BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 19-11-009 (Filed November 7, 2019)

**TRACK 2 PROPOSAL OF
CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL, CPOWER, ENEL X NORTH AMERICA, INC., AND LEAPFROG POWER, INC.**

Greg Wikler
Executive Director
California Efficiency +
Demand Management Council
1111 Broadway, Suite 300
Oakland, CA 94607
Telephone: 925-286-1710
E-mail: policy@cedmc.org

Jennifer A. Chamberlin
Executive Director, Market Development
CPower
2475 Harvard Circle
Walnut Creek, CA 94597
Telephone: 925-433-2165
E-mail: JAC@CPowerEnergyManagement.com

Mona Tierney-Lloyd
Senior Director, Regulatory Affairs
Enel X North America, Inc.
2071 Altair Lane
Reno, NV 89521
Telephone: 415-238-3788
E-mail: mona.tierney-lloyd@enel.com

Andrew Hoffman
Chief Development Officer
Leapfrog Power, Inc.
1700 Montgomery Street, Suite 200
San Francisco, CA 94111
Telephone: 415-409-9783
E-mail: andrew@leap.ac

February 21, 2020

TABLE OF CONTENTS

Page

TABLE OF AUTHORITIES

Page

CPUC DECISIONS AND RESOLUTIONS

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 19-11-009 (Filed November 7, 2019)

TRACK 2 PROPOSAL OF CALIFORNIA EFFICIENCY + DEMAND MANAGEMENT COUNCIL, CPOWER, ENEL X NORTH AMERICA, INC., AND LEAPFROG POWER, INC.

The California Efficiency + Demand Management Council, CPower, Enel X North America, Inc., and Leapfrog Power, Inc. (hereinafter "the Joint Parties") respectfully submit its Track 2 Proposal in Rulemaking ("R.") 19-11-009 (Resource Adequacy ("RA"). The Joint Parties' Track 2 Proposal is filed and served pursuant to the Rules of Practice and Procedure of the California Public Utilities Commission ("CPUC" or "Commission") and the Assigned Commissioner's Scoping Memo and Ruling, dated January 22, 2020 ("Scoping Memo").

I. INTRODUCTION

The Scoping Memo in Section 4(b)(iii) asks what rules should be required for Third-Party demand response ("DR"). The Joint Parties submit their Proposal as to this item below. For third-party DR to become a regular RA resource type, rules covering a broad range of issues are needed beginning with rules governing Qualifying Capacity ("QC") valuation. Other areas needing definition include test events, guidelines associated with customer movement and double-counting, and a process for managing issues associated with the provision of Revenue Quality Meter Data ("RQMD"). Many of the lessons learned from the Demand Response Auction Mechanism ("DRAM") are directly applicable to third-party DR in the RA market so it would be logical to use them as a basis rather than developing a new set of rules. Below, the Joint Parties propose a comprehensive set of rules that, if approved, will create the necessary structure for third-party DR to play a broader role in meeting load-serving entities' ("LSEs'") RA requirements.

II.
QUALIFYING CAPACITY VALUATION

A. Rules for Third-Party DR Should be Transparent and Easy to Implement.

The rules governing the QC valuation of third-party DR must be transparent, administratively efficient, and as objective as possible. The major centralized wholesale capacity markets in the country subject DR providers ("DRPs") to a clear set of information requirements to ensure that DRPs can deliver the amount of capacity they claim in their bids. Despite being rigorous, these requirements are administratively efficient in that the amount of effort required is reasonable, the process timeline is short, and the required documentation is simple enough for the DRPs to complete without hiring consultants. As a guiding principle, the Commission should seek a similar approach.

Transparent, efficient, and objective QC rules for third-party DR will result in a wide range of benefits. Customers will be better able to access the value of DR due to easier program participation, DRPs will benefit from reducing a significant barrier to participating in the RA market, and LSEs, including community choice aggregators ("CCAs"), will face less complexity in procuring third-party DR.

