JOINT IOUs INFORMAL COMMENTS ON DECEMBER 6, 2019 WORKSHOP ON THE NEM SUCCESSOR TARIFF EVALUATION RESEARCH PLAN

I. Introduction

Southern California Edison, San Diego Gas & Electric, and Pacific Gas and Electric ("the Joint IOUs") appreciate the opportunity to provide these informal comments on the draft scope of the Net Energy Metering ("NEM") Evaluation. The Joint IOUs are generally supportive of the planned scope, and primarily offer clarifying suggestions. We urge the California Public Utilities Commission ("CPUC" or "Commission") and its consultants to proceed on the planned schedule. This study and the subsequent revisit of the NEM program was originally envisioned to have started in earnest during 2019 per the NEM Successor Tariff Decision ("D.") 16-01-44. The Joint IOUs offer many suggestions (with general comments offered in regarding priority) but urge Itron and the CPUC to use their judgement on what can be accomplished between now and June 2020 when determining what suggestions to accept.

A. <u>General Overarching Comments</u>

In this section, the Joint IOUs provide comments that are not addressed by any of the initial questions posed in the draft research plan.

The Joint IOUs believe that this study will be most helpful if published in June 2020, as planned, and that the study should not be delayed. The results of the study are meant to inform the new Order Instituting Rulemaking ("OIR") that will review the successor tariff. The Commission recently stated that it will initiate this proceeding in 2020.[1] Delaying the work in the NEM Evaluation could further delay the OIR, which the Joint IOUs previously understood the Commission originally planned to initiate in 2019. Given the growing burden placed on non-participants in the NEM program, the Joint IOUs urge the Commission and Itron to proceed on the planned schedule, with the final report published in June 2020.

1. The Study should evaluate the successor tariff in relation to the original tariff

The current scope of the study is ambiguous on whether the cost effectiveness of the original tariff will also be evaluated alongside the cost effectiveness of successor tariff. While the final key research question is "how have the answers to the above questions changed from NEM 1.0 to NEM 2.0," the remainder of the scoping document only mentions the original tariff in the context of comparing the physical characteristics of the original and successor tariff systems. The Joint IOUs believe that evaluating the successor tariff program in a vacuum without regard for the impact of the original tariff will fail to assess the cumulative impacts of the NEM program as a whole, as well as make it difficult, if not impossible, to truly understand if the successor tariff satisfies the AB 327's express statutory requirements and legislative intent. AB 327 was a rate reform bill designed to, among other things, reform the NEM program to correct the rate impact of the NEM subsidy. A baseline evaluation of that impact is required for a sounds and robust study. If the study does not analyze the original tariff with the same level of rigor as the successor tariff, it should at least provide approximate estimates of how the results of key cost effectiveness tests have changed.

2. The Study should proceed on schedule, and should base the value of solar on the results of the most up to date CPUC-Approved Avoided Cost Calculator ("ACC")

The Joint IOUs support using the most up-to-date approved version of the ACC that will allow the study to be completed on the planned timeline. At the workshop on December 6, several attendees suggested moving the planned delivery date of this study to accommodate the planned 2020 ACC update, or, if that could not be done, deviating from the approved 2019 ACC in conducting cost effectiveness analyses. While the Joint IOUs encourage Itron to develop its analysis such that it can readily accept the results of the 2020 ACC when available, this study should proceed as scheduled. If time allows the 2020

[1] June 28, 2019 Scoping Memo and subsequent prehearing conference transcript discussing a new OIR.

ACC to be incorporated into this study, those results should be used. If not, the 2019 ACC should be used without selective alteration as suggested by SEIA. These issues have been litigated for years in the IDER and DRP proceeding. This is not the appropriate venue to modify the results of those proceedings.

