Code Section 399.12(j)(2).
\textsuperscript{12} P.U. Code Section 380(a).
\textsuperscript{13} P.U. Code Section 2836(a).
\textsuperscript{14} P.U. Code Section 454.51(d) and 454.52(c).
reform of non-bypassable charges, not through a once-off Application that would only impact a single IOU’s jurisdiction.

D. There is No Rush—the Commission Should Take a Measured and Reasonable Approach to the Closure of Diablo Canyon

The anticipated closure of Diablo Canyon is markedly different from the last major shutdown of a nuclear plant in California, the San Onofre Generating Station (“SONGS”). SONGS was shut down in June 2013 due to emergency circumstances that began with radiation leaks first detected in January 2012.\(^\text{15}\) As a result, the Commission had very little time to assess the impacts related to SONGS’ closure. Unlike Diablo Canyon, which has been determined by the California Independent Systems Operator to not provide a local reliability need,\(^\text{16}\) SONGS served as a critical asset for local reliability needs in both Southern California Edison and San Diego Gas and Electric Companies’ service territories. Given the urgency to replace SONGS-related generation and capacity, the Commission still decided to conduct a SONGS-specific needs assessment within a separate track of the 2012 LTPP rulemaking that ultimately determined to how SONGS generation and capacity would be promptly replace with new resource procurement.

The anticipated shutdown of Diablo Canyon in 2025 is completely different than the unexpected shutdown of SONGS. The Commission has nine years until Diablo Canyon will stop producing electricity, which gives the Commission plenty of time to determine how PG&E should replace the lost generation, whether continued growth by CCAs throughout PG&E’s service territory will offset the need for additional procurement for PG&E’s bundled customers,


\(^{16}\) Chapter 2 of PG&E Testimony at 2-20 and 2-21.
whether such generation should be from new or existing GHG-free resources, and who should pay for it. Even assuming that significant amounts of utility-scale greenfield renewable resources need to be developed, the Commission still has at least 5+ years to authorize the development of such resources. **There simply is no rush, and the Commission should view PG&E’s claims of urgency with significant skepticism.**

Senate Bill 350 directs the Commission to conduct an IRP process to evaluate how long-term electricity procurement plans can help meet the state’s ambitious GHG reduction goals, and the matter of how to replace Diablo Canyon generation in a way that is GHG-emissions net neutral is a perfect test case for this new planning framework. **Accordingly, the Commission should recognize that the IRP is the ideal proceeding to evaluate the replacement electricity procurement needs and constraints caused by the retirement of Diablo Canyon.**

V. **RULE 2.6(D) COMPLIANCE**

A. **Proposed Category**

The instant proceeding is appropriately categorized at “ratesetting.”

B. **Need for Hearing**

Evidentiary hearings will be necessary, at the very least to assess the significant anti-competitive impacts on CCAs resulting from specific non-bypassable charge funding requests within PG&E’s proposal. The factual record will need to be explored in detail to determine whether these proposed cost recovery mechanism are lawful, accurate, and reasonable.

C. **Issues to Be Considered**

The Commission should amend the scope of this Application to clearly state what matters are deemed inside and outside of the scope. Based on the list presented by PG&E in Section
VI.D.3 of its Application, matters that should be deemed outside of the scope should include Issues 1-5 and matters that should remain within the scope include Issues 6-13.

D. Proposed Schedule

MCE believes this proceeding will require a much more thorough exploration of the Application, likely through a combination of workshops and formal discovery. As such, MCE does not believe the schedule presented by PG&E in its initial Application is reasonable. Exactly how much time within the schedule should be reserved for such workshops and discovery will depend heavily on what portions of the Application remain within the formal scope. MCE presents two procedural schedules below: Schedule A assumes MCE’s requests regarding scope are granted, and Schedule B assumes the Application proceeds with the entirety of the scope presented in PG&E’s Application.

17 PG&E Application at 17-18.
**Schedule A – Limited Scope (Items 6-13 Only)**

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<tr>
<th>Date</th>
<th>Event</th>
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<tbody>
<tr>
<td>Aug. 11, 2016</td>
<td>PG&amp;E Files Application</td>
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<tr>
<td>Aug. 16, 2016</td>
<td>Notice of Application in Daily Calendar</td>
</tr>
<tr>
<td>Sept. 15, 2016</td>
<td>Protests and Responses Filed</td>
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<tr>
<td>Sept. 26, 2016</td>
<td>Reply to Protests Filed</td>
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<tr>
<td>Oct. 3, 2016</td>
<td>Prehearing Conference</td>
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<tr>
<td>Oct. 17, 2016</td>
<td>Workshop 1 – Presentation by PG&amp;E on the Details of its Request</td>
</tr>
<tr>
<td>Nov. 4, 2016</td>
<td>ORA and Intervenor Testimony served (if any)</td>
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<tr>
<td>Dec. 2, 2016</td>
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<td>Jan. 23, 2017</td>
<td>Opening Briefs</td>
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<tr>
<td>Feb. 10, 2017</td>
<td>Reply Briefs</td>
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<td>March 3, 2017</td>
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<td>May 2017</td>
<td>Proposed Decision</td>
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<td>June 2017</td>
<td>Final Decision</td>
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## Schedule B – Entire Scope (Items 1-13)

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<td>Oct. 18, 2016</td>
<td>Workshop 2 – Replacement Procurement Request by PG&amp;E</td>
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<tr>
<td>Oct. 19, 2016</td>
<td>Workshop 3 – Cost Allocation Requests by PG&amp;E</td>
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VI. SERVICE

Filings and other communications to this proceeding should be served to the following individuals:

MCE Regulatory
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA  94901
Telephone: (415) 464-6010
Facsimile: (415) 459-8095
E-Mail: regulatory@mceCleanEnergy.org

Jeremy Waen
Senior Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA  94901
Telephone: (415) 464-6027
Facsimile: (415) 459-8095
E-Mail: jwaen@mceCleanEnergy.org

VII. CONCLUSION

MCE thanks Commission President Picker and Assigned Administrative Law Judge Peter V. Allen for their thoughtful consideration of this protest and the issues detailed herein.

Respectfully submitted,

/s/ Jeremy Waen

Jeremy Waen
Senior Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6027
Facsimile: (415) 459-8095
E-Mail: jwaen@mceCleanEnergy.org

September 15, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric
Company for Adoption of Electric Revenue
Requirements and Rates Associated with its
2015 Energy Resource Recovery Account
(ERRA) and Generation Non-Bypassable
Charges Forecast (U 39 E)

Application 14-05-024
(Filed May 30, 2014)

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Catalina Murphy
Legal Assistant
MARIN CLEAN ENERGY
1125 Tamalpias Avenue
San Rafael, CA 94901
Telephone: (415) 464-6014
Facsimile: (415) 459-8095
E-Mail: cmurphy@mceCleanEnergy.org

September 21, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric
Company for Adoption of Electric Revenue
Requirements and Rates Associated with its
2015 Energy Resource Recovery Account
(ERRA) and Generation Non-Bypassable
Charges Forecast (U 39 E)

Application 14-05-024
(Filed May 30, 2014)

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the Commission’s Rules of Practice and Procedure, Marin Clean
Energy (“MCE”) hereby gives notice of the following ex parte communication. By request of
MCE, a phone meeting was held on Wednesday, September 21, 2016 at approximately 10:00 am
between Mr. Scott Murtishaw, Energy Advisor to Commission President Michael Picker, Ms.
Dawn Weisz, CEO of MCE, and Mr. Jeremy Waen, Senior Regulatory Analyst for MCE. The
meeting lasted approximately 30 minutes and no written materials were used.

During this conversation Ms. Weisz and Mr. Waen discussed areas of concern with revised
sections of the July 19, 2016 Revision 1 to the Proposed Decision of ALJ Tsen to resolve the
vintaging methodology for the Power Charge Indifference Adjustment (“PCIA”) for Community
Choice Aggregation (“CCA”). Ms. Weisz and Mr. Waen urged the Commission to resolve these
matters in a manner that strives for administrative simplicity and ease of communication to
customers. Specifically, Ms. Weisz and Mr. Waen argued that the Commission should weigh the
materiality of an individual customer’s impacts on an Investor Owned Utility’s (“IOU”)
procurement due to that customer’s choice to opt out and opt back into CCA service when
determining whether the vintage for that customer’s PCIA obligations should be adjusted. MS.
Weisz and Mr. Waen also argued for the striking of the sentence within section 2.3 that reads “If
the CCA chooses not to participate in the BNI process, it must then assume the risk for all IOU power purchased up to the CCA’s initiation of service” because it is factually flawed and would risk the creation of legal error if included in the Final Decision. Ms. Weisz and Mr. Waen also asked for the Commission to provide clearer guidance within the Proposed Decision for what the Commission expects should happen if consensus cannot be reached on certain issues within the working group described by Ordering Paragraph 4. Lastly, Ms. Weisz and Mr. Waen made themselves available to answer any questions that Mr. Murtishaw had on these matters.

Respectfully submitted,

/s/ Catalina Murphy

Catalina Murphy
Legal Assistant
MARIN CLEAN ENERGY
1125 Tamalpias Avenue
San Rafael, CA 94901
Telephone: (415) 464-6014
Facsimile: (415) 459-8095
E-Mail: cmurphy@mceCleanEnergy.org

September 21, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of its Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for Program Years 2015-2017.

And Related Matters.

Application 14-11-007 (Filed November 18, 2014)
Application 14-11-009
Application 14-11-010
Application 14-11-011

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Catalina Murphy
Legal Assistant
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6014
Facsimile: (415) 459-8095
E-Mail: cmurphy@mceCleanEnergy.org

September 2, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of its Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for Program Years 2015-2017.

And Related Matters.

Application 14-11-007
(Filed November 18, 2014)

Application 14-11-009
Application 14-11-010
Application 14-11-011

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the Commission’s Rules of Practice and Procedure, Marin Clean Energy ("MCE") hereby gives notice of the following ex parte communication. The communication was held in-person on August 31, 2016 at the California Public Utilities Commission offices in San Francisco, CA at 4:25 PM and lasted approximately 40 minutes. The meeting was initiated by Marin Clean Energy and included Beckie Menten, MCE Director of Customer Programs, Mike Callahan-Dudley, MCE Regulatory Counsel, and Michael Colvin, Advisor to Commissioner Sandoval.

At the beginning of the meeting, Ms. Menten expressed support for the Alternate Proposed Decision (APD). Ms. Menten highlighted several beneficial components of the alternate decision including policy changes and authorization for MCE to deliver energy efficiency to low-income communities supported by Energy Savings Assistance Program (ESAP). Ms. Menten discussed the benefits of streamlining the delivery of programs to customers including the general energy efficiency programs and ESAP, as proposed in MCE's Low-Income Families and Tenants (LIFT) pilot proposal that the alternate proposed decision
approves, with modifications. Ms. Menten recommended the heat pump measures be included in the pilot due to ability to pass the 3-prong test, cost effectiveness in certain settings, and the ability to implement demand response and thermal storage. Ms. Menten also identified that the changes proposed in the APD reflect recommendations from stakeholders who have been working on these issues for many years, whereas the Proposed Decision (PD) largely reflects status quo.

Ms. Menten highlighted several policy changes in the APD. The APD removes the modified three-measure minimum rule, allows for ESAP funding for common area measures, and removes prohibition against serving a customer that has been served in the past ten years. Ms. Menten noted that MCE supported these policy changes leading up to the issuance of the proposed decisions. Ms. Menten suggested that the Single Point of Contact (SPOC) model should include simultaneous delivery of programs.

Mr. Callahan-Dudley stated that MCE supports the APD and that it supports MCE applying for future funding and that all CCAs should have the same opportunities. Mr. Callahan-Dudley also suggested the Commission ensure funding is available to MCE for the pilot. MCE also asked about the implications of requesting ESAP participants to participate in DR programs or dynamic pricing tariffs.

Respectfully submitted,

/s/ Catalina Murphy

Catalina Murphy
Legal Assistant
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6014
Facsimile: (415) 459-8095
E-Mail: cmurphy@mceCleanEnergy.org

September 2, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2015 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast (U 39 E)

Application 14-05-024 (Filed May 30, 2014)

MARI N CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Catalina Murphy
Legal Assistant
MARIN CLEAN ENERGY
1125 Tamalpias Avenue
San Rafael, CA 94901
Telephone: (415) 464-6014
Facsimile: (415) 459-8095
E-Mail: cmurphy@mceCleanEnergy.org

September 27, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric
Company for Adoption of Electric Revenue
Requirements and Rates Associated with its
2015 Energy Resource Recovery Account
(ERRA) and Generation Non-Bypassable
Charges Forecast (U 39 E)  

Application 14-05-024  
(Filed May 30, 2014)

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the Commission’s Rules of Practice and Procedure, Marin Clean Energy (“MCE”) hereby gives notice of the following ex parte communication. By request of MCE, a phone meeting was held on Tuesday, September 27, 2016 at approximately 11:10 am between Ms. Sepideh Khosrowjah, Chief of Staff and Advisor to Commissioner Florio, Ms. Shalini Swaroop, Regulatory and Legislative Counsel of MCE, and Mr. Jeremy Waen, Senior Regulatory Analyst for MCE. The meeting lasted approximately 12 minutes and no written materials were used.

During this conversation Ms. Swaroop and Mr. Waen discussed areas of concern with revised sections of the July 19, 2016 Revision 1 to the Proposed Decision of ALJ Tsen to resolve the vintaging methodology for the Power Charge Indifference Adjustment (“PCIA”) for Community Choice Aggregation (“CCA”). Ms. Swaroop and Mr. Waen urged the Commission to resolve these matters in a manner that strives for administrative simplicity and ease of communication to customers. Specifically, Ms. Swaroop and Mr. Waen argued that the Commission should weigh the materiality of an individual customer’s impacts on an Investor Owned Utility’s (“IOU”) procurement due to that customer’s choice to opt out and opt back into CCA service when determining whether the vintage for that customer’s PCIA obligations should
be adjusted. Ms. Swaroop and Mr. Waen also asked for the Commission to provide clearer
guidance within the Proposed Decision for what the Commission expects should happen if
consensus cannot be reached on certain issues within the working group described by Ordering
Paragraph 4. Lastly, Ms. Swaroop and Mr. Waen made themselves available to answer any
questions that Ms. Khosrowjah had on these matters.

Respectfully submitted,

/s/ Catalina Murphy

Catalina Murphy
Legal Assistant
MARIN CLEAN ENERGY
1125 Tamalpias Avenue
San Rafael, CA 94901
Telephone: (415) 464-6014
Facsimile: (415) 459-8095
E-Mail: cmurphy@mceCleanEnergy.org

September 27, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Rulemaking 13-11-005  
(Filed November 14, 2013)

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Catalina Murphy  
Legal Assistant  
MARIN CLEAN ENERGY  
1125 Tamalpais Avenue  
San Rafael, CA 94901  
Telephone: (415) 464-6014  
Facsimile: (415) 459-8095  
E-Mail: cmurphy@mceCleanEnergy.org

October 10, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA


Rulemaking 13-11-005  
(Filed November 14, 2013)

MARIN CLEAN ENERGY NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the Commission’s Rules of Practice and Procedure, Marin Clean Energy (“MCE”) hereby gives notice of the following ex parte communication. The communication was initiated by MCE and occurred on October 6, 2016 at approximately 11:40 a.m. at the California Public Utilities Commission offices. The communication was between Beckie Menten, MCE Director of Customer Programs, and David Gamson, Chief Advisor to Commissioner Peterman, and lasted approximately 30 minutes. The communication was oral and no written materials were provided.

In the meeting, Ms. Menten discussed Decision 16-08-019. Ms. Menten discussed the role of Community Choice Aggregator’s (“CCAs”) in the context of the new statewide and third party programs. Ms. Menten also sought guidance on attribution for statewide programs, specifically, how to determine the share apportioned to CCAs due to an inconsistency in the Decision. Ms. Menten also discussed MCE’s proposals for the downstream pilots.
Respectfully submitted,

/s/ Catalina Murphy

Catalina Murphy
Legal Assistant
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6014
Facsimile: (415) 459-8095
E-Mail: cmurphy@mceCleanEnergy.org

October 10, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for
Adoption of Electric Revenue Requirements and Rates
Associated with its 2015 Energy Resource Recovery
Account (ERRA) and 2015 Generation Non-
Bypassable Charges Forecasts (U 39 E).

A.14-05-024
(Filed May 30, 2014)

OPENING COMMENTS OF CITY OF LANCASTER,
MARIN CLEAN ENERGY AND SONOMA CLEAN POWER AUTHORITY
ON THE PROPOSED DECISION

Scott Blaising
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.
915 L Street, Suite 1270
Sacramento, CA 95814
Telephone: (916) 712-3961
E-mail: blaising@braunlegal.com

Counsel for the City of Lancaster
and Sonoma Clean Power Authority

August 8, 2016
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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for
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Bypassable Charges Forecasts (U 39 E).

OPENING COMMENTS OF CITY OF LANCASTER,
MARIN CLEAN ENERGY AND SONOMA CLEAN POWER AUTHORITY
ON THE PROPOSED DECISION

In accordance with Rule 14.3 of the Rules of Practice and Procedure of the Public Utilities Commission of the State of California (“Commission”), the city of Lancaster (“Lancaster”), Marin Clean Energy (“MCE”) and Sonoma Clean Power Authority (“SCPA”) (collectively, “CCA Parties”) hereby submit the following comments on the Proposed Decision of ALJ Tsen (“Proposed Decision”). The CCA Parties’ proposed changes to the findings of fact and conclusions of law are set forth in Appendix A.

I. INTRODUCTION AND SUMMARY

Commission staff are to be commended for resolving a longstanding concern of the CCA Parties – one first raised by MCE over two years ago.\(^1\) Commission staff undertook extraordinary efforts to fully understand the “endless permutations in which PCIA vintages can

\(^1\) See Proposed Decision at 13; note 29 (referencing the Response of Marin Clean Energy at 4-5 [“[Pacific Gas and Electric Company’s ("PG&E")] ‘re-vintaging’ [methodology] distorts the purpose of the [Power Charge Indifference Adjustment ("PCIA")]] and enables PG&E to recover procurement costs from unbundled customers indefinitely. Such re-vintaging occurrences provide PG&E with a significant competitive advantage.”].
be reset….” Commission staff also sought to more fully understand broader PCIA issues. All
told, staff coordinated and managed two key workshops, including the development of
accompanying workshop reports, and analyzed multiple rounds of written comments and briefs.
The CCA Parties appreciate these extraordinary efforts.

The Proposed Decision concludes that, among other defects, “[t]he current [vintaging]
methodology is administratively cumbersome” and “inconsistent with Commission
precedents.” The CCA Parties support these conclusions. Based on these foundations and on
the bundled customer indifference principle, the Proposed Decision generally provides a fair and
easily-implemented solution to the vintaging issue. However, the Proposed Decision requires
clarification in two areas.

First, the Proposed Decision should be clarified with respect to its conclusion that
“vintages are assigned based on initial service in a territory [and] that vintage should be locked
to the service area.” Specifically, as further described below, even in a CCA service
“area/territory” that, for administrative or other reasons, has multiple roll-out tranches, a single
vintage should apply, provided the roll-out is described in the implementation plan for the
service area.

Second, the Proposed Decision should be clarified insofar as necessary to ensure that the
Proposed Decision’s lone “re-vintaging” exception only applies when it is reasonably clear that
the investor-owned utility (“IOU”) would expect to incur long-term generation liabilities. As it

________________________________________
2  See Proposed Decision at 14.
3  See Proposed Decision at 14.
4  See Proposed Decision at 20; Conclusion of Law 2.
5  See, e.g., Proposed Decision at 16 (“We believe th[e] [adopted] method is consistent with
commission precedent, is administratively simple, and conforms with the bundled customer
indifference principle.”)

Opening Comments of the CCA Parties on the Proposed Decision
stands now, the Proposed Decision could be construed as saddling a single residential customer with a new vintage if that customer remains with the IOU and then later elects to receive service from the Community Choice Aggregator. Such an approach would violate the Commission’s administrative simplicity standard, and it would be at odds with Commission precedent that embraces a materiality standard – one that assumes reasonable levels of load migration. The Proposed Decision should be clarified to apply the re-vintaging exception to customers large enough to materially impact IOU long-term load forecasts, not residential or small customers.

Finally, the CCA Parties commend the Commission for inviting further collaborative efforts with respect to PCIA reforms. The CCA Parties look forward to participating in the working group process inaugurated in the Proposed Decision, particularly with respect to key issues surrounding the transparency and “certainty” of the PCIA. The working group process is the first step in fulfilling the commitment made by the Commission to re-examine PCIA issues. The CCA Parties are committed to working collaboratively through the working group process to ultimately achieve the goal first articulated by the Assigned Commissioner: “to come up with a [PCIA] method which complies with Commission precedent, reduces stranded costs to bundled customers, and allows for an eventual end to vintaging charges.”

II. COMMENTS

A. The Proposed Decision Should Further Underscore The Universality Of A Single Vintage Within A CCA Service Territory

The Proposed Decision adopts a simple, overarching approach to the PCIA within “a CCA area/territory.” At the outset, it might be helpful to define terms. The Proposed Decision interchangeably refers to the terms “area” and “territory,” and the CCA Parties understand these

terms to mean a discrete geographic area within which the Community Choice Aggregator will provide service, as reflected in its CCA implementation plan. As illustrated by MCE’s and SCPA’s programs, the breadth of a Community Choice Aggregator’s overall CCA “program” may, over time, include multiple service areas.7 These multiple service areas might have different vintages reflective of different service initiation dates.8 Importantly, however, as further discussed below, roll-out tranches or phases within a particular service area would not have different vintages; all roll-out tranches or phases within a service area would have the same vintage. The CCA Parties believe this is clearly reflected in the Proposed Decision.

The Proposed Decision states that “PCIA vintages [should] be assigned to CCA customers based on the date that CCA service is initiated in that area—whether it is through initiating service, or the binding notice of intent process.”9 As part of its explanation of this approach, the Proposed Decision further states that “[s]ince vintages are assigned based on initial service in a territory, that vintage should be locked to the service area.”10 Simply stated, within a CCA service area there will be one PCIA vintage, with only one exception: a later vintage will be assigned to individual customers that affirmatively opt out of CCA service, receive service from an IOU and then return to CCA service, and in doing so negatively affect the IOU’s generation procurement liabilities.

The clarity and simplicity of the Proposed Decision’s approach may be compromised by

7 For example, MCE’s CCA program has grown over time to include multiple service areas. MCE’s service area relating to the city of Richmond is different than MCE’s CCA service area relating to unincorporated Napa County.
8 For example, MCE initiated CCA service to unincorporated Napa County in February 2015 and MCE will initiate CCA service to the incorporated cities in Napa County in September 2016, resulting in different vintages for these service areas.
9 Proposed Decision at 15.
10 Proposed Decision at 15.
PG&E. On July 29, 2016, counsel for PG&E distributed what PG&E refers to as “Vintaging Implementation Rules” (“PG&E Rules”). PG&E distributed the PG&E Rules for the purpose of advancing its views and getting input, in particular on a situation PG&E believes is not “explicitly addressed” in the Proposed Decision. Specifically, PG&E wishes to advance a new rule for “circumstances where a [Community Choice Aggregator] phases in service for a single geographic period [sic] over an extended period of time – in some cases up to 5 to 6 years.”

Under the PG&E Rules, instead of having one PCIA vintage for the entire CCA service area, as reflected in the Proposed Decision, customers within the same CCA service area would have different PCIA vintages. The PG&E Rules would assign a later PCIA vintage to customers that are part of successive roll-out tranches within the same CCA service area.

In light of potential confusion and customer inequity caused by the PG&E Rules, the Proposed Decision should further clarify that a single PCIA vintage will apply to a CCA service area irrespective of the fact that the Community Choice Aggregator may roll-out or phase-in service in that area over different periods of time, provided such roll-out is described in the Community Choice Aggregator’s CCA implementation plan.

Not only is the “one vintage” approach explicitly called out in the Proposed Decision, but treatment of the roll-out circumstance also can be reasonably inferred with reference to other parts of the Proposed Decision. An example of this is the Proposed Decision’s treatment of

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11 The CCA Parties understand that PG&E will be introducing the PG&E Rules as part of its opening comments. As requested by PG&E, counsel for the CCA Parties provided initial feedback and input on the PG&E Rules. While the CCA Parties are appreciative of PG&E’s effort to obtain advanced feedback, the CCA Parties are dismayed that PG&E has chosen yet-again to pursue an approach that would make the PCIA vintaging methodology “administratively cumbersome” and “inconsistent with Commission precedents.”
“new service points in a CCA territory.”12 The Proposed Decision states that “[w]e also see no reason why new vintages would need to be assigned to new service points in a CCA territory after initiation of CCA service.”13 As rationale, the Proposed Decision further states that “[s]ince we task each CCA with forecasting its load once it initiates service, any new load within CCA territory should be assigned the same vintage based on the CCA phase in date.”14 From a long-term generation procurement perspective, there is no practical difference between the IOU’s procurement obligation for a “new service point,” on the one hand, and a customer in a succeeding roll-out tranche, on the other hand. This is so because re-vintaging (i.e., assigning a later vintage) turns on whether there is an obligation or reasonable expectation to procure long-term resources.15 The operative issue is who, as between the IOU and the Community Choice Aggregator, has the reasonable expectation of providing for the long-term electric needs of the load. In both cases, since the Community Choice Aggregator is the default provider, this expectation resides with the Community Choice Aggregator.16 As such, in both cases there is no need to assign a later vintage.

As described above, the CCA Parties believe that the Proposed Decision should be reinforced to affirm that a single vintage will apply to the entire service area reflected in the Community Choice Aggregator’s CCA implementation plan, even in a service area that, for

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12 See Proposed Decision at 14 -15.
13 Proposed Decision at 14.
14 Proposed Decision at 15.
15 See, e.g., D.08-09-012; Appendix C (defining “stranded costs” as “costs related to utility investments in generation plants or long-term power contracts that are not economical in a competitive market.”).
16 See, e.g., Administrative Law Judge’s Ruling Establishing Second Phase And Amending Scope Of The Proceeding, dated February 26, 2015 at 1 (describing Community Choice Aggregators as “default providers for customers within their service area after the phase in date.”). See also Phase 2 Workshop Report, dated March 27, 2015, at 4.
administrative or other reasons, has multiple roll-out tranches. Relying on the Community Choice Aggregator’s CCA implementation plan should allay any fears or concerns that PG&E may have as to its need to procure long-term generation resources for later roll-out tranches.

B. The Proposed Decision Should Be Clarified So That The Re-Vintaging Exception Only Applies To Customers That Might Impact The IOUs’ Generation Liabilities

The Proposed Decision establishes a lone exception to the rule that a single PCIA vintage should apply universally to all customers within the CCA service territory: The Proposed Decision states that the “PCIA vintage should be reset only when a customer affirmatively opts out of CCA service, and then opts back in at a later time.” The basis for this exception is a finding by the Proposed Decision that “utilities incur generation liabilities on behalf of those customers, and a new PCIA vintage should be assigned when they elect to leave bundled service at a later date.” As further described below, while such a finding might apply with respect to large customers that migrate, this finding would not apply to residential and small customers. Moreover, resetting the PCIA vintage for every residential or small customer that might switch (perhaps even mistakenly based on confusion regarding the opt-out process) would violate the administrative simplicity standard, which is repeatedly and clearly articulated in the Proposed Decision. For these reasons, the Proposed Decision should be modified to clarify that resetting the PCIA vintage only applies to large customers. For those customers, the PCIA should reflect only the incremental generation liabilities incurred on their behalf for the time period they

17 Proposed Decision at 14 (emphasis added). The Proposed Decision concludes that the relevant period for considering a customer’s “opt out” is at the phase in or initiation of CCA service, not later action by the customer. (See Proposed Decision at 21; Conclusion of Law 3. See also Finding of Fact 9, Conclusion of Law 1 and Ordering Paragraph 2.) This point should be further clarified, as described in Attachment A.

18 Proposed Decision at 14. See also Proposed Decision at 20; Finding of Fact 9.
received IOU service (i.e., from their initial opt out until their return to CCA service).

Minor customer load migration has been previously addressed by the Commission. In D.08-09-012, the Commission described how small CCA customer migration (switching) issues should be addressed in the context of the PCIA. Importantly, the Commission did not intimate that the PCIA vintage should be reset for small load migration. To the contrary, the Commission embraced the view that small load variations should level out over time and should not result in stranded costs.19 As such, the remedy provided was not tied to the PCIA and re-vintaging; rather, the remedy provided was tied to forecasting, with the expectation that the IOUs are fully capable of adjusting their portfolios to account for small load variations.20 Stated differently, in these situations, the utilities do not incur long-term generation liabilities, and therefore there are no “stranded” costs to be recovered.21

The Proposed Decision is right to give great weight to the importance of administrative simplicity. For example, in criticizing the re-vintaging methodology, the Proposed Decision held that the “[t]he current methodology is administratively cumbersome…”22 while stating that

19 See, e.g., D.08-09-012 at 21 (“[T]here may be differences between the amounts of departing load implicit in the load forecasts and the amounts recorded on a year-by-year basis, over time any such variations should level out and bundled customer indifference will be maintained.”).

20 See, e.g., D.08-09-012 at 54 (“[T]he utilities can, over time, adjust their load forecasts and resource portfolios to mitigate the effects of [departing load] on bundled service customer indifference.”).

21 See note 18, above (describing the Commission’s definition of “stranded costs”). See also D.04-12-046 at 29 (describing the connection between proper resource planning by the IOUs and the recovery of stranded costs [“Our complementary objective is to minimize the CRS (and all utilities liabilities that are not required) and promote good resource planning by the utilities.”]).

22 See Proposed Decision at 14.
the adopted methodology is “administratively simple.” Assigning a new PCIA vintage to residential and small customers that switch service would violate the administrative simplicity standard. This approach is also not justified. As shown above, it would be factual error to hold that the IOUs incur stranded costs for minor levels of small customer load switching; this simply is not the case. As such, the CCA Parties request that the Proposed Decision be clarified to ensure that re-vintaging does not apply to residential or small customers.

C. The CCA Parties Look Forward To Collaboratively Participating In The Upcoming PCIA Working Group Process

The Proposed Decision references the wide-ranging discussion that occurred at the March 8, 2016 PCIA workshop, and then concludes that “[m]ost parties at the workshop seemed amenable to working together whether as a working group or through settlement negotiations to propose changes to the PCIA program.” As a result, the Proposed Decision directs the formation of a working group, co-led by SCPA and Southern California Edison Company (“SCE”). The working group will address issues related to the PCIA, with particular focus on improved transparency and certainty related to the PCIA. The CCA Parties support this effort.

Changes to the PCIA methodology should be expected. This is consistent with past Commission decisions and natural insofar as such changes reflect future expectations based on actual history of CCA activities. As noted by the Assigned Commissioner, “[w]hen the Commission issued its line of decisions and resolution on [Community Choice Aggregators] and

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23 See Proposed Decision at 16. See also Proposed Decision at 11-12; note 23 (referencing D.[0]4-12-046 at 27 [stating “a preference for a method that resulted in ‘administrative simplicity and certainly for the CCAs and the Utilities.’”]).

24 Proposed Decision at 17.

25 See Proposed Decision at 18.
vintaging issues, the implementation of CCA programs was in its nascent stage."26 This view was underscored by the Commission in D.08-09-012 when it stated that “[a]t this time, there is insufficient history of such [CCA] transactions and limited knowledge of [CCA] customers’ intent to pursue such transactions in the future, for the [Investor-Owned Utilities (“IOUs”)] to use in determining how much, or how long, power should be procured on such customers’ behalf.”27 Nevertheless, instead of categorically fixing a particular methodology, the Commission stated that “[g]iven the potential long-term nature of the charge, we must allow for the possibility that certain future circumstances may result in a need to modify the NBC related processes adopted in this decision.”28

One of the most notable areas where a change is needed relates to new load in a CCA service area. The CCA Parties addressed this extensively in their opening brief.29 The CCA Parties recognize that the Proposed Decision addresses this issue as follows: “[s]ince we task each CCA with forecasting its load once it initiates service, any new load within CCA territory should be assigned the same vintage based on the CCA phase in date.”30 However, as noted above, the principal reason previously given by the Commission for not addressing CCA load in a manner comparable to municipal departing load was the absence of “sufficient history” of CCA transactions and knowledge about customers’ intent to pursue CCA service.31 Much has changed in nearly eight years. As such, the CCA Parties request that the working group and Commission give place for robust discussion on whether new load within a CCA service area should be

26  ACR at 3.
27  D.08-09-012 at 20 (emphasis added).
28  D.08-09-012 at 57-58.
29  See CCA Parties Opening Brief at 14-16.
30  Proposed Decision at 15.
31  See note 30 (citing D.08-09-012 at 20).
exempt from the PCIA, and if not whether there are nevertheless distinctions that would allow new load to be treated differently with respect to PCIA vintaging.

In sum, with the passage of time and actual operating history, there has been increasing expectations that the Commission would engage in an ongoing examination of the PCIA. To date, however, this has not occurred in a substantive way, and so the CCA Parties reiterate their appreciation for the Commission’s willingness to now examine these key issues.

III. PROPOSED CHANGES

In accordance with Rule 14.3(c), and in light of the discussion above, the CCA Parties set forth certain revised findings of fact and conclusions of law, as shown in Appendix A.

IV. CONCLUSION

The CCA Parties thank Administrative Law Judge Tsen and Commissioner Florio for their attention to the matters discussed herein.

Dated: August 8, 2016
Respectfully submitted,

/s/ Scott Blaising

Scott Blaising
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, CA 95814
Telephone: (916) 712-3961
E-mail: blaising@braunlegal.com

Counsel for the City of Lancaster
and Sonoma Clean Power Authority

/s/ Shalini Swaroop

Shalini Swaroop
Regulatory Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Drive
San Rafael, CA 94901
Telephone: (415) 464-6040
E-Mail: sswaroop@mceCleanEnergy.org

Counsel for Marin Clean Energy

Appendix A: Redlined Changes to the Findings of Fact and Conclusions of Law

32 See, e.g., D.13-08-023 at 17. (“[W]e continue to be open to re-evaluating specific departing load charges in appropriate proceedings if changed circumstances warrant doing so.”)
Appendix A  
to the  
Opening Comments of City of Lancaster, Marin Clean Energy  
And Sonoma Clean Power Authority on the Proposed Decision  

In accordance with Rule 14.3(c), the CCA Parties provide this appendix setting forth revised finding of facts and conclusions of law that incorporate comments offered by the CCA Parties:

<table>
<thead>
<tr>
<th>Finding of Fact 9</th>
<th>When a large customer in a CCA territory opts out of CCA service and remains a bundled customer, the utility may incur unexpected, long-term generation costs on that customer’s behalf.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conclusion of Law 1</td>
<td>PCIA vintage should be assigned to a CCA territory based on the date of initial CCA service, except for large customers that opt to remain with the incumbent utility and then opt back into CCA service at a later time. The PCIA vintage should be the same for the entire CCA territory, even for a CCA territory that rolls-out service in different tranches, provided the roll-out plan is described in the CCA implementation plan.</td>
</tr>
<tr>
<td>Conclusion of Law 3</td>
<td>Since large customers may cause the utilities to incur unexpected, long-term generation costs, large customers opting out of CCA service at the phase in date should be assigned a new vintage if and when they opt into CCA service at a later date.</td>
</tr>
</tbody>
</table>
Opening Comments of the CCA Parties on the Proposed Decision
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

A.14-05-024
(Filed May 30, 2014)

NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the California Public Utilities Commission’s (“Commission”) Rules of Practice and Procedure, the city of Lancaster (“Lancaster”), Marin Clean Energy (“MCE”) and Sonoma Clean Power Authority (“SCPA”) (collectively, “CCA Parties”) hereby give notice of the following ex parte communication.

The communication was initiated by the CCA Parties and consisted of an e-mail, dated September 12, 2016, sent by Scott Blaising, counsel to the CCA Parties, to Sepideh Khosrowjah, chief of staff to Commissioner Michael Florio, and Matthew Tisdale, energy advisor to Commissioner Michael Florio. The following energy advisors were also copied on the e-mail: Scott Murtishaw (Commission President Michael Picker), Ehren Seybert (Commissioner Carla Peterman), Sean Simon (Commissioner Liane Randolph) and Michael Colvin (Commissioner Catherine Sandoval). A copy of the e-mail is attached. Consistent with Rule 8.3(c)(3), a copy of the e-mail was forwarded to the service list for A.14-05-024 on the same day that the e-mail was sent to the decisionmakers.

Dated: September 14, 2016

Respectfully submitted,

Scott Blaising
BRAUN BLAISING MC LAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, California 95814
Telephone: (916) 712-3961
E-mail: blaising@braunlegal.com

Counsel for the CCA Parties
Scott Blaising

Scott Blaising

From: Scott Blaising
Sent: Monday, September 12, 2016 5:16 PM
To: Sepideh Khosrowjah (sepideh.khosrowjah@cpuc.ca.gov); Matthew Tisdale (matthew.tisdale@cpuc.ca.gov)
Cc: Scott Murtishaw (sgm@cpuc.ca.gov); Ehren Seybert (ehren.seybert@cpuc.ca.gov); Sean Simon (sean.simon@cpuc.ca.gov); Colvin, Michael
Subject: A.14-05-024 - Deletion of Erroneous Statement in Agenda Decision

Sepidah and Matthew –

I am writing to your office since Commissioner Florio is the assigned commissioner in A.14-05-024 (PCIA vintaging phase). However, I am copying other commissioners’ energy advisors in order to apprise them of this matter and seek their assistance and support. Additionally, consistent with Rule 8.3(c)(3), I plan to forward this e-mail later today to parties on the service list for A.14-05-024.

I received a copy of the revised agenda decision in A.14-05-024 (PCIA vintaging matters). (See attached redlined copy.) The agenda decision has been revised to clarify that the Binding Notice of Intent (BNI) process is the only means by which a multi-phase Community Choice Aggregation (CCA) program may be implemented so that a single Power Charge Indifference Amount (PCIA) vintage applies to the entire CCA service territory. For reasons previously stated, the CCA parties believe that the BNI process should not be the only means by which a single PCIA vintage would apply. Relying only on the BNI process departs from and contradicts the Commission’s general requirement that investor-owned utilities (IOUs) must use all reasonable means of forecasting departing load associated with CCA programs. That said, the CCA parties will not re-argue this point. Rather, by this e-mail the CCA parties urge the deletion of a statement in the agenda decision that is clearly erroneous as a matter of law.

Specifically, the agenda decision states as follows: “If the [Community Choice Aggregator] chooses not to participate in the BNI process, it must then assume the risk for all IOU power purchased up to the CCA’s initiation of service.” (See attached redlined Agenda Decision at 16 [yellow-shading]; emphasis added.) This statement is wrong and unnecessary to support other elements of the agenda decision. Nowhere in any decision has the Commission imposed an obligation on the Community Choice Aggregator for power procured by the IOU unless the Community Choice Aggregator participates in the BNI process. Stated differently, if a Community Choice Aggregator does not participate in the BNI process it has no obligation for power purchased by the IOU. As written, however, the agenda decision would purport to extend this obligation. Such an extension is inappropriate and unfounded. As such, the CCA parties request that the above-noted sentence be deleted from the final decision.

Thank you for your consideration of this request.

Scott Blaising,
On behalf of the City of Lancaster, Marin Clean Energy and Sonoma Clean Power Authority
Braun Blaising McLaughlin & Smith PC
915 L Street, Suite 1480
Sacramento, CA 95814
(916) 712-3961 (cell)
blaising@braunlegal.com

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Application 16-06-003
Adoption of Electric Revenue Requirements and Rates (Filed June 1, 2016)
Associated with its 2017 Energy Resource Recovery
Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast
Revenue and Reconciliation (U 39 E).

OPENING BRIEF OF MARIN CLEAN ENERGY

Scott Blaising
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, CA 95814
Telephone: (916) 712-3961
E-mail: blaising@braunlegal.com
Counsel for Marin Clean Energy

Jeremy Waen
Senior Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Drive
San Rafael, CA 94901
Telephone: (415) 464-6027
E-Mail: jwaen@mceCleanEnergy.org

September 27, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for
Adoption of Electric Revenue Requirements and Rates
 Associated with its 2017 Energy Resource Recovery
Account (ERRA) and Generation Non-Bypassable
Charges Forecast and Greenhouse Gas Forecast
Revenue and Reconciliation (U 39 E).

Application 16-06-003
(Filed June 1, 2016)

OPENING BRIEF OF MARIN CLEAN ENERGY

In accordance with the Scoping Memo And Ruling Of Assigned Commissioner, dated August 18, 2016 (“Scoping Memo”), and pursuant to the Rules of Practice and Procedure of the Public Utilities Commission of the State of California (“Commission”), Marin Clean Energy (“MCE”) hereby submits this opening brief on matters relating to Pacific Gas and Electric Company’s (“PG&E”) forecasted Power Charge Indifference Adjustment (“PCIA”) for 2017, and related matters. References to exhibits below are to PG&E’s and MCE’s exhibits, with numbering designations accepted at the evidentiary hearing and via e-mail by Administrative Law Judge (“ALJ”) Tsen on September 16, 2016.

Other than the Introduction and Summary sections below, MCE has conformed its opening brief to the common briefing outline agreed to by the parties.

INTRODUCTION

MCE is a community choice aggregator that has been serving customers within PG&E’s service territory since May 7, 2010. MCE operates the first Community Choice Aggregation (“CCA”) program in California. MCE currently provides electric supply services to approximately 250,000 customer accounts within twenty-four distinct communities across four
counties, amounting to approximately 500 megawatts (‘MWs’) of peak electric demand.\footnote{Communities currently participating in MCE’s CCA program include: the City of American Canyon, City of Belvedere, City of Benicia, City of Calistoga, Town of Corte Madera, City of El Cerrito, Town of Fairfax, City of Lafayette, City of Larkspur, City of Mill Valley, County of Marin, City of Napa, County of Napa, City of Novato, City of Richmond, Town of Ross, City of Saint Helena, Town of San Anselmo, City of San Pablo, City of San Rafael, City of Sausalito, Town of Tiburon, City of Walnut Creek, and City of Yountville.} For context and by comparison, MCE’s load is approximately 4 percent of the load served by PG&E. As with other CCA programs, MCE operates as the default provider of electric supply service within its service territories, providing electric supply services to its customers while PG&E provides delivery and billing services.