Below is an overview of the QC valuation and enforcement rules from PJM, NYISO, and ISO-New England.

i. PJM

DRPs are required to complete a DR Sell Offer Plan prior to a capacity auction to validate that they can deliver on all capacity they bid into the auction.[1] This DR Sell Offer Plan must be accompanied by an officer certification attesting to the capacity of the DRP to deliver all of its capacity that clears the auction.[2] To complete the DR Sell Offer Plan, DRPs must provide the following information:

- A description of the DR program the DRP plans to employ to achieve the load reduction at end-use customer sites;

[1] The PJM DR Sell Offer Plan template can be found here: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/demand-response-sell-offer-plan-template-for-2020-2021-delivery-year.ashx?la=en

[2] The PJM Demand Response Sell Offer Plan Officer Certification Form can be found here: https://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/dr-sell-offer-plan-officer-certification-form.ashx

- Any equipment that will be used to control load at end-use customer sites including what equipment the DRP plans to install at the end-use customer sites; if applicable, this should include a description of the cycling control strategy;
- A description of the DRP's customer acquisition strategy including any strategic partnerships and third-party mechanisms; this should include all key customer-related assumptions used in the developed the estimated DR capacity, current size of sales force, and expected size of sales force to achieve the planned amount of DR; and
- Any additional key assumptions that were not already captured.

For capacity zones where greater than 10% of the capacity requirement was met by DR over the past three years, customer-specific data are required. PJM reviews the DR Sell Offer Plan and has the right to de-rate or disqualify any capacity not backed by existing customers.

ii. NYISO.

Capacity auctions occur in the NYISO significantly closer to the delivery period compared to PJM and ISO-New England, so DRPs are required to submit the interval data and baseline peak days/intervals of their enrolled customers (with no forecasted enrollments allowed) in advance of each capacity auction which the NYISO uses to calculate a peak baseline for a DRP's resources. This baseline then determines the amount of capacity a DRP is able to bid in the capacity auction.[3]

iii. ISO-New England.

The ISO-New England validation process is the most rigorous among the three markets discussed here, and requires for each new resource a Show of Interest, Customer Acquisition Plan, Funding Plan, and a supporting market-sizing analysis to demonstrate that there is a sufficient pool of customers for the DRP to recruit. Existing resources are not subject to these requirements and can rely on their historical performance. The Show of Interest must include how installed measures (i.e., products, equipment, systems, services, practices and/or strategies) that result in additional and verifiable reductions in end-use demand will be developed, operated, and maintained, and describe project development strategies, assumptions, customer engagement and partnerships.[4] The Customer Acquisition Plan must include the customer types and classes,

[3] https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338

[4] https://www.iso-ne.com/static-assets/documents/2017/01/dr_project_description_for_soi_final.pdf

ideal customer characteristics, customer acquisition and retention strategy, and marketing strategy.[5] The Funding Plan must show the source of the DRP's funds as well as duration of funds, credit rating, general funding strategy, and budget details.[6]

These three capacity markets demonstrate that a QC validation process can be rigorous, fairly objective, transparent, and efficient.

B. The Load Impact Protocols ("LIPs") in Their Current Form are Not Suitable for the QC Valuation of Third-party DR.

As most recently affirmed in Decision ("D.") 19-06-026, the QC value of third-party DR is currently determined using the DR LIPs to develop a load impact evaluation that is assessed by the Energy Division who determines the final QC value. This approach has been used to assess the QC value of investor-owned utility ("IOU") DR programs for ten years but for several reasons, the LIPs are highly unsuitable for this purpose for third-party DR. A fundamental difficulty in applying all of the LIPs in their current form to third-party DR is the difference in the relatively stable nature of the IOU DR program composition compared to the more dynamic composition of third-party DR. For example, LIPs are applied on a programmatic level to IOU DR programs with long histories and relatively stable participation. Even though DR aggregators participated in programs such as the Capacity Bidding Program ("CBP") or the since-canceled Aggregator Managed Portfolio ("AMP"), the IOUs have assessed their performance on a programmatic basis, not on an aggregator-by-aggregator basis.

The programmatic approach allows the IOU to "smooth out" variances among the aggregators that are the result of DR customers moving from one aggregator to another. Similarly, relative to the history of the IOUs' DR programs, DR provided by DRPs is relatively new, beginning with the DRAM in 2016. Since then, the number of customers and associated capacity that has changed hands from one DRP to another has been dramatic.[7] So much so, that it is very difficult to use a DRP's historic profile of a portfolio of DRAM capacity in one year to reflect the capabilities of a future commitment, particularly as many DRPs build their resource

---

[5] https://www.iso-ne.com/static-assets/documents/markets/othrmkts_data/fcm/qual/forms/custacquisition_20140501.pdf
[6] https://www.iso-ne.com/static-assets/documents/markets/othrmkts_data/fcm/qual/forms/fundingplan_20140501.pdf
[7] For the purposes of this proposal, DR aggregator aggregates customers for IOU DR programs whose load response the IOU then bids and dispatches in the CAISO market. DRPs aggregate customers, <u>and</u> bid and dispatch their load response in the CAISO market.

portfolio to match their explicit commitments – not on an open-ended basis with no specific procurement targets as the IOUs typically operate their programs.