Parties requesting a delay seemed to believe that the 2020 ACC would provide more favorable results for their positions than the 2019 ACC. However, at the August 30 Workshop in the IDER proceeding, the developer of the ACC indicated that the proposed structural changes to the ACC would likely reduce the estimated value of solar relative to the 2019 ACC.[2] The Joint IOUs also have objections to the 2019 ACC, but nevertheless contend the Commission move forward. For instance, the marginal costs for distribution and generation capacity in the ACC model may not be indicative of the Joint IOUs actual marginal cost allocation structures.[3] The IOUs accept, however, that this is not the appropriate venue to litigate ACC modeling assumptions. Instead, the Joint IOUs recommend that the CPUC and Itron clarify that the ACC's modeling assumptions do not necessarily reflect the IOUs' marginal costs.

3. Ratepayer Impact Test (RIM)

The Joint IOUs raise three issues regarding the RIM test. First, the draft research plan correctly identifies that D.19-05-019 sets the scope of the cost effectiveness analysis to the TRC, RIM, PAC, and PCT tests. However, at the December 6 workshop Itron staff cited language from that decision requiring TRC to be the primary test of cost effectiveness. The quoted section of the decision omits via ellipsis the full context of that order. It reads "Hence, we find it reasonable to designate the TRC as the primary cost-effectiveness test, **except where expressly prohibited by statute or Commission Decision.**"[4] This is further clarified in a footnote: "In comments to the proposed decision, PG&E provides two examples where other legislation or Commission Decision has required a specific test be performed: 1) the Net Energy Metering tariff requires the use of the RIM test pursuant to Assembly Bill 327 and 2) the Energy Savings Assistance (ESA) program requires use of the ESA Cost-Effectiveness Test and a Resource Measure TRC pursuant to D.14-08-030."[5] The Joint IOUs contend that it is important to evaluate the successor tariff program from the TRC, RIM, and PCT perspectives, but the final research scope should clarify that the RIM test, not TRC, is the more meaningful test in the context of this evaluation. The TRC evaluates technologies, not tariffs, and is intuitively of less use in the context of NEM.

Second, the current study plan describes the RIM test imprecisely. The RIM test does not quantify the impacts of a measure on "non-participants" as stated in the draft plan. Rather, it measures the impacts of a measure on the rates paid by all remaining utility customers. While NEM customers do often reduce their utility bills to *de minimis* levels, they remain in the population of customers to whom

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[2] E3 Presentation on "Integrating DER into the IRP," at p. 23, August 30, 2019.

[3] SCE's newly implemented rate structures and marginal cost changes were presented in the SCE's most recent General Rate Case (GRC) Phase 2 Application A.17-06-030 and approved in CPUC D.18-11-027. They include distribution capacity marginal cost allocation split between peak and grid and generation capacity marginal cost split between peak and flex. SCE's approved marginal cost changes are from its most recent General Rate Case ("GRC") have not been incorporated into the CPUC's most recent ACC model and that the ACC model may still reflect distribution capacity marginal costs fully allocated to peak; and therefore, fully avoidable and generation capacity marginal cost fully allocated to peak. *See* November 20, 2019 ALJ Ruling at p. 42 (confirming use of R. 14-08-013's recommendations, introducing staff proposal for major updates to avoided cost calculator, and stating, "Specifically, this proposal uses GRC total distribution capacity costs for all utilities and does not make a distinction between peak and grid distribution capacity.)

[4] D.19-05-019, p. 24.

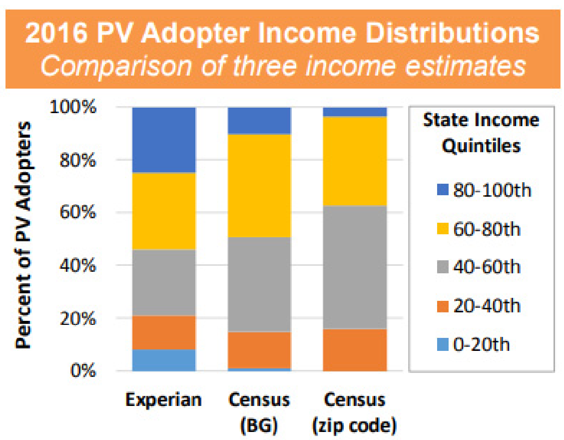
[5] *Id*. at p. 24, fn. 43.

the costs are shifted. Thus, while non-participants bear the vast majority of the NEM cost shift, RIM reflects impacts on all customers.