MCE’s customers are subject to PG&E’s procurement costs by way of so-called non-bypassable charges (‘NBCs’), principal of which is the PCIA. As described in the Scoping Memo, “[t]he PCIA is intended to maintain legislatively mandated ‘bundled customer indifference’….\footnote{Scoping Memo at 5.}” Importantly, the PCIA can be positive and it can also be “negative,” reflecting the Commission’s long-held policy pronouncement that “bundled customers should be no worse off, nor should they be any better off as a result of customers choosing alternative energy suppliers (ESP, CCA, POU or customer generation).\footnote{Decision (‘D.’) 08-09-012 at 10 (emphasis added).}”

As the Commission is well aware, policy and technical issues surrounding the PCIA are complex, thorny and interrelated, and are of particular importance with respect to the emergence of CCA programs.\footnote{See generally Final Workshop Report, introduced into the record of Application (“A.”)14-05-024 (Phase 2) by ALJ ruling on September 9, 2016 (“PCIA Workshop Report”).} In light of the importance of these issues, a separate, rulemaking-like phase was established in A.14-05-024, involving all investor-owned utilities (“IOUs”), to consider
PCIA-related issues for CCA customers.\textsuperscript{5} Given unresolved PCIA-related issues in that phase, and the “DA and CCA parties’ legitimate interest in increased transparency and the ability to forecast long term PCIA trends”, parties anticipate the occurrence of further Commission-directed efforts aimed at modifying existing PCIA decisions.\textsuperscript{6}

In this proceeding, two far-reaching PCIA changes were announced by PG&E, both of which implicate the other IOUs and are best resolved in the context of broad-based, working group discussions. First, as revealed through cross-examination, PG&E has already implemented a significant PCIA change without express Commission authorization.\textsuperscript{7} Specifically, PG&E has eliminated the PCIA for pre-2009 Vintage customers. What this means, among other things, is that the PCIA, which is \textit{negative}, is no longer available for customers to offset another NBC, the ongoing Competition Transition Charge (“\textbf{CTC}”). Stated differently, PG&E now collects more revenue from NBCs, to the benefit of bundled customers, than it otherwise would have had PG&E not eliminated the pre-2009 negative PCIA. In addition to being surreptitious and unauthorized, PG&E’s action in eliminating the pre-2009 PCIA pre-judges and unilaterally implements an outcome that is presently being litigated by the other IOUs.\textsuperscript{8}

Second, in last year’s ERRA proceeding, PG&E revealed in a data request response that it planned to simply eliminate PG&E’s billion-dollar negative indifference amount balance.

\textsuperscript{5} See D.15-12-022 at 20-21 (Conclusions of Law 3-5).

\textsuperscript{6} See, e.g. Agenda Decision in A.15-04-024 (Revision 1) ("PCIA Agenda Decision") at 25 (Ordering Paragraph 5) (directing participants to present recommended PCIA changes in the form of Petitions to Modify or a Petition for Rulemaking ("Future PCIA Petitions").

\textsuperscript{7} See Reporter’s Transcript ("RT") at 39:2 – 42:21 (PG&E/Barry).

\textsuperscript{8} As discussed in Section VIII.A, below, in their respective ERRA proceedings Southern California Edison Company (“\textit{SCE}”) and San Diego Gas & Electric Company (“\textit{SDG&E}”) are objecting to elimination of the pre-2009 PCIA.
PG&E provided no description of this plan in its application or testimony. When discovered by MCE, MCE strongly opposed PG&E’s plan. The Commission deferred the issue, ordering PG&E to expressly request authority to dispose of the negative indifference amount balance. Elimination of PG&E’s sizable negative indifference amount balance implicates a host of policy issues, as further described below, affecting the other IOUs. Moreover, PG&E’s proposal would upend numerous Commission decisions that repeatedly affirm the ongoing relevance and importance of maintaining negative indifference amounts and applying these amounts to offset positive charges.

For these and other reasons, MCE argues below that PG&E’s proposals should be rejected in this proceeding. These proposals are best addressed in the context of upcoming discussions on changes to the PCIA. If it so chooses, PG&E may seek such changes in the context of those discussions.

**SUMMARY OF MCE’S POSITIONS**

The following is a summary of MCE’s principal positions and recommendations, as further described below:

- Since customers under PG&E’s Green Tariff Shared Renewables (“GTSR”) program are subject to the PCIA, PG&E should provide additional information in future ERRA applications about the applicability of the PCIA to GTSR customers and ratemaking inputs related to such charges (e.g., revenues, credits, dollar flows, etc.)

- The Commission should order PG&E to reinstate the negative PCIA for pre-2009 Vintage customers (with credits for past overcharges) until the Commission has decided whether it is appropriate to eliminate the negative indifference amount balance and offsetting credits related thereto. PG&E failed to provide proper notice to the Commission and parties of this material ratemaking change. PG&E’s reliance on silence is unreasonable. Additionally, because PG&E’s

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9 See D.15-12-022 at 9.
10 See D.15-12-022 at 23 (Ordering Paragraph 5).
proposal to remove the pre-2009 PCIA implicates similar issues being addressed in the other IOUs’ respective ERRA proceedings, this issue should be addressed in the context of the Future PCIA Petitions process.

- PG&E’s proposal to eliminate the negative indifference amount balance should be rejected in this proceeding. While MCE believes that PG&E’s proposal is contrary to numerous Commission decisions, and could be categorically rejected by the Commission, MCE believes that PG&E should have an opportunity to present its proposed changes as part of the Future PCIA Petitions process.

COMMON BRIEFING OUTLINE\textsuperscript{11}

I. INTRODUCTION

Not applicable. MCE has set forth certain introductory statements and background information in the preceding section.

II. PROCEDURAL BACKGROUND

The Commission has designated the IOUs’ ERRA proceedings as the appropriate forum for addressing issues related to the calculation of the overall Cost Responsibility Surcharge (“CRS”), and its associated components (including the PCIA).\textsuperscript{12} The Scoping Memo reiterates that the focus of this proceeding is on ratemaking and compliance issues, not policy issues.\textsuperscript{13} PG&E’s two proposals raise major policy-related issues. To its credit, PG&E was following Commission directive in last year’s ERRA decision (D.15-12-022) with respect to one of

\textsuperscript{11} The outline and major headings used below are those agreed to by the parties, as submitted by PG&E to ALJ Tsen on September 15, 2016.

\textsuperscript{12} See, e.g., D.06-07-030 at 57; Ordering Paragraph 6. See also D.08-09-012 at 69 (“[I]ssues regarding consistency of the implementation and calculation of the CRSs with respect to this decision can be raised and litigated in the forecast phase of the IOUs’ ERRA proceedings.”) and D.11-12-018 at 8 (“The indifference amount is updated annually in each IOU’s Energy Resource Recovery Account (ERRA) proceeding.”).

\textsuperscript{13} See Scoping Memo at 4 (emphasis added) (“As we have stated before, the ERRA forecast proceeding is a ratesetting proceeding intended to address rate recovery for annual forecasted procurement costs and not to resolve policy issues.”).
PG&E’s proposals (elimination of PG&E’s negative indifference amount balance). That said, it is appropriate to reconsider this procedural directive in light of two intervening events.

First, subsequent to the issuance of D.15-12-022, the Commission conducted a PCIA workshop and received into the record of A.14-05-024 (Phase 2) several documents and presentations that suggest changes are needed to the PCIA methodology. In response, the Commission is poised to issue a final decision that, among other things, directs the formation of a working group and orders the presentation of PCIA-related reforms. In light of this subsequent activity, it is reasonable and appropriate to address PG&E’s negative indifference amount proposal in the context of the Future PCIA Petitions process. Addressing this issue in isolation in this proceeding is not consistent with a holistic approach to PCIA, and excludes key related issues and parties (specifically, SDG&E and SCE). For reasons aptly stated in the PCIA Agenda Decision, single ERRA proceedings are simply not the appropriate forum for considering PCIA changes.

Second, subsequent to the issuance of D.15-12-022, similar issues implicating PG&E’s negative indifference amount proposal (and PG&E’s negative PCIA proposal) were raised in SDG&E’s and SCE’s respective ERRA proceedings. As described more fully in Section VIII.A, below, the other IOUs have positions that are contrary to PG&E’s position with respect to the continuing applicability of the PCIA for pre-2009 Vintages. Because this issue is not an IOU-

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14 See PCIA Agenda Decision at 24 (Ordering Paragraphs 4 and 5). The PCIA Agenda Decision is scheduled for adoption at the September 29, 2016 Commission meeting [Item 2].

15 See, e.g., PCIA Agenda Decision at 22 (Finding of Fact 16) (“[A]ny proposed [PCIA] changes must occur within the appropriate forum.”). See also PCIA Agenda Decision at 2 (“While [PCIA reform] views merit further exploration, they are outside the scope of the current Energy Resource Recovery Account proceeding.”).
specific issue, but rather affects all IOUs, the Commission should address this issue in a single forum.

III. PG&E’S 2017 ERRA FORECAST REQUESTS

A. ERRA Forecast Revenue Requirement And Inclusion in Rates
Not applicable. MCE has no position or recommendation on this matter.

B. Ongoing Competition Transition Charge (CTC) Forecast Revenue Requirement
Not applicable. MCE has no position or recommendation on this matter.

C. Power Charge Indifference Amount Forecast Revenue Requirement
Not applicable. MCE has no position or recommendation on this matter.

D. Cost Allocation Mechanism (CAM) Revenue Requirement
Not applicable. MCE has no position or recommendation on this matter.

IV. PG&E’S 2017 ELECTRIC SALES FORECAST

Not applicable. MCE has no position or recommendation on this matter. That said, MCE offers a few statements in Section VII, below, on PG&E’s proposal for a process to include CCA load forecasts.

V. GREENHOUSE GAS ISSUES

A. ERRA Forecast Revenue Requirement And Inclusion in Rates
Not applicable. MCE has no position or recommendation on this matter.

B. Ongoing Competition Transition Charge (CTC) Forecast Revenue Requirement
Not applicable. MCE has no position or recommendation on this matter.

C. Power Charge Indifference Amount Forecast Revenue Requirement
Not applicable. MCE has no position or recommendation on this matter.

D. Cost Allocation Mechanism (CAM) Revenue Requirement
Not applicable. MCE has no position or recommendation on this matter.

VI. PG&E’S NEGATIVE INDIFFERENCE AMOUNT PROPOSAL

A. PG&E’s Proposal To Eliminate The Negative Indifference Amount Balance Must Be Understood Within The Context Of Bundled Customer Indifference

In this proceeding, PG&E proposes to eliminate its negative indifference amount balance. The balance is currently about one billion dollars. By PG&E’s calculation, this would mean that PG&E’s bundled customers have benefited, in the form of reduced generation rates, by over $77 million. PG&E’s proposal to eliminate this major balance is essentially the flip-side of the coin to action prematurely taken by PG&E to eliminate the negative PCIA. In effect, what PG&E is saying is that the Commission’s clear and repeated pronouncements regarding the carry-forward of negative indifference amounts and the use of negative PCIA to offset the CTC do not apply now that the Department of Water Resource’s (“DWR”) contracts have expired. To properly understand the import of PG&E’s proposal (and its premature action), it is first necessary to generally review the Commission’s hallmark doctrine with respect to NBCs: bundled customer indifference. Further exploration of this doctrine is also provided in Section VI.C, below.

Bundled customer indifference has its roots in the original CCA law - Assembly Bill (“AB”) 117, and relates to the recovery of the IOU’s “net unavoidable” electricity costs. As stated by the Commission, “[t]he threshold policy issue underlying cost responsibility surcharges is to ensure that remaining bundled ratepayers remain indifferent to stranded costs left by the

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16 See D.14-12-053 at 11. See also PG&E-1 at 10-6 (Table 10-2; line no. 10).
17 See PG&E-1 at 10-8:11-12.
18 See discussion below in Section VIII.A.
19 See, e.g., PG&E-1 at 10-8:24-27.
departing customers.”21 “Indifference” is defined as the scenario in which “bundled customers should be no worse off, nor should they be any better off as a result of customers choosing alternative energy suppliers (ESP, CCA, POU or customer generation).”22 As such, bundled customer indifference is a two-way street; costs as well as benefits must be considered.23 In situations involving a “negative” indifference amount, the Commission has held that, temporally, bundled customers have been “better off.”24 This condition of being “better off” would violate the bundled customer indifference principle but for the fact that the IOUs have been directed to maintain negative indifference amount balances, carry this negative balance forward and eventually use the negative balance to offset a positive balance, thereby resulting in bundled customer indifference.25

B. PG&E Has a Vastly Different View of Bundled Customer Indifference Than The Commission Does

Through cross-examination, it became clear that PG&E has a view of bundled customer indifference that is markedly different than and contrary to the Commission’s view. This view has permeated PG&E’s actions. On the one hand, the Commission has stated that a negative

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21 D.08-09-012 at 10 (referencing D.04-12-048; Finding of Fact 28).
22 D.08-09-012 at 10 (emphasis added). Bundled customers are better off because the departure of customers has allowed the IOU to use more of its lower-cost generation resources to serve bundled customers.
23 Senate Bill (“SB”) 790 underscored this point as follows: “Estimated net unavoidable electricity costs paid by the customers of a community choice aggregator shall be reduced by the value of any benefits that remain with bundled service customers, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits.” (Pub. Util. Code § 366.2(g) (added by SB 790).)
24 See, e.g., D.08-09-012 at 41 (“If the total portfolio costs are lower than market costs resulting in a negative indifference amount, the customers’ departure is economic.”).
25 See, e.g., D.08-09-012 at 48 (“It is similarly necessary that negative indifference amounts be carried over for use in subsequent years to maintain bundled customer indifference.”).
indifference amount means that bundled customers are better off as a result of the departure of customers.\textsuperscript{26} To mitigate this temporal effect, the Commission requires a carry-forward and future offsetting of the negative indifference amount.\textsuperscript{27} On the other hand, \textit{PG&E} asserts unreservedly and without support that “[t]he amounts that accumulate…in the negative indifference [have] no benefit to bundled customers.”\textsuperscript{28} In this regard, \textit{PG&E} merely views the bundled customer indifference as a theoretical exercise using administratively determined inputs, not real data, producing no practical benefit.\textsuperscript{29}

\textbf{C. \textit{PG&E’s Has Repeatedly And Unsuccessfully Attempted To Eliminate The Carry-forward Of Negative Indifference Amounts}}

\textit{PG&E} has tried numerous times to eliminate the mitigating effect of negative CRS elements, whether it is the PCIA or other NBCs. In response, the Commission has repeatedly rejected \textit{PG&E}’s efforts, principally because \textit{PG&E}’s proposals undermine and violate the overarching rule governing the CRS – bundled customer indifference.

The use of negative PCIA balances was first addressed by the Commission in D.06-07-030, in which the Commission expressly held that “[t]he PCIA component of DA CRS may be a negative number in those instances in which ongoing competition transition charge (CTC) is larger than the indifference charge, so that overall indifference is maintained.”\textsuperscript{30} The Commission addressed a similar issue in D.07-05-005, which was issued in response to a petition

\textsuperscript{26} See, e.g., D.08-09-012 at 41.
\textsuperscript{27} See, e.g., D.08-09-012 at 48.
\textsuperscript{28} RT at 53:3-8 (\textit{PG&E}/Barry).
\textsuperscript{29} See, e.g., RT at 54:14-20 (\textit{PG&E}/Barry) (“So customers won’t be better off because of the calculation. It simply reflects that the portfolio for that particular forecast year is below an – a forecast, administratively-determined market price benchmark. They are no better off, no worse off.”)
\textsuperscript{30} D.06-07-030; Ordering Paragraph 7 (emphasis added).
for modification filed by PG&E. PG&E argued that negative CRS amounts should not be carried-forward to be used to offset positive CRS amounts. In D.07-05-005, the Commission rejected PG&E’s proposed modification, expressly stating that “PG&E’s proposed modification would not result in bundled customer indifference.”31 The Commission affirmed that “in order to maintain indifference, both positive and negative indifference effects must still be tracked, with the negative amounts offsetting positive amounts.”32

PG&E again tried to upend these directives in R.06-02-013 – the proceeding that examined, among other things, how the indifference amount should be calculated with the inclusion of so-called “new world” generation resources. In that proceeding, as it had done repeatedly in past proceedings, PG&E advanced a proposal that, if approved, would have resulted in a negative indifference element not being used to offset a positive indifference element. In D.08-09-012, the Commission again flatly rejected PG&E’s proposal. In that decision, the Commission first affirmed the ongoing relevance of D.07-05-005 with respect to the principle of bundled customer indifference, stating that “[w]hile the Commission’s reasoning in [D.07-05-005] applied to the existing DA/DL CRS calculations, the basic principles directly relate to handling of negative charges in this proceeding….33 As it had previously concluded in D.07-05-005, the Commission likewise concluded in D.08-09-012 that “[i]t is similarly necessary that negative indifference amounts be carried over for use in subsequent years to

31 D.07-05-005 at 19.
32 D.07-05-005 at 19.
33 D.08-09-012 at 48.
maintain bundled customer indifference. The total portfolio approach is consistent with this principle. PG&E’s separate approach is not.”

Apparently unaffected by the Commission’s repeated rejections, PG&E again advanced a proposal in R.07-05-025 (PCIA Reform) that would have had the effect of eviscerating negative indifference amounts. In D.11-12-018, the Commission rejected PG&E’s proposal, recounting the numerous times in which the Commission had previously rejected PG&E’s “similar proposals” and reiterating the Commission’s continuing view that negative amounts must be used to offset positive amounts.

Although apparently PG&E would prefer to ignore the Commission’s views with respect to negative indifference amounts, it should not be allowed to do so. The Commission’s views are as relevant now as they were the numerous times in the past that such views have been used to reject PG&E’s previous proposals.

D. The Commission Should Again Reject PG&E’s Proposal To Eliminate Its Negative Indifference Amount Balance

In D.15-12-022, the Commission ordered PG&E to request authority from the Commission if PG&E wished to retire its billion-dollar negative indifference balance. In its application, PG&E seeks Commission authorization “to retire the DWR PCIA negative indifference amount…” Importantly, PG&E refers to the PCIA as the “DWR PCIA,” and

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34 D.08-09-012 at 48.
35 See D.11-12-018 at 40 (“Consistent with our prior review of similar proposals as noted in the above-referenced decisions, we find no basis to approve PG&E’s proposed modification here. … PG&E’s proposal would violate the bundled customer indifference principle by recognizing only the cost to bundled customers…while not recognizing the offsetting benefit accruing to bundled customers….”).
36 See D.15-12-022 at 23 (Ordering Paragraph 5).
37 PG&E Application at 11.
hangs the entirety of its legal argument on the mistaken view that “[b]ecause the last DWR contract has expired, it is now appropriate to retire the negative indifference amount consistent with the Commission’s earlier determination.”38 As discussed below, PG&E’s proposal runs contrary to the Commission’s fundamental “bundled customer indifference” standard. Moreover, PG&E’s proposal hinges on an anachronistic and wrong view of the Commission’s earlier determinations with respect to DWR contracts. As such, the Commission should reject PG&E’s proposal.

Boiled down to its core elements, the issue raised by PG&E’s proposal is as follows: is it proper and consistent with the bundled customer indifference standard to continue to apply negative indifference amounts as an offset against positive indifference amounts? Contrary to PG&E’s view, the Commission has said repeatedly, and in particular in recent years, the answer is “yes.” In short, the Commission’s precedent in this regard can be summarized with reference to two fundamental Commission holdings, both of which stand in opposition to PG&E’s proposal. First, “[t]he threshold policy issue underlying cost responsibility surcharges is to ensure that remaining bundled ratepayers remain indifferent to stranded costs left by the departing customers.”39 Second, “[i]t is similarly necessary that negative indifference amounts be carried over for use in subsequent years to maintain bundled customer indifference.”40 These

38 PG&E Application at 11. See also Exhibit PG&E-1 at 10-8 (“Retirement is warranted at this time because the underlying DWR contracts have all expired or been terminated and thus, the requirement to preserve customer indifference for this portfolio of resources is no longer applicable.”) and Exhibit PG&E-1 at 10-6 (“The last remaining DWR contract eligible for stranded cost recovery pursuant to D.06-07-030 expired on April 15, 2015, which effectively ended the need for stranded cost recovery.”).
39 D.08-09-012 at 10 (referencing D.04-12-048; Finding of Fact 28).
40 D.08-09-012 at 48.
holdings stand in opposition to PG&E’s proposal, and PG&E’s reliance on the expiration of DWR contracts is unavailing to overcome this opposition.

Indeed, the entirety of PG&E’s argument for eliminating the negative indifference amount balance hinges on the fact that the DWR contracts have expired, and PG&E’s belief that, as a result, the Commission’s holdings with respect to carrying forward of negative indifference amounts are no longer applicable. In this regard, PG&E’s argument must be examined from two perspectives. First, from a practical perspective, PG&E stands alone among the IOUs in the view that the expiration of DWR contracts has halted application of the carry-forward requirement, as described in Sonoma Clean Power Authority’s (“SCPA”) protest. SCPA shows as an example SCE’s continuing use of its negative indifference amount and then rightly observes that if expiration of the carry-forward requirement coincides with expiration of DWR contracts, as PG&E supposes, “....it is unusual that the other investor-owned utilities have not implemented this action, particularly since the other investor-owned utilities’ Department of Water Resources’ (DWR) contracts expired much earlier than PG&E’s DWR contracts.”

Second, from a legal perspective, PG&E’s argument stands in flat contrast to the express holding in D.08-09-012. Interestingly, PG&E’s legal analysis does not mention D.08-09-012, relying instead on two pre-D.08-09-012 decisions to explain the “use of the negative indifference amount.” D.08-09-012 directly addresses the issue raised by PG&E’s proposal, as follows:

“[T]he current provisions related to negative indifference charge carryover for use in subsequent years should be continued once DWR power charge recovery ends. Again, this is necessary to maintain bundled customer indifference. D.07-05-005 did

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41 See SCPA Protest at 3-5.
42 SCPA Protest at 4.
43 See Exhibit PG&E-1 at 10-6:6-7 (“The Commission has addressed the use of the negative indifference amount associated with the DWR PCIA in D.06-07-030 and D.07-05-005.”).
state that at the expiration of the DWR contract term, the applicability of the indifference requirement would also expire. That made sense in the context of that decision, since it was the recovery of the DWR contracts themselves that necessitated the total portfolio approach and bundled customer indifference as it relates to such recovery. With the expiration of the DWR contract term, none of this would have been necessary, and the applicability of the indifference requirement as it relates to DWR power charge cost recovery should also have ended. However, with the inclusion of D.04-12-048 cost recovery as part of the total portfolio, the reasons cited in D.07-05-005, as discussed above as to why negative indifference charge carryover is appropriate, apply even after expiration of the DWR contract term. That reasoning is as valid for cost recovery related to the ongoing CTC and D.04-12-048 charges as it was for cost recovery related to the ongoing CTC and DWR power charges.44

It is difficult to see how the Commission could have been clearer on this point. Nevertheless, to punctuate this point and provide additional certainty to PG&E, the Commission subsequently stated in D.11-12-018 that “[c]onsistent with our prior review of similar proposals as noted in the above-referenced decisions, we find no basis to approve PG&E’s proposed modification here. … PG&E’s proposal would violate the bundled customer indifference principle by recognizing only the cost to bundled customers…while not recognizing the offsetting benefit accruing to bundled customers….”45

E. PG&E Is Free To Resurrect Its Negative Indifference Amount Proposal As Part Of The Future PCIA Petitions Process

As shown above, PG&E’s reliance on pre-D.08-09-012 decisions is misplaced. D.08-09-012 speaks authoritatively about the continuing applicability of negative indifference amounts after the expiration of DWR contracts. PG&E offers nothing in its testimony to suggest that changed circumstances warrant a reversal of D.08-09-012’s clear holding. Moreover, even if PG&E were to attempt to do so, a single IOU’s ERRA proceeding is the wrong forum for

44 D.08-09-012 at 51-52. See also D.08-09-012 at 99 (Finding of Fact 28) (“With the inclusion of D.04-12-048 cost recovery as part of the total portfolio, the reasons cited in D.07-05-005 as to why negative indifference charge carryover is appropriate apply even after expiration of the DWR contract term.”).

45 D.11-12-018 at 40.
addressing this proposed modification. Elimination of the negative indifference amount implicates a host of important PCIA issues. If PG&E wishes to propose such a fundamental change, it should do so as part of the Future PCIA Petitions process where appropriate scrutiny and discussion may occur, and due process afforded.

VII. PG&E’S PROPOSAL FOR A PROCESS TO INCLUDE CCA LOAD FORECASTS

In its testimony, PG&E offers what it refers to as a “formalized process” that will facilitate and presumably improve PG&E’s ability to forecast departing load associated with CCA programs.46 It is unclear to MCE what PG&E means by a “formalized process,” since PG&E states that, “[u]nder [its] proposal, [Community Choice Aggregators] are not required to submit the requested information to PG&E.”47 MCE requests that the Commission view PG&E’s proposal as an informal, collaborative process that is reflective of the joint interest held by PG&E and Community Choice Aggregators to properly forecast departing load. Additionally, MCE offers the following two points.

First, recognition by the Commission of this informal, collaborative process should not negatively affect the ability of Community Choice Aggregators to meaningfully engage in discovery and other means of exploring and addressing departing load forecast information after PG&E submits its ERRA application. If PG&E intends that its proposed “formalized process” would have this negative effect, MCE objects to it. Often, departing load forecast information is only revealed through a discovery process, and MCE would not want this process to be compromised.

46 See Exhibit PG&E-1 at 2-12 – 2-14.
47 Exhibit PG&E-1 at 2-13:6-8 (emphasis added).
Second, recognition by the Commission of this informal, collaborative process should not limit or modify the controlling policy with respect to PG&E’s obligation to forecast departing load.\textsuperscript{48} The IOUs are required to use information \textit{from all reasonable sources}, including in particular from the Community Choice Aggregators and the California Energy Commission, to estimate levels of departing load.\textsuperscript{49} PG&E’s proposed process should not limit or modify this standard, and PG&E should continue to use information from all reasonable sources to estimate levels of departing load.

With these points in mind, MCE does not object to PG&E’s use of its proposed process as an informal, collaborative process.

\textbf{VIII. WHETHER ALL CALCULATIONS, INCLUDING BUT NOT LIMITED TO THE CALCULATION OF THE ERRA, ONGOING CTC, PCIA, CAM, GHG, NON-BYPASSABLE CHARGES, ERRA UNDER-COLLECTION, PROCUREMENT COSTS, VINTAGING, ARE IN COMPLIANCE WITH ALL APPLICABLE RESOLUTIONS, RULINGS, AND DECISIONS FOR ALL CUSTOMER TYPES}

\textbf{A. PG&E’s Premature Elimination Of The PCIA For Pre-2009 Vintage Customers Has Not Been Authorized And PG&E’s Action In This Regard Compromises Other Parties’ Rights To Litigate This Issue}

At the evidentiary hearing, PG&E’s witness revealed that PG&E has already eliminated the negative PCIA for pre-2009 Vintage customers.\textsuperscript{50} When asked to show authority for PG&E’s elimination of the negative PCIA, the best that PG&E’s witness could do was generically point to PG&E’s “2016 ERRA decision” (D.15-12-022), essentially arguing from

\begin{footnotesize}
\begin{itemize}
\item \textsuperscript{48} See Scoping Memo at 4 (“As we have stated before, the ERRA forecast proceeding is a ratesetting proceeding intended to address rate recovery for annual forecasted procurement costs and not to resolve policy issues.”).
\item \textsuperscript{49} See, \textit{e.g.}, D.14-02-040 at 16.
\item \textsuperscript{50} See RT at 39:15-16 (PG&E/Barry) (“So our tariffs today for 2016 do not reflect a pre-2009 PCIA.”).
\end{itemize}
\end{footnotesize}
silence.51 In essence, PG&E’s regulatory formula seems to be reliant on a double-negative: (a) if PG&E did not “present a PCIA associated with that vintage in last year's testimony”52 and (b) if D.15-12-022 did not address the absence of a pre-2009 PCIA then (c) the Commission must have authorized PG&E’s action. PG&E’s pattern of surreptitiously addressing key PCIA matters through inarticulate, improperly noticed and even subversive means should not be countenanced by the Commission.53 This pattern denies parties reasonable notice of proposals that might negatively affect them or have significant policy ramifications. If PG&E wishes to make significant changes to the PCIA it should properly notify the Commission and parties. PG&E failed to do so, again, in this case.

The action taken by PG&E in eliminating the negative PCIA is neither trivial nor ministerial. The action has major policy and practical ramifications. As noted earlier, SDG&E and SCE are facing the flip-side of this same issue in their respective ERRA proceedings.54 Specifically, using arguments similar to those advanced by PG&E, the Alliance for Retail Energy Markets and Direct Access Customer Coalition (“DA Parties”) submitted testimony on August 8, 2016 in SDG&E’s ERRA proceeding (A.16-04-018) and on August 19, 2016 in SCE’s ERRA proceeding (A.16-05-001) in which the DA Parties asserted that the PCIA should be

51 See RT at 39:17-26 (PG&E/Barry).
52 RT at 39:24-26 (PG&E/Barry).
53 See D.15-12-022 at 9 (noting that PG&E’s proposal to have its negative indifference amount balance “simply go away” was not presented by PG&E in its application or testimony, but rather needed to be ferreted out by MCE in a data request).
54 Pursuant to Rule 13.9 and Evid. Code § 452(d), the Commission may take official notice in this proceeding of the existence of this issue in SDG&E’s and SCE’s respective ERRA proceedings. See, e.g., D.16-01-014 at 20 (affirming, among other things, that the Commission may “take official notice of the existence of pleadings…in other proceedings….”).
eliminated for pre-2009 Vintage customers. SDG&E and SCE are opposed to this proposal. In consultation with SDG&E and SCE, the DA Parties agreed to withdraw this testimony and to instead use the briefing process as the means by which the DA Parties will argue for elimination of the PCIA. As currently calendared, opening briefs on this issue will be presented in both proceedings on October 3, 2016, with reply briefs due on October 14, 2016.

PG&E’s witness acknowledged at the evidentiary hearing that the practical effect of a negative PCIA is that it offsets the CTC. Implicit in this acknowledgement is the understanding that the practical effect of not having a negative PCIA to offset the positive CTC is that PG&E will be collecting from departing customers CTC revenue that it would not have otherwise collected. This benefits bundled customers and affects bundled customer indifference.

PG&E should be directed to promptly reinstate the negative PCIA, and adjust customers’ bills accordingly. PG&E has failed to properly notify the Commission and parties of its plan (and subsequent action) to materially change the PCIA methodology. If PG&E wishes to propose this change, it should do so in the context of other PCIA-related changes (e.g., the Future PCIA Petitions process). Likewise, MCE urges ALJ Tsen to coordinate with ALJ Kelly

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55 In the case of SDG&E and SCE, the pre-2009 Vintage PCIA is positive, not negative.
56 See e-mail ruling of ALJ Kelly (A.16-04-018), dated September 15, 2016 and e-mail ruling of ALJ Miles (A.16-05-001), dated September 22, 2016.
57 See RT at 46:3-4 (PG&E/Barry).
58 See RT at 50:27 – 51:9 (PG&E/Barry).
59 PG&E’s witness implicitly acknowledged this point by stating that “[t]he more revenues [PG&E] expect[s] to receive from the PCIA, the lower the bundled customers' generation rate will be.” (RT at 33:27 – 34:2). By no longer offsetting the CTC with a negative PCIA, PG&E is collecting more revenue and thereby lowering bundled customers’ generation rate.
and ALJ Miles in order that this fundamental PCIA change may be considered on a statewide basis, not in individual ERRA proceedings.

**B. Since The PCIA Is Now Applicable To GTSR Customers, PG&E Should Provide Additional Information Regarding Its Calculation And Other Related Ratemaking Matters**

At the evidentiary hearing, PG&E’s witness stated that this is the first ERRA proceeding in which GTSR issues have been addressed.\(^6\) By Commission decision, GTSR customers are supposed to pay the PCIA insofar as this charge is generally intended to reflect the above-market costs for resources that were already procured on behalf of GTSR customers that depart bundled procurement.\(^6\) Details of how this charge is derived are supposed to be included both in the IOUs’ respective GTSR advice letters and also in the IOUs’ respective annual ERRA forecast proceeding.\(^6\)

PG&E’s witness acknowledged that, although GTSR customers continue to receive power from PG&E, GTSR customers are similar to departing customers insofar as “they are served with a different portfolio of resources for the commodity….”\(^6\) As a result, and consistent with D.15-01-051, the PCIA applies to GTSR customers,\(^6\) reflecting “the stranded costs associated with the resource commitments made on behalf of customers that now [accept] the [GTSR] option.”\(^6\)

\(^6\) See RT at 11:12-13 (PG&E/Barry).
\(^6\) See generally D.15-01-051 at 100-104.
\(^6\) See D.15-01-051 at 103-104.
\(^6\) RT at 14:3-4 (PG&E/Barry).
\(^6\) See RT at 15:14-17 (PG&E/Barry).
\(^6\) RT at 16:18-21 (PG&E/Barry).
With respect to accounting treatment, PG&E’s witness stated that, similar to revenue associated with PCIA payments by departing customers, revenue associated with payment of the PCIA by GTSR customers is subtracted from the ERRA revenue requirement, which is collected from bundled customers.\textsuperscript{66} Moreover, PG&E’s witness also spoke to the fact that PG&E separately books and accounts for PCIA amounts that are received by GTSR customers, on the one hand, and by departing customers, on the other hand.\textsuperscript{67} While PG&E’s witness orally described this process, she was unable to point to testimony to demonstrate how this process is applied, referring instead to workpapers.\textsuperscript{68}

Based on the information provided by PG&E, MCE makes the following recommendation. MCE recommends that, with respect to GTSR customers, PG&E should be directed to provide more descriptive rate, load and accounting information in next year’s ERRA application. Although PG&E states that GTSR load is different than departing load, it has many characteristics that make it similar to departing load. As such, to the same extent and degree PG&E provides information on departing load, PG&E should provide comparable information on GTSR load.

Based on discussion at the evidentiary hearing,\textsuperscript{69} PG&E submitted Exhibit PG&E-5, which was later accepted into the record. Exhibit PG&E-5 provides a narrative explanation on certain matters relating to the PCIA, as well as a quantitative analysis of how the GTSR program affects overall procurement costs. This is a helpful start, however, more is required. PG&E should be directed to provide information in Exhibit PG&E-5 as part of its testimony in next

\textsuperscript{66} See RT at 19:23 – 20:15 (PG&E/Barry).
\textsuperscript{67} See RT at 24:19 – 26:18 (PG&E/Barry). See also RT at 30:1-5 (PG&E/Barry).
\textsuperscript{68} See RT at 21:27 – 22:17 (PG&E/Barry).
\textsuperscript{69} See RT at 22:18 – 23:9 (PG&E/Middlekauff).
year’s ERRA proceeding, but PG&E should also be directed to provide additional information to show how GTSR load is factored into the calculation of the PCIA. In short, PG&E should be directed to provide the same information about GTSR load as it does for departing load.

IX. **MAKING THE PCIA SUBJECT TO REFUNDS**

The Scoping Memo states that the Commission in this proceeding plans to address “whether the PCIA should be subject to refund once procurement information is no longer confidential to market participants.”\(^70\) In last year’s ERRA proceeding (A.15-04-024), MCE and other parties extensively addressed certain ratemaking tools, such as balancing accounts, that could be used to more equitably, economically and accurately apply the PCIA. As observed in various pleadings in this year’s ERRA proceeding, PCIA “rate shock” and ratemaking concerns regarding transparency continue to be of significant concern.\(^71\)

MCE appreciates the Commission’s examination of appropriate ratemaking treatment in the context of the PCIA, and MCE supports making the PCIA subject to refund, or subjecting the PCIA to other ratemaking adjustments (such as balancing account or carry-forward treatment). Again, several proposals have previously been raised regarding ratemaking adjustments, and MCE believes that these proposals should be given due review. MCE suggests that these proposals are appropriate for discussions within the context of the Future PCIA Petitions process.

X. **SAFETY ISSUES**

Not applicable. MCE has no position or recommendation on this matter.

\(^{70}\) Scoping Memo at 4.

\(^{71}\) See, e.g., MCE Protest at 3-4, SCPA Protest at 1-3, Local Aggregation Energy Network Protest at 3, and San Francisco Protest at 1-2.
XI. CONCLUSION

MCE thanks the Commission for its attention to the matters addressed herein.

Respectfully submitted,

/s/ Scott Blaising
Scott Blaising
BRAUN BLAISING MC LAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, CA 95814
Telephone: (916) 712-3961
E-mail: blaising@braunlegal.com
Counsel for Marin Clean Energy

/s/ Jeremy Waen
Jeremy Waen
Senior Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Drive
San Rafael, CA 94901
Telephone: (415) 464-6027
E-Mail: jwaen@mceCleanEnergy.org

September 27, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA


Application 16-06-003
(Filed June 1, 2016)

REPLY BRIEF OF MARIN CLEAN ENERGY

Scott Blaising
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, CA 95814
Telephone: (916) 712-3961
E-mail: blaising@braunlegal.com
Counsel for Marin Clean Energy

Jeremy Waen
Senior Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Drive
San Rafael, CA 94901
Telephone: (415) 464-6027
E-Mail: jwaen@mceCleanEnergy.org

October 11, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for
Adoption of Electric Revenue Requirements and Rates
Associated with its 2017 Energy Resource Recovery
Account (ERRA) and Generation Non-Bypassable
Charges Forecast and Greenhouse Gas Forecast
Revenue and Reconciliation (U 39 E).

Application 16-06-003
(Filed June 1, 2016)

REPLY BRIEF OF MARIN CLEAN ENERGY

In accordance with the Scoping Memo And Ruling Of Assigned Commissioner, dated
August 18, 2016 (“Scoping Memo”), and pursuant to the Rules of Practice and Procedure of the
Public Utilities Commission of the State of California (“Commission”), Marin Clean Energy
(“MCE”) hereby submits this reply brief on matters relating to Pacific Gas and Electric
MCE has attempted to conform its reply brief to the common briefing outline agreed to by the
parties, however, a word of note is appropriate here. Since MCE provides this reply brief for the
single purpose of addressing PG&E’s arguments in support of retiring PG&E’s negative
indifference amount balance, other headings and sections of the common brief outline have been
excluded from this reply brief.

I. REPLY

[VI. PG&E’s Negative Indifference Amount Proposal]
In its opening brief, PG&E “explains why the [negative indifference account balance] should now be retired.”¹ As further discussed below, PG&E’s argument boils down to three points. First, PG&E claims that the $78 million in acknowledged benefit to bundled customers from retiring PG&E’s negative indifference amount balance is essentially “chump change” that should be disregarded. This argument is as cavalier as it is disengaged from economic reality.

Second, PG&E essentially claims that, since MCE has no pre-2009 vintage customers, MCE has no standing to argue against the principle of PG&E’s unprecedented proposal. This argument seeks to inappropriately marginalize MCE and its interests in the integrity of the PCIA, and is a red herring.

Third, PG&E claims that MCE’s reliance on Decision (“D.”)08-09-012 is misplaced. Yet, PG&E offers nothing in its opening brief to rebut or otherwise address the clear, enduring holdings of D.08-09-012. D.08-09-012 is as relevant now as it was during the existence of California Department of Water Resources (“DWR”) contracts, and the express language of D.08-09-012 (ignored by PG&E in its opening brief) affirms this point.

Finally, noticeably absent from PG&E’s opening brief is any recognition of the brouhaha occurring in the other investor-owned utilities’ (“IOUs”) respective Energy Resource Recovery Account (“ERRA”) proceedings on a related matter. The Commission should consider arguments in the other IOUs’ ERRA proceedings as it considers PG&E’s request to eliminate its negative indifference amount balance.

A. PG&E Acknowledges That Bundled Customers Would Be Better Off By PG&E’s Proposal, In Contravention To The Bundled Customer Indifference Principle

¹ PG&E Opening Brief at 15.
As MCE stated in its opening brief, the Commission has repeatedly and unswervingly stated that the bundled customer indifference standard is a two-way street: “bundled customers should be no worse off, nor should they be any better off as a result of customers choosing alternative energy suppliers (ESP, CCA, POU or customer generation).”\(^2\) The condition of being “better off” would violate the bundled customer indifference standard \textit{but for} the fact that the IOUs have been directed to maintain negative indifference amount balances, carry these negative balances forward and eventually use the negative balances to offset positive balances, thereby resulting in bundled customer indifference.\(^3\)

Importantly, in its opening brief PG&E unabashedly acknowledges that bundled customers, while also benefitting from “the vast majority” of PG&E’s $1.13 billion negative indifference amount balance, have also benefitted by an additional $77.5 million from payments made by departing customers.\(^4\) While admitting that bundled customers have been better off because of these payments, PG&E nevertheless summarily dismisses this issue because the amount ($77.5 million) is “substantially less” than one billion dollars.\(^5\) PG&E’s statement is completely divorced from economic reality. While $77.5 million may be “substantially less” than $1 billion, and may essentially be chump change to PG&E, this amount, if retired by PG&E

\(^2\) MCE Opening Brief at 9 (citing D.08-09-012 at 10 (emphasis added)).
\(^3\) See MCE Opening Brief at 9 (referencing D.08-09-012 at 48 (“It is similarly necessary that negative indifference amounts be carried over for use in subsequent years to maintain bundled customer indifference.”)). See also MCE Opening Brief at 9 (citing Senate Bill (“SB”) 790 (emphasis added), which statutorily adopted this carry-over principle: “Estimated net unavoidable electricity costs paid by the customers of a community choice aggregator shall be reduced by the value of any benefits that remain with bundled service customers, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits.” (Pub. Util. Code § 366.2(g) (added by SB 790)).
\(^4\) See PG&E Opening Brief at 17.
\(^5\) See PG&E Opening Brief at 17.
to the benefit of its bundled customers, would clearly violate the Commission’s bundled
customer indifference standard insofar as it would allow bundled customers to be permanently
better off as the result of the departure of customers. PG&E’s failure to address this point is
telling.

B. PG&E’s Attempt To Marginalize MCE Should Be Disregarded

In its opening brief, PG&E attempts to make much of the fact that “[n]one of the [direct
access (“DA”)] customer groups active in this proceeding have opposed the retirement of the
negative indifference amount. Instead, the negative indifference amount retirement has only
been opposed by CCAs, primarily MCE.”6 PG&E urges the Commission to regard this as “an
important factor in the Commission’s consideration of PG&E’s request.”7 PG&E’s statements
should be disregarded.

Anecdotes and conjecture are irrelevant in determining the outcome of a contested issue;
what matters are facts and law. PG&E seems to surmise that the DA parties have failed to
oppose PG&E’s proposal because they agree with it. This is conjecture and irrelevant. It would
be equally persuasive, though equally irrelevant, to surmise that the DA parties’ failure to
expressly oppose PG&E’s proposal is a tactical move to gain overall benefit in the DA parties’
attempt to eliminate the PCIA on a statewide basis.8 The point is this: why the DA parties did or
did not address this issue in this proceeding is irrelevant. MCE has been actively involved on
PCIA matters for years, to say the least, and it is not unsurprising or noteworthy, as PG&E
implies, for MCE to be keenly interested in a proposal by PG&E to upend decades of PCIA

6 PG&E Opening Brief at 17-18.
7 PG&E Opening Brief at 18.
8 See discussion below, Section I.D., describing the DA parties’ arguments in the other
IOUs’ ERRA proceedings.
precedent. As such, PG&E’s plea that the Commission ascribe special, extraordinary importance to the DA parties’ role in this proceeding should be disregarded.

C. PG&E’s Arguments Regarding D.08-09-012 Are Unavailing And Incomplete

In its testimony, PG&E completely ignores D.08-09-012, never even mentioning the decision. In its opening brief, because of MCE’s extensive reliance on D.08-09-012 in its protest, PG&E feels compelled to at least mention the decision, dedicating a mere paragraph to show why “MCE’s reliance on D.08-09-012 is misplaced.”9 PG&E offers one retort to MCE’s arguments. As it has wrongly done for years,10 PG&E claims that there are two PCIAs, instead of one PCIA. Conveniently packaged in two boxes, PG&E attempts to dispose of the one box by concluding “[t]hus, D.08-09-012 is not applicable to the DWR PCIA.”11 The problem with PG&E’s argument is that it completely ignores the Commission’s repeated denouncement of this view. This is a pattern and a problem. In sum, PG&E continues to have a mistaken belief that it is permissible to bifurcate the PCIA into two separate portfolios, instead of a single, total portfolio.

As a preliminary matter, it is important for the Commission to see how often, and seemingly insolently, PG&E has brought forward PCIA proposals that have the effect of calculating certain PCIA costs separately instead of on a total portfolio basis. Repeatedly, the Commission has stated that “[t]he total portfolio approach is consistent with [bundled customer

9  PG&E Opening Brief at 19.
10  See MCE Opening Brief at 10-12.
11  PG&E Opening Brief at 19. The one box that PG&E wishes to dispose of is, unsurprisingly, the negative indifference amount.
indifference] principle. PG&E’s separate approach is not.” PG&E’s proposal in this proceeding is no different, and the outcome should be no different.

More specifically with respect to D.08-09-012, MCE has previously provided a comprehensive discussion as to why PG&E’s bifurcated PCIA approach has been rejected. MCE will not restate its position, but rather MCE will let another voice speak to the relevance of D.08-09-012 and the abiding effect of a single, total portfolio approach. In its opening brief on ERRA-related matters, San Diego Gas & Electric Company (“SDG&E”) addresses this issue head-on. In general, SDG&E retraces PCIA history to show the Commission’s intent that, “[b]y incorporating these categories of costs [both DWR and IOU procurement costs], the [Cost Responsibility Surcharge (“CRS”)] would be determined on a ‘total portfolio basis’….” SDG&E then methodically walks through subsequent Commission decisions to show how the Commission has been steadfast in its insistence on a total portfolio approach.

With respect to D.08-09-012, in particular, SDG&E has a vastly different view than PG&E. Instead of relegating D.08-09-012, as PG&E does, SDG&E affirms the relevance and controlling nature of D.08-09-012. SDG&E observes that “[i]n [D.08-09-012], the Commission found that new generation non-bypassable charges authorized in D.04-12-048 should be

12 D.11-12-018 at 40 (emphasis added). See generally D.11-12-018 at 39-40.
13 See MCE Opening Brief at 11.
14 See SDG&E Opening Brief in A.16-04-018, dated October 3, 2016. As MCE previously stated, the Commission may, pursuant to Rule 13.9 and Evid. Code § 452(d), take official notice of the existence of pleadings in other Commission proceedings. See MCE Opening Brief at 18; note 54 (referencing D.16-01-014 at 20).
15 SDG&E Opening Brief at 3 (referencing D.02-11-022 [the Commission’s first substantive CRS decision] at 3-4, 24-27).
16 See SDG&E Opening Brief at 3-6 (addressing D.05-01-040, D.06-07-030, and D.08-09-012).
implemented as a component of the CRS and maintained the *total portfolio* approach it had adopted in D.06-07-030."17 More directly, SDG&E challenges the *mistaken* view "that D.08-09-012 only applies to post-2009 vintages," stating that "if the Commission had overturned its longstanding precedent from D.02-11-022 through D.06-07-030 in D.07-05-005 on such a fundamental issue, surely they would have referenced that conclusion in D.08-09-012."18 In sum, as MCE and SDG&E have found, any genuine and serious analysis of D.08-09-012 (and other Commission decisions) will inevitably lead to the conclusion that the Commission’s total portfolio approach, with carry-forward of negative indifference amount balances, must be maintained after the expiration of DWR contracts.

**D. PG&E Stands Alone Among The IOUs (Again) In Its View Regarding The Relevance Of Expiring DWR Contracts**

As stated above, SDG&E takes a completely different view than PG&E on the relevance of expiring DWR contracts with respect to the question of whether the PCIA should be eliminated (as PG&E has prematurely and impermissibly done) and whether the negative indifference amount balance should be eliminated.19 The other IOU, Southern California Edison Company ("SCE"), takes a similar view to SDG&E.20 Like SDG&E, SCE retraces Commission precedent in showing the ongoing relevance of the "‘total portfolio indifference standard’ for computing bundled service customer indifference that measured the above- or below-market cost of the *entire* generation portfolio (i.e., not just the above- or below-market costs of specific

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17 SDG&E Opening Brief at 5 (emphasis added).
18 SDG&E Opening Brief at 9-10.
19 As discussed in MCE’s Opening Brief, PG&E revealed in cross-examination that it had eliminated the negative PCIA without any express authorization by the Commission. See MCE Opening Brief at 17-20.
generation assets) to set the [CRS/PCIA].”\(^{21}\) Importantly, SCE issues a persuasive response to PG&E’s mistaken belief that D.07-07-005 is relevant in determining whether the PCIA and negative indifference amount should be eliminated.

D.07-07-005 is the centerpiece (actually, the entirety) of PG&E’s legal defense of its proposal to eliminate the PCIA and negative indifference amount.\(^ {22}\) PG&E claims that “[i]n D.07-05-005, the Commission elaborated on when it was appropriate to [eliminate] the negative indifference amount [and the PCIA]” concluding that “PG&E’s request is reasonable and entirely consistent with D.07-07-005.”\(^ {23}\) The problem with PG&E’s claim, as aptly stated by SCE, is that “reliance on D.07-05-005 is misplaced in light of other Commission decisions and the broader indifference principle.”\(^ {24}\) SCE further sharpens this point by stating as follows, all of which equally applies as a criticism of PG&E’s misplaced reliance on D.07-05-005:

Citing no good policy reason why the Commission should reverse those underlying concepts and precedents upholding the indifference principle, the DA Parties instead resort to reliance on a few sentences from D.07-05-005. The DA Parties’ citations to the three sentences in D.07-05-005 are technically accurate, but also essentially meaningless without appropriate context. In D.07-05-005, the Commission was addressing a very limited issue: whether negative indifference amounts from below-market utility-owned generation (“UOG”) should “carry-over” for Municipal Departing Load customers once the above-market DWR contracts expired. In that case, the Commission answered the question “no.”

But the context is what matters: At that point, the utilities’ UOG portfolio was below market, and the Commission decided that as a matter of policy, departing load customers should not continue to benefit from the below-market position of those resources once those customers were no longer paying above-market DWR contract costs. That decision should not be interpreted as a Commission broad policy determination that DA customers’ responsibility for UOG resources—should they ever be above market—should end once the DWR contracts expired.

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\(^{21}\) SCE Opening Brief at 4 (emphasis in the original).

\(^{22}\) See PG&E Opening Brief at 18-20.

\(^{23}\) PG&E Opening Brief at 18-19.

\(^{24}\) SCE Opening Brief at 3.

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In fact, even D.07-05-005 itself affirms the broader indifference principle when it states that “the requirement to maintain bundled customer indifference did not end on June 30, 2006 merely because PG&E’s CRS undercollection at that point was deemed to be zero.” Similarly, the requirement to maintain SCE’s bundled service customers’ indifference should not end on September 30, 2011, merely because the last of SCE’s DWR contracts expired on that day.25

II. CONCLUSION

MCE thanks the Commission for its attention to the matters addressed herein.

Respectfully submitted,

/s/ Scott Blaising
Scott Blaising
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, CA  95814
Telephone: (916) 712-3961
E-mail: blaising@braunlegal.com
Counsel for Marin Clean Energy

/s/ Jeremy Waen
Jeremy Waen
Senior Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Drive
San Rafael, CA 94901
Telephone: (415) 464-6027
E-Mail: jwaen@mceCleanEnergy.org

October 11, 2016

25  SCE Opening Brief at 5 (internal citations omitted).
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Application of Pacific Gas and Electric Company for
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Application 16-06-003
(Filed June 1, 2016)

COMMENTS OF MARIN CLEAN ENERGY
SONOMA CLEAN POWER
AND CITY AND COUNTY OF SAN FRANCISCO
ON THE NOVEMBER UPDATE

JEREMY WAEN
Senior Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Drive
San Rafael, CA 94901
Telephone: (415) 464-6027
E-Mail: jwaen@mceCleanEnergy.org

STEVEN S. SHUPE
General Counsel
SONOMA CLEAN POWER AUTHORITY
50 Santa Rosa Avenue, Fifth Floor
Santa Rosa, CA 95402
Telephone: (707) 890-8485
E-Mail: sshupe@sonomacleanpower.org

Counsel for Sonoma Clean Power Authority

SCOTT BLAISING
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, CA 95814
Telephone: (916) 712-3961
E-mail: blaising@braunlegal.com

DENNIS J. HERRERA
City Attorney
THERESA L. MUELLER
Chief Energy and Telecommunications Deputy
AUSTIN M. YANG
Deputy City Attorney
CITY AND COUNTY OF SAN FRANCISCO
City Hall Room 234
1 Dr. Carlton B. Goodlett Place
San Francisco, CA 94102-4682
Telephone: (415) 554-6761
E-Mail: austin.yang@sfgov.org

Attorneys for the
City and County of San Francisco

November 4, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for
Adoption of Electric Revenue Requirements and Rates
Associated with its 2017 Energy Resource Recovery
Account (ERRA) and Generation Non-Bypassable
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Application 16-06-003
(Filed June 1, 2016)

COMMENTS OF MARIN CLEAN ENERGY
SONOMA CLEAN POWER
AND CITY AND COUNTY OF SAN FRANCISCO
ON THE NOVEMBER UPDATE

In accordance with the Scoping Memo And Ruling Of Assigned Commissioner, dated August 19, 2016 (“Scoping Memo”), as modified by the Email Ruling Amending Procedural Schedule, dated October 24, 2016 (“ALJ Ruling”), and pursuant to the Rules of Practice and Procedure of the Public Utilities Commission of the State of California (“Commission”), the City and County of San Francisco, Marin Clean Energy and Sonoma Clean Power Authority (collectively, “CCA Parties”) hereby submit comments on certain information related to Pacific Gas and Electric Company’s (“PG&E”) November Update.

I. SUMMARY

Pursuant to the ALJ Ruling, PG&E distributed its November Update on November 2, 2016, and parties are required to provide comments two days later, on November 4, 2016. While the CCA Parties generally understand the Commission’s desire for speedy consideration of the issues presented, the compressed schedule gives little time for parties to review and analyze the updated testimony, resulting in limited comments. As such, the Commission should not view these comments as affirming the information contained in the November Update. Two days is
simply an insufficient amount of time to review a complex filing.\textsuperscript{1} The Commission should provide further direction to the Power Charge Indifference Adjustment (“PCIA”) working group, which was formed pursuant to Decision (“D.”) 16-09-044, to consider ways for providing further time and occasion to review updated information, so that parties have a more meaningful opportunity to assess and comment on this information.

PG&E’s November Update is particularly noteworthy as it continues the trend of an ever-increasing PCIA burden on customers. The PCIA has now grown to over \textit{three cents per kWh}.\textsuperscript{2} This is noteworthy both in its rapid, volatile ascent in the last two years (rising from $0.1216 per kWh to $0.03010 – and increase of \textit{nearly 150 percent}), but also in its contrast to the placid, stable nature of PG&E’s bundled generation rates (actually decreasing by an almost imperceptible amount over the same two year-period (\textit{3.7 percent})).\textsuperscript{3} These are staggering increases, especially in light of the fact that PG&E’s PCIA far outpaces that of the other investor-owned utilities (“IOUs”), and provide further support for making the PCIA subject to refund.\textsuperscript{4}

Moreover, an increasing PCIA makes it more and more difficult for CCAs to remain competitive. Given PG&E’s proposed PCIA, CCAs will need to provide a generation portfolio, which typically has a significantly greater renewable content than PG&E’s portfolio, at roughly $0.09353.

\textsuperscript{1} The two-day review period was further compressed by certain limitations in PG&E’s ability to deliver workpapers. That said, the CCA Parties appreciate PG&E’s efforts to overnight material to parties and otherwise work cooperatively to assist parties’ review of information.

\textsuperscript{2} See November Update at 50 (Table 15-3). All references to rates in these comments are to residential rates and to the 2012 PCIA Vintage, unless otherwise noted.

\textsuperscript{3} Based on a calculation of the percent difference between the residential class average generation rates as stated in both PG&E’s 2015 ERRA proceeding ($0.09894, Table 11-1) and PG&E’s 2017 November Update within the instant ERRA proceeding ($0.09353, Table 15-1).

\textsuperscript{4} See Opening Brief of the City and County of San Francisco at 2.
six cents per kWh.⁵ Two conclusions arise from these facts. First, the current PCIA methodology contributes to unreasonable levels of rate volatility and should be further examined, at a minimum, by the PCIA working group. Second, as it did previously with respect to direct access (“DA”) viability, the Commission should consider whether the current PCIA methodology impedes state policy with respect to CCA program development and the attendant benefits of greenhouse gas (“GHG”) emission reduction goals.⁶ As CCAs have a limited balance sheet compared with IOUs and are non-profit/quasi-governmental agencies, these volatile and significant charges make it very challenging for Community Choice Aggregators to serve customers and contribute to climate goals. The inability to forecast PCIA years into the future makes it extremely difficult to commit to procuring increasing amounts of renewable energy through long-term contracts while preventing rate shock and investing in customer programs, such as energy efficiency and electric vehicles.

Finally, given PG&E’s recent application to retire the Diablo Canyon Power Plan (“Diablo Canyon”) (A.16-08-006), the Commission should closely examine the impact of single resources on the PCIA. For example, information provided by PG&E in this proceeding indicates that calculating the indifference amount after removing Diablo Canyon from PG&E’s portfolio would cause the PCIA to decrease by approximately 33 percent. This is certainly noteworthy, if not material to any future examination of the PCIA.

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⁵ See November Update; Tables 15-1 and 15-3 (using the bundled generation rate of $0.09353 per kWh for residential customers less the PCIA of $0.03010 per kWh).

⁶ See Senate Bill (“SB”) 790 (2011) § 2(a) (“It is the policy of the state to provide for the consideration, formation, and implementation of community choice aggregation programs….”). See also D.04-12-046 at 3 (emphasis added) (“The state Legislature has expressed the state’s policy to permit and promote CCAs by enacting AB 117….”).
The Commission should consider these and other key factors as the Commission determines the appropriate level of the PCIA in this proceeding and ultimately examines any necessary PCIA reforms.

II. COMMENTS

A. The November Update Underscores The Problematic Nature Of The Current PCIA Methodology

Rate stability is a key principle of rate design. The Commission should ensure that this tenet is meaningfully applied in the context of the PCIA. PG&E’s November Update reveals that its PCIA has increased by approximately 150 percent in two years and is now proposed to be over 3 cents per kWh. This is remarkable, particularly when considered in light of additional non-bypassable charges that CCA customers are subject to. Particularly troubling is the very significant increase in costs to low-income (EL-1) customers, whose bills are set to rise 26 percent. All told, residential CCA customers are expected to pay approximately 3.5 cents per kWh in generation-related exit fees. These proposed exit fees are even greater than the Commission-approved generation-related exit fees (the DA Cost Responsibility Surcharge ("CRS")) during the “Energy Crisis.” The cap for those fees was set at 2.7 cents per kWh for.

The disparate treatment of DA customers during the Energy Crisis and CCA customers currently is particularly telling because it shows that the Commission has yet to conduct the same

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8 See November Update at 50 (Table 15-3).
9 See November Update at 50-51 (Tables 15-2 and 15-4), listing rates associated with the Competition Transition Charge and New System Generation Charge, respectively.
10 See generally D.02-11-022 (adopting an interim cap of 2.7 cents per kWh) and D.03-07-030 (affirming the 2.7 cents per kWh cap). In both decisions, substantial discussion and consideration occurred regarding the need to balance bundled customer indifference with the goal of preserving the economic viability of DA.
type of serious assessment of economic impact the Commission previously conducted with respect to the CRS. In the case of the CRS cap, the Commission extensively examined the overall value of the DA program and counterbalanced benefits from the DA program against bundled customer indifference.\textsuperscript{11} The following excerpt from D.03-07-030 is instructive, and should be considered by the Commission as an approach with respect to CCA customers:

To preserve bundled customer indifference, any DA CRS cap must be high enough to assure bundled customers are fully reimbursed for any funds advanced over time, including interest, to cover the DA CRS undercollections. Counterbalancing this goal, any DA CRS cap should be set low enough so that the cumulative burden of all energy charges faced by DA customers do not render the DA option untenable.\textsuperscript{12}

As noted in the Commission’s statement, bundled customer indifference is not sacrosanct; it must be harmonized with other state policies. Stated differently, to achieve all of the State’s energy goals, including the growth of CCA programs,\textsuperscript{13} the Commission must give meaningful consideration to rate stability, CCA program viability, and the attendant GHG emissions reductions and increased renewable energy content provided by Community Choice Aggregators. The Commission must consider each of these goals as it determines the appropriate treatment of PG&E’s PCIA. The CCA parties urge the Commission to give thoughtful consideration to potential impacts of an ever-increasing PCIA and make any PCIA revenue requirement subject to refund.

\textsuperscript{11} See, e.g., D.03-07-030 at 8-9 (“[I]n order to balance the countervailing goals of bundled customer indifference and preventing harm to DA, we devised an approach in D.02-11-022 whereby the DA obligation is paid off over time, subject to a cap limiting current DA CRS payments.”). See generally D.02-03-055, D.02-07-032 and D.02-11-022.

\textsuperscript{12} D.03-07-030 at 9.

\textsuperscript{13} See Senate Bill (“SB”) 790 (2011) § 2(a) (“It is the policy of the state to provide for the consideration, formation, and implementation of community choice aggregation programs….”). See also D.04-12-046 at 3 (emphasis added) (“The state Legislature has expressed the state’s policy to permit and promote CCAs by enacting AB 117….”).

5
B. PG&E’s CCA Load Forecast Conclusions Are Questionable

In its November Update, PG&E describes its process for reviewing and updating its CCA load forecasts. Moreover, in its November Update PG&E asks the Commission to adopt PG&E’s proposal for formally establishing CCA load forecasts, including PG&E’s three-part criteria. While the process proposed by PG&E is helpful, and Community Choice Aggregators worked cooperatively with PG&E in this process, PG&E’s criteria should not be adopted by the Commission as the exclusive test for establishing CCA load forecasts.

Of particular note, notwithstanding the fact that PG&E considered as “reasonable” the load forecasts provided by Peninsula Clean Energy (“PCE”) and Silicon Valley Clean Energy (“SVCE”), PG&E declined to incorporate the forecasts because the forecasts do not meet “PG&E’s criteria.” The Commission previously directed the IOUs to use information from the California Energy Commission and other sources to estimate “reasonable” levels of expected CCA load. While PG&E’s criteria are relevant, it is disconcerting that PG&E is ignoring other sources of information, which PG&E acknowledges as being reasonable.

C. The Commission Should More Actively Consider How Single Resources Impact The PCIA

In this proceeding, PG&E provided a data request response that addresses the impact associated with excluding Diablo Canyon from the indifference amount calculation. The CCA Parties have attached a copy of PG&E’s response (“Attachment A”). The data request shows

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14 See November Update at 2-4.
15 PG&E’s Prepared Testimony at pp. 2-12 through 2-14.
16 See November Update at 3:28-29.
17 See November Update at 4:1-7.
18 See D.14-02-040 at 16.
that the PCIA revenue requirement, shown on line 15 of Table 9-4 (2017 Indifference Calculation), would drop from $1,914 million to $1,275 million if Diablo Canyon were excluded from the indifference amount calculation. In other words, Diablo Canyon accounts for approximately $639 million (approximately 33 percent) of PG&E’s PCIA revenue requirement. Applying this 33 percent reduction to the PCIA would presumably mean that the PCIA would fall from 3 cents per kWh to approximately 2 cents per kWh if Diablo Canyon were not in the indifference calculation, all things otherwise equal.

III. CONCLUSION

The November Update and additional information provided by PG&E underscore ongoing concerns with the PCIA methodology. The Commission has started efforts to examine PCIA-related issues, particularly issues related to certainty of the PCIA. The CCA Parties believe that the PCIA working group established pursuant to D.16-09-044 would be aided by further direction from the Commission on PCIA-related issues that warrant additional examination and modification.

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19 See Table 9-4 in Attachment A as compared to Table 9-4 in Exhibit PG&E-1 (June 1, 2016 Testimony).

20 See, e.g., D.16-09-044 at 23; Finding of Fact 18 (“The departing load community has legitimate interests in improving transparency and certainty for PCIA, but any proposed changes must occur within the appropriate forum.”) See also D.16-09-044 at 20 (“We therefore direct the formation of a working group…on the issues of improved transparency and certainty related to PCIA.”).
The CCA Parties thank the Commission for its attention to the matters addressed herein.

Respectfully submitted,

/s/ Jeremy Waen

JEREMY WAEN
Senior Regulatory Analyst
MARIN CLEAN ENERGY
1125 Tamalpais Drive
San Rafael, CA 94901
Telephone: (415) 464-6027
E-Mail: jwaen@mceCleanEnergy.org

SCOTT BLAISING
BRAUN BLAISING Mclaughlin & Smith, P.C.
915 L Street, Suite 1480
Sacramento, CA 95814
Telephone: (916) 712-3961
E-mail: blaising@braunlegal.com
Counsel for Marin Clean Energy

/s/ Steven S. Shupe

STEVEN S. SHUPE
General Counsel
SONOMA CLEAN POWER AUTHORITY
50 Santa Rosa Avenue, Fifth Floor
Santa Rosa, CA 95402
Telephone: (707) 890-8485
E-Mail: sshupe@sonomacleanpower.org

Counsel for Sonoma Clean Power Authority

/s/ Austin M. Yang

DENNIS J. HERRERA
City Attorney
THERESA L. MUELLER
Chief Energy and Telecommunications Deputy
AUSTIN M. YANG
Deputy City Attorney
CITY AND COUNTY OF SAN FRANCISCO
City Hall Room 234
1 Dr. Carlton B. Goodlett Place
San Francisco, CA 94102-4682
Telephone: (415) 554-6761
E-Mail: austin.yang@sfgov.org
Attorneys for the
City and County of San Francisco

November 4, 2016
### QUESTION 1

Please present a revised Total Portfolio Indifference Calculation (Table 9-4), Market Price Benchmark (Table 9-5), and Power Charge Indifference (Table 15-3) calculations for all vintages of departing load under the following scenarios:

a. If the Ivanpah solar thermal generation units #1 and #3 were excluded from these calculations.

b. If the Diablo Canyon Power Plant nuclear generation units #1 and #2 were excluded from these calculations.

### ANSWER 1

Question 1.a was withdrawn.

With respect to question 1.b, PG&E’s forecast of Diablo Canyon generation is confidential and thus, providing the details regarding the change in these tables with and without Diablo Canyon generation would reveal confidential information.

Alternatively, PG&E can provide revised results for the total portfolio indifference calculation (Table 9-4, Line 15) and the market price benchmark (MPB) calculation (Table 9-5, Line 30) under the scenario described in question 1.b, as shown in the tables below.
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<tr>
<td>15</td>
<td>PCIA RRQ ($1000) = Indifference - Ongoing CTC (Line 12 - line 13)</td>
<td>$1,002,097</td>
<td>$1,187,507</td>
<td>$1,247,214</td>
<td>$1,275,045</td>
<td>$1,280,343</td>
<td>$1,254,205</td>
<td>$1,230,540</td>
<td>$1,229,818</td>
<td>$1,229,818</td>
<td>15</td>
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### Table 9-4

**2017 ERRA Forecast**

**Total Portfolio Indifference**

#### Vintaged PCIA

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<td>$1,230,540</td>
<td>$1,229,818</td>
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### Table 9-5

**PACIFIC GAS AND ELECTRIC COMPANY**

**2017 VINTAGED MARKET PRICE BENCHMARK**

#### ERRA Application

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<th>Line No.</th>
<th>2017 Forecast Year</th>
<th>Market Price Benchmark</th>
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</thead>
<tbody>
<tr>
<td>30</td>
<td>2017 MPB with Renewable Premium, by Vintage</td>
<td>$71.56</td>
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</table>
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902-E) for Rehearing of Resolution E-4874)
Application No. 16-09-013)
(Filed September 19, 2016)

RESPONSE OF THE CITY OF LANCASTER
AND MARIN CLEAN ENERGY

Scott Blaising
David Peffer
Ty Tosdal, of Counsel
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, CA  95814
Telephone: (916) 712-3961
E-mail: blaising@braunlegal.com

Counsel for the City of Lancaster and
Marin Clean Energy

October 4, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902-E) for Rehearing of Resolution E-4874
Application No. 16-09-013
(Filed September 19, 2016)

RESPONSE OF THE CITY OF LANCASTER
AND MARIN CLEAN ENERGY

In accordance with Rule 16.1 of the Rules of Practice and Procedure of the Public Utilities Commission of the State of California ("Commission"), the City of Lancaster ("Lancaster") and Marin Clean Energy ("MCE") (collectively, "CCA Parties") hereby submit this response to the Application for Rehearing of Resolution E-4874 filed by San Diego Gas & Electric Company ("SDG&E") and assigned the above captioned docket ("Application for Rehearing"). Notice of SDG&E’s Application for Rehearing first appeared in the Daily Calendar on September 30, 2016. Therefore, in accordance with Rule 16.1(d), this response is timely filed. For the reasons set forth below, SDG&E’s objections to Resolution E-4874 ("Resolution") do not identify any errors of fact or law, and as such are without merit. The Commission should thus deny SDG&E’s Application for Rehearing.

I. RESPONSE

SDG&E’s Application for Rehearing is a further attempt by SDG&E to prevent its affiliate independent marketing division from being subject to meaningful Commission oversight and accountability. SDG&E’s choice to structure its independent marketing division ("IMD") as an affiliate, rather than an independent division of SDG&E, was a strategic decision made by SDG&E, presumably with the goal of limiting Commission authority and oversight over the IMD. SDG&E’s strategy has been partly successful – the Resolution found that the Commission
has only limited jurisdiction to enforce the Community Choice Aggregation ("CCA") Code of Conduct ("COC") on affiliates, and therefore only a subset of the COC rules apply to affiliate IMDs.\(^1\) This finding means that many of the COC’s key mechanisms for ensuring compliance with Senate Bill ("SB") 790 and the COC apply only to SDG&E, not the IMD. For instance, the Resolution found that expedited complaint procedure (COC Rules 24 and 25) is not available to bring complaints against the affiliate-IMD.\(^2\)

For the CCA Parties, the Resolution’s contested finding that affiliate IMDs are subject to limited Commission jurisdiction and only a subset of the COC rules was counterbalanced, somewhat, by the Resolution’s finding that the proposed IMD is a Rule II.B Affiliate subject to the full set of the Commission’s Affiliate Transaction Rules ("ATRs"). In its Application for Rehearing, SDG&E is seeking to further insulate the IMD from even this significantly reduced regulatory oversight by requesting that the IMD be re-categorized as a Rule II.C. Affiliate, subject to only a small subset of the ATRs, and by requesting further limitations on the scope of COC requirements to which the IMD is subject. If the Commission were to grant SDG&E’s requests, the practical result would be that SDG&E’s affiliate-IMD would be able to actively lobby and market against CCA programs, yet not be subject to meaningful Commission oversight and without meaningful mechanisms to ensure compliance with SB 790 and the COC. Such an outcome is directly contrary to the legislature’s definitively stated purpose in adopting SB 790: “provid[ing] for the consideration, formation, and implementation of community choice aggregation programs....”\(^3\)

\(^1\) See Resolution E-4874 at 19-20. The COC was approved by the Commission in Decision ("D") 12-12-036.
\(^2\) See Resolution E-4874 at 22; Finding 7.
\(^3\) SB 790, § 2(a).
A. The Resolution’s Categorization Of The Affiliate-IMD As A Rule II.B. Affiliate Is Reasonable And Consistent With All Relevant Requirements

The Resolution properly finds that SDG&E’s affiliate-IMD would provide a service related to the use of electricity, and therefore is subject to all Affiliate Transaction Rules under ATR II.B. SDG&E offers three main objections to this finding: (1) the finding violates due process by imposing a significant reinterpretation of ATR II.B. outside of a normal rulemaking; (2) by subjecting SDG&E’s affiliate-IMD to both the COC and the full set of ATRs, the finding exceeds the scope of Public Utilities Code Section 707, the COC, and D.12-12-036; and (3) the finding would expose SDG&E’s Affiliate-IMD to “double jeopardy” by subjecting it to the possibility of two sets of penalties for the same conduct. For the reasons discussed below, these objections are without merit and should be rejected by the Commission.

1. The Resolution’s Finding That The IMD Is A Rule II.B. Affiliate Is Consistent With The Clear Meaning Of ATR Rule II.B.

The Resolution’s finding that the IMD is a Rule II.B. affiliate does not modify the ATRs. Nor does the finding modify any other Commission Rules or Decisions. Rather, the finding merely applies Rule II.B to SDG&E’s request without modification or reinterpretation. This application of Rule II.B. is entirely consistent with Rule II.B.’s plain meaning, its context (the other ATRs), Commission precedent, and common sense.

The ATRs divide affiliates into two categories. Under ATR II.B., affiliates “engaging in the provision of a product that uses gas or electricity or the provision of services that relate to the

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4 See Resolution E-4874 at 21; Finding 1.
5 See SDG&E Application for Rehearing at 5-7.
6 All further statutory references are to the Public Utilities Code, unless otherwise noted.
7 See id. at 9-13.
8 See id. at 7-9.
use of gas and electricity” are subject to the full set of ATRs, unless specifically exempted. Under ATR II.C., affiliates that do not provide gas or electricity related services are subject to a significantly limited subset of ATR requirements.

The Resolution correctly interprets and applies the ATRs in categorizing the proposed IMD as a Rule II.B. affiliate. SDG&E admits that the IMD will be “engaged in a communication/information business. The topics may involve energy.” Thus, there is no disputed issue of fact. The question is limited to one of legal interpretation of the meaning of Rule II.B, namely, is lobbying and marketing against CCA programs “a service that relate[s] to the use of... electricity?”

The answer to this question is clearly yes. The principles for interpreting statutes and administrative rules in California are well established. If a statute or regulation’s plain text “evinces an unmistakable plain meaning,” no further interpretation is required. By its plain meaning, ATR II.B. applies not only to the “provision of a product that uses gas or electricity” through generation, transmission, and distribution services; but also the direct provision of services to a utility that relate to the use of electricity, including the oversight, administrative, support, legal, marketing, and lobbying activities that relate to SDG&E’s electric service.

SDG&E’s argument that ATR II.B. only applies to affiliates that offer an energy-related product or service to the market is incorrect. SDG&E’s only support for this argument is two Commission Resolutions – Resolution E-3548 and G-3461 – which can be easily distinguished from the present facts. Here, the proposed affiliate-IMD will provide lobbying and marketing services that directly support SDG&E’s electricity operations and business strategy. Normally,  

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9 Resolution E-4874 at 6.
these services would be performed internally by an independent division of SDG&E. It is beyond question that such lobbying and marketing functions are “electricity related” when performed by SDG&E, as the costs of lobbying and marketing on electricity issues are included in SDG&E’s customer electricity rates. When performed by an affiliate, no meaningful distinction exists. In other words, there is no basis for asserting that the same services are electricity-related when performed internally at SDG&E, but the exact same services, provided directly to SDG&E and relating directly to SDG&E’s electricity business, are not electricity-related when outsourced to an affiliate. In contrast, none of the Rule II.C. affiliates discussed in Resolution E-3548 or G-3641 was engaged in the direct provision to a utility of a service that is normally performed internally and relates directly to electricity.

2. **The Resolution’s Finding That The IMD Is An ATR II.B. Affiliate Is Procedurally Proper**

SDG&E presents two procedural objections to the finding that the IMD is an ATR II.B. affiliate. First, SDG&E argues that the Resolution does not provide sufficient justification for the finding in the form of findings of fact and conclusions of law supported by substantial record evidence, and as such is “arbitrary, capricious, and devoid of reasoned decision making.”11 Second, SDG&E argues that the finding violates due process by “changing the ATRs”12 and “depart[ing] from Commission precedent”13 outside of a generally applicable rulemaking or a petition for modification, and without notice and an opportunity to be heard.

Neither of SDG&E’s procedural objections has merit. Both objections are based on the same incorrect assumption: that the finding either modifies ATR II.B. or significantly

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11 Application for Rehearing at 5-6.
12 Id. at 3.
13 Id. at 6-7.
reinterprets the rule in a manner inconsistent with Commission precedent, and thus requires significant procedure. This assumption is entirely baseless. As established above, the finding merely applies the plain meaning of ATR II.B., and in no way modifies or reinterprets the rule. The Commission is not required to engage in lengthy discussion or develop a robust evidentiary record in the context of a rulemaking or petition for modification when applying the plain meaning of a previously established rule to undisputed facts.

SDG&E’s objection that the finding is not supported by findings of fact and a substantial evidentiary record is similarly flawed. Whether anti-CCA marketing and lobbying is a “service that relate[s] to the use of gas and electricity” under ATR II.B. is purely an issue of legal interpretation, and thus does not require factual findings or an evidentiary record.

3. **Both The ATRs And The COC Apply To The Affiliate-IMD**

SDG&E objects to the finding that the proposed affiliate-IMD is an ATR II.B. affiliate on the grounds that by requiring that the affiliate-IMD comply with both the full set of ATRs and the COC, the Commission has exceeded the scope of Section 707(a)(4)(B) and (C), D.12-12-036 and the express terms of the COC Rules.¹⁴

This objection is without merit. If a utility decides to structure its IMD as an affiliate, it is entirely appropriate and consistent with all statutory requirements for the Commission to require that the affiliate-IMD comply with both the COC and the ATRs. When an entity “wears two hats” and is thus subject to multiple regulatory schemes, those regulatory schemes do not cancel each other, even if they impose parallel requirements. SDG&E’s proposed affiliate-IMD is both an affiliate, subject to the ATRs, and an IMD, subject to the COC.

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¹⁴ Application for Rehearing at 3.
Contrary to SDG&E’s claims,15 nothing in Section 707 indicates that the legislature intended to exempt affiliate-IMDs from complying with both the ATRs and COC. Section 707(a)(4) requires that the Commission adopt a Code of Conduct, associated rules, and enforcement procedures that:

(A) Incorporate rules that the commission finds to be necessary or convenient in order to facilitate the development of community choice aggregation programs, to foster fair competition, and to protect against cross-subsidization paid by ratepayers.

(B) It is the intent of the Legislature that the rules include, in whole or in part, the rules approved by the commission in Decision 97-12-088 and Decision 08-06-016.

(C) This paragraph does not limit the authority of the commission to adopt rules that it determines are necessary or convenient in addition to those adopted in Decision 97-12-088 and Decision 08-06-016 or to modify any rule adopted in those decisions.

Nothing in Section 707 limits the application of the COC to affiliate-IMDs, and nothing in the statute indicates that the legislature intended to exempt affiliate-IMDs from one set of requirements or another. Section 707 addresses only the COC requirements, and in no way addresses the ATRs (other than to require that the COC borrow language from them). Section 707 is entirely silent on, and irrelevant to, the question of whether an IMD that is structured as an affiliate is properly categorized as an ATR II.B. affiliate or an ATR II.C. affiliate. Had the

15 Id. at 7-8.
legislature intended to exempt Affiliate-IMDs from either sets of rules, it would have clearly stated as such.

SDG&E’s argument that applying both the COC and ATRs would be unjust\textsuperscript{16} is disingenuous. SDG&E was in no way required to structure its IMD as an affiliate. Rather, SDG&E made the strategic decision to structure the IMD as an affiliate presumably with the aim of reducing Commission oversight over the IMD. SDG&E has directly benefitted from this strategic decision, as the IMD is subject to significantly weaker regulation because it is an affiliate.\textsuperscript{17} Applying both the COC and the full set of ATRs to SDG&E is not some unjust outcome imposed upon SDG&E. Rather, it is the clearly foreseeable consequence of a strategic decision by SDG&E.

4. SDG&E’s “Double Jeopardy” Concern Is Unfounded

SDG&E further objects to the application of both the COC and the full set of ATRs to the IMD on the grounds that being subject to both sets of rules could place the IMD in “double jeopardy” by exposing it to two sets of penalties for the same conduct.\textsuperscript{18} For three reasons, this argument does not provide a reasonable basis for limiting the application of ATRs to the affiliate-IMD. First, by choosing to structure the IMD as an affiliate SDG&E accepted the risk that IMD misconduct that violates both the COC and ATRs could lead to multiple penalties. Had SDG&E wished to avoid this possibly, it had the option of structuring the IMD as an independent division.

\textsuperscript{16} See Application for Rehearing at 12.
\textsuperscript{17} See Resolution at 19-20.
\textsuperscript{18} See Application for Rehearing at 7-8.
Second, SDG&E cites no authority to support its claim that a single act resulting in multiple penalties under different regulatory rules constitutes “double jeopardy” or is otherwise unreasonable. To the contrary, it is common for a single act to result in multiple penalties under different sets of laws and regulations. This does not constitute double jeopardy, nor does it invalidate one of the sets of laws or regulations.

Third, SDG&E’s concerns about double jeopardy and duplicative penalties are not realistic. In any instance where IMD misconduct resulted in penalties under both the COC and ATR, SDG&E would have the opportunity to make its case, and the Commission would have the authority to set, modify, or reduce any penalties to avoid unjust and unreasonable outcomes.

B. The Resolution’s Requirement That The Affiliate-IMD File An Annual Report Is Consistent With Commission Jurisdiction And Authority And Does Not Violate The First Amendment

The Resolution requires that SDG&E file an annual report with the Energy Division detailing the IMD’s spending and shareholder funding.\(^{19}\) SDG&E objects to this requirement, arguing that it (1) exceeds the Commission’s jurisdiction and authority over IMDs, and (2) violates the First Amendment by burdens the IMD’s speech and discriminating against the IMD’s speech based on its content.\(^{20}\) These objections are entirely unfounded, and do not identify legitimate errors of fact or law in the Resolution. As such, the Commission should not grant rehearing of this issue.

The annual reporting requirement is fully consistent with the Commission’s SB 790 and COC regulatory authority over IMDs. SB 790 grants the Commission broad authority to adopt a

\(^{19}\) See Resolution at 23; Ordering Paragraph 11.

\(^{20}\) See Application for Rehearing at 15-16
CCA Code of Conduct and associated rules and enforcement procedures.\textsuperscript{21} This authority applies to all IMDs, regardless of how they are structured, and nothing in SB 790 limits the Commission’s authority over IMDs that are structured as affiliates. The reporting requirement is an “associated rule” that is directly related to ensuring compliance with SB 790 and the COC. SB 790 and the COC strictly prohibit the IMD from using ratepayer money,\textsuperscript{22} meaning that the IMD must be funded entirely with shareholder funds. If SDG&E were to violate SB 790 and the COC by subsidizing the IMD with ratepayer money, one would expect to observe a gap between the IMD’s expenditures and the amount of shareholder money coming into the IMD. The disclosure requirement is thus directly relevant to ensuring COC compliance, and is fully consistent with the Commission’s Section 707 authority to adopt COC “associated rules.”