Third, at the workshop, Itron indicated that it would conduct all the of the cost effectiveness tests on an NPV basis. The Joint IOUs agree that this is appropriate but suggest the study also report the cost shift associated with the NEM successor tariff program in 2020. This would be equivalent to the first year of the NPV calculation of the RIM test. Since rates are likely to increase over time, while the value of solar is forecasted to fall over time in the ACC, it is likely this value would be lower than the annualized NPV of the RIM test. However, this value can be translated into approximate bill impacts of the NEM successor tariff, which may be an intuitively useful way of presenting the results of the RIM test.

4. The Study should carefully characterize census data

The Joint IOUs agree that the American Community Survey (ACS) is an appropriate source of demographic data for this study given the need to rely on publicly available data. However, Itron should carefully characterize the results of such analysis. ACS data is still limited providing summary demographics at the census block group or census tract level, which can include hundreds to thousands of households. As such, ACS demographics can only describe the neighborhoods in which solar customers are more or less likely to be present. As an example of the limitations posed by this data, a 2018 study by LBNL compared income statistics for solar adopters using income data at the zip code, census block group, and individually estimated level. As shown below, the aggregated data exhibited regression to the mean, showing much lower adoption in the top and bottom quintiles of income levels. In describing the results of its demographic research, Itron should be careful to avoid making conclusions that cannot be supported by census block group level data.



Notes: *For the Census (BG) distribution, the income assigned to each PV system is the corresponding BG median income. For the Census (zip code) distribution, the income assigned to each PV system is the average of the BG median incomes within the corresponding zip code, weighted by the residential population in each BG.*

5. Greenhouse Gas Abatement Cost Metrics

The draft scope notes that in addition to the SPM cost effectiveness tests the study will report other financial metrics such as payback time and IRR. The Joint IOUs think it would also be useful to report the results of the TRC, PCT, and RIM tests from a GHG abatement cost perspective. These results would be expressed as a $\$/t_{CO2e}$ cost or benefit (inclusive of any embedded GHG reduction benefit in the ACC) and could be compared to the net abatement costs of other measures as calculated in the IRP or other proceedings, such as supply side renewables or energy efficiency.

B. <u>Responses to Questions</u>

1. What key characteristics should be used to form groupings, or bins, of customers?

When conducting the segmentation analysis, the Joint IOUs encourage Itron to focus on what characteristics will drive meaningful differences in the cost effectiveness or cost of service results. Itron's proposal to use clustering algorithms to aid in this segmentation is vague, as only two characteristics are identified that could usefully be used in a clustering algorithm (gross consumption and percent offset by PV). The IOUs would be happy to iterate further on this issue in the process of scoping Itron's data needs, but preliminarily suggest the following classification layers for its segmentation to balance precision against analytical complexity. For example, the most accurate way to estimate participant bill savings would be to model every rate design that a customer can take service under. With the proliferation of rates options and TOU grandfathering, this would include over 50 rate schedules for PG&E alone. Modeling all of these would likely not provide meaningfully improved results relative to an analysis that selected a limited number of representative rates.