The annual reporting requirement is fully consistent with the First Amendment. The requirement is narrowly tailored, as it requires the disclosure of only certain, specified financial information that is directly relevant to ensuring regulatory compliance. The requirement also serves a compelling state interest—California’s interest in protecting community choice aggregators.\textsuperscript{23}

SDG&E’s First Amendment argument has a fundamental logic gap—SDG&E does not explain how the reporting requirement “burdens” or “discriminates against” the IMD’s speech. The reporting requirement has nothing to do with the content of the IMD’s shareholder-funded speech. It does not compel, limit, restrict, or prohibit shareholder-funded speech in any way. The requirement merely requires the disclosure of specified financial information, which is

\footnotesize{\textsuperscript{22}} \textit{See} Pub. Util. Code § 707(a)(1).
\footnotesize{\textsuperscript{23}} \textit{See} SB 790, § 2(a).
The First Amendment protects the form and content of speech. SDG&E has taken the radical position that the First Amendment also prohibits regulators from requiring that an entity disclose financial information that includes the entity’s costs/expenditures on making protected speech. This position is entirely unsupported by the relevant case law, and SDG&E has not cited a single authority to support it.

C. The Resolution’s Clarification Of The Term Personnel Is Valid And Appropriate

COC Rule 13 prohibits an electrical corporation from sharing personnel involved in marketing and lobbying with its IMD. The Resolution clarifies that the term “personnel” used Rule 13 includes “not only employees, but all agents, including contractors and consultants.” SDG&E objects to this clarification, arguing that it “essentially modifies COC Rule 13” and expands the term “beyond what the currently effective COC Rule 13 already expressly provides.” SDG&E further argues that the clarification was not made in a rulemaking proceeding and thus violates due process, and that the Resolution did not include the clarification in its findings or ordering paragraphs.

SDG&E’s objections hinge on the legal argument that, as used in COC Rule 13, the term “personnel” refers only to employees. This argument is incorrect for three reasons. First, the ordinary meaning of the term “personnel” does not imply the existence of a specific legal or contractual relationship. Merriam-Webster’s definition of “personnel” includes both “the people who work for a particular company or organization” and “a body of persons usually employed

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24 Resolution at 15.
25 Application for Rehearing at 17.
26 See id. at 17-18.
Under this ordinary meaning, personnel are not limited to full-time employees, but may also include part-time employees, contractors, consultants, and other agents who “work for” a company. Second, had the Commission intended to limit COC Rule 13 to utility employees, the Commission would have used the term “employees” rather than “personnel.” The Commission’s use of the term personnel clearly indicates that Rule 13 was intended to apply to more than just employees.

Third, SDG&E’s interpretation of the term is directly contrary to SB 790 and the COC. The purpose of both SB 790 and the COC is to protect vulnerable CCA efforts by prohibiting utilities from using ratepayer money to lobby and market against CCA programs. To achieve this, both SB 790 and the COC require that any IMD lobbying or marketing against CCA be “physically and functionally separate” from its electrical corporation. SDG&E’s interpretation of COC Rule 13 is inconsistent with the separation requirement. It makes no sense to forbid the IMD from sharing some people who perform lobbying and marketing work for SDG&E, while allowing it to share others, based solely on the specifics of the lobbyist/marketer’s contractual relationship with SDG&E. Whether a lobbyist or marketer is an employee or works for SDG&E under some other arrangement is irrelevant to the letter and purpose of the separation requirement.

D. The Resolution’s Finding That The COC Trumps SDG&E’s Plan Is Reasonable and Appropriate

The Resolution finds that “To the extent that San Diego Gas and Electric Company’s Code of Conduct Compliance Plan is inconsistent with the Community Choice Aggregation Regulation...”

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27 Available at: http://www.merriam-webster.com/dictionary/personnel
28 SB 790, § 2(a).
Code of Conduct, the Community Choice Aggregation Code of Conduct controls.”30 SDG&E objects to this finding, arguing that the requirement is contrary to “the very purpose of requiring Commission review and approval of a compliance plan” which “is to ensure that the plan comports with the COC and to give the utility assurance that if it acts in conformance with its approved-plan, it is acting in accordance with the COC.”31

Contrary to SDG&E’s objections, the finding that the COC trumps SDG&E’s compliance plan is legally correct and entirely consistent with due process. SDG&E cites no authority to support its assertion that the purpose of requiring a COC compliance plan is to assure utilities that all actions under the compliance plan are consistent with the COC, and nothing in SB 790 or the COC itself supports SDG&E’s position. Rather, the purpose of the Compliance Plan requirement is to demonstrate to the Commission that the utility has taken basic steps to ensure compliance with SB 790 and the COC.32 SDG&E’s plan provides, in significant part, only broad declarative statements that SDG&E intends to comply with the COC, rather than detailed descriptions of specific compliance mechanisms. Given this lack of detail, the Commission cannot reasonably “assure” SDG&E that any conduct that does not violate SDG&E’s Compliance Plan is automatically in compliance with the COC. Nor is SDG&E in any way entitled to such assurance under SB 790 and the COC.

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30 Resolution at 21; Finding 4.
31 Application for Rehearing at 18.
32 See COC Rule 22.
II. CONCLUSION

For the reasons set forth above, the Commission should deny SDG&E’s Application for Rehearing.

Dated: October 4, 2016

Respectfully submitted,

/s/ David Peffer

Scott Blaising
David Peffer
Ty Tosdal, of Counsel
BRAUN BLAISING McLAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, CA 95814
Telephone: (916) 712-3961
E-mail: blaising@braunlegal.com

Counsel for the City of Lancaster an Marin Clean Energy
BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements

Rulemaking 16-02-007 (Filed February 11, 2016)

INFORMAL COMMENTS OF THE CITY OF LANCASTER, MARIN CLEAN ENERGY AND SONOMA CLEAN POWER AUTHORITY ON PROPOSED ANALYTICAL FRAMEWORK

Scott Blaising
David Peffer
Ty Tosdal, of Counsel
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, CA 95814
Telephone: (916) 712-3961
E-mail: blaising@braunlegal.com
Counsel for the City of Lancaster

Shalini Swaroop
Regulatory Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Drive
San Rafael, CA 94901
Telephone: (415) 464-6040
E-Mail: sswaroop@mceCleanEnergy.org
Counsel for Marin Clean Energy

Steven S. Shupe
General Counsel
SONOMA CLEAN POWER AUTHORITY
50 Santa Rosa Avenue, Fifth Floor
Santa Rosa, California 95402
Telephone: (707) 890-8485
E-Mail: sshupe@sonomacleanpower.org
Counsel for Sonoma Clean Power Authority

October 14, 2016
INFORMAL COMMENTS OF THE CITY OF LANCASTER,
MARIN CLEAN ENERGY AND SONOMA CLEAN POWER AUTHORITY
ON PROPOSED ANALYTICAL FRAMEWORK

Pursuant to instructions provided by the Energy Division of the Public Utilities
Commission of the State of California (“Commission”), dated September 30, 2016, the City of
Lancaster (“Lancaster”), Marin Clean Energy (“MCE”), and Sonoma Clean Power Authority
(“SCPA”) (collectively, “CCA Parties”) hereby submit informal comments in response to
questions about the proposed analytical framework for Integrated Resource Planning (“IRP”)
presented by the Energy Division at a public workshop on Monday, September 26, 2016
(“Proposed Framework”). The CCA Parties provide background and context about Community
Choice Aggregation (“CCA”) programs, and then, as requested in the instructions regarding the
Proposed Framework, respond to the questions.

I. Background

As explained further in recent comments by the CCA Parties, the CCA Parties manage
and operate CCA programs in their respective communities, providing procurement services and
serving customer load. This proceeding is unfolding in the midst of robust expansion of existing

1 See Informal Pre-Workshop Comments of City Of Lancaster, Marin Clean Energy and
Sonoma Clean Power Authority, R. 16-02-007, August 31, 2016.

(footnote continued)
CCA programs and the emergence of several new CCA programs throughout the state within the next two years. The issues addressed in this proceeding should be viewed in the context of substantial departing load associated with CCA programs. As discussed in the CCA Motion, additional engagement and cooperation with CCA program representatives is warranted in light of expected CCA program growth and the significance of this departing load on IRP-related issues. Accordingly, the CCA Parties request that the Proposed Framework be revised to more clearly describe points at which cooperative interaction with CCA programs will occur.

II. Responses to Questions on the Proposed Analytical Framework for Integrated Resource Planning Presented at the Public Workshop on September 26, 2016

1. How often should Loss of Load Probability (LOLP) modeling be updated? Is a full LOLP analysis needed for each IRP, or can a Planning Reserve Margin (PRM)-like metric be used in some cases?

   Planning Reserve Margin-based analyses have been relied on for years to ensure system and local reliability. These models should continue to be relied upon to demonstrate reliability, and may possibly be augmented by Loss of Load Probability models.

2. Does LOLP-based system reliability assessment also need to be repeated in Box 5 in order to validate all Load Serving Entity (LSE)-preferred IRPs together, or can this validation be deferred until Box 2 of the subsequent IRP two-year planning cycle?

   The CCA Parties have no response to this question at this time, and will take it under consideration for a future response.

3. How often should local reliability needs be checked? What vintage of CAISO TPP analysis should be used, considering a potential one-year lag in the demand forecast associated with the CAISO TPP analysis?

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2 See Motion of the City of Lancaster, Marin Clean Energy and Sonoma Clean Power for Official Notice, R. 16-02-007, October 7, 2016 (requesting that the Commission take official notice of the load forecasts of existing CCA programs and official actions of local governments to investigate or form CCA programs) (“CCA Motion”).
The CCA Parties have no response to this question at this time, and will take it under consideration for a future response.

4. **How important is it for the system reliability assessment to be able to evaluate intrahour and chronological commitment and dispatch of resources (considering the possibility that the generation fleet may be moving from an era of significant over-capacity to an era where flexible gas generators retire due to insufficient revenues)?**

   The CCA Parties have no response to this question at this time, and will take it under consideration for a future response.

5. **What other naming conventions should staff consider for plans currently referred to as “Reference System Plan” and “Preferred System Plan?”**

   The CCA parties have no recommendations with regard to alternative naming conventions that should be considered for the noted plans.

6. **What is a tractable technical approach for CPUC to provide guidance to LSEs regarding how LSEs should reflect the resources selected as a part of the Reference System Plan to fulfill systemwide needs within LSE-preferred plans? For example, should CPUC require that LSEs submit at least one portfolio that includes a load-based share of any new system resources that appear in the Reference System Plan?**

   **General**

   CCA programs are autonomous with regard to resource planning and procurement, subject to compliance with applicable legislation and implementing regulations. Public Utilities Code Section 366.2(a)(5) states:

   A community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator’s customers, except where other generation procurement arrangements are expressly authorized by statute.¹

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¹ Added by Senate Bill (“SB”) 790 (2011). *See also* Pub. Util. Code § 380(b)(4) (“In establishing resource adequacy requirements, the Commission shall...maximize the ability of community choice aggregators to determine the generation resources used to serve their customers.”). All subsequent statutory references are to the Public Utilities Code, unless otherwise noted.

(footnote continued)
The Commission has been expressly authorized by statute to regulate specific areas of CCA procurement to ensure compliance with several requirements, including the Resource Adequacy ("RA") requirement,\(^4\) Renewables Portfolio Standard ("RPS"),\(^5\) Energy Storage requirement,\(^6\) and the Greenhouse Gas Emissions Performance Standard.\(^7\) CCA programs comply with these obligations, including California’s RA Program, which is focused on promoting and maintaining system reliability. CCA programs regularly engage in internal planning and procurement activities to meet compliance obligations. The CCA Parties believe that the Commission should explicitly recognize the independent planning and procurement activities of CCA programs when developing current or future Reference System Plans that involve a broader group of LSEs.

The CCA Parties recognize, however, that there is a certain degree of tension that exists between the Commission’s obligations under SB 350 regarding overall IRP goals and objectives, on the one hand, and the Legislature’s express intent to allow CCA programs the maximum degree of autonomy with respect to generation procurement activities. The CCA Parties look forward to working with the Commission to harmonize these statutory goals. For now, the CCA Parties believe that the Proposed Framework should be structured such that CCA programs are allowed to develop their resource plans independently, using the inputs, assumptions, and methodologies selected by each community choice aggregator. The CCA Parties look forward to further teasing-out these principles.

\(^4\) Pub. Util. Code § 380
\(^5\) Pub. Util. Code § 399.12(j)
\(^6\) Pub. Util. Code § 2386(a)(1)
\(^7\) Pub. Util. Code § 366.2(c)(4)
Input

The Commission is likely aware of the relatively fast and widespread growth of CCA programs throughout the state, so it is reasonable to assume that CCA programs will become increasingly significant in administering various statewide and regional planning processes. CCA operations, planning and procurement should be explicitly considered when developing the Reference System Plan. However, in recognition of CCA procurement autonomy, CCA resource plans should be treated as exogenous inputs to the Reference System Plan.

System Needs

Further work will be necessary to better understand the nature and scope of so-called “system needs.” For reasons previously stated, community choice aggregators should be given the maximum ability to procure their own system needs. The CCA Parties therefore understand the term “system needs” largely in the context of situations in which the planning analysis reveals a need for new system resources to meet a CCA-specific procurement requirement (such as RA or Renewables Integration) after accounting for CCA resource plans and other LSE inputs, or if the analysis reveals an IOU system need that, but for self-provision by the community choice aggregator, would be imposed on CCA customers through a non-bypassable charge (“NBC”). In these situations, CCA programs should be given an opportunity to self-provide their share of the identified need.

It is imperative that the criteria for meeting the identified CCA-specific or NBC-eligible procurement requirement be clearly and objectively defined so that an evaluation

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8 See generally CCA Motion.
can be made with respect to two matters. First, an evaluation should occur as to the degree to which CCA programs have already met their respective share of the procurement requirement through resources identified in the CCA programs’ resource plans. Second, an evaluation should occur so that any remaining share of the procurement requirement can be met through self-provision by the community choice aggregator. In this regard, iterative processes will likely be needed. CCA programs should be given the opportunity to submit a revised resource plan that includes resources the CCA programs have chosen to meet the CCA-specific or NBC-eligible procurement requirement. CCA programs that take on this obligation through self-provision should be exempt from any costs of procurement by the investor-owned utilities (“IOUs”) related to the requirement.

**Output**

To the extent that any CCA-specific obligations result from Commission-administered planning processes, two overarching principles should be recognized and applied. First, as described above, the obligations should be determined in a manner that gives due deference to and rightly harmonizes CCA procurement autonomy. Second, the obligations should not be subsumed under the planning and procurement responsibilities of the IOUs. CCA programs have proven to be highly effective at resource planning and procurement, so community choice aggregators should maintain independent responsibility when satisfying reliability or other applicable planning obligations.
7. For Community Choice Aggregators (CCAs), what methodology and/or metrics should CPUC use to determine whether a CCA-proposed alternative to a renewable integration solution identified in the Reference System Plan meets the statutory criteria for CPUC approval?

As a preliminary matter, the CCA Parties note that “renewable integration” has not been comprehensively defined by the Commission. The CCA Parties look forward to participating in discussions to clarify and apply this term. In this regard, the Commission planning process should build upon the existing RA framework, which identifies system and local reliability needs as well as renewable integration needs through LSE requirements for flexible RA capacity.

If a CCA program elects to self-provide its share of the renewable integration solution identified in the Reference System Plan, the adequacy of the self-provided resources should be evaluated based on their effectiveness in meeting the defined need. The Commission’s evaluation of self-provided renewable integration resources should take advantage of existing RA frameworks. In general, the RA process provides objective eligibility criteria for reliability and integration that enable each LSE to effectively manage their own obligations. One noteworthy difference, however, from the current RA program is that self-provision of renewable integration requirements is optional for CCA programs.

The criteria used to determine the renewable integration requirement, as well as each CCA’s share of that requirement, must be specified in advance to facilitate self-provision by CCA programs. Once a CCA program’s share of the renewable integration requirements is defined, self-provided resources can be evaluated based on (1) whether the self-provided resources are adequate to satisfy the program’s renewable integration share, and (2) whether the self-provided resources satisfy existing CCA-specific statutory
procurement requirements. The net costs of any residual need beyond self-provided resources would be allocated among LSEs that have not contributed their respective share of the defined need.

8. **Should CPUC conduct any additional modeling of the aggregated LSE Plans as part of the evaluation process? If so, what type of analysis is needed?**

   As previously noted, the CCA Parties strongly recommend that any modeling completed by the Commission should acknowledge the planning and procurement activities that have been and can be reasonably assumed to be undertaken by CCA programs. In other words, CCA procurement should be treated as an exogenous input to the Commission’s modeling, not an output to be determined through such modeling. If the planning and procurement activities of CCA programs are not explicitly considered in Commission modeling efforts, the results will be incomplete and/or inaccurate.

   The CCA Parties also believe that close and regular collaboration should occur among the CCA programs and Commission staff. In this regard, the CCA Parties look forward to working with Commission staff to clearly define the purpose and effect of any Commission modeling that relates to CCAs, including any modeling of aggregated LSE plans.

9. **If the aggregate of LSE plans fails to meet reliability, GHG, or other standards, should CPUC perform additional modeling or other technical analysis? For example, should CPUC conduct modeling to try to determine the extent to which each LSE plan contributes to the failure? If so, what type of modeling could be used and how should it be performed?**

   The Commission refers to “reliability, GHG, or other standards….” It would be helpful to identify the specific “standards” that are assumed to apply to CCA programs, including the basis for such assumptions. The Commission may be aware that California’s operating CCA programs plan to undertake individual IRP processes that are
intended to address a broad scope of mandatory obligations and voluntary commitments
across a broad scope of considerations, including sufficiency of supply, renewable energy
procurement, reserve capacity, emissions impacts, efficiency and other complementary
ing energy programs. Such planning efforts are focused on the obligations and regulatory
programs with which CCA programs must comply, so it would be helpful if the
Commission could elaborate on the specific standards that it believes are applicable to
CCA programs.

10. **Regardless of whether or not the aggregated LSE plans fail to meet any specified standards, should CPUC conduct any additional modeling to assess whether a specific LSE’s plan is appropriate in the context of the Reference System Plan (or to validate an LSE rationale for a significant deviation from the System Plan)? If so, what type of modeling should be used?**

   It is unclear what purpose would be served by the Commission’s additional
   assessment, so the CCA Parties do not provide a substantive response to this question.

   As a general matter, in light of the statutory autonomy of CCA programs, the CCA
   Parties believe that the Commission’s assessment of CCA programs should be limited.
   The principal role of the Commission as it relates to CCA programs is to review and
   incorporate information contained in CCA program resource plans into the overall system
   plan and to facilitate the self-provision process.
III. Conclusion

The CCA Parties thank the Energy Division for its consideration of these informal comments.

Dated: October 14, 2016

Respectfully submitted,

/s/ Scott Blaising
Scott Blaising
David Peffer
Dan Griffiths
Ty Tosdal, of Counsel
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, CA 95814
Telephone: (916) 712-3961
E-mail: blaising@braunlegal.com
Counsel for the City of Lancaster

/s/ Shalini Swaroop
Shalini Swaroop
Regulatory Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Drive
San Rafael, CA 94901
Telephone: (415) 464-6040
E-Mail: sswaroop@mceCleanEnergy.org
Counsel for Marin Clean Energy

/s/ Steven S. Shupe
Steven S. Shupe
General Counsel
SONOMA CLEAN POWER AUTHORITY
50 Santa Rosa Avenue, Fifth Floor
Santa Rosa, California 95402
Telephone: (707) 890-8485
E-Mail: sshupe@sonomacleanpower.org
Counsel for Sonoma Clean Power Authority
BEFORE THE PUBLIC UTILITIES COMMISSION
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Order Instituting Rulemaking to Develop an
Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements

Rulemaking 16-02-007
(Filed February 11, 2016)

REPLY OF THE CITY OF LANCASTER, MARIN CLEAN ENERGY AND SONOMA CLEAN POWER AUTHORITY

Scott Blaising
David Peffer
Dan Griffiths
Ty Tosdal, of Counsel
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, CA  95814
Telephone: (858) 704-4711
E-mail: ty@tosdallaw.com

Counsel for the City of Lancaster

Shalini Swaroop
Regulatory Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Drive
San Rafael, CA  94901
Telephone: (415) 464-6040
E-Mail: sswaroop@mceCleanEnergy.org

Counsel for Marin Clean Energy

November 3, 2016

Steven S. Shupe
General Counsel
SONOMA CLEAN POWER AUTHORITY
50 Santa Rosa Avenue, Fifth Floor
Santa Rosa, California 95402
Telephone: (707) 890-8485
E-Mail: sshupe@sonomacleanpower.org

Counsel for Sonoma Clean Power Authority
REPLY OF THE CITY OF LANCASTER, MARIN CLEAN ENERGY
AND SONOMA CLEAN POWER AUTHORITY

I. INTRODUCTION


Forecasts of substantial load growth among operational CCA programs and official documents showing the large number of cities and counties throughout California that are currently exploring CCA programs provide the Commission with useful and uncontroversial

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1 See Joint Response of Pacific Gas and Electric Company (U 39-E), San Diego Gas & Electric Company (U 902-M), and Southern California Edison Company (U 338-E) to Motion of the City of Lancaster, Marin Clean Energy and Sonoma Clean Power Authority for Official Notice, R.16-02-007, October 24, 2016. The Joint IOU Response was filed in response to the Motion of the City of Lancaster, Marin Clean Energy and Sonoma Clean Power Authority for Official Notice, R.16-02-007, October 7, 2016 (“CCA Motion”).
facts that are relevant to the Integrated Resource Planning ("IRP") issues being considered in this proceeding. Contrary to several of the arguments raised in the Joint IOU Response, these facts are suitable and appropriate for official notice. For these reasons, the CCA Motion should be granted.

II. REPLY

The CCA Parties appreciate the opportunity to reply to the Joint IOU Response and clarify the nature of their request for official notice. The CCA Parties are seeking official notice of the fact that several operational CCA programs have forecast substantial load growth on the order presented in their motion\(^2\) rather than notice of the fact that the CCA programs will serve a certain amount of load on a particular date. Similarly, the CCA Parties are seeking to obtain official notice of the fact that a number of cities and counties have taken official action to form CCA programs or explore CCA program formation\(^3\) rather than notice of the fact that a certain number of CCA programs will be operational on a particular date. CCA load and program growth may deviate from these load projections and planning activities, but the information presented in the CCA Parties’ motion is based on official documents generated by local governments at various stages of the CCA formation process. Whether accepted as part of the record in this proceeding, or simply used as important background information, the fact that CCA programs are projecting additional load growth and that cities and counties are exploring CCA programs are both relevant to this proceeding and suitable for official notice.

A. CCA Load Growth and Program Adoption Are Highly Relevant to Implementation of SB 350 and the Integrated Resource Planning Process

The growth of CCA load and adoption of CCA programs are crucial for the development

\(^2\) See CCA Motion at 5.
\(^3\) See CCA Motion at 6.
of modeling assumptions and for resource planning, which are integral to the implementation of Senate Bill ("SB") 350. The Joint IOUs acknowledge that there is growing interest in CCA programs in a number of communities, but take issue with CCA Parties’ request for official notice on grounds of timing and relevance. The arguments advanced by the Joint IOUs miss the big picture, and should be rejected by the Commission.

The Commission initiated this proceeding to implement SB 350 and develop requirements for Load Serving Entities ("LSEs"), including CCA programs, to generate and file IRPs. To address the impact of SB 350 on future procurement needs, the Commission anticipates building on previous Long-Term Procurement Planning ("LTPP") proceedings. In addition, advance work is being done at this stage of the proceeding to develop and refine “modeling assumptions to assess the need for additional flexible resources to integrate variable renewable energy resources.” Related, another issue affecting CCA programs in this proceeding is the development of “procurement rules for non-investor-owned utility (IOU) LSEs now required to develop IRPs who did not previously submit LTPPs .” Notably, CCA programs have the option of self-providing in order to integrate renewable resources under the statute.

The load served by CCA programs – especially in the short term – has been and continues to be relevant to LTPP proceedings, and should be considered in the development of

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4 Joint IOU Response at 2.
5 See Order Instituting Rulemaking to Develop An Electricity Integrated Resource Planning Framework And to Coordinate and Refine Long-Term Procurement Planning Requirements ("OIR"), R. 16-02-007, February 19, 2016 at 2-3.
6 See Joint Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, R. 16-02-007, May 26, 2016 at 13-16.
7 OIR at 3.
8 OIR at 3.
9 See, e.g., Pub. Util. Code, § 454.51(d); OIR at 23.
resource modeling assumptions and procurement guidance for CCA self-provision. In previous LTPP proceedings, the Commission has recognized the need to consider CCA load forecasting in the IOU Bundled Procurement Plans (“BPPs”) and adopted forecasting as part of the last BPP cycle.\textsuperscript{10} A continuation of that process is anticipated to occur in this proceeding.

In addition, developing modeling assumptions will involve different scenarios that vary based on the amount of load that CCA programs serve and the extent to which CCA programs self-provide resources. Lastly, the nature and scope of the procurement guidance that the Commission provides during this proceeding will depend in part on CCA load. In general, there is likely to be greater attention and guidance given to procurement by CCA programs if it is anticipated that they will serve a significant percentage of overall load in the state than if that were not the case. In sum, the CCA Motion seeks official notice of facts related to CCA load and program growth, which have a direct impact on resource planning issues in this proceeding.

B. CCA Load and Program Growth Are Entirely Suitable and Appropriate Facts for Official Notice by the Commission

The Commission should take official notice of the fact that operational CCA programs have forecast substantial load growth and that several cities and counties are officially planning or exploring CCA programs. As explained further in the CCA Motion, these facts are suitable and appropriate for official notice, notwithstanding the arguments raised by the Joint IOUs. The various documents that the CCA Parties reference in the CCA Motion, which contain the facts subject to notice, were generated by local governments as part of an official action on the part of their respective decision-making bodies, whether city council or board of supervisors.\textsuperscript{11} The Joint


\textsuperscript{11} See CCA Motion at 5-6.
IOUs make no argument that the underlying facts presented in the CCA Motion are inaccurate or unreliable. As such, the facts fall under the requirements of Evidence Code section 452 and are suitable and appropriate for notice under Rule 13.9.

Without responding to the Joint IOU Response point by point, it is important to recognize that while the Joint IOUs frame their arguments around whether the standards for official notice have been met, the arguments go to the weight of the evidence, rather than admissibility. For example, the Joint IOUs argue in opposition to the motion that planning or exploring a CCA program does not commit the program to procure power for customers, and that such a commitment is made only upon submission of a Binding Notice of Intent ("BNI"). The Joint IOUs raise a fair substantive point, but that point concerns the weight that the Commission should give CCA program load forecasts and local government efforts to plan and explore CCA programs, rather than admissibility of the facts under the standards for official notice. Whether a CCA program has submitted a BNI does not bear on whether the Commission should take official notice of the facts presented in the CCA Parties’ motion, which concerns steps that CCA programs and local governments have taken to procure resources and serve load in the future. Other arguments raised in the Joint IOU Response also go to weight, rather than admissibility.

The fact that the load forecasts are projections does not disqualify them for purposes of official notice. The Commission frequently relies on forecasts as a planning tool, accepts them into the record, and makes consequential decisions based on them, despite the uncertainties inherent in making judgments about the future.\(^\text{12}\) Forecasts are useful, and without them, it is difficult to see how the Commission would carry out its responsibilities to comply with

\(^\text{12}\) See, e.g., Decision Authorizing Long-Term Procurement for Local Capacity Requirements due to Permanent Retirement of the San Onofre Nuclear Generations Stations, D.14-03-004, March 13, 2014 at 28-65.
legislative mandates and ensure there is an adequate energy supply to meet future demand.

Accordingly, the load forecasts presented in the CCA Parties’ motion are suitable for official
notice.

III. CONCLUSION

For all the reasons stated above, the motion of the CCA Parties for official notice of the
documents described in their motion should be granted.

Dated: November 3, 2016

Respectfully submitted,

/S/ Ty Tosdal

Scott Blaising
David Peffer
Dan Griffiths
Ty Tosdal, of Counsel
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, CA 95814
Telephone: (858) 704-4711
E-mail: ty@tosdallaw.com

Counsel for the City of Lancaster

/S/ Shalini Swaroop

Shalini Swaroop
Regulatory Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Drive
San Rafael, CA 94901
Telephone: (415) 464-6040
E-Mail: sswaroop@mceCleanEnergy.org

Counsel for Marin Clean Energy

/S/ Steven S. Shupe

Steven S. Shupe
General Counsel
SONOMA CLEAN POWER AUTHORITY
50 Santa Rosa Avenue, Fifth Floor
Santa Rosa, California 95402
Telephone: (707) 890-8485
E-Mail: sshupe@sonomacleanpower.org

Counsel for Sonoma Clean Power Authority
Via Regular Mail and E-Mail

Mr. Ed Randolph
Director, Energy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA  94102

Re:   Comments on Draft Resolution E-4805

Dear Mr. Randolph:

Pursuant to Rule 14.5 of the Rules of Practice and Procedure of the Public Utilities Commission of the State of California (“Commission”), the City of Lancaster (“Lancaster”), Marin Clean Energy (“MCE”) and Sonoma Clean Power Authority (“SCPA”) (collectively “CCA Parties”) hereby submit these comments on Draft Resolution E-4805 (“Draft Resolution”). The Draft Resolution was issued on the Energy Division’s own motion, and if adopted by the Commission would authorize procurement pursuant to Senate Bill (“SB”) 859 (2016) from bioenergy facilities supplied from forest fuel high hazard zones in connection with the state’s tree mortality emergency (“HHZ Procurement”). As discussed below, the CCA Parties request that the Draft Resolution be modified to address two matters. First, the Draft Resolution should give due recognition of the self-provision option for community choice aggregators, as contemplated in SB 790 (2011) and SB 350 (2015). Second, the Draft Resolution’s proposed construct for a “Tree Mortality Nonbypassable Charge” should be clarified in order to harmonize SB 859 with SB 790.

BACKGROUND

The CCA Parties are operational community choice aggregators providing generation procurement services for their respective Community Choice Aggregation (“CCA”) customers. The emergence of new and expanding CCA programs, spurred by SB 790, is significantly changing the generation procurement landscape, and should be taken into consideration by the Commission as new generation programs, policies and charges are implemented. Importantly, the legislature has stated that, unless expressly authorized in statute, community choice aggregators should be solely responsible for all generation procurement activities for their customers, and that the Commission should pursue objectives that maximize the ability of community choice aggregators to determine the generation resources used to serve their customers.1

The Draft Resolution implements SB 859, which, among other things, expressly authorized the Commission to recover HHZ Procurement costs from all customers on a nonbypassable basis. The Draft Resolution establishes certain principles for the Tree Mortality NBC, but directs the investor-owned

1 See, e.g., Pub. Util. Code §§ 366.2(a)(5) and 380(a)(4) (added by SB 790).
utilities ("IOUs") to file tier 2 advice letters to further specify and seek final approval of the Tree Mortality NBC. As currently written, the Draft Resolution directs that “capacity costs and benefits of [HHZ Procurement]” should be allocated through the Tree Mortality NBC, but that renewable energy costs and benefits will not be allocated in the charge.²

COMMENTS

1. The CCA Parties Generally Oppose New NBCs

   Given the increase in consideration of proposed new NBCs at both the legislature and the Commission, the CCA Parties are concerned that new NBCs are becoming an all-too-convenient method for cost allocation, particularly in circumstances in which self-provision is a viable option. As such, the CCA Parties generally oppose new NBCs. As mentioned above, the legislature has clearly stated that community choice aggregators should have sole responsibility of generation procurement activities for their CCA customers, and that the Commission should pursue objectives that maximize the ability of community choice aggregators to determine the generation resources used to serve their customers. Adding new NBCs and associated resources without considering and harmonizing the legislature’s intentions in SB 790 leads to several negative outcomes. Among other things, such an approach unduly interferes with community choice aggregators’ desired energy portfolio balances, and can distort rate signals and the competitive posture of CCA programs.

   Given the state of emergency due to tree mortality and the express authorization in SB 859, the CCA Parties will not oppose cost allocation in this circumstance. However, the CCA Parties will consistently oppose new NBCs both at the legislature and the Commission insofar as such new NBCs generally compromise the statutory right of community choice aggregators to have sole responsibility over their own generation procurement activities.

2. The Draft Resolution Should Recognize The Self-Provision Option For Community Choice Aggregators

   Disappointingly, the Draft Resolution is devoid of any discussion of a self-provision option for Community Choice Aggregators. While SB 859 does not expressly provide this option, it does not expressly preclude this option either, and as such it is appropriate to interpret SB 859 in a manner that is consistent with SB 790. The self-provision option is consistent with the legislature’s intent in SB 790 that community choice aggregators should be solely responsible for all generation procurement activities for their customers, and that the Commission should pursue objectives that maximize the ability of community choice aggregators to determine the generation resources used to serve their customers. As such, the CCA Parties request that the Draft Resolution be modified to include a self-provision option for community choice aggregators.

   In addition to being consistent with the intent of the legislature in SB 790, inclusion of a self-provision option in this circumstance is a reasonable next step in light of the Commission’s integrated resource planning ("IRP") process. In the context of the IRP process, SB 350 requires the Commission

² See Draft Resolution at 11.
to permit community choice aggregators to self-provide their share of renewable energy integration resources, subject to certain findings by the Commission. The Commission can and should use the HHZ Procurement process to introduce and begin to tease-out this self-provision process. If, however, the Commission chooses to not include a self-provision option for the HHZ Procurement process, the Draft Resolution should at least be modified to include a discussion of the self-provision option and an expression of intent by the Commission to meaningfully consider this option on a going-forward basis.

3. Clarifications To The Draft Resolution Are Necessary

As discussed above, the CCA Parties do not oppose cost allocation in this circumstance, however, clarifications to the Draft Resolution are necessary to harmonize legislative principles and to conform the proposed Tree Mortality NBC to existing NBC valuation methodologies. In this regard, the CCA Parties urge three clarifications.

First, as noted above, the Commission is directed to maximize the ability of community choice aggregators to determine their own generation resources. The proposed allocation of capacity from the HHZ Procurement unnecessarily conflicts with this directive. Quite simply, there is no need to allocate capacity from the HHZ Procurement to community choice aggregators. This capacity should be retained by the IOUs, and any above-market cost associated with this retained capacity can be incorporated into the Tree Mortality NBC. The Draft Resolution appears to adopt this approach for renewable energy costs/benefits, and the Draft Resolution should be modified to adopt this approach for capacity. The so-called Cost Allocation Methodology (“CAM”) process has proven to be administratively complex and unduly cumbersome, often resulting in an allocation of capacity to community choice aggregators that cannot be effectively used. The CAM process should not be replicated here.

Second, the Draft Resolution should be clarified so that the valuation methodology for the Tree Mortality NBC does not unnecessarily conflict with existing NBC valuation methodologies. Again, the CCA Parties are not opposing cost allocation for HHZ Procurement in this circumstance. However, only the above-market or net cost should be allocated through the Tree Mortality NBC. To do this, the Commission already has a ready-made process for determining above market costs. This process, as described in D.11-12-018, is already used to determine various NBCs, including the ongoing competition transition charge and the power charge indifference amount. In this circumstance, the Tree Mortality NBC may be determined by determining the total HHZ Procurement cost, and then deducting the value associated with retained capacity and renewable energy. The Commission’s existing market price benchmark (“MPB”), as modified and clarified in D.11-12-018, has been subject to robust scrutiny and discussion, and until a successor MPB is adopted the existing MPB should be used to value capacity and renewable energy associated with HHZ Procurement.

Third, the Draft Resolution should be clarified so that cost allocation under the Tree Mortality NBC is expressly limited in duration to the prescribed five-year financial commitment of the IOUs.

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4 See Pub. Util. Code § 399.20.3(b) (added by SB 859)
REQUESTED MODIFICATIONS

The CCA Parties request that Findings 8 and 9 be revised to read as follows, with conforming changes in the body of the Draft Resolution:

8. Subject to Finding 9, PG&E, SCE, and SDG&E should create a Tree Mortality Nonbypassable Charge to allocate the net costs of procurement ordered in this Resolution to unbundled customers, exclusive of the capacity and renewable energy value retained by PG&E, SCE and SDG&E, as determined using the market price benchmark valuation methodology adopted in D.11-12-018.

9. In order to avoid application of the Tree Mortality Nonbpassable Charge to their respective customers, community choice aggregators should be given the opportunity to self-provide their load-ratio share of MWs of procurement ordered herein, subject to the Commission’s finding that the resource(s) proposed by community choice aggregators provide comparable attributes and that bundled customers of the IOUs will be indifferent from the approval of community choice aggregator proposals.

CONCLUSION

The CCA Parties thank the Commission in advance for consideration of these comments.

Respectfully,

Scott Blaising

Braun Blaising McLaughlin & Smith, P.C.
915 L Street, Suite 1480
Sacramento, CA 95814
(916) 326-5812 (office)
blaising@braunlegal.com

Copy (via e-mail) to: Maria Sotero (Maria.Sotero@cpuc.ca.gov)
Cheryl Lee (Cheryl.lee@cpuc.ca.gov)
Service Lists: R.15-02-020 and R.08-08-009
Marin Clean Energy (MCE) requests that the CAISO revise its proposal on adjustments to intra-year load forecasts. The CAISO states that it is “appropriate to allow LSEs to update load forecasts intra-year only for load migration due to retail choice.”¹ MCE strongly concurs. However, the CAISO then appears to restrict such intra-year adjustments to load migration solely attributable to direct access. MCE requests that the CAISO revise its proposal to specify that intra-year adjustments to load forecasts would be permitted for all load migration associated retail choice, including load migration attributable to community choice aggregation (CCA). The CPUC rules currently permit such intra-year adjustments for all load migration, both direct access and CCA, and the CAISO rules should be consistent.

Marin Clean Energy takes no position on the remainder of CAISO’s proposal at this time.

¹ 3rd Revised Straw Proposal, p. 11.
August 18, 2016

CA Public Utilities Commission
Energy Division
Attention: Energy Efficiency Branch
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

Advice Letter 17-E

Re: Request for Approval of MCE Seasonal Savings Pilot Program


Effective Date: September 18, 2016

Tier Designation: Tier 2

Pursuant to General Order 96-B, Energy Industry Rule 5.2 this advice letter is submitted with a Tier 2 designation.

Purpose

The purpose of this advice filing is to seek approval of the MCE Seasonal Savings Pilot Program and utilize budget from suspended activities in MCE’s single family program to fund the proposed pilot.

Background

The purpose of a pilot project is to test a new and innovative concept, partnership, or program design that is intended to address a specific area of concern or gap in existing programs.3 The Commission articulated ten criteria for proposed pilots in D.09-09-047.4 The Energy Efficiency Policy Manual restates those criteria.5 MCE plans to launch the Seasonal Savings Pilot Program, an innovative program designed to investigate the potential cost-effective savings in utilizing smart thermostat technology to remotely modify set points on Heating, Ventilation, and Air

1 D.09-09-047 at p. 48-49.
3 D.09-09-047 at p. 48.
4 D.09-09-047 at p. 48-49.
Conditioning ("HVAC") equipment. MCE engaged with Energy Division through the ideation process to address each of the criteria in MCE’s pilot program design. The results of that process with some additional implementation details of the MCE Seasonal Savings Pilot Program are provided in this advice letter as Attachment A: MCE Seasonal Savings Pilot Plan.

**MCE Seasonal Savings Pilot Program**

The MCE Seasonal Savings Pilot Program will test an innovative approach to achieving energy savings with energy management technology. This pilot is different from the energy efficiency studies intended to produce a work paper based on energy savings from smart thermostats themselves (i.e. “out-of-the-box” efficiency, where customers begin to save energy as soon as they install and begin to use the device).

The Nest Learning Thermostat has already been proven to save energy out-of-the-box. There are a large number of third party measurement and verification (“M&V”) studies that have been conducted on the Nest Learning Thermostat and other smart thermostats, including studies underway in partnership with the California investor-owned utilities (“IOUs”). The results of these studies indicate that Nest Learning Thermostats can drive savings equal to approximately:

- 10%-12% of heating usage, and
- 15% of electrical cooling usage in homes with central air conditioning.

The Seasonal Savings pilot program takes the Nest Learning Thermostat energy savings one step further by providing customers with incremental energy savings throughout a particular heating or cooling season. The thermostat does this by making micro set point adjustments to the thermostat’s schedule for those customers who have opted in to the program over a three week period. The result is cost-effective, incremental energy savings and customer engagement. Nest has run this program elsewhere in the United States but not yet in Northern California’s unique climate zones. The attached white paper (Attachment B) summarizes the results of Nest’s recent Seasonal Savings deployment in Massachusetts. Of note:

- Participants’ set points declined by an average of 1.3°F over the course of the three week algorithm.
- The Program reduced heating usage by an average of 3.5% over the course of the winter, based on a weather-adjusted analysis of run times that included a control group from neighboring states. These savings include the effect of the impact reductions over time.

This program will help to bolster the California-specific energy savings data available to the broader energy program stakeholder group currently studying energy savings. These are driven by smart thermostats like the Nest Learning Thermostats. The current efforts include studies by California’s IOUs focused on out-of-the-box efficiency and demand response. While the pilot is proposed specifically in conjunction with Nest, the lessons learned from this pilot will be

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relevant to any energy management technology that is equipped with controls that allow access to customer thermostat settings.

The details on the pilot design are provided in the MCE Seasonal Savings Pilot Plan, included as Attachment A to this advice letter. This plan includes the results of the ideation process completed by MCE and Energy Division staff prior to submission of this advice letter. The plan includes elements such as the experimental design; the pilot metrics; and an Evaluation, Measurement, and Verification (“EM&V”) plan.

**Funding for the Pilot**

MCE intends to fund the MCE Seasonal Savings Pilot Program out of MCE’s existing single family program budget. MCE has recently suspended activities in its Single Family program, creating an opportunity to support an innovative new pilot concept.

**Suspension of My Energy Tool**

MCE’s My Energy Tool is an online engagement tool that helps customers understand their energy usage and receive information about low and no-cost options to save energy. At the time MCE developed the tool, it was an innovative offering that did not exist among the Program Administrators (“PAs”). Since then, a common vendor was retained under contract to the statewide Marketing, Education, and Outreach consultant to develop a similar tool available to all ratepayers in California at no additional cost to MCE. This tool rendered MCE’s program duplicative. A recent evaluation report found that MCE’s Home Utility Reports (“HURs”) program, the core resource activity in MCE’s single family program, was not achieving statistically significant savings. In response to the evaluation, MCE suspended the HURs program. In recognition of the newly available statewide tool and to ensure effective use of ratepayer funds, MCE concluded the vendor agreement that covered both the MCE Single Family Home Utility Reports (“HURs”) program and MCE’s My Energy Tool. The remaining budget from MCE’s MyEnergyTool for 2016-2017 is sufficient to fund the MCE Seasonal Savings Pilot Program as shown in Table 1 below. The Seasonal Savings Pilot expenses will be divided equally between Winter 2016 and Summer 2017.

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Table 1: MyEnergyTool Budget Available to Fund Seasonal Savings Pilot

<table>
<thead>
<tr>
<th>Single Family Program</th>
<th>2016 Budget</th>
<th>2017 Budget</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Seasonal Savings Pilot</td>
<td>$30,000</td>
<td>$30,000</td>
<td>$60,000</td>
</tr>
<tr>
<td>Available MyEnergyTool Budget*</td>
<td>$63,000</td>
<td>$126,000</td>
<td>$189,000</td>
</tr>
</tbody>
</table>

*The Available MyEnergyTool Budget includes six months of the 2016 budget and the full 2017 budget for MCE’s MyEnergyTool.

Notice

Anyone wishing to protest this advice filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice filing. Protests should be mailed to:

CPUC, Energy Division  
Attention: Tariff Unit  
505 Van Ness Avenue  
San Francisco, California 94102  
E-mail: EDTariffUnit@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address above).

In addition, protests and all other correspondence regarding this advice letter should also be sent by letter and transmitted via facsimile or electronically to the attention of:

Michael Callahan-Dudley  
Regulatory Counsel  
MARIN CLEAN ENERGY  
1125 Tamalpais Avenue  
San Rafael, CA 94901  
Phone: (415) 464-6045  
Facsimile: (415) 459-8095  
E-mail: mcallahan-dudley@mceCleanEnergy.org

and

Beckie Menten  
Energy Efficiency Director  
MARIN CLEAN ENERGY  
1125 Tamalpais Avenue  
San Rafael, CA 94901  
Phone: (415) 464-6034  
Facsimile: (415) 459-8095  
E-mail: bmenten@mceCleanEnergy.org
There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

MCE is serving copies of this advice filing to the relevant parties shown on the R.13-11-005 service list. For changes to this service list, please contact the Commission’s Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

**Correspondence**

For questions, please contact Michael Callahan-Dudley at (415) 464-6045 or by electronic mail at mcallahan-dudley@mceCleanEnergy.org.

/s/ Michael Callahan-Dudley

Michael Callahan-Dudley
Regulatory Counsel
MARIN CLEAN ENERGY

cc: Service List R.13-11-005
Attachment A:
MCE Seasonal Savings Pilot Plan
MCE SEASONAL SAVINGS PILOT PLAN

The MCE Seasonal Savings Pilot Plan is structured using the criteria provided in the Ideation Process document⁹ that restates and supplements the pilot criteria articulated by the Commission.¹⁰

1. A specific statement of the concern, gap, or problem that the pilot seeks to address and the likelihood that the issue can be addressed cost-effectively through utility programs. This statement should include any market research done to support the statement of gap and the solution proposed.

Customers continue to adopt new consumer electronics products that have a significant impact on their energy use. Programs must be tested that specifically target the energy savings that can be delivered in a more connected world. In addition to the energy efficiency studies leading to a work paper based on energy savings from smart thermostats themselves (i.e. “out-of-the-box” efficiency), it is important to test concepts like Seasonal Savings that help to deliver even more energy savings to customers in a particular geography. This type of energy efficiency service marks a new strategy for delivering energy savings and engaging customers.

The Nest Learning Thermostat has already been proven to save energy out-of-the-box (i.e. customers begin to save energy as soon as they install and begin to use the device). The number of third party M&V studies that have been conducting on the Nest Learning Thermostat, and other smart thermostats, continues to grow. Nest has summarized some of these results, along with data from its own study, in a white paper that is available online.¹¹ In summary, Nest Learning Thermostats drive savings equal to approximately:

- 10%-12% of heating usage.
- 15% of electrical cooling usage in homes with central air conditioning.

The MCE Seasonal Savings Pilot takes the Nest Thermostat energy savings one step further by providing customers with incremental energy savings throughout a particular heating or cooling season. It does this by making micro set point adjustments to a customer’s schedule - after receiving their permission - over a three week period. The result is incremental energy savings and customer engagement. Nest has run this program elsewhere in the United States but not yet in Northern California’s unique climate zones. The attached white paper (Attachment B) summarizes the results of Nest’s recent Seasonal Savings deployment in Massachusetts. Of note:

- Participants’ set points declined by an average of 1.3°F over the course of the three week algorithm.
- Seasonal Savings reduced heating usage by an average of 3.5% over the course of the winter based on a weather-adjusted analysis of run times that included a control group from neighboring states. These savings include the effect of the impact reductions over time.

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¹⁰ D.09-09-047 at p. 48-49.
This program will help to bolster the California-specific energy savings data available to the broader energy program stakeholder group currently studying energy savings that are driven by smart thermostats like the Nest Learning Thermostats. These current efforts include studies by California’s IOUs focused on out-of-the-box efficiency and demand response.

2. Whether and how the project will address a Strategic Plan goal or strategy and market transformation.

This project aligns with the following broader goals and strategies:

<table>
<thead>
<tr>
<th>Document</th>
<th>Section</th>
<th>Description</th>
<th>How Aligned?</th>
</tr>
</thead>
<tbody>
<tr>
<td>CA Energy Efficiency Strategic Plan (LTEESP)¹²</td>
<td>Policy tools for market transformation¹³</td>
<td>Technical Assistance</td>
<td>By remotely configuring customers’ thermostat set points, with their permission, this pilot will ensure that customers’ knowledge barriers don’t hamper the progress of critical efficiency initiatives.</td>
</tr>
<tr>
<td>CA Energy Efficiency Strategic Plan (LTEESP)¹²</td>
<td>“Big Bold” Energy Efficiency Strategies¹⁴</td>
<td>All new residential construction in California will be zero net energy by 2020.</td>
<td>This pilot will demonstrate the potential role smart thermostats can play in helping residential customers achieve zero net energy homes.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Emerging Technologies</td>
<td>This pilot will demonstrate the energy saving potential of an innovative strategy (set point configuration) used to optimize an emerging technology (smart thermostats).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Heating, Ventilation and Air Conditioning (HVAC) will be transformed to ensure that its energy performance is optimal for California’s climate.</td>
<td>This pilot will shed light on the potential energy savings to be gleaned from making the management of residential HVAC systems “smarter.” The pilot will be constrained to MCE’s service territory (i.e., the North Bay Area’s temperate climate).</td>
</tr>
</tbody>
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¹³ LTEESP at p. 5.
¹⁴ LTEESP at p. 6.
| DSM Coordination & Integration<sup>15</sup> | Energy efficiency, energy conservation, demand response, advanced metering, and distributed generation technologies are offered as elements of an integrated solution that supports energy and carbon reduction goals. | If energy savings are demonstrated through this pilot and funds are made available to administer similar programs in the future, then rebates for smart thermostats could be offered to customers who don’t yet have them. Expanding the pool of customers with smart thermostats and acclimating residential customers to the remote control of their devices are two important steps towards enrolling customers in automated demand response programs. |
| AB 793 (2015) | “The commission shall require an electrical or gas corporation to...[d]evelop a program no later than January 1, 2017...to provide incentives to a residential or small or medium business customer to acquire energy management technology for use in the customer’s home or place of business....The electrical or gas corporation shall work with third parties, local governments, and other interested parties in developing the program. The electrical or gas corporation shall establish incentive amounts based on savings estimation and baseline policies adopted by the commission....For purposes of this section, ‘energy management technology’ may include a product, service, or software that allows a customer to better understand and manage | By demonstrating energy savings this pilot will help establish savings estimates and incentive levels for similar programs focused on providing incremental and ongoing energy savings from smart thermostats, and thereby move the State closer to fulfilling the directives outlined in AB 793 regarding providing residential customers with energy management technology. |

<sup>15</sup> LTEESP at p. 67-69.
| **SB 350 (2015)** | **Sections 2 & 6** | “To double the energy efficiency savings in electricity and natural gas final end uses of retail customers through energy efficiency and conservation.”<sup>16</sup> “The targets established in subdivision (c) may be achieved through energy efficiency savings and demand reduction resulting from a variety of programs that include, but are not limited to, the following…(8) Programs of electrical or gas corporations, local publicly owned electric utilities, or community choice aggregators, that achieve energy efficiency savings through operational, behavioral, and retrocommissioning activities…. “<sup>17</sup>  
This pilot will help the State achieve its goals of doubling energy efficiency savings through the improved operation of previously installed energy management devices. |
| **California Existing Buildings Energy Efficiency Action Plan (EBEEAP)**<sup>18</sup> | **Consumer-Focused Energy Efficiency, Program Design Enhancement (Strategy 2.2)** | “Revamp efficiency program designs to respond better to customer needs and values, as well as industry practice…. Design programs based upon actual, verified performance rather than ‘deemed’ savings. Design programs to incorporate building operations and behavior.”<sup>19</sup> This pilot is focused on optimizing energy savings in existing buildings through improved operation of previously installed energy management devices. |

<sup>16</sup> SB 350, Section 2(a)(2).  
<sup>17</sup> SB 350 Section 6(d).  
<sup>19</sup> EBEEAP at p. 2.
3. **Specific goals, objectives and end points for the project (end points should clearly state how this project is expected to be scaled up in the portfolio or modify an existing offering in the portfolio)**

**Goals:**
- Study the impact of deployable energy efficiency in California’s northern bay area climate zones.
- Engage customers with an energy program on an ongoing basis (i.e. in successive seasons) to deliver persistent savings.
- Deliver incremental energy savings above and beyond that provided by the smart thermostat device itself.

**End Points:**
Two distinct end points exist for this program. The first comes after the completion of the Winter 2016/17 heating season in which Seasonal Savings will be deployed. At that point, a report on the heating energy savings will be prepared. The second end point will come after the completion of the Summer 2017 season, at which point a report of the cooling savings will be prepared.

**Scaling:**
After successful completion of the two reports mentioned above, this program can quickly scale to all Nest Thermostat customers in MCE’s service area, which is a base that continues to grow. As such, the program will continue to grow as the Nest install base grows, driven in the future by incentives and rebates for additional smart thermostat programs.

**Key Performance Indicators (KPIs):**
- % of eligible customers opting in to the program should be greater than 50%.
- Energy savings should exceed 1.5% of HVAC usage.

**Additional Metrics of Interest:**
- Average temperature set point change of treatment vs. control, which is illustrative of the change driven by the algorithm.
- Total number of participants who opted out of the program.

4. **New and innovative design, partnerships, concepts or measure mixes that have not yet been tested or employed.**

Nest’s Seasonal Savings program is a novel software service that can be delivered to residential customers to increase the energy savings delivered by their smart thermostat. Nest has deployed Seasonal Savings to customers in other parts of North America, but has not yet deployed the algorithm in a climate similar to the northern Bay Area. As such, this is a first-of-its-kind pilot.
5. A clear budget and explanation of funding source.

<table>
<thead>
<tr>
<th>Item</th>
<th>Budget</th>
<th>Funding Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Program Implementation Cost (Nest Contract)</td>
<td>$40,000</td>
<td>MCE Single Family Program</td>
</tr>
<tr>
<td>MCE Staff Costs</td>
<td>$20,000(^{20})</td>
<td>MCE Single Family Program</td>
</tr>
<tr>
<td>Total Budget</td>
<td>$60,000</td>
<td>MCE Single Family Program</td>
</tr>
</tbody>
</table>

The EM&V budget and funding source will be determined in coordination with Energy Division staff. MCE is interested in the possibility of leveraging other evaluation work to limit the expense associated with evaluating this pilot. MCE currently does not have access to EM&V funds. Energy Division staff has expressed an interest in ensuring the study is completed, but additional discussion is needed to resolve the question. MCE is filing this advice letter now in order to ensure the possibility that the pilot can launch to customers this winter. Once the budget and funding source for the EM&V study is determined, MCE will file a supplemental advice letter to provide those additional details. The EM&V Plan is provided below in Section 13.

6. Program performance metrics or non-resource objectives and success criteria

See KPIs in item number 3.

7. Timeframe to complete the project and obtain results within a portfolio cycle (subject to R.13-11-005 Phase 2 determination) - projects should not be continuations of programs from previous PAs portfolios.

- First season = Winter, 2016/17
- Second season = Summer, 2017
- In this case, the end of a season is defined by the point at which the weather changes such that most customers no longer require significant heating or cooling load (i.e. the beginning of a shoulder season).

8. Information on relevant baselines metrics or a plan to develop baseline information against which the project outcomes can be measured.

- See KPIs in item number 3.
- Program participants must have a Nest Learning Thermostat installed at the time of program deployment. Savings will be measured relative to customers who have a Nest Learning Thermostat but are not enrolled in the Seasonal Savings program.

\(^{20}\) Assuming 25% of a full-time equivalent employee.
9. A concrete strategy to identify and disseminate best practices and lessons learned from the pilot project to all California utilities and to transfer those practices to programs, as well as a schedule and plan to expand the pilot project to utility and hopefully statewide usage, including expected funding source for the planned new program or program modification if known.

MCE and Nest will work together to submit a draft report and hold a workshop/webinar to share results of the pilot. MCE will leverage its relationships with other emerging community choice aggregators, local government agencies and community benefits organizations to try and ensure that the program activities, if deemed successful, are repeated and scaled. Assuming the pilot demonstrates cost-effective savings, the expected funding source for expanding Seasonal Savings and other similar programs would be Commission administered EE funds collected from ratepayers. Importantly, any recommendations for future program design or work paper development will be technology neutral, as opposed to recommending the Nest technology specifically.

10. PA staff project manager and assigned EM&V liaison- names and contact info.

<table>
<thead>
<tr>
<th>Name</th>
<th>Title</th>
<th>Role</th>
<th>Contact Info</th>
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<tbody>
<tr>
<td>Daniel Genter</td>
<td>MCE Program Specialist</td>
<td>MCE project manager</td>
<td><a href="mailto:dgenter@mcecleanenergy.org">dgenter@mcecleanenergy.org</a></td>
</tr>
<tr>
<td>Beckie Menten</td>
<td>MCE Director of Customer Programs</td>
<td>MCE secondary contact</td>
<td><a href="mailto:bmenten@mcecleanenergy.org">bmenten@mcecleanenergy.org</a></td>
</tr>
<tr>
<td>Jeremy Battis</td>
<td>Local Government and Regional Initiatives</td>
<td>Energy Division lead</td>
<td><a href="mailto:jeremy.battis@cpuc.ca.gov">jeremy.battis@cpuc.ca.gov</a></td>
</tr>
<tr>
<td></td>
<td>Statewide Lead Analyst at the Commission</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peter Franzese</td>
<td>Regulatory Analyst at the Commission</td>
<td>Energy Division secondary and EM&amp;V lead</td>
<td><a href="mailto:peter.franzese@cpuc.ca.gov">peter.franzese@cpuc.ca.gov</a></td>
</tr>
</tbody>
</table>

11. Ex-Ante Review data collection form (see last slide in this deck)

The project savings claims are based solely on evaluated *ex post* savings, thus no *ex ante* showing is needed at this time.

12. Methodologies to test the cost-effectiveness of the project.

The pilot will utilize a standard total resource cost (“TRC”) calculation. Of particular interest in the model will be the Net-to-Gross (“NTG”) value. Because customers cannot purchase Seasonal Savings on their own (i.e. it must be delivered by an energy partner), MCE proposes a NTG of 100% for this program (i.e. by definition, no customers would have done this on their own without the program).
13. A proposed EM&V plan and PCG plan

EM&V Study Approach
Nest’s Seasonal Savings algorithm deployment lends itself very well to the Intent-to-Treat (“ITT”) EM&V approach, a style of Randomized Control Trial (“RCT”), because three groups are naturally created by the deployment:

1. A control group consisting of Nest Thermostat owners in MCE service area to whom the algorithm is not deployed.
2. A treatment group consisting of Nest Thermostat owners in MCE service area to whom the algorithm is deployed, which is broken into two groups:
   a. Customers who accept the deployment and participate in Seasonal Savings
   b. Customers who decline the deployment and do not participate in Seasonal Savings

M&V Plan
Part 1: Pre-Deployment
The Nest team will set up the deployment of Seasonal Savings to ensure that the Intent-to-Treat strategy can be used. To do so, the Nest team will take the following steps:

1. Identify all eligible Nest Thermostats within MCE’s service area
2. Separate the devices into two groups: treatment and control
   a. These groups will be created randomly to facilitate the RCT component of the ITT methodology
   b. The relative sizing of the groups will be mutually agreed upon by the Nest and MCE teams (e.g. it can be evenly split 50/50, weighted toward treatment, etc).
3. Nest then deploys Seasonal Savings to the treatment group

Part 2: Post-Deployment
Following the deployment of Seasonal Savings, Nest will provide the EM&V vendor individual thermostat data (without personally identifiable information) to facilitate the evaluation of set point/runtime differences between the treatment and control groups. Nest will also analyze the data and offer insights, including a preliminary calculation of savings.

Example of the ITT Strategy and its Benefits

1. Assume, for this example, that there are 5,000 potential Seasonal Savings participants in the MCE service area
2. Withhold the algorithm deployment from a portion of those eligible customers, assume 1,000 customers
3. Deploy the algorithm to the remaining 4,000 customers
4. A portion of the 4,000 will opt-in, assume 70% opt-in
5. As a result of the opt-in, 2,800 participants run the algorithm

MCE Advice Letter 17-E
Attachment A: MCE Seasonal Savings Pilot Plan
8
6. This creates 3 distinct groups:
   ○ 1,000 randomized control group customers for whom the offer and algorithm were withheld
   ○ 1,200 customers who chose not to allow the algorithm to run
   ○ 2,800 customers who ran the algorithm

7. Allows us to measure the unbiased treatment effect (i.e. we can measure against a group who would have received the offer under normal circumstances). These three customer groups now allow us to measure the savings of intending to treat, rather than just of treating, which eliminates even the selection bias that can occur in a standard RCT (i.e. standard RCTs even have selection bias because you aren't able to know which customers wouldn't have run an algorithm or service)

MCE will discuss the pilot and EM&V Plan with the Residential Project Coordination Group (“PCG”) 2. Any changes to the EM&V Plan that result from the discussion with the Residential PCG-2 will be included in the supplemental advice letter filing referred to above.

14. Proposed Peer Review Group (“PRG”) (or list of leads to engage in proposal development/project tracking. May include industry, advocates, etc.)

This pilot does not require a PRG.21

15. Any other relevant information requested by Commission staff to support review.

No other information was requested by Commission staff.

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Attachment B:
Nest Seasonal Savings
Massachusetts Department of Energy Resources
Impact Evaluation
Executive Summary

The Massachusetts Department of Energy Resources contracted with Nest Labs in December 2014 to deploy Nest’s Seasonal Savings algorithm to all Nest customers in Massachusetts in January 2015 with the goal of reducing residential energy usage in the winter of 2015. This report provides an analysis of the energy savings achieved by the algorithm.

Seasonal Savings offers Nest customers a way to improve the efficiency of their thermostat settings by making small adjustments to the programmed set points over a three week period and learning when and by how much the set points could be adjusted without impacting comfort.

The key findings of the evaluation include:

- A total of 20,104 thermostats completed the Seasonal Savings algorithm – equal to 54% of all eligible thermostats in Massachusetts
- Participants’ set points declined by an average of 1.3°F over the course of the three week algorithm
- About half of the initial set point reduction was taken back by the end of the winter. The extreme weather and snow-related school and business closings appear to have adversely affected the impacts.
- Seasonal Savings reduced heating usage by an average of 3.5% over the course of the winter based on a weather-adjusted analysis of run times that included a control group from neighboring states. These savings include the effect of the impact reductions over time.
- The heating savings are estimated to have reduced energy bills by $21 per thermostat and $44 per customer, yielding aggregate savings of $427,000. These savings only include impacts from mid-January 2015 through April 2015. They do not include any future savings and also exclude other smaller sources of savings from customers who dropped out and from ancillary electric use of heating systems.

The evaluation found that Seasonal Savings was an effective approach for reducing heating energy use cost-effectively. The savings potential may be larger in winters with less extreme weather.
**Program Participation**

Nest identified 37,586 thermostats in Massachusetts for potential algorithm deployment. Customers must have an active Nest account; have activated their Nest thermostat by December 25, 2014 (to have sufficient time to develop a schedule); and must have heating controlled by the thermostat. Customers were offered Seasonal Savings on their thermostat (and app) and had to opt-in to participate. The offer was sent out to the thermostats on January 12, 2015. A total of 20,104 thermostats completed the Seasonal Savings process and opted to keep their new schedule. Table 1 summarizes the participation process.

**Table 1. Seasonal Savings Participation**

<table>
<thead>
<tr>
<th>Participation</th>
<th># Thermostats</th>
<th>% of Thermostats</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Population Sent</td>
<td>37,586</td>
<td>100%</td>
</tr>
<tr>
<td>Not Received (not on-line)</td>
<td>1,904</td>
<td>5.1%</td>
</tr>
<tr>
<td>Did Not Qualify (primarily devices not in heating mode)</td>
<td>3,108</td>
<td>8.3%</td>
</tr>
<tr>
<td>Did Not Opt-In</td>
<td>10,555</td>
<td>28.1%</td>
</tr>
<tr>
<td>Exited Early</td>
<td>1,915</td>
<td>5.1%</td>
</tr>
<tr>
<td><strong>Completed Seasonal Savings</strong></td>
<td><strong>20,104</strong></td>
<td><strong>53.5%</strong></td>
</tr>
</tbody>
</table>

About 13% of the targeted customers either did not receive the offer or did not qualify to participate. Overall, 28% of the customers (32% of those qualified) did not choose to participate. About 85% of those who opted to participate completed the Seasonal Savings algorithm.

The timing of the Seasonal Savings algorithm proved to be challenging. The algorithm ran from January 12th through early February\(^2\). Massachusetts experienced record snowfall with multiple major storms and numerous days of school and business closings. The two biggest storms of the season occurred on January 27th and February 2nd -- both during the three week Seasonal Savings algorithm period. Three more major snow events occurred between February 8th and 15th. These record storms altered occupancy patterns and likely had an adverse impact on the Seasonal Savings algorithm’s ability to identify more

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\(^2\) 90% of thermostats completed the algorithm by February 5th and 99% completed by February 10th
efficient set point schedules. The extreme weather also may have led customers to revert back toward less efficient set points during the remainder of the winter.

**Analysis Methods**

Nest employed two primary analysis approaches to assessing the energy savings from Seasonal Savings.

- The first approach compares customer schedules before and after running Seasonal Savings and calculates the average change in set point. This change in set point temperature is then multiplied by the estimated heating savings per degree change in set point that has been empirically determined by large scale data analysis Nest has performed on the climate zone level. A second comparison is performed using the set points from 8 weeks after the algorithm finished to assess the longevity of the impacts.

- The second approach is similar to a standard pre/post billing data analysis used for energy efficiency program evaluation – analyzing daily run time as a function of weather. The analysis included two methods – a customer level pre/post weather normalized usage analysis and a pooled regression modeling approach that also explored adjustments for snowfall and Away mode.

The set point approach has the advantage of being directly observable for all customers and, given the short time frame, would not typically require a control group to adjust for population trends -- although the extreme weather led that to not be the case in this instance. The disadvantages include the uncertainty in the relationship between set point changes and heating run-time (which varies by customer and by the timing and magnitude of the changes) and that the approach ignores the impacts of Away mode and manual adjustments to set points -- only looking at changes in the schedule.

The run time approach has the advantage of directly analyzing the outcome of interest -- the run time of the heating system -- and doesn’t depend on a model of how set points affect seasonal heating use and implicitly includes the impact of all set point adjustments. The main disadvantages of the run time approach are that the relationship between run time and outdoor temperature may not be well determined for some thermostats and that run time varies with factors other than outdoor temperature (e.g., wind, solar gain, occupancy pattern changes due to holidays and snow storms, etc.) and so the approach requires a control group, which may not be readily available or well matched.
Control Group
A control group\textsuperscript{23} was selected to estimate how set points and run time would have changed without Seasonal Savings. For the set point analysis, a control group may not be required in most cases since customer schedules tend to change gradually over time. But due to the extreme weather in Massachusetts during the algorithm deployment and over the rest of the season, we included a control group for both analyses.

The Seasonal Savings algorithm was run for all eligible customers in Massachusetts and so the control group needed to be drawn from other states. We used Nest customers in all adjacent states (RI, NH, CT, VT, NY) that were located in counties that border Massachusetts. To better match the control customers to the participants, we divided Massachusetts into 5 regions: Boston & South Shore, North Shore, Cape, Central, and West. The control group for each region was created from Nest customers in bordering counties of neighboring states.

Table 2. Regions and Control Group

<table>
<thead>
<tr>
<th>Region</th>
<th>Massachusetts Counties</th>
<th>Control Counties</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boston / South Shore</td>
<td>Bristol, Norfolk, Plymouth,</td>
<td>Providence RI</td>
</tr>
<tr>
<td></td>
<td>Suffolk</td>
<td></td>
</tr>
<tr>
<td>North Shore / NE</td>
<td>Essex, Middlesex</td>
<td>Hillsborough NH, Rockingham NH, York, ME</td>
</tr>
<tr>
<td>Central</td>
<td>Hampden, Hampshire, Worcester</td>
<td>Cheshire NH, Hartford CT, Tolland CT, Windham CT,</td>
</tr>
<tr>
<td>Western</td>
<td>Berkshire, Franklin</td>
<td>Bennington VT, Columbia NY, Litchfield CT, Rensselaer NY, Windham VT</td>
</tr>
<tr>
<td>Cape/Islands</td>
<td>Barnstable, Dukes, Nantucket</td>
<td>Bristol RI, Newport RI</td>
</tr>
</tbody>
</table>

The control group differed from the participants in several respects, even within region. There were differences in pre period average set points that were mostly traceable to differences in heating fuels (more bulk fuel in control group) and the use of Away mode (e.g., vacation homes on the Cape). For the run-time analysis we stratified the population on these factors to better match the control customers to the participants.

Findings: Set Points Approach
The set point analysis was based on comparing participant’s schedules immediately before and after running the Seasonal Savings algorithm and also analyzing the schedule 8 weeks later to assess the short-term persistence of the changes. Prior Nest analysis had estimated

\textsuperscript{23} Technically speaking it’s a comparison group. “Control group” is for use in a randomized control trial.
that each 1°F change in heating set point should reduce heating energy use by 4% for homes in Massachusetts. Table 3 summarizes the set point analysis results for customers that completed Seasonal Savings and for the control group.

Table 3. Heating Savings: Set Point Changes °F

<table>
<thead>
<tr>
<th></th>
<th>SS Participants</th>
<th>Control</th>
<th>Net Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average set point before SS</td>
<td>65.10</td>
<td>64.58</td>
<td>0.52</td>
</tr>
<tr>
<td>Average set point after SS</td>
<td>63.82</td>
<td>64.65</td>
<td>-0.83</td>
</tr>
<tr>
<td>Average set point after 8 weeks</td>
<td>64.57</td>
<td>64.74</td>
<td>-0.17</td>
</tr>
<tr>
<td>Average set point change</td>
<td><strong>-1.29</strong></td>
<td><strong>+0.06</strong></td>
<td><strong>-1.35 ±0.03</strong></td>
</tr>
<tr>
<td>Average set point change after 8 weeks</td>
<td><strong>-0.52</strong></td>
<td><strong>+0.14</strong></td>
<td><strong>-0.67 ±0.04</strong></td>
</tr>
<tr>
<td>Estimated Savings: initial</td>
<td>5.2%</td>
<td>-0.2%</td>
<td>5.4%</td>
</tr>
<tr>
<td>Estimated Savings: after 8 weeks</td>
<td>2.1%</td>
<td>-0.6%</td>
<td>2.7%</td>
</tr>
<tr>
<td>Estimated Savings: Average over period</td>
<td>3.6%</td>
<td>-0.4%</td>
<td>4.0%</td>
</tr>
</tbody>
</table>

The average heating set point declined by 1.29°F (±0.02°F) after Seasonal Savings. The control group set point increased by an average of 0.06°F (±0.02 °F), implying a net 1.35°F set point reduction for participants. At 4% savings per degree set point, heating savings of 5.4% would be expected. But 8 weeks after Seasonal Savings the net set point reduction was only half as large and so estimated savings dropped to 2.7%. Assuming a linear decline over the 8 weeks, average savings are estimated at 4.0% of heating use for the period (or 4.2% if weighted by degree days).

For Seasonal Savings customers that exited early, a comparable analysis found an average set point reduction (net of control group) of 0.61°F immediately after SS and 0.19°F at the end of 8 weeks, leading to estimated average savings of 1.6% (2.4% declining to 0.8%).

The distribution of average set point changes for participants that completed Seasonal Savings is shown in Figure 1 (excluding about 1% of cases with more extreme changes).
Figure 1. Distribution of schedule set point changes after Seasonal Savings

The plot shows that the most common change in set point was about a 1.7°F reduction but the distribution is skewed right leading to a mean value lower than the median or mode.

Figure 2 repeats this histogram but changes the vertical scale so that it can be compared to a histogram for the control group using the same scale.

Figure 2. Distribution of schedule set point changes vs. Control Group
The spike at zero for the control group shows that more than 60% of the control group had essentially no change in average set point over the period. There is no segment of the control group that experienced the large set point changes found among participants—showing that self-selection could not explain the large shift in set points over the period.

Figure 3 shows the distribution of set point changes 8 weeks after Seasonal Savings.

![Set Point Changes After 8 weeks: SS Completed](image)

**Figure 3. Distribution of schedule set point changes 8 weeks after Seasonal Savings**

The distribution shape changed as some customers have apparently reverted back to something close to their old schedules while a significant fraction maintained their new schedules. The control group distribution appeared about the same although the mean set point change increased to 0.14°F.

The hourly profile of the immediate set point changes is shown in Figure 3.
Figure 3. Mean set point changes by hour of day

The plot shows that set point reductions averaged more than 2°F during the night and less than 1°F during the middle of the day. The night setback changes were similar for weekdays and weekends but the daytime reductions were larger on weekdays than weekends -- an expected finding. The smallest changes in set points occurred when people were waking up in the morning and in the prime evening hours. The Seasonal Savings algorithm captures the largest set point improvements at times when they have the least impact on comfort.

A more detailed look at the set point changes is provided in Figure 4, which is the same data as presented in Figure 3, but also shows the distribution of the changes in set point for each hour using a box plot. The plot shows the mean change as the horizontal black line on each box and shows the median as the white break between the red boxes. The red boxes extend out to the 25th and 75th percentiles. The lines extend out to the 10th and 90th percentiles.
Figure 4. Distribution of set point changes by hour of day

The plot shows how the typical (median) temperature reductions are more than 2.5°F at night and just below 1°F during the day. The lower bound 10th percentiles show that the period of 6PM - 8PM has the least flexibility in set points -- the 10th percentile line barely extends below the -1°F line.

Set Point Changes Over Time

We analyzed the changes in the set point schedules over time in greater detail to better understand the apparent decline in algorithm impacts.

Figure 5 plots the heating schedule set points over the course of this past winter for three groups of customers: Seasonal Savings participants, customers who opted not to participate in Seasonal Savings or dropped out prior to completion, and a control group of customers from neighboring states. The graph shows data for the North Shore region (Northeastern MA and adjacent counties in NH and ME) region. The set points plotted are a 7-day moving average (the average of the prior 7 days for each date). The blue points along the top of the graph show the dates of snowstorms in Eastern Massachusetts.
Prior to deployment of Seasonal Savings, the Massachusetts customers had higher set points than the control group by about a half degree. The participants then show a clear drop of more than 1°F during the algorithm deployment and then a fairly significant increase in the few weeks after Seasonal Savings finished – giving back about half the gains. During this same period the control group and the opt-out groups both experienced gradual but clear increases in set points. The graph show similar behavior over time for the control group and the opt-out group, suggesting that the opt-out group may have served as a viable control group.

A few weeks after the algorithm ran, the set points had stabilized for all three groups, implying that any degradation in impacts occurred quickly and then leveled out. A key question is what role the multiple major snow storms played in suppressing the impact of Seasonal Savings and especially in the set point increases in the following few weeks.

Figure 6 explores the changes in greater detail -- plotting the change in set point for each date compared to the same day seven days prior (therefore accounting for day of week variations).
Figure 6. Change in Scheduled Set Point vs. 7 days prior

For clarity, this plot only shows participants and the control group and snowstorms are shown as symbols on the line. It appears that snowstorms may have reduced the algorithm impacts (snow coinciding with the stutter in the set point declines around the middle of the deployment) and also contributed to the reversion in set points shortly after the algorithm completed. After about two or three weeks, participant set point changes settled down and became similar to the control group. The post-deployment decline in algorithm impacts was immediate and short lived, suggesting no further on-going degradation in savings after the initial couple of weeks. Other regions showed similar.

Data from next winter will be needed to confirm that the remaining savings persist, but it appears that they may have based on this data.

**Run Time Analysis**

The run-time based analysis employed two methods that are each based on standard billing data analysis approaches – a house-level pre/post treatment/comparison weather normalization and a pooled fixed effects econometric analysis. The house level analysis provides useful insights into savings variability but the pooled model is easier to replicate, involves fewer analytical decisions, and can potentially account for the impacts of snowfall and Away mode on run time.
Findings: House Level Run Time Analysis

The house level weather normalization analysis employed a variable-base degree day ratio estimation. Ratio estimation results were screened for reliability based on having at least 10 days of data in the pre and post treatment periods and having a reasonable model fit as indicated by a CV(RMSE) of less than 65%. In addition, a small fraction of cases with extreme changes in usage were classified as outliers (% change in usage greater than 2.5 interquartile ranges from the median percent change in usage). The data screening caused about 25% overall attrition, with the vast majority due to the CV(RMSE) requirement.

An initial analysis was performed based on the standard definition of the post-treatment period as starting when the algorithm deployment finished. This analysis found a net 3.5% reduction in run time, equal to 29 hours in annual runtime reduction. But the significant changes in set points in the few weeks after deployment suggests that this annualized savings value may over-state actual impacts. The ratio estimation was repeated with the post-treatment period starting on the day the algorithm deployed so that the full savings over the course of the winter could be assessed. The impacts for the actual post treatment period through the end of April 2015 were then calculated based on these results. The analysis is summarized in Table 4.

Table 4. Heating Savings: Run-Time Analysis VBDD ratio estimation

<table>
<thead>
<tr>
<th>Group</th>
<th># T-stats</th>
<th>Pre</th>
<th>Post</th>
<th>Savings</th>
<th>%Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>Seasonal Savings</td>
<td>14,883</td>
<td>826</td>
<td>776</td>
<td>50</td>
<td>6.1% ±0.4%</td>
</tr>
<tr>
<td>Control Group</td>
<td>7,442</td>
<td>797</td>
<td>773</td>
<td>23</td>
<td>2.9% ±0.6%</td>
</tr>
<tr>
<td><strong>Net Annual Savings</strong></td>
<td></td>
<td></td>
<td></td>
<td><strong>27 ±6</strong></td>
<td><strong>3.2% ±0.7%</strong></td>
</tr>
<tr>
<td><strong>Net Savings Jan 2015 – Apr 2015</strong></td>
<td></td>
<td></td>
<td></td>
<td><strong>17.4 ±3.6</strong></td>
<td><strong>3.2% ±0.7%</strong></td>
</tr>
</tbody>
</table>

Note: ± values are 95% confidence intervals on the means

Weather-adjusted annualized run-time for the Seasonal Savings participants declined by 50 hours but the control group experienced an average 23 hour reduction yielding a net savings estimate of 27 hours per year. These savings equal 3.2% of heating use. The savings actually achieved from deployment through the end of April are estimated at 17 hours of run time based on the actual weather experienced.

Savings were estimated to be a little larger for homes with gas heat compared to those with other types of heat (3.6% vs. 2.3%) but the difference was not statistically significant.
Participants in the analysis had an average of 1.9 Nest thermostats per home. Overall, 58% of participants had one Nest thermostat, 28% had two thermostats, and 14% had three or more thermostats. The estimated net savings were larger for homes with two or more thermostats -- averaging 32 hours of run time per thermostat (3.8% ±1.0% heating savings). Based on available customer-reported data, home size averaged 2,572 sq.ft. overall but was 1,811 sq.ft. for homes with one thermostat compared to 3,016 sq.ft. for homes with multiple thermostats (2,558 sq.ft. for homes with two thermostats, and 3,610 sq.ft. for homes with three or more thermostats).

The 3.2% savings reported in Table 4 are a little less than the 4.0% savings reported in Table 3 from the set point analysis averaged over the 8 weeks. But this difference should be expected given two potential sources of over-estimation in the set point analysis -- being based solely on schedule set points (omitting the impact of Away mode and manual adjustments) and the larger set point reductions at night (which may save less than 4%/°F since night set back temperatures aren't always binding).

**Findings: Pooled Run Time Analysis**

The pooled run time analysis involved using a single regression model of the daily run time for all participants and control group customers. This type of pooled modeling is commonly employed in billing data analysis studies. Two different model specifications were analyzed:

1. a base model that fit daily heating run time as a function of heating degree days (HDD base 60°F), and indicator variables for participation and for the post treatment period and interactions between degree days and participation and also the post treatment period.

2. An expansion of the base model to include variables for snowfall and for time spent in Away mode and an interaction between Away mode and HDD60. Away mode was considered an exogenous factor unrelated to Seasonal Savings participation. The purpose of the expanded model was to account for additional factors expected to affect heating run time and develop more precise estimates.

The models were fit using a fixed-effects regression model that included thermostat-specific effects. Differences in the relative size of the control group for each region and the potential for different impacts in different regions led to fitting a separate model for each region and then combining the estimated impacts based on the size of the participant population in each region.

The models defined the pre and post treatment periods as before and after January 12, 2015 – just as in the ratio estimation approach. The inclusion of the algorithm deployment period should lead to slightly lower percent savings but capture a greater overall level of
savings. The results of this analysis are summarized in Table 5. The detailed regression modeling output is shown in Table 6.

Table 5. Heating Savings: Run Time Analysis Pooled Fixed Effects

<table>
<thead>
<tr>
<th>Region</th>
<th>Analysis Sample Size</th>
<th>% Heating Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Boston &amp; South Shore</td>
<td>6,645 1,343,505</td>
<td>4.0% ±0.4% 4.0% ±0.4%</td>
</tr>
<tr>
<td>North Shore /NE</td>
<td>9,501 2,057,098</td>
<td>2.5% ±0.3% 2.9% ±0.3%</td>
</tr>
<tr>
<td>Central</td>
<td>1,900 735,816</td>
<td>4.3% ±0.4% 4.2% ±0.4%</td>
</tr>
<tr>
<td>Western</td>
<td>246 427,004</td>
<td>-1.9% ±1.4% -1.1% ±1.4%</td>
</tr>
<tr>
<td>Cape/islands</td>
<td>923 300,106</td>
<td>5.9% ±0.9% 5.2% ±0.9%</td>
</tr>
<tr>
<td>Total</td>
<td>19,215 4,863,529</td>
<td>3.4% ±0.4% 3.5% ±0.4%</td>
</tr>
</tbody>
</table>

Table 6. Pooled Fixed Effects Model Output

<table>
<thead>
<tr>
<th>Region</th>
<th>Base Model</th>
<th>Full Model</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Boston/ S Shore</td>
<td>0.0499</td>
<td>0.0121</td>
</tr>
<tr>
<td>North Shore / NE</td>
<td>0.0499</td>
<td>0.0870</td>
</tr>
<tr>
<td>Central</td>
<td>0.0499</td>
<td>0.0121</td>
</tr>
<tr>
<td>Western</td>
<td>0.0499</td>
<td>0.0121</td>
</tr>
<tr>
<td>Cape/Islands</td>
<td>0.0499</td>
<td>0.0121</td>
</tr>
<tr>
<td>Total</td>
<td>0.0499</td>
<td>0.0121</td>
</tr>
</tbody>
</table>

Both pooled models estimated that Seasonal Savings reduced heating usage by about 3.5% — very close to the 3.2% found from the house level ratio estimation approach. The addition of the snowfall and Away mode variables barely affected the overall estimated
savings but did reduce the variance in estimates across regions – implying that the estimates are more reliable.

The estimated savings varied by region, but the estimates for the Western and Cape/Island regions were based on fairly small samples with larger uncertainty and only represent about 10% of the overall participant population.

The run time savings for this past winter were calculated using the actual elapsed heating degree days and days. The resulting estimate is a 15.1 hour reduction in run time – a little less than the 17.4 hours estimated from the ratio estimation approach. The slightly higher percent savings yet slightly lower absolute hours savings can be explained by differences in the sample composition and weighting – the ratio estimation sample is about 25% smaller primarily due to screening criteria on the thermostat-specific model fit.

Peak Day Impacts
One of the goals of the analysis was to estimate the impacts of Seasonal Savings on peak day gas throughput. We used the pooled model results to estimate the savings on the ten peak days of heating system run time in the post treatment period. Heating system run time on these ten peak days ranged from 7 to 9 hours and averaged 7.6 hours. For the 14,756 gas heated homes, the aggregate reduction in peak day gas use is estimated at 305 Mcf and ranged from 282 Mcf to 361 Mcf.

Fuel and Cost Savings
The three analysis methods provided fairly consistent estimates of the impacts of Seasonal Savings – 3.2%-3.5% for the run time analysis results and about 4.0% for the analysis based on set points. Considering the potential biases and the advantages and disadvantages of each approach, we believe the pooled fixed effects estimate using the full model is the best estimate to use for the overall savings. Converting this estimate into fuel and cost savings requires making assumptions about system fuel input rates and appropriate energy costs.