1. IOU (SCE, SDG&E, PG&E)
2. Technology Type (Solar, Solar+Storage, Other)
    a. *Note: The IOUs agree that analysis of non-solar technologies should be less rigorous, and likely would not require as much segmentation.*
3. NEM Program (NEM 1.0, NEM 2.0, NEM-A 1, NEM-A 2, VNEM 1.0, VNEM 2.0, NEMVMASH, NEMV2MSH)
    a. *Note: NEMA and VNEM billing arrangements are very complex and difficult to model. While VNEM accounts for a relatively small amount of capacity, NEMA is a major factor in the agricultural class. For both, Itron could pursue a simplified modeling approach that frames solar generation into TOU periods to estimate bill savings, rather than conducting a pre- and post-adoption bill analysis of customers with allocations from these systems.*
4. Rate Schedule(s) – *At minimum, the most common rate schedule taken by solar customers should be modeled for each customer type.*
    a. Residential Non-CARE
    b. Residential CARE
    c. Small Commercial
    d. Medium Commercial
    e. Large Commercial
    f. Industrial
    g. Agricultural
5. Grandfathering TOU Status (Non-residential Only)
    a. Legacy TOU
    b. Updated TOU
    c. *Note: While there is grandfathering for residential TOU rates as well, the scope and duration is much less significant. Non-residential TOU grandfathering is rather complex due to the remaining duration being based on the permission to operate date, but will be a significant factor in the RIM and PCT tests. This may require simplifying assumptions by Itron to avoid having every interconnection year be a different segment.*
6. Baseline Territory (Residential Only)

   a. *Note: Small baseline territories (e.g. "Q" for PG&E) can be combined with similar baseline territories for the purposes of this analysis*

7. Gross Usage
8. Load Factor (Potentially Non-Residential Only)
   a. *Note: This layer is most important for determining how much a customer can save money via demand charge management with batteries or by switching to a rate with less demand charges (e.g. "Option R" rates) but may also be useful for the cost-of-service analysis.*
9. Fraction of Gross Consumption Covered by PV System
10. Fraction of Gross Generation from PV System Exported
    a. *Note: This layer would effectively capture how much NEM 2.0's non-bypassable charge component impacts participating customers. Since the impact on overall economics is likely modest and this factor is somewhat correlated with layer 9, this may not be necessary in this evaluation. However, given that "net billing" tariffs are a common post-NEM structures, it may be worthwhile to start analyzing the impact of this variable.*

After proceeding through layers 1 through 6 of the segmentation, layers 7-10 could then be fed into a clustering algorithm. However, it is unclear if this added analytical complexity is worth the time involved. From the Joint IOUs experience, Itron will likely spend significant time processing the data to mitigate the effect of outliers on this cluster analysis. The benefit of cluster analysis tends to be most apparent when segmenting against many variables that an unaided human analyst cannot feasibly segment – for example, load shape segmentation (from 24 hour averages to annual 8760s) is often done with cluster analysis. It is unclear if that amount of work is necessary here, and as a time saving measure Itron could simply split these usage related variables into quartiles.

2. *What customer segments or demographics are important to examine in the cost-effectiveness analysis?*

The segmentation layers above are proposed for the purpose of identifying segments that are expected to have meaningfully different cost effectiveness results while also being feasible to include from a data availability perspective.

Other layers that could impact the cost effectiveness results but would further increase analytical complexity include:

- **Customers unable to monetize the Federal Investment Tax Credit:** This would primarily include tax exempt public agencies that do not utilize a "third party owned" financing structure but would also include some low income residential customers. However, identifying which installations this applies to may not be feasible, and this issue may be better addressed through a sensitivity analysis.
- **Rebate Program Participation:** This is mostly important for original NEM systems that participated in CSI, but some other programs such as SGIP, SASH, MASH, and NSHP also benefit NEM successor tariff customers and would meaningfully impact the cost effectiveness results for those installations.
- **Financing Method:** Previous cost effectiveness analysis of NEM has assumed that customers purchase their systems, while the majority of customers now utilize some type of financing, be it a traditional loan, Property Assessed Clean Energy (PACE), or a third party owned lease/PPA. Often, these financing arrangements eliminate payback time as a factor for customers by

providing immediate savings at the cost of lower lifetime NPVs.[6] As mentioned by commission staff at the workshop, these financing structures can result in poor outcomes for participating customers. While it may not be feasible to segment the customer base according to what financing method they used (if any), this could instead be addressed through a sensitivity analysis.