We estimated an average heating system input rate of 80,000 Btu/hour based on data from a recent evaluation of the Massachusetts High Efficiency Heating Equipment program24. As a cross check, we calculated the implied annual gas heating usage using this input rate and the 826 hours of average annualized run time from the ratio estimation, yielding 661 therms per thermostat. This value is about 13% less than the 760 therm annual household average natural gas use estimate on the DOER web site25 but it makes sense given the frequency of multi-system homes.

25 see http://www.mass.gov/eea/energy-utilities-clean-tech/misc/household-heating-costs.htm
We used the same 80 Kbtu/hr estimated input for all fuels, although it is likely an under-estimate for oil (equal to just 0.58 gph).

For the few homes with electric heat pumps, we assumed an overall seasonal efficiency of 2.5 COP and adjusted the Btu input accordingly. For energy costs, we estimated $1.55/therm of natural gas, $3.13/gallon of heating oil, $3.09/gallon of propane, and $0.15/kWh of electricity based on data from the DOER web site.

Table 7 summarizes the fuel and cost savings based on these heating system input rates and energy costs and using the 2015 run time savings of 15.1 hours from the pooled model.

Table 7. Fuel and Cost Savings: Winter 2015

<table>
<thead>
<tr>
<th>Fuel</th>
<th>% Units</th>
<th>Savings/Unit</th>
<th>Savings/Home</th>
<th>Aggregate Savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td>73.4%</td>
<td>12.1 $18.72</td>
<td>25.0 $38.76</td>
<td>178,257 $276,297</td>
</tr>
<tr>
<td>Oil</td>
<td>20.7%</td>
<td>8.7 $27.20</td>
<td>18.3 $57.12</td>
<td>36,096 $112,982</td>
</tr>
<tr>
<td>Propane</td>
<td>3.4%</td>
<td>13.0 $40.14</td>
<td>31.2 $96.33</td>
<td>8,748 $27,031</td>
</tr>
<tr>
<td>Electric (kWh)</td>
<td>2.6%</td>
<td>142 $21.24</td>
<td>256.3 $38.45</td>
<td>73,455 $11,018</td>
</tr>
<tr>
<td>Total</td>
<td>100%</td>
<td>$21.26</td>
<td>$44.47</td>
<td>$427,329</td>
</tr>
</tbody>
</table>

The overall savings is estimated at about $21 per thermostat, $44 per customer and more than $400,000 in aggregate.

The fuel and cost savings reported don’t include three more sources of additional savings:

- savings that occurred (or will occur) after April 2015
- savings for customers who opted in to Seasonal Savings but exited early (although they showed some set point reductions)
- savings in electricity consumption of fuel-fired heating systems due to furnace fans, boiler pumps, and other electric use. These savings may have been about $1 per thermostat.

The overall savings from these factors may be significant relative to the savings reported in Table 7.
Further Observations

In addition to the issue of excluding savings after April 2015 and from early exit customers, there are two other factors that may have limited the savings from this specific deployment of the Seasonal Savings algorithm:

1. The record setting snowfall and associated school and business closings during this past winter coincided with the algorithm deployment and may have reduced the impacts from Seasonal Savings and contributed to the decline in savings over time.

2. The algorithm wasn't deployed until January 12th and ran through early/mid February, limiting the savings to about half the winter. If the algorithm had been deployed at the start of December, the savings for this winter would have been about 40% larger than the 15 hours reported here.
**MARIN CLEAN ENERGY**

**Utility type:**
- ☑ ELC
- □ GAS
- □ PLC
- □ HEAT
- □ WATER

**Utility type descriptions:**
- ELC = Electric
- GAS = Gas
- PLC = Pipeline
- HEAT = Heat
- WATER = Water

**Phone #:** 415-464-6045

**E-mail:** mcallahan-dudley@mceCleanEnergy.org

---

**EXPLANATION OF UTILITY TYPE**

<table>
<thead>
<tr>
<th>ELC</th>
<th>GAS</th>
<th>PLC</th>
<th>HEAT</th>
<th>WATER</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric</td>
<td>Gas</td>
<td>Pipeline</td>
<td>Heat</td>
<td>Water</td>
</tr>
</tbody>
</table>

**Advice Letter (AL):** 17-E

**Subject of AL:** Request for Approval of MCE Seasonal Savings Pilot Program

**Tier Designation:** □ 1 ☑ 2 □ 3

**Keywords (choose from CPUC listing):**
- AL filing type: □ Monthly □ Quarterly □ Annual ☑ One-Time □ Other

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution: D.09-09-047

**Does AL replace a withdrawn or rejected AL?** If so, identify the prior AL:

**Summarize differences between the AL and the prior withdrawn or rejected AL:**

**Resolution Required?** □ Yes ☑ No

**Requested effective date:** September 18, 2016

**No. of tariff sheets:**

---

**Estimated system annual revenue effect:** (%):

**Estimated system average rate effect:** (%):

**When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).**

**Tariff schedules affected:**

**Service affected and changes proposed**:

**Pending advice letters that revise the same tariff sheets:**

---

**Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:**

**CPUC, Energy Division**

**Utility Info (including e-mail)**

- Attention: Tariff Unit
- 505 Van Ness Ave.,
- San Francisco, CA 94102
- EDTariffUnit@cpuc.ca.gov

- Marin Clean Energy
- Michael Callahan-Dudley, Regulatory Counsel
- (415) 464-6045
- mcallahan-dudley@mceCleanEnergy.org

---

**Note:** Discuss in AL if more space is needed.
September 15, 2016

CA Public Utilities Commission
Energy Division
Attention: Energy Efficiency Branch
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

Advice Letter 18-E

Re: MCE 2017 Annual Energy Efficiency Program and Portfolio Budget Request

In compliance with the California Public Utilities Commission’s (“Commission”) Decision (“D.”) 15-10-028, Ordering Paragraph (“OP”) 4, issued October 22, 2015, Marin Clean Energy (“MCE”) submits this advice letter filing to request the 2017 annual energy efficiency portfolio budget. D.15-10-028 called for the advice letter to be filed on the first business day in September.\(^1\) On August 29, 2016, the Commission’s Executive Director Timothy Sullivan authorized MCE’s request for an extension to file the advice letter by September 15, 2016.

Effective Date: October 15, 2016

Tier Designation: Tier 2

Pursuant to General Order 96-B, Energy Industry Rule 5.2 and D.15-10-028, this advice letter is submitted with a Tier 2 designation.

Purpose

The purpose of this advice filing is to comply with D.15-10-028, OP 4 and request MCE’s 2017 annual energy efficiency program and portfolio budget.

Background

The Commission is in the process of transitioning to a rolling portfolio framework for energy efficiency programs. The Commission started with a ten-year funding authorization.\(^2\) Subsequently, the Commission adopted related processes and rules to implement a rolling portfolio.\(^3\) The process includes filing this annual budget advice letter to provide a range of information including: (1) the next annual budget; (2) the portfolio cost effectiveness; (3) portfolio changes; (4) fund shifting; (5) carryover or encumbered funds; and (6) the electronic

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\(^2\) D.14-10-046, OP 21 at p. 167.
\(^3\) See D.15-10-028; D.16-08-019.
query output from the online filing of the application summary tables (included as Attachment A). Energy Division staff provided guidance on the advice letter.

**Discussion**

MCE requests a budget for 2017 supported by the appendices that were filed on the California Energy Data and Reporting System’s Filing Module (“CEDARS FM”). MCE’s 2017 budget includes the Commission’s authorized EM&V funds. MCE also provides a context for the portfolio cost effectiveness for 2017.

**2017 Energy Efficiency Budget**

MCE received an annual budget authorization in D.14-10-046 totaling $1,220,267. In 2016, the Commission increased MCE’s annual budget to $1,586,347 to account for new communities that joined MCE’s service area. MCE filed advice letter 16-E to comply with the decision that increased the budget and included the budget allocation to each MCE program. MCE’s requested budget for 2017 continues that allocation of funding for each program as shown in Table 1 below.

<table>
<thead>
<tr>
<th>MCE Programs</th>
<th>Budget</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single Family</td>
<td>$233,050</td>
</tr>
<tr>
<td>Multi-Family</td>
<td>$667,555</td>
</tr>
<tr>
<td>Small Commercial</td>
<td>$658,711</td>
</tr>
<tr>
<td>Financing</td>
<td>$27,031.00</td>
</tr>
<tr>
<td><strong>Program Subtotal</strong></td>
<td><strong>$1,586,347</strong></td>
</tr>
<tr>
<td>Evaluation Measurement and Verification (“EM&amp;V”)</td>
<td>$96,342</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$1,690,952</strong></td>
</tr>
</tbody>
</table>

---

4 D.15-10-028 at p. 58-63.
5 Clarifications on Annual Budget Filings for Program Year 2017 (August 19, 2016), Commission Energy Division.
6 D.14-10-046 at p. 125.
7 D.16-05-004.
8 D.16-05-004, OP 5 at p. 13-14.
9 MCE Advice Letter 16-E at p. 3.
10 This amount includes only the PA distribution based on 27.5% of the total EM&V budget as indicated in the discussion in the EM&V Funds section below. MCE included 100% of the EM&V budget in the appendices uploaded to the CEDARS FM.
EM&V Funds

As a component of the budget, MCE includes authorized EM&V funding. EM&V funds for program years 2013-2016 are based on a gross up of MCE’s 2013-2016 annual program budgets and are summarized in Table 2 below. Pacific Gas and Electric Company’s (“PG&E”) EM&V budget request was based on a total budget that included MCE’s authorized budget. These funds have been collected from customers, but MCE has not received EM&V funds from PG&E. Table 2 below provides the outstanding EM&V funds that PG&E has collected based on MCE’s budgets.

Table 2: Retrospective EM&V Funds

<table>
<thead>
<tr>
<th>Years</th>
<th>Program Budget</th>
<th>EM&amp;V Budget</th>
<th>Total Budget</th>
<th>EM&amp;V Portion of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013-14</td>
<td>$4,015,205(^{12})</td>
<td>$167,300</td>
<td>$4,182,505</td>
<td>4%</td>
</tr>
<tr>
<td>2015</td>
<td>$1,220,267(^{13})</td>
<td>$50,844</td>
<td>$1,271,111</td>
<td>4%</td>
</tr>
<tr>
<td>2016</td>
<td>$1,586,347(^{14})</td>
<td>$66,097</td>
<td>$1,652,444</td>
<td>4%</td>
</tr>
<tr>
<td>Total</td>
<td>$6,821,819</td>
<td>$284,241</td>
<td>$7,106,060</td>
<td>4%</td>
</tr>
</tbody>
</table>

The EM&V funds collected based on MCE’s budgets from 2013-2016 equals $284,241, as provided in Table 2 above. MCE’s distribution of these funds is based on a PA portion of 27.5%.\(^{15}\) Thus MCE’s distribution from 2013-2016 program years is $78,166 in EM&V funds. MCE requests that these funds be transferred according to the procedure defined in D. 16-08-019.\(^{16}\)

The EM&V funds, based on MCE’s approved budget for 2017, equal $18,176 as indicated below in Table 3.

\(^{11}\) MCE’s 2013-14 budget was included when determining the EM&V budget for 2013-2014 portfolios. See D.12-11-015 at p. 96 (“[A] portion of the energy efficiency budget is set aside for EM&V activities at the level of 4% of the total energy-efficiency funds, including those allocated for REN and [MCE] activities….”). The Commission also used MCE’s annual budget in the calculation of the 4% of EM&V budgets for the 2015-2025 program years. Figure 6 in D.15-01-023 illustrates that the EM&V budget for Pacific Gas and Electric Company’s (“PG&E’s”) service area was based, in part, on MCE’s annual budget. D.15-01-023 at p. 1-2.


\(^{13}\) The Commission authorized an annual program budget for MCE spanning the years 2015-2025 totaling $1,220,267. D.14-10-046 at p. 125.

\(^{14}\) D.16-05-004, OP 2 at p. 13.

\(^{15}\) The Commission increased the portion of EM&V funds available to the PA from 27.5% to 40% starting once the business plans are approved. D.16-08-019 at p. 80-81.

\(^{16}\) “Approved budgets for CCA administrators shall be transferred on January 15 of every year by the relevant utility.” D.16-08-019, OP 16 at p. 112.
Table 3: Prospective EM&V Funds

<table>
<thead>
<tr>
<th>2017 Programs Budget</th>
<th>4% EM&amp;V Funding Level</th>
<th>27.5% EM&amp;V PA Distribution</th>
<th>Total Prospective EM&amp;V Funds</th>
</tr>
</thead>
<tbody>
<tr>
<td>$1,586,347(^{17})</td>
<td>$66,097</td>
<td>$18,176</td>
<td>$18,176</td>
</tr>
</tbody>
</table>

MCE’s 2017 budget request includes $96,342 in EM&V funds for program years 2013-2017, which is included in MCE’s budget request in Table 1, and reflected in the Appendices.

**Portfolio Cost Effectiveness**

MCE’s portfolio cost-effectiveness results for 2017 are:
- Total Resource Cost Test Ratio (“TRC”): 0.91
- Program Administrator Cost Test Ratio (“PAC”): 1.01

In 2013, MCE administered the first EE programs under the authority granted in § 381.1(a)-(d). These programs were initially restricted by the Commission to serve gaps in investor-owned utility (“IOU”) programs and hard-to-reach markets.\(^{18}\) The Commission subsequently concluded that these restrictions may cause MCE’s proposals to fail the TRC test and did not initially impose a minimum cost-effectiveness requirement.\(^{19}\) In 2014, the Commission lifted the restrictions\(^{20}\) and imposed the same cost-effectiveness standards on CCAs as IOUs.\(^{21}\) However, MCE has not been invited to file an application since the restrictions were lifted, as the 2014 programs were extended to 2015, 2016, and now 2017 while the Commission is transitioning to the rolling portfolio.\(^{22}\) Lifting the restrictions improves MCE’s ability to meet the minimum 1.25 TRC ratio because very few cost-effective opportunities exist within the gaps in IOU programs and hard-to-reach markets.

MCE has been working to improve the cost-effectiveness of its offerings through comprehensive changes to its portfolio. In October 2015, MCE filed a business plan that proposed expanded offerings to multiple new customer sectors and a more balanced portfolio intended to achieve long-term cost effectiveness.\(^{23}\) While a prehearing conference was convened for this application on February 1, 2016, no further Commission action occurred. While the Commission has not made any additional progress on the comprehensive update of MCE’s portfolio, MCE has continued to make efforts aimed at improving the cost effectiveness of its portfolio. These efforts are discussed below in Portfolio Changes.

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\(^{17}\) D.16-05-004, OP 2 at p. 13.

\(^{18}\) D.12-11-015 at p. 45-46.

\(^{19}\) D.12-11-015 at p. 46.

\(^{20}\) D.14-01-033 at p. 14. See also D.14-10-046 at p. 120 (Commission clarifying the restrictions do not apply to gas programs).

\(^{21}\) D.14-01-033 at p. 36.

\(^{22}\) D.14-10-046 at p. 30-32.

\(^{23}\) A.15-10-014.
**Portfolio Changes**

In 2016, MCE took several steps to improve the cost effectiveness of its portfolio. MCE suspended the Home Utility Reports (“HURs”) component of its Single Family program in response to an evaluation that indicated the HURs were not producing savings. MCE shifted those funds into the Multifamily and Small Commercial Programs.\(^{24}\) In 2017, MCE will continue the suspension of the HURs. MCE has also requested authority to provide a Seasonal Savings pilot that, if approved, will be administered in 2016 and 2017.\(^{25}\) MCE anticipates the Seasonal Savings pilot will increase the cost effectiveness of MCE’s portfolio. However, as the savings associated with this pilot will be purely on an *ex post* basis, these savings figures have not been included in the cost-effectiveness analysis for the 2017 portfolio. MCE anticipates achieving a higher cost effectiveness in its portfolio due to the pilot results. Apart from these changes, MCE is continuing its 2016 portfolio of programs in 2017.

**Fund Shifting**

D.16-05-004 approved MCE’s most recent budget.\(^{26}\) The budget allocation was provided in MCE advice letter 16-E.\(^{27}\) MCE has performed no fund shifting since that allocation was approved.

**Carryover or Encumbered Funds**

MCE’s encumbered funds consist entirely of loan loss reserve (“LLR”) funds associated with MCE’s Financing program. MCE’s Financing program was first authorized in D.12-11-015.\(^{28}\) This program included LLR funds used to leverage private financing for Single Family, Multifamily, and Small Commercial customers. MCE closed its Single Family On-Bill Repayment component and utilized a portion of the LLR funds for program activity in 2015, leaving a small portion to support one outstanding loan.\(^{29}\) The remaining LLR funds are available to support loans for Multifamily and Small Commercial customers. These LLR funds are shown in Table 4 below.

**Table 4: MCE’s Encumbered Funds**

<table>
<thead>
<tr>
<th>LLR Accounts</th>
<th>Encumbered</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single Family</td>
<td>$500</td>
</tr>
<tr>
<td>Multifamily and Small Commercial</td>
<td>$548,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$548,500</strong></td>
</tr>
</tbody>
</table>

\(^{24}\) MCE Advice Letter 15-E.  
\(^{25}\) MCE Advice Letter 17-E.  
\(^{26}\) D.16-05-004.  
\(^{27}\) MCE Advice Letter 16-E at p. 3.  
\(^{28}\) D.12-11-015 at p. 49-51.  
\(^{29}\) MCE Advice Letter 10-E.

MCE Advice Letter 18-E  5
Notice

Anyone wishing to protest this advice filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice filing. Protests should be mailed to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address above).

In addition, protests and all other correspondence regarding this advice letter should also be sent by letter and transmitted via facsimile or electronically to the attention of:

Michael Callahan
Regulatory Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA  94901
Phone:  (415) 464-6045
Facsimile: (415) 459-8095
E-mail: mcallahan@mceCleanEnergy.org

and

Beckie Menten
Energy Efficiency Director
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA  94901
Phone:  (415) 464-6034
Facsimile: (415) 459-8095
E-mail: bmenten@mceCleanEnergy.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.
MCE is serving copies of this advice filing to the relevant parties shown on the R.13-11-005 service list. For changes to this service list, please contact the Commission’s Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

Correspondence

For questions, please contact Michael Callahan at (415) 464-6045 or by electronic mail at mcallahan@mceCleanEnergy.org.

/s/ Michael Callahan

Michael Callahan
Regulatory Counsel
MARIN CLEAN ENERGY

cc: Service List R.13-11-005
Attachment A:
CEDARS Filing Confirmation
CEDARS FILING SUBMISSION RECEIPT

The MCE portfolio filing has been submitted and is now under review. A summary of the filing is provided below.

PA: Marin Clean Energy (MCE)

Filing Year: 2017

Submitted: 17:09:58 on 15 Sep 2016

By: Beckie Menten

Advice Letter Number: 11-E

* Portfolio Filing Summary *

- TRC: 0.9138
- PAC: 1.0126
- TRC (no admin): 2.3839
- PAC (no admin): 3.1969
- RIM: 1.0126
- Budget: $1,586,346.78

* Programs Included in the Filing *

- MCE01: Multi-Family
- MCE02: Small Commercial
- MCE03: Single Family
- MCE04: Financing Pilots
**CALIFORNIA PUBLIC UTILITIES COMMISSION**

**ADVICE LETTER FILING SUMMARY**

**ENERGY UTILITY**

MUST BE COMPLETED BY LSE (Attach additional pages as needed)

<table>
<thead>
<tr>
<th>Marin Clean Energy</th>
<th>Michael Callahan</th>
</tr>
</thead>
<tbody>
<tr>
<td>Utility type:</td>
<td></td>
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<tr>
<td>☑ ELC</td>
<td>☐ GAS</td>
</tr>
<tr>
<td>☐ PLC</td>
<td>☐ HEAT</td>
</tr>
<tr>
<td>☐ WATER</td>
<td></td>
</tr>
<tr>
<td>Phone #: 415-464-6045</td>
<td></td>
</tr>
<tr>
<td>E-mail: <a href="mailto:mcallahan@mceCleanEnergy.org">mcallahan@mceCleanEnergy.org</a></td>
<td></td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>EXPLANATION OF UTILITY TYPE</th>
<th>(Date Filed/Received Stamp by CPUC)</th>
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<tbody>
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<td>ELC = Electric</td>
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<td>GAS = Gas</td>
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<tr>
<td>HEAT = Heat</td>
<td></td>
</tr>
<tr>
<td>WATER = Water</td>
<td></td>
</tr>
</tbody>
</table>

Advice Letter (AL): 18-E

Subject of AL: MCE 2017 Annual Energy Efficiency Program and Portfolio Budget Request

Tier Designation: ☐ 1 ☑ 2 ☐ 3

Keywords (choose from CPUC listing):

- ☑ Monthly
- ☐ Quarterly
- ☑ Annual
- ☐ One-Time
- ☐ Other

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution: D.15-10-028

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: ____________________________

Summarize differences between the AL and the prior withdrawn or rejected AL: ____________________________

Resolution Required? ☐ Yes ☑ No

Requested effective date: October 15, 2016

No. of tariff sheets: ____________________________

Estimated system annual revenue effect (%): ____________________________

Estimated system average rate effect (%): ____________________________

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected:

- Service affected and changes proposed: ____________________________

Pending advice letters that revise the same tariff sheets: ____________________________

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

**CPUC, Energy Division**

Attention: Tariff Unit

505 Van Ness Ave.,

San Francisco, CA 94102

**Utility Info (including e-mail)**

Marin Clean Energy

Michael Callahan-Dudley, Regulatory Counsel

(415) 464-6045

mcallahan-dudley@mceCleanEnergy.org

---

1 Discuss in AL if more space is needed.
October 24, 2016

CA Public Utilities Commission
Energy Division
Attention: Energy Efficiency Branch
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

Advice Letter 19-E

Re: Request for Approval to Shift Funds in Anticipation of 2016 Spending

In compliance with the California Public Utilities Commission’s (“Commission”) Decision (“D.”) 09-09-047, Ordering Paragraph (“OP”) 43, filed September 24, 2009 and the Energy Efficiency Policy Manual,\(^1\) Marin Clean Energy (“MCE”) submits this filing to request a fund shift between MCE’s programs to accommodate anticipated spending for the remainder of 2016.

**Effective Date:** November 24, 2016

**Tier Designation:** Tier 2

Pursuant to General Order 96-B, Energy Industry Rule 5.2 this advice letter is submitted with a Tier 2 designation.

**Purpose**

The purpose of this advice letter filing is to seek approval for a fund shift between MCE’s programs to accommodate anticipated spending for the remainder of 2016.

**Background**

MCE administers a Financing Program that involves On-Bill Repayment (“OBR”) options and marketing and outreach support to connect MCE customers with financing options to complete energy efficiency improvements to their home or business. MCE’s financing program requires additional funding for 2016 primarily due to workload associated with marketing and outreach for Property Assessed Clean Energy (“PACE”) programs.

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Fund Shifting for MCE’s 2016 Budget

MCE requests authority to shift funds from its Single Family Program to its Financing Program to support the Financing Program’s forecasted expenditures through the end of 2016. The proposed fund shift is included in Table 2 below.

Table 2: Requested Fund Shifts in MCE’s 2016 Budget

<table>
<thead>
<tr>
<th>MCE Programs</th>
<th>Approved 2016</th>
<th>Fund Shifts</th>
<th>Final 2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single Family</td>
<td>$233,050</td>
<td>($5,000)</td>
<td>$228,050</td>
</tr>
<tr>
<td>Multi-Family</td>
<td>$667,555</td>
<td>-</td>
<td>$667,555</td>
</tr>
<tr>
<td>Small Commercial</td>
<td>$658,711</td>
<td>-</td>
<td>$658,711</td>
</tr>
<tr>
<td>Financing</td>
<td>$27,031</td>
<td>$5,000</td>
<td>$32,031</td>
</tr>
<tr>
<td>Total</td>
<td>$1,586,347</td>
<td>$5,000</td>
<td>$1,586,347</td>
</tr>
</tbody>
</table>

MCE proposes to shift funds out of the Single Family Program to support its Financing Program. MCE AL 15-E advised the Commission of MCE’s suspension of its single family Home Utility Reports (“HURs”). The suspension is still in effect, and will continue into 2017. As a result of the suspension, MCE’s Single Family Program is expected to have available funds at the end of 2016. As such, MCE proposes to shift $5,000 out of the Single Family Program to support expenses accrued by its Financing Program. The funds that remain in the Single Family Program budget will continue to support the remaining activities including a Seasonal Savings pilot that, if approved, will begin in 2016 and continue through 2017.³

Although MCE has scaled back its Financing Program with the closure of the Single Family OBR option,⁴ MCE continues to incur costs associated with administration and implementation of its Financing Program. Funds are needed to continue to support and drive enrollment in the Multi-Family and Small Commercial offerings. MCE also provides support to connect MCE customers with PACE programs. MCE proposes to shift funds into its Financing Program budget to accommodate these costs.

Notice

Anyone wishing to protest this advice filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice filing. Protests should be mailed to:

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² MCE’s budget was originally approved in D.14-10-046. Pursuant to D.16-05-004 and MCE AL 16-E, MCE’s annual budget increased by $366,080 to accommodate newly enrolled communities in MCE’s service area in 2016.
³ MCE AL 17-E.
⁴ MCE AL 10-E.
CPUC, Energy Division  
Attention: Tariff Unit  
505 Van Ness Avenue  
San Francisco, California 94102  
E-mail: EDTariffUnit@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address above).

In addition, protests and all other correspondence regarding this advice letter should also be sent by letter and transmitted via facsimile or electronically to the attention of:

Michael Callahan  
Regulatory Counsel  
MARIN CLEAN ENERGY  
1125 Tamalpais Avenue  
San Rafael, CA  94901  
Phone:   (415) 464-6045  
Facsimile:   (415) 459-8095  
E-mail: mcallahan@mceCleanEnergy.org

and

Beckie Menten  
Energy Efficiency Director  
MARIN CLEAN ENERGY  
1125 Tamalpais Avenue  
San Rafael, CA  94901  
Phone:   (415) 464-6034  
Facsimile:   (415) 459-8095  
E-mail: bmenten@mceCleanEnergy.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

MCE is serving copies of this advice filing to the relevant parties shown on the R.13-11-005 service list. For changes to this service list, please contact the Commission’s Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.
Correspondence

For questions, please contact Michael Callahan at (415) 464-6045 or by electronic mail at mcallahan@mceCleanEnergy.org.

/s/ Michael Callahan

Michael Callahan
Regulatory Counsel
MARIN CLEAN ENERGY

cc: Service List R.13-11-005
Marin Clean Energy

Utility type: Michael Callahan
☐ ELC    □ GAS    Phone #: 415-464-6045
□ PLC    □ HEAT    □ WATER    E-mail: mcallahan@mceCleanEnergy.org

EXPLANATION OF UTILITY TYPE
ELC = Electric    GAS = Gas
PLC = Pipeline    HEAT = Heat    WATER = Water

Advice Letter (AL): 19-E
Subject of AL: Request for Approval to Shift Funds in Anticipation of 2016 Spending
Tier Designation: □ 1 ☑ 2 □ 3
Keywords (choose from CPUC listing):
AL filing type: □ Monthly □ Quarterly □ Annual ☑ One-Time □ Other ____________________________
If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution: N/A
Does AL replace a withdrawn or rejected AL? If so, identify the prior AL ____________________________
Summarize differences between the AL and the prior withdrawn or rejected AL: ____________________
Resolution Required? □ Yes ☑ No
Requested effective date: November 24, 2016
Estimated system annual revenue effect: (%):
Estimated system average rate effect (%):
When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).
Tariff schedules affected:
Service affected and changes proposed1:
Pending advice letters that revise the same tariff sheets:

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Ave.,
San Francisco, CA 94102
EDTariffUnit@cpuc.ca.gov

Utility Info (including e-mail)
Marin Clean Energy
Michael Callahan, Regulatory Counsel
(415) 464-6045
mcallahan@mceCleanEnergy.org

---

1 Discuss in AL if more space is needed.
BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue
Implementation and Administration, and
Consider Further Development, of California
Renewables Portfolio Standard Program

R.15-02-020

REPLY COMMENTS OF SHELL ENERGY NORTH
AMERICA (US), L.P. ON BEHALF OF THE JOINT DA/CCA
PARTIES ON PRESIDING JUDGE SIMON’S PROPOSED
DECISION ADDRESSING SB 840, GOVERNOR’S EMERGENCY
PROCLAMATION, AND BIOENERGY FEED-IN TARIFF

John W. Leslie
Dentons US LLP
4655 Executive Drive, Suite 700
San Diego, California  92121
Tel: (619) 699-2536
Fax: (619) 232-8311
E-Mail: john.leslie@dentons.com

Attorneys for Shell Energy North America (US), L.P.

and on behalf of the City of Lancaster,
Marin Clean Energy, Sonoma Clean Power
Authority, Direct Access Customer Coalition,
and Alliance for Retail Energy Markets

Date:  October 24, 2016
BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program

R.15-02-020

REPLY COMMENTS OF SHELL ENERGY NORTH AMERICA (US), L.P. ON BEHALF OF THE JOINT DA/CCA PARTIES ON PRESIDING JUDGE SIMON’S PROPOSED DECISION ADDRESSING SB 840, GOVERNOR’S EMERGENCY PROCLAMATION, AND BIOENERGY FEED-IN TARIFF

In accordance with Rule 14.3(d) of the Commission’s Rules, Shell Energy North America (US), L.P., for itself and on behalf of the City of Lancaster, Marin Clean Energy, Sonoma Clean Power Authority, Direct Access Customer Coalition, and the Alliance for Retail Energy Markets (“Joint DA/CCA Parties”) submit reply comments on the Presiding Judge’s September 27, 2016 proposed decision (“PD”) in the above-referenced proceeding. The PD recommends certain adjustments to the Bioenergy Market Adjusting Tariff (“BioMAT”) program in response to the Governor’s October 30, 2015 Emergency Proclamation and Senate Bill (“SB”) 840. The Joint DA/CCA Parties respond in opposition to the joint opening comments filed on October 17, 2016
by Southern California Edison Company ("SCE") and San Diego Gas & Electric Company ("SDG&E").

In their opening comments, SCE and SDG&E assert that "[b]ecause there are above-market costs in the BioMAT program, they should be recovered from all customers through a nonbypassable charge." Comments at p. 2. SCE and SDG&E's comments on a new nonbypassable charge should be rejected or ignored. These comments extend beyond the scope of issues to be addressed in connection with the Commission's implementation of SB 840 and the Governor's Emergency Proclamation and are otherwise unsupported.

I.

THE SCOPE OF THIS PROCEEDING IS LIMITED TO ISSUES RAISED IN THE GOVERNOR'S EMERGENCY PROCLAMATION AND SB 840

The PD explains that there are two objectives in this phase of the proceeding: first, to implement a portion of the Governor's October 30, 2015 Emergency Proclamation, which includes "consideration of adjustments to the BioMAT program" (PD at p. 4); and second, to implement that portion of SB 840 that "revise[s] the eligibility requirements for participation in BioMAT." PD at p. 6. The Presiding Judge issued a Ruling on February 12, 2016 soliciting comments on a Staff Proposal to make "targeted changes" to the BioMAT program to facilitate contracts with generation facilities burning fuel from "high hazard zones." Neither the Presiding Judge's February 12, 2016 Ruling nor the accompanying Staff Proposal mentioned adoption of a "nonbypassable charge" for the "above-market" costs of the IOUs' procurement under the BioMAT program.
II.

THE PD DECLINES TO ALTER THE CURRENT PRICING STRUCTURE UNDER THE BIOMAT PROGRAM

The PD rejects a proposal by the Commission Staff to increase the price to be offered under the BioMAT tariff for generation fueled by biomass from high hazard zones. The PD does so to limit the changes to the BioMAT tariff to those that are required under SB 840 and the Governor’s Emergency Proclamation. The PD states that the “BioMAT pricing structure should be maintained, without the complications attendant on incentives for the use of [high hazard zone] fuel.” PD at p. 12.

As a consequence of its recommendation respecting the BioMAT pricing structure, the PD also recommends that the Commission decline to rule on the investor-owned utilities’ (“IOU”) proposal to allocate the “above market costs” of any changes to the BioMAT price to the cost allocation mechanism (“CAM”) or some other nonbypassable charge. The PD states:

It is . . . unnecessary to address the details of the CAM proposal on the merits, because the underlying premise of the IOUs’ proposal is not consistent with the treatment of BioMAT Category 3 procurement in this decision. The Commission is not creating any incentives, surcharges, adders, or other above-market costs in the BioMAT program. Rather, we are allowing the BioMAT market-based mechanism to adjust as designed in D.14-12-081, and temporarily using more frequent program periods. There will therefore be no above-market costs that could be collected through the use of CAM. PD at p. 26. The PD’s recommendation to maintain the existing BioMAT pricing structure renders moot the IOUs’ proposal to allocate any BioMAT “surcharge” costs to a nonbypassable charge.

SCE and SDG&E’s opening comments ignore the PD’s recommendations and advance a proposal that extends far beyond the issues identified for consideration in the PD or in the Ruling setting the issues for this phase of the proceeding. SCE and SDG&E argue that all so-called
“above market” costs of the BioMAT program should be reflected in a nonbypassable charge that is imposed on all IOU ratepayers. Comments at p. 2. SCE and SDG&E further argue that SB 859 (the subject of Resolution E-4805 (October 13, 2016)) demonstrates the legislature’s intention that all “above market” costs of procurement of generation fueled by biomass from high hazard zones (under the BioRAM program) should be spread to all customers through a nonbypassable charge. Comments at p. 3. On this basis, SCE and SDG&E assert that so-called “above market” procurement costs under the BioMAT program should be imposed on all customers.

The Presiding Judge’s February 12, 2016 Ruling did not solicit comments on whether “above market” costs incurred by the IOUs through BioMAT procurement should be allocated on a nonbypassable basis. In fact, the Commission Staff’s proposals herein provided that “[a]ll other rules established in D.14-12-081 and D.15-09-004 [including cost allocation] continue to apply.” February 12, 2016 Ruling, Attachment A, pp. 7, 8. The PD properly concluded that an amended cost allocation approach for BioMAT procurement costs is not a proper subject for the Commission’s consideration herein.

This is not the forum in which to address the imposition of a new nonbypassable charge under the BioMAT program. The limited changes to the BioMAT program recommended in the PD, which are in direct response to SB 840 and the Governor’s Emergency Proclamation, do not warrant examination or adoption of a new nonbypassable charge.

In Resolution E-4805, the Commission established a process through which it will address the creation of a “Tree Mortality” nonbypassable charge, as expressly authorized in SB 859. Resolution at p. 16. Pursuant to this Resolution, the IOUs must file applications on or before November 14, 2016 to propose such a nonbypassable charge. The IOUs are free to argue,
in those applications, regarding the scope of costs recoverable under SB 859. The Joint DA/CCA Parties merely note at this juncture that these applications should not be used by the IOUs as a “catch-all” for any and all BioMAT and BioRAM procurement costs, but rather should be limited to addressing procurement costs expressly authorized in SB 859.

III.

CONCLUSION

The Commission should reject SCE and SDG&E’s proposal to allocate the above-market costs of the IOUs’ BioMAT program procurement through a nonbypassable charge.

Respectfully submitted,

John W. Leslie
Dentons US LLP
4655 Executive Drive, Suite 700
San Diego, California 92121
Tel: (619) 699-2536
Fax: (619) 232-8311
E-Mail: john.leslie@dentons.com

Attorneys for Shell Energy North America (US), L.P.

and on behalf of the City of Lancaster, Marin Clean Energy, Sonoma Clean Power Authority, Direct Access Customer Coalition, and Alliance for Retail Energy Markets

Date: October 24, 2016
VERIFICATION

I am an officer of Shell Energy North America (US), L.P. and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on October 24, 2016 at San Diego, California.

[Signature]
Edward Brown
Vice President – Environmental Products
Shell Energy North America (US), L.P.
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue
Implementation and Administration, and Consider
Further Development, of California Renewables
Portfolio Standard Program.

Rulemaking 15-02-020
(Filed February 26, 2015)

REPLY COMMENTS OF THE CITY OF LANCASTER, MARIN CLEAN ENERGY,
AND SONOMA CLEAN POWER AUTHORITY ON THE DRAFT 2016 RENEWABLES
PORTFOLIO STANDARD PROCUREMENT PLANS

Dan Griffiths
Scott Blaising
Braun Blaising McLaughlin & Smith, P.C.
915 L Street, Suite 1480
Sacramento, CA 95814
Telephone: (916) 326-5812
griffiths@braunlegal.com
Counsel for the City of Lancaster

Jeremy Waen
Regulatory Counsel
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6027
jwaen@mceCleanEnergy.org

Steven S. Shupe
General Counsel
Sonoma Clean Power Authority
50 Santa Rosa Avenue, Fifth Floor
Santa Rosa, CA 95404
Telephone: (707) 890-8485
sshupe@sonomacleanpower.org

Dated: September 16, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue
Implementation and Administration, and Consider
Further Development, of California Renewables
Portfolio Standard Program. (Rulemaking 15-02-020)
(Filed February 26, 2015)

REPLY COMMENTS OF THE CITY OF LANCASTER, MARIN CLEAN ENERGY,
AND SONOMA CLEAN POWER AUTHORITY ON THE DRAFT 2016 RENEWABLES
PORTFOLIO STANDARD PROCUREMENT PLANS

I. INTRODUCTION


II. REPLY COMMENTS

A. IEP and LSA’s Comments Do Not Substantiate a Recommendation for the Commission to Explore a Procurement Entity for CCAs or Other Mechanisms When CCAs are Already Meeting Procurement Obligations at Competitive Prices

In comments, the Independent Energy Producers Association (“IEP”) proposed that the Commission explore establishing larger utilities as procurement entities for Community Choice

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Aggregation ("CCA") programs for long-term contracts.\(^1\) Though IEP notes that all retail sellers are required to meet certain long-term contracting requirements, IEP makes this request specific for CCA programs.\(^2\) Similarly, the Large-Scale Solar Association ("LSA") recommends that the Commission “look at possible safeguards” to protect against a procurement shortfall, particularly related to CCAs.\(^3\) Aside from stating that larger utilities “could” enable lower cost purchases, IEP does not provide any information on why CCAs are in particular need of a procurement entity.\(^4\) LSA similarly expresses a concern that there “may be” a “potential” disconnect between IOU and CCA procurement planning, but does not explain what disconnect exists and why a safeguard is needed.\(^5\)

The CCA Parties are presently meeting their RPS procurement requirements at competitive prices, and do not foresee a need for an optional procurement entity. Though Public Utilities Code Section 399.13(f)(1) permits an optional procurement entity related to any retail seller, the Commission is expressly prohibited from requiring that such an entity be used.\(^6\) CCAs have sole responsibility over the procurement of resources through the review and approval of their respective governing body, unless expressly restricted (or circumscribed) by statute.\(^7\)

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1. IEP Comments at 23.
2. Id.
3. LSA Comments at 3.
4. IEP comments at 23.
5. LSA comments at 3.
6. See Section 399.13(f)(1)(emphasis added) (“[The commission] shall not...require any party to purchase eligible renewable resources from a procurement entity.”). All further statutory references are to the Public Utilities Code unless otherwise noted.
7. “A community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator’s customers, except where other generation procurement arrangements are expressly authorized by statute.” Section 366.2(a)(5).
noted in CCA Parties’ Procurement Plans, the CCAs intend to meet or exceed applicable RPS procurement obligation over the 20-year time frame provided in the ACR, which includes the 2021 long-term contracting timeframe specified in Section 399.13(b). The quantity of long-term contracts and the respective risks associated with long- and short-term contracts are important considerations as part of a CCA’s forecasting and procurement processes, and will continue to factor into CCA procurement beyond 2021.

B. Contrary to the Explicit Language of SB 350 and the Commission’s May 17, 2016 Ruling, the Joint Utilities Incorrectly Apply Procurement Plan Requirements to ESPs and CCAs

The Joint Utilities\(^\text{10}\) claim that Senate Bill (“SB”) 350’s modifications to RPS Procurement Plans now require CCAs “to participate in the RPS program subject to the same terms and conditions applicable to electrical corporations” and therefore request that the Commission require CCAs and Electric Service Providers (“ESPs”) to file supplements to their RPS Procurement Plans that include additional materials that IOUs file.\(^\text{11}\) To support this claim, the Joint Utilities do not cite SB 350’s Procurement Plan requirements, but instead cite the general definition of a retail seller.\(^\text{12}\) Noting that CCAs and ESPs are retail sellers under Section 399.12(j) does not provide the legal basis that CCA and ESP RPS Procurement Plans must include additional materials that IOUs file. Indeed, explicit language in SB 350, the May 17, 2016 ACR, and past Commission decisions are to the contrary.

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\(^8\) See, e.g., City of Lancaster 2016 RPS Procurement Plan at 2 and Appendix A.

\(^9\) See id. at 2-3 (for procurement and risk assessment).


\(^11\) Joint Utilities Comments at 1-2.

\(^12\) Id.
SB 350’s treatment of RPS program participation contains important distinctions and qualifications particular to certain entities. Section 399.13(a)(1) directs electrical corporations to prepare a renewable energy procurement plan that “includes the matter in paragraph (5).”¹³ This language contrasts with all other retail sellers, which are directed to submit renewable energy procurement plans that “address the requirements identified in paragraph (5).”¹⁴ Electrical corporations have many RPS program requirements in Section 399.13 that do not apply to CCAs and ESPs,¹⁵ and to extend these requirements to CCAs and ESPs is contrary to the explicit language in SB 350.

The ACR, issued on May 17, 2016, acknowledges that Commission decisions and existing legislation require the investor-owned utilities (“IOUs”) to comply with all Procurement Plan requirements, while ESPs and CCAs are only subject to a subset of these requirements:

Consistent with the Commission’s decisions and applicable legislative changes, compliance with all of the requirements set forth below is required by Pacific Gas and Electric Company (PG&E), Southern California Electric Company (SCE), San Diego Gas & Electric Company (SDG&E) (collectively investor-owned utilities or IOUs) ... ESPs and CCAs are also subject to a subset of these requirements, as described below.¹⁶

Past Commission decisions are consistent with this statement. For example, Decision (“D.”)¹⁴-11-042 required only the IOUs to address economic curtailment,¹⁷ which is reflected in the ACR’s direction that only IOUs should complete question 6.9 in the ACR. Indeed, since the Commission’s review of CCA participation in the RPS program in D.05-11-025, the

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¹³ Id. (emphasis added).
¹⁴ Section 399.13(a)(1).
¹⁵ As an example, Section 399.13(a)(2), (a)(3)(B), (a)(4)(A)(v)(I), (a)(4)(C)-(D), (a)(6), (a)(7), (c), (d), (e), and (g) specifically address electrical corporation requirements.
¹⁶ ACR at 5.
¹⁷ D.14-11-042 at 42.
Commission has expressed legal, regulatory, and policy support for the finding that CCA RPS program participation is not the same as for IOUs, or even ESPs:

We approach this question as an issue of policy. ESPs and CCAs each are subject to separate and distinct legal and regulatory requirements. Although they are each subject to certain requirements of this Commission as assigned by the Legislature, neither is regulated as a “public utility” as defined by the Public Utilities Code, nor are they subject to Commission regulatory authority as a matter of course. Instead, the Commission is granted specific regulatory authority over these entities for particular issues, in this case, RPS. Because of this, each of these entities in existence or planned operates under a business model that is different from a regulated public utility.

***

This Commission has less overall control over how ESPs and CCAs operate than we do over how utilities operate. Also, to the extent we consider ESP and CCA operations, our concerns about their operations differ somewhat from our concerns about the operations of the investor-owned utilities. In the context of the RPS program, our primary concern is to ensure that ESPs and CCAs do in fact reach the goal of 20% renewable energy by 2010. [citation omitted] We are, however, somewhat less concerned about the details of how they get there.

Therefore, we do not believe it is reasonable to require these entities to be subject to the exact same steps for RPS implementation purposes as the utilities we fully regulate. We also do not believe that it is necessarily reasonable to subject ESPs and CCAs to the same RPS process requirements as each other, simply because they are not utilities. A CCA, for example, will likely be answerable to the political authorities in the community in which it is operating, in addition to its customers. The business of an ESP, on the other hand, is much more highly sensitive to price pressures than a utility, which has captive customers, at least at this time. Thus, we are sensitive to the particular requirements and pressures of each type of entity and do not necessarily want to impose a “one size fits all” RPS regulatory scheme.18

The Commission further described their findings on more limited RPS Procurement Plan oversight for CCAs in D.06-10-019:

One area where our oversight is limited is CCAs’ RPS procurement plans. We agree with the CCA Parties’ interpretation of D.05-11-025, that a CCA will inform us of its RPS plans, but we will not have oversight of its RPS process. Thus, for example, a CCA will not be required to file annual procurement plans, but will be required to meet its APT annually. As explained more fully in the discussion of contracting, below, we also agree

with the CCA Parties that a variety of contracting and procurement mechanisms may be utilized for RPS compliance.\textsuperscript{19}

The findings in D.05-11-025 and D.06-10-019 concerning CCA and ESP RPS program participation were described again in D.11-01-026, where the Commission concluded that requiring ESPs to submit procurement plans “does not necessitate changing the long-standing method of requiring what is stated in statute along with determining the supplemental content, if any, of each annual RPS procurement plan.”\textsuperscript{20} In another 2011 decision, D.11-01-025, the Commission noted that the Commission is not responsible for CCA rates or reviewing RPS contracts, nor do the upfront showing requirements for IOUs apply to CCAs.\textsuperscript{21}

Thus, the Joint Utilities provide no support in SB 350 or elsewhere for why the Commission should break from over a decade of precedent and hold that other entities are subject to requirements that apply solely to the IOUs. Indeed, the language of SB 350 and Commission decisions provide explicit support for the contrary.

C. If the Joint Parties Intended to Address CCA and ESP Inclusion in an LCBF Process under Section 454.51, the CCA Parties Do Not Find that Inclusion Consistent with Section 454.51(b)

In a footnote to a June 1, 2016 motion attached to its comments, the Joint Parties\textsuperscript{22} recommend that the IOUs charge CCAs and ESPs higher direct costs incurred to avoid over-generation curtailment if they do not adopt a type of least-cost, best-fit (“LCBF”) process, pursuant to Section 454.51.\textsuperscript{23} The goal of the June 1, 2016 motion was to “ensure that the IOUs’

\begin{footnotes}
\item[19] D.06-10-019 at 18.
\item[20] D.11-01-026 at 15.
\item[21] D.11-01-025 at 10.
\item[22] The Joint Parties consist of the California Biomass Energy Alliance, California Wind Energy Association, Calpine Corporation, Geothermal Energy Association, and Ormat Nevada.
\item[23] Joint Parties Comments, Attachment 1 at 6 (fn. 10).
\end{footnotes}
2016 RPS Plans contained sufficient information to inform parties’ comments and Commission decisions on these [energy curtailment] issues.” In comments, Joint Parties described findings that largely approved of SCE’s treatment of curtailment issues, and noted some remaining curtailment concerns in comments. Thus, Joint Parties may not have intended to incorporate all issues addressed in the June 1, 2016 motion into its comments. To the extent that the Joint Parties did intend to raise cost allocation and LCBF process issues, the CCA Parties note that an LCBF methodological discussion requirement, or an adoption of LCBF components, is not required for CCAs. Section 454.51, cited by the Joint Parties, directs electrical corporations to include a strategy for identifying best-fit and least-cost resources to satisfy portfolio needs. CCAs are permitted to submit proposals for satisfying renewables integration need, but that permission does not include or require a strategy for identifying best-fit or least cost resources.

As noted in the CCA Parties’ Procurement Plans, CCAs conduct bid solicitations that address a broad range of considerations, including the need for eligible resources, locational preferences, and required online dates. The solicitation and procurement decisions of CCA programs are overseen by governing boards that are typically comprised of local elected officials, and are designed to comply with locally-established targets. Thus, the CCA Parties object to any recommendation for CCA inclusion in a LCBF process adoption or any proposed

24 Joint Parties Comments at 1-2.
25 Id.
26 Section 454.51(b).
27 See Section 454.51(a)-(d).
28 See, e.g., City of Lancaster 2016 RPS Procurement Plan at 4.
29 Id.
consequences for not doing so. Not only would this be administratively inefficient, but LCBF does not ensure the diverse and balanced portfolio of resources sought by many CCAs.

III. CONCLUSION

The CCA Parties thank the Commission for the opportunity to provide reply comments in this proceeding.

Dated: September 16, 2016

Respectfully submitted,

/s/ Dan Griffiths
Dan Griffiths
Scott Blaising
Braun Blaising McLaughlin & Smith, P.C.
915 L Street, Suite 1480
Sacramento, CA 95814
Telephone: (916) 326-5812
griffiths@braunlegal.com
Counsel for the City of Lancaster

/s/ Jeremy Waen
Jeremy Waen
Regulatory Counsel
Marin Clean Energy
1125 Tamalpais Avenue
San Rafael, CA 94901
Telephone: (415) 464-6027
jwaen@mceCleanEnergy.org

/s/ Steven S. Shupe
Steven S. Shupe
General Counsel
Sonoma Clean Power Authority
50 Santa Rosa Avenue, Fifth Floor
Santa Rosa, CA 95404
Telephone: (707) 890-8485
sshupe@sonomacleanpower.org
VERIFICATION

I, Dan Griffiths, am authorized to make this Verification under Rules 1.8(d) and 1.11(d) on behalf of the City of Lancaster, Marin Clean Energy, and Sonoma Clean Power Authority, who are absent from the County of Sacramento, California, where I have my office. I declare under penalty of perjury that the statements in the foregoing REPLY COMMENTS OF THE CITY OF LANCASTER, MARIN CLEAN ENERGY, AND SONOMA CLEAN POWER AUTHORITY ON THE DRAFT 2016 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters I believe them to be true.

Executed on September 16, 2016, at Sacramento, California.

/s/ Dan Griffiths
Dan Griffiths
Braun Blasing McLaughlin & Smith, P.C.
915 L Street, Suite 1480
Sacramento, CA 95814
Telephone: (916) 326-5812
griffiths@braunlegal.com
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an
Electricity Integrated Resource Planning Framework
and to Coordinate and Refine Long-Term Procurement
Planning Requirements

Rulemaking 16-02-007
(Filed February 11, 2016)

INFORMAL PRE-WORKSHOP COMMENTS OF
CITY OF LANCASTER, MARIN CLEAN ENERGY
AND SONOMA CLEAN POWER AUTHORITY

Scott Blaising
David Peffer
Dan Griffiths
Ty Tosdal, of Counsel
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, CA  95814
Telephone: (916) 712-3961
E-mail: blaising@braunlegal.com
Counsel for the City of Lancaster

Shalini Swaroop
Regulatory Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Drive
San Rafael, CA  94901
Telephone: (415) 464-6040
E-Mail: sswaroop@mceCleanEnergy.org
Counsel for Marin Clean Energy

Steven S. Shupe
General Counsel
SONOMA CLEAN POWER AUTHORITY
50 Santa Rosa Avenue, Fifth Floor
Santa Rosa, California 95402
Telephone: (707) 890-8485
E-Mail: sshupe@sonomacleanpower.org
Counsel for Sonoma Clean Power Authority

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INFORMAL PRE-WORKSHOP COMMENTS OF
CITY OF LANCASTER, MARIN CLEAN ENERGY
AND SONOMA CLEAN POWER AUTHORITY

Pursuant to instructions provided by the Energy Division of the Public Utilities Commission of the State of California ("Commission"), the City of Lancaster ("Lancaster"), Marin Clean Energy ("MCE"), and Sonoma Clean Power Authority ("SCPA") (collectively, "CCA Parties") hereby submit informal pre-workshop comments on the CPUC Staff Concept Paper on Integrated Resource Planning, dated August 11, 2016 ("Staff Concept Paper"). As requested in the e-mail transmitting the Staff Concept Paper, the CCA Parties address each question presented in the Staff Concept Paper, and also address and explain other issues related to Integrated Resource Planning ("IRP") matters, while first providing general context and background for these issues.

I. INTRODUCTION AND SUMMARY

A. Summary Of The CCA Parties

MCE operates the first Community Choice Aggregation ("CCA") program in California. By the end of September 2016, MCE will provide generation service to approximately 250,000 customer accounts throughout Marin County, Napa County, and the Cities of Richmond, San Pablo, El Cerrito, Lafayette, Walnut Creek, and Benicia. In total, MCE will serve a peak electric demand of about 500 MWs. For context and by comparison, MCE’s load is approximately 4
percent of the load served by Pacific Gas and Electric Company (“PG&E”), the investor-owned utility (“IOU”) that surrounds MCE’s service territories. As with other CCA programs, MCE operates as the default provider of electric service within its service territories, providing generation services to its customers while PG&E provides delivery and billing services. As further discussed below, a copy of MCE’s most recent Integrated Resource Plan may be found at the following link: MCE IRP.

Lancaster is the first CCA program in Southern California Edison Company’s (“SCE”) service area. Lancaster launched its CCA program, known as Lancaster Choice Energy (“LCE”), in May 2015 as a means by which Lancaster could further advance its aggressive alternative energy goals, principally solar energy. Lancaster serves approximately 580,000 MWhs of electric load on an annual basis, with peak electric demand of about 160 MWs. Lancaster’s load is less than 1 percent of the load served by SCE.

SCPA is the second operational CCA program in California, and currently serves about 198,000 accounts encompassing a population of approximately 450,000, which includes all of Sonoma County except for the City of Healdsburg, which has its own municipal electric utility. SCPA is governed by a nine-member Board of Directors comprised of appointees from the participating cities and the County of Sonoma. SCPA provides its customers with stable and competitive electric rates, providing a power portfolio with a higher renewable content (and lower greenhouse-gas emissions) than the incumbent utility. The reduction of greenhouse gas emissions in Sonoma County is one of the reasons for SCPA’s formation, under the joint powers agreement that formed SCPA.

Without unduly emphasizing one event, it is clear that Senate Bill (‘SB”) 790 (Stats. 2011, ch. 599) ushered in a new era with respect to generation services. SB 790 was enacted to, among other things, facilitate the implementation of CCA programs and establish key regulatory parameters for such programs. As explained by the Commission, “[i]n SB 790, the legislature directed the Commission to develop rules and procedures that ‘facilitate the development of community choice aggregation programs, … foster fair competition, and … protect against cross-subsidization paid by ratepayers.’” These views are consistent with prior Commission precedent.

As intended, since the enactment of SB 790, CCA programs have flourished. In addition to the three CCA Parties, the City and County of San Francisco launched CleanPowerSF in 2016, becoming the fourth operational CCA program in California. Also, as described recently in its Renewables Portfolio Standard (“RPS”) Procurement Plan, Peninsula Clean Power (“PCP”) will launch in October 2016, with an additional phase in April 2017, ultimately serving approximately 260,000 customers in San Mateo County and supplying roughly 3,400,000 MWhs on an annual basis. The Commission recently reported to the Governor and legislature that, “as

1 D.12-12-036 at 6 (citing SB 790, § 2(h), and Pub. Util. Code § 707(a)(4)(A)).
2 See D.04-12-046 at 3 (emphasis added) (“The state Legislature has expressed the state’s policy to permit and promote CCAs by enacting AB 117….”). See also D.10-05-050 at 13 (emphasis added) “Certainly, Section 336.2(c)(9) [the provision in AB 117 that requires cooperation from the utilities] evidences a substantial governmental interest in encouraging the development of CCA programs and allowing customer choice to participate in them.”).
of March 2016, more than 20 communities are pursuing CCA.” Indeed, SB 790 has facilitated the development of CCA programs, and it will be important for the Commission in this proceeding to thoughtfully consider ways in which the IRP process may be implemented so as to be harmonized with SB 790 and ongoing efforts to develop CCA programs.

C. **Collaboration And Cooperative Interaction Should Be Key Attributes Marking The Integrated Resource Planning Process**

In SB 790, the legislature recognized past efforts in pursuing “the right of local governments to aggregate their electricity loads for the purpose of procuring and generating more renewable energy, expanding consumer choice, and greatly accelerating regional efforts to address global climate change.” In this IRP process, CCA programs seek to maintain the right of local governments to develop and tailor CCA programs to their particular jurisdiction, while also actively engaging in cooperative interaction with the Commission. For the Commission to promote and encourage CCA development, an appropriate degree of deference to the resource planning activities of local governmental entities is necessary. CCA programs’ governing boards consist of local elected officials, who are responsive to the particular resource needs of their communities and can better integrate resource planning and procurement within broader local planning efforts.

The Commission should value and respect these local efforts, and develop a climate of cooperative interaction on resource planning issues. The CCA Parties have no reason to expect otherwise from the Commission. Indeed, in various decisions addressing jurisdictional matters,

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4 See Actions to Limit Utility Cost and Rate Increases, May 2016, at 7-8 (referencing the April 2016 CCA Quarterly Report).
5 SB 790, Section 2(j) (emphasis added).
6 See D.04-12-046 at 3.
7 See D.10-05-050 at 13.
the Commission has appropriately respected jurisdictional divides and interactive responsibilities. Notably, the Commission comprehensively addressed jurisdictional issues in D.05-12-041 (the Commission’s seminal decision on CCA implementation). After citing certain limited exceptions (like resource adequacy requirements), the Commission concluded that its authority over Community Choice Aggregators is “circumscribed.”\(^8\) Nothing in SB 350 changes this exception-based view of the Commission’s authority. Further, the Commission distinguished its authority over Electric Service Providers (“ESPs”) versus its authority over Community Choice Aggregators, reasoning that the legislature purposely and understandably gave the Commission broader authority over ESPs.\(^9\) Most importantly, on both a practical and legal level, the Commission evidenced deference and respect for the local and public processes under which Community Choice Aggregators operate, stating that such processes have the effect of promoting accountability and that Commission oversight would not contribute anything further in this regard.\(^{10}\) The CCA Parties appreciate the Commission’s past statements on jurisdictional issues, and looks forward to collaborating and cooperatively interacting with the Commission on IRP matters.

D. Summary of the CCA Parties’ Initial Positions With Respect To Certain Integrated Resource Planning Issues

As further developed in Section II, below, the CCA Parties’ initial position on certain IRP issues is summarized as follows:

- The Commission has limited jurisdiction over CCA programs.
- CCA programs are entitled to meaningfully self-provide for purposes of implementing IRP requirements.

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\(^{8}\) See D.05-12-041 at 8-9.

\(^{9}\) See D.05-12-041 at 10.

\(^{10}\) See D.05-12-041 at 10-11.
• CA program load forecasting should be addressed as part of this proceeding.

• CCA program issues should be addressed on a separate track, which precedes or progresses faster than the IOU track.

II. GENERAL COMMENTS

The IRP process must be conducted in a manner that preserves the ability of CCA programs and their governing boards to procure resources and meet IRP obligations without unwarranted oversight or regulation from the Commission. As explained further below, CCA program autonomy is protected by law and remains unchanged by SB 350. The same principle extends to self-provision of resources obtained to meet IRP requirements. In addition, there is a related and unresolved issue of CCA load forecasting, which affects resource obligations and cost recovery, which should be addressed as part of this proceeding. For these reasons, and to avoid confusion and delay, CCA programs should be addressed separately from the IOUs in this proceeding.

A. The Commission Has Limited Jurisdiction Over CCA Programs

The Commission is aware that procurement authority is vested in CCA program governing boards. The Commission’s jurisdiction over CCA programs remains limited, as it has always been, despite the additional requirements that the legislature established in SB 350 for the programs themselves. All aspects of the IRP process should comply with Public Utilities Code section 366.2(a)(5), by preserving the operational and procurement independence that CCA programs enjoy under the law, except where Commission involvement has been specifically authorized by the legislature. All further statutory references are to the Public Utilities Code unless otherwise noted.
aggregator’s customers, except where other generation procurement arrangements are expressly 
authorized by statute.”\textsuperscript{12} SB 350 does not change this bedrock legal principle. To the contrary, 
SB 350 even references this bedrock principle in the IRP enabling statute. 

SB 350 merely gives the Commission the authority to “adopt a \textit{process} for each load 
serving entity to file an integrated resource plan …”\textsuperscript{13} It does not extend authorization to the 
Commission to determine how CCA programs develop their plans, what is contained in the 
plans, or whether the resources contained in the plans should be approved or not. Likewise, 
while the Commission may approve or reject CCA program proposals for self-provision of 
renewable integration resources for purposes of meeting IRP obligations,\textsuperscript{14} nowhere in SB 350 or 
in any other statute does the legislature authorize the Commission to approve or reject a CCA 
program’s portfolio of resources, or its action plan for that matter. In the absence of any explicit 
authorization, the independence and autonomy of CCA programs established in section 
366.2(a)(5) is the law and must be respected. 

B. CCA Programs Are Entitled To Meaningfully Self-Provide For Purposes Of 
Implementing IRP Requirements 

SB 350 explicitly authorizes CCA programs to self-provide resources for the purpose of 
meeting IRP obligations, as long as those proposals meet several requirements.\textsuperscript{15} Given the legal 
status and operations of CCA programs, this self-provision option is likely to be the preferred 
option, and should remain a viable option for CCA programs, regardless of what they choose to 
self-provide in any single IRP sequence or update cycle. Accordingly, the issue should be given 

\textsuperscript{12} Pub. Util. Code, § 366.2(a)(5).
\textsuperscript{13} Pub. Util. Code, § 454.52(a)(1) (emphasis added).
\textsuperscript{14} Pub. Util. Code, § 454.51(d).
\textsuperscript{15} Pub. Util. Code, § 454.51(d).
prominent attention in this proceeding.

Self-provision is not only explicitly authorized under SB 350, it is also supported by other statutes, including statutes governing resource adequacy. CCA programs are responsible for certain resource adequacy requirements, and self-provision is a means by which those requirements can be met. To that end, the legislature has directed that the Commission establish such requirements for all LSEs and in doing so, it must “[m]aximize the ability of community choice aggregators to determine the generation resources used to serve their customers.”\(^\text{16}\) Self-provision, then, is a means for CCA programs to procure resources that meet resource adequacy requirements, and avoid being forced to pay for procurement conducted by the IOUs through the Cost Allocation Mechanism (“CAM”), a process over which they have no control. At bottom, self-provision should be respected as a means of CCA program participation in both the IRP and resource adequacy contexts, and should be regarded as a fundamental principle to which action taken in this proceeding should be harmonized.

C. **CCA Program Load Forecasting Should Be Addressed As Part Of This Proceeding**

An outstanding issue that has been unresolved to date is the methodology for CCA program load forecasting. Load forecasts are important for several reasons, not least of which is the fact that they are used to determine what cost recovery is available to IOUs – and what CCA customers ultimately pay – for stranded costs that result from departing load. The value of those costs vary widely depending on the methodology and means used to determine departing load forecasts. To date, the Commission has not provided guidance on what methodology should be used for this purpose. As mentioned in the comments that the CCA programs submitted

previously on the Order Instituting Rulemaking, this proceeding is an appropriate venue for addressing load forecasting methodology.

In the context of the IOUs’ Bundled Procurement Plans, the Commission has required the IOUs to forecast CCA load departures on a 10-year horizon. However, there has been scant consideration of late given to whether the IOUs’ forecasts include the most recent and reliable information and how the IOUs’ forecasts actually affect stranded cost recovery assigned to CCA departing load. Past Commission decisions, on the other hand, actively considered departing load forecasts and used this data to inform decisions on departing load charges. The CCA Parties are concerned that a failure to actively consider, renew and apply CCA departing load forecasts may result in unjustified and unsubstantiated costs being charged to CCA programs. The issue is not confined to existing CCA programs; new CCA programs will also be affected. This proceeding should resume past practices by actively considering and addressing CCA departing load forecasts, and the consequences of such forecasts on departing load charges. Included among this consideration should be a practice by which past forecasts are renewed and replaced with the most current and reliable information.

D. CCA Program Issues Should Be Addressed On A Separate Track, Which Precedes Or Progresses Faster Than The IOU Track

The Scoping Memo states that to avoid “unnecessary complication” and “potential confusion” the Commission is not intending to separate this proceeding into tracks but rather go

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17 Comments of Marin Clean Energy, Sonoma Clean Power Authority, and City Of Lancaster Regarding Preliminary Scoping Memo Contained Within the Order Instituting Rulemaking, March 21, 2016, at 6.
18 See, e.g., D.14-02-040 at 16.
19 See, e.g., D.08-09-012 at 10-32.
forward based on a chronological sequence of events.\textsuperscript{20} Whether the Commission intended that statement to be a preliminary determination that may be revisited at a later date, or final determination that will govern the procedural schedule for the duration of the proceeding, is not clear. Nevertheless, the CCA Parties urge the Commission to give CCA programs separate treatment, if not a separate track or phase of the proceeding. Moreover, the CCA Parties request that the separate track precede or progress faster than the IOUs’ track. While the CCA Parties observe and appreciate that the Staff Concept Paper seeks to make certain distinctions and categorizations of load-serving entities (“LSEs”),\textsuperscript{21} the CCA Parties believe that there are rights and responsibilities unique to Community Choice Aggregators that warrant special consideration. Moreover, in order for certain of these rights and responsibilities to have practical significance (for example, self-provision), timely, sequential action by the Commission is necessary. In light of this, separate treatment of Community Choice Aggregators will provide a substantial degree of clarity and efficiency that cannot be achieved in a combined proceeding that addresses all LSEs together.

As compared to the IOUs, CCA programs do not stand in the same position, or even a similar position. As described above, the Commission has broad authority over the IOUs to approve IRPs and the specific resources that conform to those plans. But the Commission’s jurisdiction over CCA programs is much more limited and different in nature. A distinguishing feature between IOUs and CCA programs is the ability to self-provide IRP resources. Because of these differences, the Commission’s approach to IOUs is going to be very different than its approach to CCA programs. Much of the work that the Commission will do as part of this


\textsuperscript{21} See, e.g., Staff Concept Paper at 18; Table 2 (describing required IRP features by LSE).
proceeding will address IOU IRP plans and resources that simply do not apply to CCA programs. Likewise, much of the work that the Commission will do to develop rules and procedures around self-provision, for example, will not apply to IOUs.

Addressing the substantive issues around CCA programs and IOUs together, without a meaningful division, will increase the complexity of addressing any one subject matter, slow the process down, and also increase the risk that a general set of rules may be applied to all LSEs. A practical illustration may be helpful. If there is to be an opportunity for self-provision by Community Choice Aggregators, then this opportunity needs to be identified and presented to the Community Choice Aggregators early enough that the Community Choice Aggregators can then act on this opportunity prior to the Commission giving orders to the IOUs to procure to meet the same need. Contemporaneous procurement by Community Choice Aggregators and IOUs for the same need will result in over-procurement that could be avoided by letting Community Choice Aggregators procure to meet their portion of the need first and second directing the IOUs to procure for whatever the remaining need is.

III. RESPONSES TO STAFF CONCEPT PAPER QUESTIONS

The CCA Parties provide preliminary responses to the specific questions set forth in the Staff Concept Paper. The CCA Parties note the significant technical and policy issues implicated in the questions, and request that the responses below be viewed as preliminary, reserving an opportunity to supplement these responses as the CCA Parties have had further time to consider these issues and formulate more refined responses.

1. **Are any of the guiding principles inconsistent with any statutory, Commission, or other requirements? If so, please identify the principle, explain the inconsistency, and suggest how the inconsistency should be resolved.**
Without qualifications, guiding principles 1, 2, and 3 could be viewed as inconsistent with the IRP process for Community Choice Aggregators specified by the legislature in SB 350, as well as the principle of Community Choice Aggregator procurement independence codified at Section 366.2(a)(5). As noted above, because of the significant differences in regard to the IRP process for Community Choice Aggregators and other LSEs, in particular the IOUs, separate treatment of Community Choice Aggregators would allow the Commission to apply its guiding principles in a manner that would not need to be qualified with respect to Community Choice Aggregators.

Guiding principle 1 states: “the structure and design of the IRP process should prioritize minimizing customer costs while meeting the states’ other policy goals.” The Commission does not have jurisdiction over Community Choice Aggregator cost issues. The Commission does not review Community Choice Aggregator’s rates for reasonableness, and does not have the authority to direct Community Choice Aggregator procurement based on cost (or any other) considerations. Under Section 366.2(a)(5), Community Choice Aggregators are “solely responsible” for their own procurement, except where Commission jurisdiction has been “expressly authorized” by the legislature. Nothing in SB 350 or any other statute expressly grants the Commission jurisdiction over cost issues associated with Community Choice Aggregator procurement. Therefore, while guiding principle 1 is a worthy goal, it should be read with the recognition that the Commission is limited in its ability to fully effectuate this principle.

Applying guiding principle 2 to Community Choice Aggregators could be similarly inconsistent with SB 350 and Section 366.2(a)(5). Guiding principle 2 states: “the IRP process should be transparent and accessible to the extent possible for parties, members of the public,

\[22\] Staff Concept Paper at 10.
and customers of each LSE.” Although the CCA Parties agree that transparency and accessibility are important goals, they question the appropriateness of the Commission asserting a role in managing Community Choice Aggregators’ procurement to achieve such goals. Nothing in SB 350 or any other statute expressly grants the Commission jurisdiction or authority to regulate Community Choice Aggregators’ procurement transparency and accountability. In addition to exceeding the Commission’s jurisdiction and potentially violating Community Choice Aggregators’ operational and procurement independence, such regulation would be redundant and inefficient. Community Choice Aggregators already have robust mechanisms for ensuring transparency and accountability to their customers, because as public agencies, they are already subject to the Brown Act and Public Records Act requirements.

Applying guiding principle 3 to Community Choice Aggregators could also be inconsistent with SB 350 and Section 366.2(a)(5). Guiding principle 3 states: “the IRP process should provide clear and consistent market signals to facilitate sufficient, timely, and cost-effective technology and infrastructure investments.” To the extent this principle relates to defining system resource needs in order to facilitate self-provision by Community Choice Aggregators in lieu of CAM treatment, it would be consistent with SB 350. However, neither SB 350 nor any other legislation gives the Commission the authority to direct Community Choice Aggregator procurement based on the goal of sending market signals. Nor is such direction necessarily needed. As public entities accountable to their customers, Community Choice Aggregators are subject to a different set of incentives than for-profit LSEs. Commission-established “market signals” are not needed to facilitate sufficient, timely, cost-effective technology and infrastructure investments by Community Choice Aggregators.
Therefore, to the extent that guiding principle 3 is meant to apply to Community Choice Aggregators, it should be qualified to reflect these key points.

2. Are there any additional guiding principles that should be included? If so, describe the guiding principle and explain why it should be included.

Two additional guiding principles should be added to the Concept Paper. First, the Commission should adopt a guiding principle recognizing the principle of Community Choice Aggregator procurement independence established in Section 366.2(a)(5). This Section states:

A community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator’s customers, except where other generation procurement arrangements are expressly authorized by statute.

The following guiding principle should be included to recognize that Section 366.2(a)(5) is a statutory mandate that should be treated as the central guiding principle in determining the IRP requirements for Community Choice Aggregators:

All aspects of the IRP process should comply with Public Utilities Code Section 366.2(a)(5), by preserving Community Choice Aggregators’ operational and procurement independence except where Commission involvement has been specifically authorized by the legislature.

Second, while somewhat implicit in guiding principle 1, a guiding principle should be added that makes express the requirement the IOUs should pursue the most flexible procurement possible in order to more nimbly adapt to departing load due to CCA formation, distributed energy resources (“DERs”), and new technologies.

3. Are there any additional elements missing from the activities, outputs, and inputs described? If so, please explain which additional elements are necessary.

See response to Question 4.

4. Should any of the proposed required elements be eliminated or consolidated? If so, please explain why doing so will facilitate the development of an IRP process that is consistent with the guiding principles.
Many of the activities, outputs, and inputs identified in the Concept Paper are inconsistent with the Commission’s limited role in certifying Community Choice Aggregator IRPs as defined in SB 350. The Commission should adopt a separate set of activities, outputs, and inputs for Community Choice Aggregators (ideally in a separate track/phase) based on the specific IRP requirements for Community Choice Aggregators adopted by the legislature in SB 350.

SB 350 only provides the Commission with three limited grants of authority over Community Choice Aggregator IRPs:

- Community Choice Aggregators are required to submit proposals for satisfying their portion of the renewable integration need identified in the Commission’s portfolio. The Commission has the authority to approve or deny these proposals based on a specified set of statutory factors, and may require long-term contracts to meet this specific need in order to approve self-provision. (Section 454.51(d)).

- The Commission has the *procedural* authority to "adopt a process for each load serving entity... to file an integrated resource plan, and... periodic updates." (Section 454.52(a)(1)).

- Community Choice Aggregators are required to submit their IRPs to the Commission for “certification,” similar to the certification of a Community Choice Aggregator’s implementation plan. Authority to approve or deny a Community Choice Aggregator’s IRP and procurement is vested in the Community Choice Aggregator’s board, not the Commission. (Section 454.52(b)(3)).

These three provisions represent the full extent of the Commission’s authority over a Community Choice Aggregator’s IRP. Neither SB 350 nor any other legislation expressly grants the Commission the authority to:

- Adopt substantive requirements controlling how a Community Choice Aggregator develops its IRP, including requirements regarding inputs, assumptions, scenarios, and modeling methodologies.

- Approve, deny, or modify a Community Choice Aggregator’s procurement portfolio.
• Reach a determination regarding a Community Choice Aggregator’s short-term or long-term resource need (beyond a narrow Resource Adequacy finding and the Aggregator’s renewables integration requirement).

• Approve, deny, or require any amount, type, or source of procurement.

• Approve, deny, or require any procurement contract terms or duration.

Given the Commission’s limited authority over Community Choice Aggregator IRPs under SB 350, the following activities are not appropriate for Community Choice Aggregators:\textsuperscript{23}

• Activity 2 – Identify-CPUC preferred portfolio. Community Choice Aggregators have the independent authority to select their own portfolio (except for the Commission-determined renewables integration requirement). That said, the CCA Parties recognize and appreciate that there is certainly a significant amount of cooperative interaction that must occur. For example, the CPUC preferred portfolio has to account for procurement by Community Choice Aggregators and should facilitate self-provision by Community Choice Aggregators, but such cooperative interaction must not violate or compromise jurisdictional authority.

• Activity 3 – Develop Guidance. Neither SB 350 nor any other statute grants the Commission authority to impose on Community Choice Aggregators requirements for inputs, outputs, and processes for their IRPs and portfolios. That said, again, cooperative interaction would allow the Commission to provide guidance regarding system needs, for example, and allow Community Choice Aggregators to

\textsuperscript{23} The CCA Parties recognize that many of its comments below duplicate and reiterate the same point, namely, that the Commission lacks statutory authority to require certain action of Community Choice Aggregators. At the risk of being unduly redundant and perceived as unnecessarily dogmatic, the CCA Parties restate this point to ensure that additional care is given by the Commission to craft IRP requirements in a manner that respects legislatively defined lines and roles.
Aggregators to independently act on this guidance in self-providing to meet these needs.

- **Activities 4 through 7 – LSE Portfolios.** The Commission does not have the authority to assess, approve, or deny a Community Choice Aggregator’s portfolio, other than the share of the Community Choice Aggregator’s portfolio used to meet its renewables integration requirement.

- **Activity 8 – Develop IRPs.** Community Choice Aggregators should not be required to develop candidate portfolios, and the Commission does not have the authority to approve or deny any portfolio selected by a Community Choice Aggregator. That said, cooperative interaction would allow a Community Choice Aggregator’s IRP and procurement to inform and influence the IOUs’ residual needs.

- **Activity 9(a) – Determine IRP Compliance.** SB 350 does not give the Commission the general authority to set IRP requirements for Community Choice Aggregators or to determine whether a Community Choice Aggregator’s IRP complies with Commission-imposed requirements. The Commission’s authority to “certify” Community Choice Aggregator IRPs is limited to ensuring that the IRP self-supplies the Community Choice Aggregator’s renewables integration requirement, and that the IRP is consistent with Commission-jurisdictional requirements for Community Choice Aggregators (Resource Adequacy, etc.).

- **Activity 9(b) – Authorize Procurement.** The Commission does not have the authority to authorize, deny, or require Community Choice Aggregator
Procurement (except the Commission may require, but may not approve or deny procurement required to meet the renewables integration requirement).

For similar reasons, the following outputs should not apply to Community Choice Aggregators:

- **Output 1 – IRP Filing Guidance.** Under SB 350, Community Choice Aggregators are only subject to the Commission’s procedural filing rules, not its substantive rules regarding how the IRP is developed.

- **Output 2 – Integrated Resource Plans.** The Commission does not have the authority to approve, deny, or modify a Community Choice Aggregator’s portfolio, nor does it have the authority or approve, deny, or require procurement (other than procurement to meet the renewables integration requirement). As such, Community Choice Aggregators should not be required to submit candidate portfolios, LSE-recommended portfolios, an action plan, or a procurement authorization request. Rather, the Commission should accept the Community Choice Aggregator’s final, independently developed portfolio.

- **Output 4 – CPUC Preferred Portfolio.** The Commission does not have the authority to require that Community Choice Aggregators produce candidate portfolios, nor does it have the authority to select a preferred portfolio for Community Choice Aggregators. That said, as repeatedly stated above, the CCA Parties recognize and appreciate that cooperative interaction requires that the
Commission use information provided in the Community Choice Aggregators’ respective IRPs to inform and influence the CPUC Preferred Portfolio.\textsuperscript{24}

Nothing in SB 350 or any other legislation expressly authorizes the Commission to impose substantive requirements on Community Choice Aggregators regarding the inputs, modeling methodologies, scenarios, and assumptions used to develop their portfolios and IRPs. As such, none of the inputs identified in the Staff Concept Paper should be required for Community Choice Aggregators. Instead, Community Choice Aggregators should be allowed to develop their portfolios and IRPs independently, consistent with Section 366.2(a)(5) and the basic principle of Community Choice Aggregator procurement independence.

5. Which Option do parties prefer: A, B, or C? If not Option C, please provide your rationale and include consideration of any potential drawbacks or adverse impacts.

For Community Choice Aggregators, Option A is the only option that is consistent with the Commission’s limited authority under SB 350 and the principle of Community Choice Aggregator procurement independence codified at Section 366.2(a)(5). Under Option A, Community Choice Aggregators would independently develop their own portfolios. Community Choice Aggregators would then provide these portfolios to the Commission using a standard format developed collaboratively by the Community Choice Aggregators and the Commission. The Commission would then use its own resources and tools to develop a multi-LSE portfolio.

Neither Option B nor Option C is appropriate for Community Choice Aggregators. Under Option B, the Commission would develop a statewide portfolio, and require that each LSE, including Community Choice Aggregators, procure a share of the portfolio. Under Option

\textsuperscript{24} As mentioned above, the ability to meaningfully inform and influence the CPUC Preferred Portfolio depends, in part, on conducting the Community Choice Aggregators’ separate IRP track in manner that precedes or progresses faster than the IOU’s IRP track.
C, the Commission would adopt a multi-LSE optimal portfolio, as well as a set of assumptions, scenarios, and modeling rules for LSEs. LSEs would then use the Commission’s multi-LSE optimal portfolio and other guidance to develop several candidate portfolios and identify one preferred portfolio. The Commission would then review these portfolios, approve or deny them, and approve or deny procurement based on the portfolios.

Both Option B and Option C significantly exceed the authority over Community Choice Aggregator IRPs expressly granted to the Commission in SB 350, and are inconsistent with Section 454.52(b)(3) and Section 366.2(a)(5). Nowhere in SB 350 or any other statute has the legislature expressly granted the Commission authority to determine how a Community Choice Aggregator develops its portfolio. Nor does SB 350 grant the Commission the authority to approve, deny, or modify a Community Choice Aggregator’s portfolio, or to approve, deny, or require procurement based on a Community Choice Aggregator’s portfolio (other than requiring procurement to meet the renewables integration requirement).

Under Option A, CCA parties would still have a strong incentive to work closely and collaboratively with the Commission to coordinate their independently selected portfolios with the Commission’s broader IRP process. Such coordination and collaboration would mitigate or eliminate the risk of inefficiency and higher system costs.

6. **What electricity market, regulatory, and/or operational implementation issues may emerge under Option C? Please identify potential solutions to the implementation issues identified.**

See response to question 5. Applying the Option B or Option C approach to Community Choice Aggregator IRPs would exceed the Commission’s jurisdiction under SB 350, violate Section 366.2(a)(5), and unreasonably impede Community Choice Aggregator’s sole authority to approve or deny their own IRPs as set forth in Section 454.52(b)(3).
7. Are there any alternative approaches to the division of labor that offer advantages over the proposed approach (Option C)? Please be as specific as possible about any alternative approaches and what advantages they have over the proposed approach.

Although Option C is inappropriate for Community Choice Aggregators, the CCA Parties recognize that the Commission may wish to pursue Option C for other LSEs. Taking an “Option A” approach for Community Choice Aggregators is not necessarily inconsistent with the preferred “Option C” approach for other LSEs. Under a combined Option A / Option C approach, Community Choice Aggregators would independently develop their portfolios early in the IRP process. These portfolios would be provided to the Commission at the same time the other LSEs provide their input data. The Commission would then process the Community Choice Aggregator portfolios under Option A, while using the Community Choice Aggregator portfolios along with the input data from other LSEs to generate the overall Option C portfolio for other LSEs.

8. Are there any potential drawbacks with the basic procedural steps and filing frequency outlined in Table 3? If so, please suggest an alternative approach and provide your rationale for why it is optimal.

The following procedural steps outlined in Table 3 are inappropriate for Community Choice Aggregators:

- **Step 2 – CPUC Generates Multi-LSE Portfolio.** Community Choice Aggregators should be allowed to independently generate their own portfolios under Option A.

- **Step 3 – CPUC Issues Guidance for LSEs.** Neither SB 350 nor any other statute give the Commission the authority to adopt requirements for how Community Choice Aggregators develop their IRPs. Community Choice Aggregators have sole authority to determine their own assumptions, scenarios, inputs, and methodologies.
• **Step 5 – CPUC Reviews IRPs.** Section 366.2(a)(5) and Section 454.52(b)(3) give a Community Choice Aggregator’s board the sole authority to approve or reject a Community Choice Aggregator’s procurement, as reflected in its IRP. The Commission’s authority is limited to “certifying” that the IRP is consistent with the limited Commission-jurisdictional requirements for Community Choice Aggregators (self-supply of renewables integration, Resource Adequacy, etc.).

• **Step 6 – CPUC Approves Procurement.** The Commission does not have the authority to approve, deny, or require procurement based on a Community Choice Aggregator’s IRP (except, the Commission may require, but does not have the authority to approve or deny, procurement to meet the renewables integration requirement).

The CCA Parties recommend that the Commission adopt the following alternative process for handling Community Choice Aggregator IRPs:

• **Step 1 – Community Choice Aggregators Independently Develop Portfolios.** Community Choice Aggregators independently develop their own portfolios, using the inputs, scenarios, assumptions, and modeling techniques independently selected by the Community Choice Aggregator. The CCA Parties anticipate close coordination and collaboration between the Commission and Community Choice Aggregators in portfolio development.25

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25 Chief among this cooperative interaction will be the identification of so-called system needs by the Commission and the communication of these needs to Community Choice Aggregators so that they may effectively self-provide to meet these needs. (By “system needs,” the CCA Parties are referring to reliability and renewable integration resources.)
• **Step 2 – Portfolios Submitted to the Commission.** Community Choice Aggregators submit their draft or prospective “Option A” portfolios to the Commission through an informal submission to the Energy Division at the same time as other LSEs. If the Commission pursues “Option C” for other LSEs, the Commission would use the Community Choice Aggregators’ portfolios along with the input data from other LSEs to generate the multi-LSE portfolio and identify the renewables integration requirement.