- **CCA/DA Status**: The Joint IOUs recommend that all customers be modelled as bundled customers for the purposes of this analysis. Differences in overall rate levels between bundled and unbundled customers are modest enough that other inherent uncertainties are likely to be a greater source of error. However, it may still be useful to report how adoption varies by Load Serving Entity.

In addition to these factors, the demographic factors identified for analysis of adoption distribution could also be used for the segmentation. As noted above, American Community Survey data cannot be used to segment customers – only neighborhoods. In addition, it is unclear if reporting cost effectiveness at these levels of granularity will provide information not also provided by examining adoption distribution.

Other factors may not directly impact the analysis significantly.

3. What are reliable sources of data for installed PV and energy storage costs?

The IOUs believe that the cost of installed PV and energy storage should be an input on which Itron places significant emphasis and rigor. In the final report, Itron should include detailed analysis of solar pricing in the IOUs' respective service territories, and should look to publicly available sources of information, including the most recent reports by the National Renewable Energy Laboratory, Energy Sage, Greentech Media/Wood Mackenzie, Lazard, Bloomberg New Energy Finance, and other reliable and unbiased sources. The IOUs recommend that Itron develop utility-specific costs by utilizing the suggested data sources, and that Itron provide the detail and rationale for the installation and operations and maintenance costs they eventually decide are appropriate.

Additionally, the IOUs now collect contracts from new interconnections on behalf of the CPUC. These contracts could be a useful source of pricing data and contract terms that could inform sensitivity analysis on the impact on participants of certain less understood financial structures (e.g. PACE).

4. Should PV_LIB (which implements NREL's PVWatts DC power model) be used to develop solar profiles?

The IOUs support using a reliable public source as a starting point to develop solar profiles. However, NREL's PVWatts DC power model tends to overestimate actual PV production, when compared to IOU-specific solar customer production. PVWatts production estimates do not account for many factors that are important in the design of a PV system. Per NREL, the PVWatts annual output results can be expected to vary by as much as ±10% from long-term typical value. Additionally, the energy value estimates may be overly optimistic when using the default system losses value. While the PVWatts model is an appropriate starting point, Itron should work with the IOUs in developing and modifying the PVWatts solar production profiles so they are representative of actual customer segments within each utility's service territory. The IOUs recommend that Itron consider using insights from the CSI final impact evaluation, which may aid in developing solar profiles based on actual observed generation.

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[6] Assuming all else is equal, a solar PPA is likely to have a lower NPV than a solar cash purchase when using discount rates common in PCT modeling (7% to 10%). Customers that have high discount rates would perceive a higher NPV.

5. ***Besides grid upgrade costs, are there other integration costs that should be considered in the cost-effectiveness analysis?***

Besides grid upgrade costs that include interconnection facilities costs and distribution upgrades costs, other integration costs that should be considered in the cost-effectiveness analysis are:

- Cost of Additional Grid Management Measures and Tools, including
  - Interconnection Costs: new Distributed Energy Resources (DER) processing tools
  - Distributed Energy Resources Management Systems (DERMS): communication and control systems which will aid in grid and DER management due to high penetration of DERs
- Increased Grid Intelligence/Infrastructure Costs
  - Grid upgrade costs necessary to connect high levels of DER penetration
- NEM Processing and Administration Costs, including
  - Application Processing and Administration Costs
  - Billing Costs
  - Incremental NEM-Specific Customer Call Center Costs
- Distribution Engineering Costs, including
  - In-Office Review Costs
- Metering Installation, Inspection, and Commissioning Costs, including
  - Meter Change Costs
  - Remote Meter Programming Costs
  - Inspection and Commissioning Costs