• **Step 3 – Approval and Procurement.** Consistent with Section 454.52(b)(3), each Community Choice Aggregator’s board would be responsible for approving its IRP, and for all aspects of procurement based on its IRP and procurement policies.

• **Step 4 – Commission Certification.** Pursuant to Section 454.52(b)(3), Community Choice Aggregators would submit their IRPs to the Commission for “certification” through a Tier-1 advice letter. The Commission’s certification review would be limited to ensuring that the IRP includes adequate self-supply of resources to meet the renewables integration requirement, and that the IRP is consistent with the limited set of Commission-jurisdictional requirements for Community Choice Aggregators.

• **Step 5 – Commission Consideration of Residual Needs.** The Commission would consider the details of the Community Choice Aggregators’ IRPs when developing the multi-LSE portfolio, directing the IOUs to procure to address residual needs.

The CCA Parties believe that this recommended process offers the best of all worlds.
The recommended process strictly follows the requirements and division of authority set forth in SB 350, respects both Community Choice Aggregator procurement independence and the Commission’s renewables integration and certification authority, significantly reduces the Commission’s workload, provides the Commission with sufficient information to develop the multi-LSE portfolio, and provides ample opportunities for coordination and collaboration between the Commission and Community Choice Aggregators.

9. **Please provide recommendations for the IRP filing frequency, contract period, and process for submitting updates or modifications in the IRP-LTPP 2016-2017 proceeding. Where appropriate, distinguish between any near-term recommendations (i.e., for IRP 2017) and longer-term recommendations (i.e., for cycles beyond IRP 2017).**

The process described in Table C-1 is not consistent with the statutory IRP requirements for Community Choice Aggregators set forth in SB 350. As discussed in the CCA Parties’ response to Question 4, the Commission’s authority over Community Choice Aggregator IRPs is limited to ensuring that Community Choice Aggregators self-supply the renewables integration requirement, and “certifying” that the Community Choice Aggregators’ IRPs are consistent with Commission-jurisdictional requirements. Neither SB 350 nor any other legislation expressly authorizes the Commission to assess or determine a Community Choice Aggregator’s long-term or short-term procurement needs, nor has the legislature authorized the Commission to approve, deny, or require Community Choice Aggregator procurement based on its IRP (except for procurement to meet the renewables integration requirement).

The CCA Parties provide the following specific recommendations in response to Question 9. All recommendations apply to both IRP 2017 and additional future IRP proceedings.

- **Filing Frequency.** The CCA parties believe that an appropriate filing frequency for IRPs is once every two to three years. Given the likely complexity of the IRP
process, parties may benefit from the additional time provided by a three-year frequency as opposed to biennial filings. That said, the CCA Parties acknowledge the rationale for aligning IRP filings with load and resource data submittals under the California Energy Commission’s Integrated Energy Policy Report (“IEPR”) process, which generally relies on a two-year cycle.

- **Contract Period.** The Commission does not have the authority to specify the terms, conditions, or duration of Community Choice Aggregator procurement contracts, except in situations in which the Community Choice Aggregator elects to self-provide to meet system needs, and even then the Commission’s authority is general in nature vis-à-vis the Commission’s specific authority with respect to IOU procurement.

- **Updates/Modifications to Community Choice Aggregator IRPs.** SB 350 gives a Community Choice Aggregator’s board sole authority to approve the Community Choice Aggregator’s IRP. As such, each Community Choice Aggregator’s board is responsible for reviewing any updates or modifications to its IRP. When an update or modification to a Community Choice Aggregator’s IRP is submitted to its board for approval, the update should be submitted to the Energy Division through either an informal communication or a Tier 1 advice letter.

- **Updates to Load Forecast.** The CCA Parties recommend an annual update for Community Choice Aggregator load forecasting purposes. The Energy Division staff should have adaptive regulatory oversight over this process so that technical fixes do not need to be voted on by the Commission.

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Table C-1 erroneously states that Community Choice Aggregators were subject to Commission regulation in the 2014-2015 Long-Term Procurement Plan (“LTPP”) proceeding (R.13-12-010). The LTPP requirement does not apply to Community Choice Aggregators. Community Choice Aggregators are not subject to Commission LTPP jurisdiction, and have never been required to participate in the Commission’s LTPP proceedings. As such, Community Choice Aggregators should continue to be exempted from all Section 454.5 administrative requirements and activities incorporated into the IRP process, including the “long term reliability needs assessment” identified in Table C-1.27

11. Are there any categories or types of guidance for filing entities that are not addressed above, but should be? If so, explain why and include a reference to the relevant guiding principles for IRP process development.

No response.

12. Are any of the categories of guidance listed above inappropriate or problematic in light of the guiding principles for IRP process development?

All of the categories of guidance referenced in Question 1228 would be inappropriate and problematic if imposed on Community Choice Aggregators on a mandatory basis. As stated in the CCA Parties’ response to Question 4, nothing in SB 350 or any other statute expressly grants the Commission the authority to determine how Community Choice Aggregators develop their IRPs. Moving forward, the Commission should recognize that Community Choice Aggregators have sole, independent authority to determine the inputs, data standards, assumptions, scenarios, needs assessment.” identified in Table C-1.27

27 Staff Concept Paper, Appendix C, Table C-1, at 45-46
28 Question 12 references four categories of guidance discussed at pp. 23-24 of the Staff Concept Paper.
policies, and modeling standards used in their IRPs. Of course, the CCA Parties recognize the
efficiency and reduced workload to be gained through working closely and collaboratively with
the Commission on these technical issues, and the CCA Parties anticipate a high degree of
coordination and collaboration with the Commission in this regard. However, both the
Commission and Community Choice Aggregators are best served by coordination and
collaboration that respects CCA procurement independence and does not exceed the limited
authority over Community Choice Aggregator IRPs provided by SB 350.

13. What filing process would be appropriate for IRPs (e.g., advice letter,
application)? Please refer to the procedural steps in Table 3 in your response.
Please include as much detail as possible, including whether the process
should be confidential or public, posted to a website or served on a
proceeding, etc.

Community Choice Aggregators should be required to submit a draft or initial version of
their independently developed “Option A” portfolios to the Commission through an informal
submission to the Energy Division. This submission should take place as part of the
Commission’s “input data” activity. 29

Community Choice Aggregators and should be allowed to submit their IRPs to the
Commission for “certification” through a Tier 1 Advice Letter. Given the narrow scope of the
Commission’s “certification” authority, and the fact that the Commission will not be approving,
denying, or authorizing procurement based on a Community Choice Aggregator’s IRP, a Tier 1
advice letter provides adequate process and fully satisfies SB 350.

14. What consequences/incentives would be appropriate for submitting
noncompliant/compliant IRPs? What criteria should be used?

The Commission does not have the authority to adopt consequences or incentives for

29  Staff Concept Paper at 12.
noncompliant/compliant Community Choice Aggregator IRPs. The point being made here by the CCA Parties is that it is the Community Choice Aggregator’s board, not the Commission, that has responsibility to ensure that the Community Choice Aggregator complies with the approved IRP. That said, the CCA Parties acknowledge and appreciate that there are real and effective consequences associated with a failure by a Community Choice Aggregator to take certain actions. For example, a failure to self-provide will result in CCA customers bearing a share of the IOU’s costs in providing to meet the unmet system need.

15. Are there any other options for the type of action, outcomes of action, or criteria for portfolio adoption that the Commission could take consistent with Pub. Util. Code § 454.51 that should be considered?

Disregarded. 30

16. Do you agree with the proposed type of action and possible outcomes of action? Why or why not?

Disregarded. 31

17. Should the Commission have standardized, public criteria for choosing which portfolio to adopt, or should it have the flexibility to apply whatever criteria are deemed appropriate at the time the decision is made? Why or why not?

It is not appropriate for the Commission to adopt any criteria for selecting Community Choice Aggregator portfolios. For the reasons cited in the CCA Parties response to Question 4, SB 350 does not expressly grant the Commission the authority to approve or deny a Community Choice Aggregator’s portfolio. Under Sections 366.2(a)(5) and 454.52(b)(3), each Community Choice Aggregator’s board has the sole authority to adopt portfolio selection criteria. The CCA

30 As instructed in the August 25, 2016 e-mail from Energy Division staff, the CCA Parties are disregarding this question.

31 As instructed in the August 25, 2016 e-mail from Energy Division staff, the CCA Parties are disregarding this question.
Parties do not take a position on the Commission’s criteria for selecting the portfolios submitted by other LSEs.

18. Are there any other options for how the IRP process should address procurement authorization?

Community Choice Aggregators should be exempted from all elements of the Commission’s IRP process that relate to procurement authorization. As stated in the CCA Parties’ response to Question 4, the Commission has not been expressly granted the authority to authorize, deny, or require Community Choice Aggregator. Absent an express grant of authority to the Commission, Section 366.2(a)(5) guarantees each Community Choice Aggregator sole responsibility for its own procurement.

19. Do you agree with the proposed phased approach to procurement authorization in the IRP process? Why or why not?

See response to Question 18. The CCA Parties do not take a position on the IRP procurement authorization process for other LSEs.

20. Are there any other options for how the IRP process should address deviations between actual procurement and approved IRPs? What is the preferred approach to handling these deviations? Please explain your answer.

See response to Question 18. The CCA Parties do not take a position on the IRP procurement authorization process for other LSEs.

21. Should the quantity or assumed cost of a particular resource type included in the CPUC-preferred portfolio define the amount of that resource that is cost-effective to procure? If so, should it be used to limit procurement below pre-established targets (such as 50% RPS) pursuant to statutory language that requires the CPUC to maintain low rates and avoid disproportionate rate impacts? Alternatively, should the IRP process have authority to raise procurement targets but not to lower them? Why or why not?

See response to Question 18. The CCA Parties do not take a position on the IRP procurement authorization process for other LSEs.
22. What changes are needed to existing internal and external process alignment activities to be responsive to the new statutory responsibilities required for the IRP process? Please be specific with any proposed change. Parties are encouraged to work coordinate on this question in particular.

Community Choice Aggregator procurement information should feed into the Commission IRP process early so that (i) any information that the Commission shares with the other agencies for planning purposes can reflect the planned procurement activities of the Community Choice Aggregators, (ii) so that any “needs” determinations made by the Commission (or other state agencies) can factor in the planned procurement activities of the Community Choice Aggregators to assess both how already planned Community Choice Aggregator procurement may be impacting these needs, and how additional incremental procurement by Community Choice Aggregators may satisfy their proportionate share of these procurement needs, and (iii) so that any specific procurement or policy matters that are being considered in other proceedings before the Commission can be informed by the planned procurement activities of the Community Choice Aggregators.32

The CCA Parties also support process alignment among the CCA parties. The CCA Parties will coordinate to develop factors that they submit to the Commission in a standard format that adheres to the minimal requirements set forth in SB 350.

23. How should LSE-specific GHG planning targets be used in CPUC’s IRP process? What is an appropriate methodology for calculating LSE-specific GHG planning targets?

In the case of Community Choice Aggregators, the greenhouse gas (“GHG”) targets determined by their respective governing boards should be used in lieu of compliance targets developed for IOUs. This information, ideally presented in a lbs. CO2e/MWh metric, will help

32 In general, please see the five-step process described in response to Question 8.
inform the Commission on statewide progress towards specific environmental goals.

Presently it is left to the jurisdiction of each Community Choice Aggregator’s governing board to determine what each respective Community Choice Aggregator’s GHG planning target will be. As such, the Commission does not have authority to assign GHG planning targets onto Community Choice Aggregators. Instead, the Commission should use the information provided within each Community Choice Aggregator’s IRP to inform how each Community Choice Aggregator’s procurement will impact the overall GHG emissions attributable to all ratepayers within the CPUC-jurisdictional distribution utilities’ service territories. The aggregated Community Choice Aggregator GHG planning targets should be used to inform the baseline for GHG emissions from which the CPUC can direct the IOUs to alter their bundled portfolio procurement to reduce GHG emissions further.

24. [Blank]

25. What types of future uncertainties should be included among the candidate portfolios generated in IRP 2017? Please provide a prioritized list of uncertainties that should be represented, along with an explanation for the priority level assigned to each uncertainty. Please indicate which uncertainties may be appropriate to represent together and which should be represented separately, and why. For example, it may be reasonable to represent the impact of multiple GHG-reduction activities that all increase electric sector load together to create a single “high load” future in order to represent the maximum load stress on the electric system.

See Response to Question 26.

26. What metrics should be used to track the results for each policy or program area? How should the metric be calculated?

Questions 25 and 26 both relate to Commission-imposed scenarios to be modeled by the parties in developing their IRPs. Neither question is appropriate for Community Choice Aggregators, as the Commission does not have the authority to direct how Community Choice Aggregators develop their IRPs. Neither SB 350 nor any other legislation expressly grants the
Commission such authority. As the Staff Concept Paper correctly states, Commission-imposed “Assumptions and Scenarios” are a historical element of the LTPP Process. The LTPP statute, and the Commission’s LTPP authority (including the authority to impose modeling rules and scenarios) does not apply to Community Choice Aggregators. Moving forward, it would be beneficial for the Commission to identify those elements of the IRP process that are enactments of the LTPP statute (not SB 350) and clearly state that those elements do not apply to Community Choice Aggregator IRPs.

27. Is the overall assignment of modeling types to IRP activities in Table 6 reasonable? Are there types of models that may be useful for IRP that are not represented?

Questions 27 through 30 address Table 6, which provides suggested modeling types for each IRP activity. As a general response to these questions, CCA Parties reiterate that neither SB 350 nor any other statute expressly grants the Commission jurisdiction or authority to require that Community Choice Aggregators conduct any modeling to develop their IRPs, nor does the Commission have the authority to adopt requirements for any modeling that Community Choice Aggregators choose to conduct.

The CCA Parties are indifferent to what particular modeling types the Commission utilizes within the broader, multi-LSE IRP process, as long as Community Choice Aggregator planned procurement, as presented within their IRPs, is treated as inputs and fixed constraints for any modeling efforts that the Commission wishes to conduct. After factoring in collectively planned procurement by Community Choice Aggregators, if the Commission determines there are additional procurement “needs” that extend beyond the bundled rate-base, then the Commission should evaluate how each Community Choice Aggregator’s already planned procurement may be satisfying those needs, and how any incremental procurement by each Community Choice Aggregator may satisfy the specific Community Choice Aggregator’s
proportionate share of this procurement need. If a Community Choice Aggregator satisfies its proportionate share of these systemic procurement needs (both through planned procurement as demonstrated in its IRP and additional incremental procurement specifically to “self-provide” towards a Commission-identified need), then that Community Choice Aggregator should be exempt from having to receive a share of costs and benefits due IOU procurement entered into to meet that same type of need.

28. What options are available for completing the multi-LSE optimization modeling and generating an optimal portfolio by April 2017, in keeping with the proceeding schedule?

See response to Question 27.

29. What type and amount of modeling is realistic for LSEs to conduct in time to file by fall of 2017, assuming final guidance from CPUC is issued in April 2017?

As stated in the CCA Parties’ response to Question 27, the Commission does not have the authority to require that Community Choice Aggregators conduct any modeling to develop their portfolios and IRPs, nor does the Commission have the authority to adopt requirements for any modeling that Community Choice Aggregators choose to conduct.

Regarding the Commission’s broader, Multi-LSE modeling, small LSEs have very limited resources compared with the IOUs. It is unlikely they would be able to contribute significant value to modeling knowledge, nor do their relatively small territories make up a significant source of demand/supply on a singular basis. The CCA parties are pleased to see that the Staff Concept Paper recognizes the viability of hand-building portfolios to inform planning, and believe that the portfolios provided by Community Choice Aggregators should be treated as inputs in the Multi-LSE IRP process.

30. How does answer to the above question vary depending on the scope of the load included in each portfolio (e.g., individual LSE vs. aggregate CAISO load)?
31. Do you agree with how the electricity market and regulatory issues are characterized? If not, explain why, and suggest new or modified language to describe the issue.

See response to Question 29.

32. Are there any significant electricity market and regulatory issues that could impact IRP implementation that should be added to this table? Similarly, should any of the identified issues be removed from consideration?

There are four issues that should be added to Table 7 of the Staff Concept Paper and addressed in the IRP proceeding. First, the limited scope of the Commission’s jurisdiction over Community Choice Aggregator procurement and the Commission’s narrow role in SB 350’s distinct IRP process for Community Choice Aggregators is an essential regulatory issue that should be added to Table 7 of the Concept Paper.

Second, the Commission’s mandate to maximize the ability of Community Choice Aggregators to procure on behalf of their own customers should be included in Table 7. The wording of items b and c of Table 7 both presume that these types of procurement (i.e., long-lead-time, exceptionally large resources and CAM resources) are going to be necessary. The CCA parties believe that, through improved cooperative interaction between CCA and non-CCA procurement, these types of procurement can be either altogether avoided or proportionally reduced by empowering Community Choice Aggregators to focus their procurement efforts on both local-level and system-level needs.

Third, one-time, exceptional procurement needs due to the unexpected retirement of significantly large assets (such as the San Onofre Nuclear Generating Station) or the planned retirement of similar large assets (such as the Diablo Canyon Power Plant’s (“Diablo”) planned closure due to once-through cooling requirements) should be considered within the IRP proceeding.
Fourth, and related to issue three, above, the impact of IOU procurement outside the IRP process should be included as a Table 7 issue. PG&E’s recent application with respect to proposed procurement following the closure of Diablo (A.16-08-006) is a poignant example. In its application, PG&E proposes to procure unprecedented amounts of energy efficiency (“EE”) and GHG-free resources outside of the IRP and outside of EE and RPS rulemaking proceedings. These resources would generate over 4,500 GWh of energy in 2030, enough, by PG&E’s projections, to provide between 67-99% of the GHG-free energy projected to be needed to replace the energy supplied by Diablo. If PG&E (and other IOUs filing similar applications) are permitted to make “unprecedented” procurement outside of the IRP process, to the tune of billions of dollars, any benefit from an IRP will be drastically reduced, and the IRP would only apply to the small amount of left-over need.

33. For each of the identified issues: a. Indicate the priority on a scale of 1 to 3, with 1 being the highest priority. b. Identify critical path items and associated dependencies that need to be addressed.

No response.

34. Identify the top six issues in the final list.

No response.
IV. CONCLUSION

The CCA Parties thank the Energy Division for its consideration of these informal comments.

Dated: August 31, 2016

Respectfully submitted,

/s/ Scott Blaising
Scott Blaising
David Peffer
Dan Griffiths
Ty Tosdal, of Counsel
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, CA 95814
Telephone: (916) 712-3961
E-mail: blaising@braunlegal.com
Counsel for the City of Lancaster

/s/ Shalini Swaroop
Shalini Swaroop
Regulatory Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Drive
San Rafael, CA 94901
Telephone: (415) 464-6040
E-Mail: sswaroop@mceCleanEnergy.org
Counsel for Marin Clean Energy

/s/ Steven S. Shupe
Steven S. Shupe
General Counsel
SONOMA CLEAN POWER AUTHORITY
50 Santa Rosa Avenue, Fifth Floor
Santa Rosa, California 95402
Telephone: (707) 890-8485
E-Mail: sshupe@sonomacleanpower.org
Counsel for Sonoma Clean Power Authority
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an
Electricity Integrated Resource Planning Framework
and to Coordinate and Refine Long-Term Procurement
Planning Requirements

Rulemaking 16-02-007
(Filed February 11, 2016)

MOTION OF THE CITY OF LANCASTER, MARIN CLEAN ENERGY
AND SONOMA CLEAN POWER AUTHORITY FOR OFFICIAL NOTICE

Ty Tsdale, of Counsel
Scott Blaising
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, CA 95814
Telephone: (858) 704-4711
E-mail: ty@tosdallaw.com

Counsel for the City of Lancaster, Marin Clean Energy
and Sonoma Clean Power Authority

October 7, 2016
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements
Rulemaking 16-02-007 (Filed February 11, 2016)

MOTION OF THE CITY OF LANCASTER, MARIN CLEAN ENERGY AND SONOMA CLEAN POWER AUTHORITY FOR OFFICIAL NOTICE

I. INTRODUCTION

Pursuant to Rule 13.9 of the Rules of Practice and Procedure of the Public Utilities Commission of the State of California ("Commission"), City of Lancaster ("Lancaster"), Marin Clean Energy ("MCE"), and Sonoma Clean Power Authority ("SCPA"), which manage and operate Community Choice Aggregation ("CCA") programs in their respective jurisdictions (collectively "CCA Parties"), request that the Commission take official notice of future load growth among operational CCA programs, and the growing number of communities formally exploring and planning CCA programs, including communities that are planning to launch or join CCA programs in the 2017-2018 timeframe, identified below.

The CCA Parties support a regulatory process that reflects and accommodates the significant growth expected in CCA program service and resource procurement. As mentioned by CCA representatives during the recent IRP workshop, held on September 26, 2016, additional engagement and cooperation with CCA program representatives is warranted and appropriate in light of expected CCA program growth and the significance of this growth on IRP-related issues. As such, the IRP analytical framework should more clearly describe this greater degree of
cooperation.¹ The information contained in this motion will be useful for the Commission’s Energy Division as it devises a regulatory and analytical framework for Integrated Resource Planning (“IRP”) in this proceeding.

II. BACKGROUND

When Senate Bill (“SB”) 350 was passed in 2015, instructing the Commission to initiate the IRP Proceeding, there were three operational CCA programs in California: MCE, SCPA and Lancaster. With the addition of Clean Power SF and Peninsula Clean Energy, which launched this year, there are presently five operational programs. Additional programs are expected to launch in 2017, including Silicon Valley Energy Authority, Redwood Coast Community Energy, Los Angeles County, Apple Valley Choice Energy and the City of Hermosa Beach. Another round of programs is expected to launch in 2018. Several communities have also elected to join existing CCA programs rather than create separate programs.² Needless to say, CCA programs are becoming increasingly popular and are being adopted in a growing number of communities. Unsurprisingly, CCA program load has grown alongside the number of programs, and will continue to grow as new programs emerge. Table 1.1 below shows load forecasts among existing CCA programs and those that plan to form in the 2017-2018 timeframe.

¹ The CCA Parties received a copy of the request from Energy Division staff, dated September 30, 2016, for informal written comments in response to specified questions on the Energy Division’s proposed analytical framework for the IRP. The CCA Parties intend to provide informal written comments, and the CCA Parties look forward to further engaging in cooperative interaction with the Energy Division. This motion is not intended to displace informal written comments or further interaction, but rather the motion is being used to introduce factual information into the record for consideration by the Commission.

² For example, the Mendocino County Board of Supervisors voted to join Sonoma Clean Power earlier this year. See http://www.pressdemocrat.com/news/5929824-181/mendocino-county-formalizes-intent-to. Similarly, Lafayette, Walnut Creek, Napa, American Canyon, St. Helena, Calistoga and Yountville elected to join Marin Clean Energy. See http://www.eastbaytimes.com/2016/04/25/7-bay-area-municipalities-join-marin-clean-energy-raising-prospect-of-lower-rates/.
The CCA Parties are providing information about emerging CCA programs and future load growth at this time primarily for the benefit of the Energy Division, which has the difficult task of engineering a regulatory and analytical framework and planning a logical sequence of events that will culminate in achieving the goals of SB 350. To that end, the Energy Division has issued a concept paper, held a workshop, and has also issued a list of questions on the analytical framework for the proceeding. So far, the CCA Parties have responded to each opportunity to provide input on the process, and plan to remain actively involved in this proceeding. Nevertheless, it is important that the information provided as part of this motion be adopted as part of the record in this proceeding, and so the CCA Parties opted to file this motion.

III. MOTION FOR OFFICIAL NOTICE

Rule 13.9 establishes Evidence Code section 450 et seq. as the standard for official notice. Evidence Code section 450 et seq. includes the standard for judicial notice and provides that such notice is warranted for certain government documents, including “[r]egulations and legislative enactments issued by or under the authority of the United States or any public entity in the United States.” The statute also permits judicial notice of “[f]acts and propositions that are not reasonably subject to dispute and are capable of immediate and accurate determination by resort to sources of reasonably indisputable accuracy.” Facts subject to official notice include

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5 R.16-02-007: Requesting Comments on Analytical Framework for IRP Presented at 9/26 Workshop, Email Message from Energy Division, September 30, 2016.
6 Evid. Code § 452.
7 Evid. Code, § 452.
the contents of City Council resolutions and similar documents that memorialize official actions of local government.⁸

As further explained below, the standard for official notice applies to the fact that several operational CCA programs have forecast future load growth, as well as to the fact that a growing number of communities have passed resolutions or taken other official action to formally explore and plan CCA programs. Links to documents that support these facts are attached to this motion as Attachment A – Reference Documents. The contents of local government resolutions authorizing exploration of CCA programs or the programs themselves are legislative enactments by a public entity and are subject to official notice. Additionally, implementation plans and load forecasts contain facts related to CCA program formation and anticipated load growth that are not reasonably subject to dispute and capable of accurate determination by reference to the underlying documents.

The CCA Parties ask that the Commission take official notice of the facts contained in Table 1.1, which shows the launch date and expected load forecast of CCA programs that have either formed already or are anticipated to launch within the 2017-2018 timeframe and have prepared official forecasts.

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⁸ See, e.g., Shapiro v. Board of Directors of Centre City Development Corp. ((2005) 134 Cal.App.4th 170, 174).
### Table 1.1: CCA Program Load Forecast 2017-2018 (GWH)

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<td>220</td>
<td>282</td>
</tr>
<tr>
<td>Redwood Coast Energy Authority¹¹</td>
<td>544</td>
<td>839</td>
</tr>
<tr>
<td>City of Hermosa Beach¹²</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>11,516</strong></td>
<td><strong>14,625</strong></td>
</tr>
</tbody>
</table>

Source: See Attachment A – Reference Documents

---

¹⁰ Load growth identified in Table 1.1 is *not* an exhaustive list of CCA programs that may be serving load in the next two years. It is limited to programs that have prepared official load forecasts. The CCA Parties will seek to introduce additional and updated load forecasts as information becomes available. Moreover, while the CCA Parties recognize that this is just a snapshot of current activity, reflecting a dynamic, iterative process, the CCA Parties nonetheless believe this information is relevant and instructive.

¹¹ Data does not reflect load associated with Mendocino County, which is exploring joining Sonoma Clean Power Authority and is listed in the following section as a likely new CCA program or program slated for expansion. *See Attachment A – Reference Documents.* The CCA Parties understand that load associated with Mendocino County will be approximately 430 GWh.

¹² Data is from Redwood Coast Energy Authority Draft Community Choice Aggregation Implementation Plan and Statement of Intent, September 2016. *See Attachment A – Reference Documents.*

¹² The City of Hermosa Beach has prepared and approved an implementation plan and plans to serve customers next year, but it did not include load forecasts in its plan. *See Attachment A – Reference Documents.* The CCA Parties understand that load associated with Hermosa Beach’s CCA program will be approximately 80 GWh.
In addition, the CCA Parties also ask that the Commission take official notice of the cities and counties listed below. These communities have passed resolutions or taken other formal action to explore CCA programs, or taken affirmative, formal steps to launch a CCA program within the 2017-2018 timeframe: 13

- Alameda County
- Butte County
- City of Pico Rivera
- City of San Diego
- City of San Jose
- City of Solana Beach
- Contra Costa County
- Los Angeles County
- Mendocino County
- Monterey County
- Placer County
- Riverside County
- San Benito County
- San Bernardino County
- San Diego County
- San Luis Obispo County
- Santa Barbara County
- Santa Cruz County
- Ventura County

Links to documents supporting the facts listed in Table 1.1 and the list of communities above can be found in Attachment A – Reference Documents.

Because the facts described above meet the standard of the Evidence Code, and by extension Rule 13.9, the Commission should take official notice of the fact operational CCA programs have forecast future load growth and the fact that a growing number of communities have passed resolutions or taken other official action to formally explore and plan CCA

13 See Attachment A – Reference Documents. This is not an exhaustive list of communities exploring or planning CCA programs. The CCA Parties reserve the right to introduce additional information about communities exploring or planning CCA programs as information becomes available.
programs.

IV. CONCLUSION

For all the reasons stated, the motion of the CCA Parties for official notice of the documents described above should be granted.

Dated: October 7, 2016

Respectfully submitted,

/S/ Ty Tosdal

Ty Tosdal, of Counsel
Scott Blaising
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.
915 L Street, Suite 1480
Sacramento, CA 95814
Telephone: (858) 704-4711
E-mail: ty@tosdallaw.com

Counsel for the City of Lancaster, Marin Clean Energy and Sonoma Clean Power Authority
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for
Adoption of Electric Revenue Requirements and Rates
Associated with its 2015 Energy Resource Recovery
Account (ERRA) and 2015 Generation Non-
Bypassable Charges Forecasts (U 39 E).

A.14-05-024
(Filed May 30, 2014)

CERTIFICATE OF SERVICE

I hereby certify that I have this day filed and served a copy of the foregoing REPLY OF
THE CITY OF LANCASTER, MARIN CLEAN ENERGY AND SONOMA CLEAN
POWER to all parties of record in A.14-05-024 by serving an electronic copy on their email
addresses of record, and for those parties without an email address of record, by mailing a properly
addressed copy by first-class mail with postage prepaid to each party on the Commission’s official
service list for each proceeding.

This Certificate of Service is executed on August 22, 2016, in San Rafael, California.

/s/Catalina Murphy
CATALINA MURPHY
CALIFORNIA PUBLIC UTILITIES COMMISSION

Service Lists

PROCEEDING: A1405024 - PG&E - FOR ADOPTION
FILER: PACIFIC GAS AND ELECTRIC COMPANY
LIST NAME: LIST
LAST CHANGED: AUGUST 4, 2016

Parties

HOWARD CHoy
GENERAL MGR.
COUNTY OF LOS ANGELES
EMAIL ONLY
EMAIL ONLY, CA 00000
FOR: COUNTY OF LOS ANGELES, OFFICE OF SUSTAINABILITY

KATHERINE RAMSEY
LEGAL FELLOW
CLEAN COALITION
EMAIL ONLY
EMAIL ONLY, CA 00000
FOR: CLEAN COALITION

KATY MORSONY
ALCANTAR & KAHL
EMAIL ONLY
EMAIL ONLY, CA 00000
FOR: ENERGY PRODUCERS & USERS COALITION MARKETS

DANIEL W. DOUGLASS
ATTORNEY
DOUGLASS & LIDDELL
4766 PARK GRANADA, SUITE 209
CALABASAS, CA 91302
FOR: ALLIANCE FOR RETAIL ENERGY (AREM)/DIRECT ACCESS CUSTOMER (DACC)

RUSSELL A. ARCHER
SR. ATTORNEY
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVE. / PO BOX 800
ROSEMEAD, CA 91770
FOR: SOUTHERN CALIFORNIA EDISON COMPANY (US),

JOHN W. LESLIE, ESQ
ATTORNEY
DENTONS US LLP
600 WEST BROADWAY, STE. 2600
SAN DIEGO, CA 92101
FOR: SHELL ENERGY NORTH AMERICA L.P.
FREDERICK M. ORTLIEB                      CHRISTOPHER CLAY
DEPUTY CITY ATTORNEY                      CALIF PUBLIC UTILITIES COMMISSION
CITY OF SAN DIEGO                         LEGAL DIVISION
1200 THIRD AVENUE, SUITE 1100             ROOM 4300
SAN DIEGO, CA  92101-4100                 505 VAN NESS AVENUE
FOR: CITY OF SAN DIEGO                    SAN FRANCISCO, CA  94102-3214
FOR: ORA

AUSTIN M. YANG                            MATTHEW FREEDMAN
DEPUTY CITY ATTORNEY                      STAFF ATTORNEY
CITY AND COUNTY OF SAN FRANCISCO          THE UTILITY REFORM NETWORK
OFFICE OF CITY ATTORNEY DENNIS J.HERRERA  785 MARKET STREET, 14TH FL
1 DR. CARLTON B. GOODLETT PL, RM 234     SAN FRANCISCO, CA  94103
SAN FRANCISCO, CA  94102-4682             FOR: TURN
FOR: CITY AND COUNTY OF SAN FRANCISCO

NORA SHERIFF                              VIDHYA PRABHAKARAN
ALCANTAR & KAHL LLP                        ATTORNEY
345 CALIFORNIA ST., STE. 2450              DAVIS WRIGHT & TREMAINE LLP
SAN FRANCISCO, CA  94104                   505 MONTGOMERY STREET, SUITE 800
FOR: CALIFORNIA LARGE ENERGY CONSUMERS    SAN FRANCISCO, CA  94111
ASSOCIATION                                FOR: SOUTH SAN JOAQUIN IRRIGATION

CHARLES R. MIDDLEKAUFF                    JEREMY WAEN
PACIFIC GAS AND ELECTRIC COMPANY          SR REGULATORY ANALYST
LAW DEPARTMENT                             MCE CLEAN ENERGY
PO BOX 7442, MC-B30A-2475                  1125 TAMALPAIS AVENUE
SAN FRANCISCO, CA  94120                   SAN RAFAEL, CA  94901
FOR: PACIFIC GAS AND ELECTRIC COMPANY     FOR: MARIN CLEAN ENERGY (MCE)

SHAWN MARSHALL                            MICHAEL BOCCHADISORO
DIRECTOR                                  WEST COAST ADVISORS
LEAN ENERGY US                             925 L STREET, STE. 800
PO BOX 961                                 SACRAMENTO, CA  95814
MILL VALLEY, CA  94941                     FOR: AGRICULTURAL ENERGY CONSUMERS
FOR: LEAN ENERGY US                        ASSOCIATION

SCOTT BLAISING                            KAREN NORENE MILLS
ATTORNEY                                  ATTORNEY
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.    CALIFORNIA FARM BUREAU FEDERATION
915 L STREET, STE. 1270                    2300 RIVER PLAZA DRIVE
SACRAMENTO, CA  95814                      SACRAMENTO, CA  95833
FOR: POWER AND WATER RESOURCES POOLING    FOR: CALIFORNIA FARM BUREAU
FEDERATION AUTHORITY (PWRPA) / CITY OF LANCASTER /
FOR: SOUTH SAN JOAQUIN IRRIGATION
FOR: SONOMA CLEAN POWER (SCP)

ANN L. TROWBRIDGE
ATTORNEY
DAY CARTER & MURPHY LLP
3620 AMERICAN RIVER DR., STE. 205
### Information Only

<table>
<thead>
<tr>
<th>Name</th>
<th>Position</th>
<th>Company/Agency</th>
<th>Contact Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>BARBARA R. BARKOVICH</td>
<td>Consultant</td>
<td>BARKOVICH &amp; YAP, INC.</td>
<td>EMAIL ONLY, CA 00000</td>
</tr>
<tr>
<td>BRIAN KORPICS</td>
<td>Staff Attorney</td>
<td>THE CLEAN COALITION</td>
<td>EMAIL ONLY, CA 00000</td>
</tr>
<tr>
<td>CASE ADMINISTRATION</td>
<td>Case Coordination</td>
<td>PACIFIC GAS AND ELECTRIC COMPANY</td>
<td>EMAIL ONLY, CA 00000</td>
</tr>
<tr>
<td>JASON FRIED</td>
<td>S.F. Local Agency Information Commission</td>
<td>EMAIL ONLY, CA 00000</td>
<td></td>
</tr>
<tr>
<td>JUDY PAU</td>
<td>Email Only</td>
<td>DAVIS WRIGHT TREMAINE</td>
<td>EMAIL ONLY, CA 00000</td>
</tr>
<tr>
<td>KELLEN C. GILL</td>
<td>Senior Case Manager/Regulatory Affairs</td>
<td>PACIFIC GAS AND ELECTRIC COMPANY</td>
<td>EMAIL ONLY, CA 00000</td>
</tr>
<tr>
<td>LAUREN HUDSON</td>
<td>Email Only</td>
<td>SENIOR CASE MANAGER/REGULATORY AFFAIRS</td>
<td>PACIFIC GAS AND ELECTRIC COMPANY</td>
</tr>
<tr>
<td>MAGGIE CHAN</td>
<td>MCE Regulatory</td>
<td>MARIN CLEAN ENERGY</td>
<td>EMAIL ONLY, CA 00000</td>
</tr>
<tr>
<td>SHALINI SWAROOP</td>
<td>Email Only</td>
<td>MARIN CLEAN ENERGY</td>
<td>EMAIL ONLY, CA 00000</td>
</tr>
<tr>
<td>TRINA HORNER</td>
<td>Email Only</td>
<td>LEAN ENERGY US</td>
<td>EMAIL ONLY, CA 00000</td>
</tr>
<tr>
<td>KAREN TERRANOVA</td>
<td>Email Only</td>
<td>ALCANTAR &amp; KAHL</td>
<td>EMAIL ONLY, CA 00000-0000</td>
</tr>
<tr>
<td>KELLY CRANDALL</td>
<td>Email Only</td>
<td>CASE ADMINISTRATION</td>
<td>EMAIL ONLY, CA 00000</td>
</tr>
<tr>
<td>EQ RESEARCH, LLC</td>
<td>Email Only</td>
<td>LAW DEPARTMENT</td>
<td>EMAIL ONLY, CA 00000</td>
</tr>
</tbody>
</table>
MARCIE A. MILNER  
VP, REGULATORY AFFAIRS  
SHELL ENERGY NORTH AMERICA (U.S.). LP  
4445 EASTGATE MALL, STE. 100  
SAN DIEGO, CA  92121

KELLY FOLEY  
PILOT POWER GROUP  
8910 UNIVERSITY CENTER LANE, SUITE 520  
SAN DIEGO, CA  92122

WILLIAM FULLER  
CALIF. REGULATORY AFFAIRS  
SAN DIEGO GAS & ELECTRIC COMPANY  
8330 CENTURY PARK COURT, 32CH  
SAN DIEGO, CA  92123-1548

SUE MARA  
CONSULTANT  
RTO ADVISORS, LLC  
164 SPRINGDALE WAY  
REDWOOD CITY, CA  94062

BRIAN STEVENS  
CLEANPOWERSF-POWER ENTERPRISE COMM.  
SAN FRANCISCO PUBLIC UTILITIES COMM.  
525 GOLDEN GATE AVE., 7TH FL.  
SAN FRANCISCO, CA  94102

JIM HENDRY  
SAN FRANCISCO PUBLIC UTILITIES  
525 GOLDEN GATE AVE., 7TH FLOOR  
SAN FRANCISCO, CA  94102-3220

WILLIAM K. SANDERS  
DEPUTY CITY ATTORNEY  
CITY AND COUNTY OF SAN FRANCISCO  
1 DR. CARLTON B. GOODLETT PLACE, RM. 234  
SAN FRANCISCO, CA  94102-4682

PAUL ESFORMES  
SR. REGULATORY CASE MGR.  
PACIFIC GAS AND ELECTRIC COMPANY  
77 BEALE STREET, MC B9A  
SAN FRANCISCO, CA  94105

LISA ALTIERI  
350 BAY AREA  
3790 EL CAMINO REAL, STE. 364  
PALO ALTO, CA  94306

ALEX PORTESHAWVER  
SENIOR SUSTAINABILITY PLANNER  
MICHAEL BAKER INTERNATIONAL  
500 12TH STREET, SUITE 250  
OAKLAND, CA  94607

ROGER LIN  
STAFF ATTORNEY  
COMMUNITIES FOR A BETTER ENVIRONMENT  
1904 FRANKLIN ST., STE. 600  
OAKLAND, CA  94612

TIM LINDL  
COUNSEL  
KEYES FOX & WIEDMAN LLP  
436 14TH STREET, STE. 1305  
OAKLAND, CA  94612
WILLIAM A. MONSEN
MRW & ASSOCIATES, LLC
SERVICES
1814 FRANKLIN STREET, SUITE 720
OAKLAND, CA  94612

TIM MASON
ENERGY & TRANSMISSION ADVISORY SERVICES
1000 FRESNO AVE.
BERKELEY, CA  94707

SHANA LAZEROW
ATTORNEY
COMMUNITIES FOR A BETTER ENVIRONMENT
120 BROADWAY, SUITE 2
RICHMOND, CA  94804

SCOTT VAN VUREN
MODESTO IRRIGATION DISTRICT
1231 11TH STREET
MODESTO, CA  95354

DEB EMERSON
DIR - POWER SERVICES
SONOMA CLEAN POWER
50 SANTA ROSA AVENUE, 5TH FLR.
SANTA ROSA, CA  95404

CAROLYN KEHREIN
ENERGY MANAGEMENT SERVICES
ENERGY USERS FORUM
2602 CELEBRATION WAY
WOODLAND, CA  95776

CAMILLE STOUGH, ESQ.
BRAUN BLAISING MCLAUGHLIN & SMITH PC
915 L STREET, STE. 1480
P.C.
SACRAMENTO, CA  95814

DAN GRIFFITHS
ATTORNEY
BRAUN BLAISING MCLAUGHLIN & SMITH,
P.C.
915 L STREET, SUITE 1480
SACRAMENTO, CA  95814

KEVIN WOODRUFF
WOODRUFF EXPERT SERVICES
1127 - 11TH STREET, SUITE 514
COMMERCE
SACRAMENTO, CA  95814
FOR: TURN

SUE KATELEY
CHIEF CONSULTANT
ASSEMBLY COMM. ON UTILITIES & COMMERCE
STATE CAPITOL, ROOM 5136
SACRAMENTO, CA  95814

ANN L. TROWBRIDGE
ATTORNEY
DAY CARTER & MURPHY LLP
3620 AMERICAN RIVER DR., STE. 205
SACRAMENTO, CA  95864
FOR: AGRICULTURAL ENERGY CONSUMERS ASSOCIATION (AECS)

State Service

MITCHELL SHAPSON
STAFF ATTORNEY
CALIFORNIA PUBLIC UTILITIES COMMISSION
EMAIL ONLY
EMAIL ONLY, CA  00000

XIAN M. LI
CPUC - ORA
EMAIL ONLY
EMAIL ONLY, CA  00000