6. ***Regarding Itron's cost-effectiveness model used for SGIP battery storage cost-effectiveness, are there any inputs or assumptions that should be modified for this analysis?***

Itron's most recent 2019 cost-effectiveness model is not currently publicly available. The Joint IOUs base their comments regarding the forthcoming model on a review of Itron's December 3 "2019 SGIP Energy Storage Market Assessment and Cost-Effectiveness Report", as it is the Joint IOUs' understanding that the 2019 SGIP model described in this report will be used as the basis for the forthcoming cost-effectiveness model.

Itron's cost-effectiveness model should use the Joint IOUs metered data for storage and paired storage that are reflective of current Time-of-Use (TOU) periods. For example, SCE's currently effective TOU rates with a peak period of 4:00pm to 9:00pm, implemented as of March 2019[7] may not be reflected in the ACC model.

7. ***What scenarios should be included in the cost of service analysis?***

As a threshold matter, Itron and the CPUC should understand the limits of cost of service analysis. The draft study claims that "[t]he total cost of service estimates the cost of servicing the remaining or net load." This is incorrect. Rather, the total cost of service is a function of the allocation of

[7] These currently effective rate structure changes were approved in the Company's Rate Design Window Application A.16-09-003 and approved in CPUC Decision D.18-07-006.

a utility's total costs to a customer or group of customers according to the cost of service principles used in the cost of service study. The purpose of these studies in utility GRCs is to allocate revenue among customer classes at a high level and does not attempt to identify all cost drivers. Many costs that have little or nothing to do with electricity usage are still allocated by a customer group's usage.[8] Because the total cost of service allocation is based on each group's share of marginal costs, reductions in a group's marginal cost due to a change in usage result in its total cost of service falling by an amount greater than its marginal cost reduction. This in turn results in the total cost of service for all other customers increasing. While cost of service analysis is useful, it only represents a theoretical estimate of what a customer group ought to pay according to the assumptions of the analysis and, unlike the somewhat related RIM test, does not attempt to estimate the impacts of one customer's decisions on other customers. As such, it often sets aside the impacts of other policy preferences in rate design, such as the impacts of tiered rates,

The cost of service analysis should use a cost-based rate architecture for distribution and generation charges that reflect the value of each cost component uniquely in the provision of service to the customer. The cost of serve analysis should also include a contribution to margin requirement that can be developed using the base revenue portion of the Equal Percentage of Marginal Cost Scalar (EPMC)[9] scalar to eliminate the idiosyncrasies of revenue balancing account collections and policy/program driven revenue requirements beyond base revenues.

Alternatively, the cost of service analysis can use a marginal cost floor approach where the group allocated marginal cost revenues divided by forecasted sales establish a unit marginal cost floor. All social-economic components embedded in the retail rate would be considered separately from the unit marginal cost floor rates but in so much as they should not be by-passable (including but not limited to Transmission, Public Purpose Program Charges (PPPC), Nuclear Decommissioning Charge (NDC), New System Generation Charge (NSGC), and Department of Water Resource Bond Charges (DWRBC)), they should be included in the analysis. The cost-based rates structure would be applicable to both photovoltaic and paired storage.

When performing the cost to serve analysis, the Joint IOUs recommend a rate factor approach, which uses TOU time dimensions for calculating bills, thus bills would be aligned to cost. It is imperative that the cost to serve analysis be derived based on a consistent dimension of time. Therefore, using a rate factor approach will help align the dimensions of time for both the bill and cost components when conducting such a comparison.

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8 For example, many utility costs such as vegetation management are related more to population density and local geographic conditions than anything to do with usage. Other costs represent policy decisions, such as incentive programs (SGIP) or above market procurement.

9 The Equal Percentage Marginal Cost Scalar (EPMC) is a multiplier that scales costs from a marginal cost basis to a retail rate basis.