In addition to the foundational reasons explained above, the following are reasons why the LIPs and their application are unsuitable for third-party DR:

i. The Accuracy of the LIPs for Third-Party DR is Unproven.

To the Joint Parties' knowledge, no recent assessment has been performed on the ability of the LIPs to accurately forecast the QC values of third-party DR. Without a clear understanding of the LIPs' accuracy, it is unclear whether the LIPs, which are highly time- and resource-intensive, are better than any other QC valuation approach. This is especially a concern when the LIPs are applied to a DRP's portfolio with a relatively small number of large customers or a large number of new customers. The LIPs are most effective with large numbers of customers with a history of DR performance with a single DRP, but they have no track record for assessing a small number of customers that may differ significantly from one another in their load reduction potential, temperature sensitivity, and sources of load reduction (e.g. manufacturing process vs. HVAC load). Similarly, the LIPs provide very little guidance for estimating the load impacts of customers with no history of DR performance.

ii. Confidentiality Issues are a Major Concern.

The LIPs contain no provisions protecting the confidential data in third-party DRPs' load impact evaluations. This includes the specification of what data are confidential and how that data should be protected. Though D.06-06-066 may provide some protection for DRPs' data, exactly what data are protected and what remedies are available to DRPs are not specified.

iii. LIPs Rely Heavily on Temperature as a Correlating Factor for Load Impacts.

The guidelines for regression analyses contained in the LIPs use temperature as the primary correlative factor in developing ex ante load impacts. This certainly remains relevant for a lot of DR but with the proliferation of more DR backed by technologies that are not temperature-sensitive (e.g. energy storage), this dependency could be a significant factor affecting the accuracy of the LIPs.

iv. The Frequency of the LIP Process Prevents Participation in Some Requests for Offers ("RFOs").

The once-per-year nature of the LIP process has limited the ability of DRPs to participate in LSE solicitations that occur outside of this process. Once the process begins for determining the QC value of a DRP's portfolio, there is no process in place for a DRP to recruit additional customers to respond to an RFO and receive an incremental QC value. Any customers recruited by a DRP after their final load impact evaluation is submitted would be required to wait until the following year to participate in DR after the DRP includes the customers recruited in the prior year into their next evaluation. Forcing new customers to wait up to a year before being allowed to participate in a DRP's DR portfolio is not conducive to growing DR, which the Joint Parties note remains a Preferred Resource.

v. The LIPs are Backward Looking.

Ex ante load impacts, which serve as the basis for the QC valuation of a DRP's portfolio are typically calculated utilizing ex post load impacts in a regression analysis. This approach ensures that QC values always rely on historical load impacts. However, historical load impacts are not always indicative of future load impacts. This is especially true because the QC received by a DRP for any given year will always be based on *two-year-old* data (e.g., 2021 QC will be based on ex post load impacts from 2019). As discussed above, this may be suitable for IOU DR programs that are fairly static in their customer composition and size, but DRPs' portfolios can change significantly from one year to the next. Furthermore, if a DRP recruits a significant number of new customers with no DR performance history, a regression analysis would be meaningless. Though the LIPs allow for the use of publicly-available estimates as a proxy for ex post load impacts for new customers, these are not necessarily going to be accurate, especially for larger non-residential customers with unique loads.

vi. LIPs Do Not Take into Account New Technologies Such as Energy Storage.

The LIPs do not account for the measuring precision that is available for energy storage-backed DR. Energy storage is often sub-metered so it is often simple to directly measure the performance of energy storage customers during a DR event. This accuracy would seem to forego the need for regression analyses when such analysis would often be less accurate than using sub-meter data to calculate ex post load impacts.

vii. The LIPs are Financially and Administratively Burdensome.

The amount of time and resources required to develop a load impact evaluation is highly excessive for the DRPs. IOUs have been performing analyses using the LIP for many years, but they have been able to use ratepayer funds to do so. Because DRPs must fully finance these evaluations themselves, the LIP requirement may be a significant barrier to entry for new and smaller DRPs. Even for larger DRPs, the LIP evaluation is a substantial resource commitment.

To date, OhmConnect, Inc. is the only DRP to have developed its own load impact evaluation using the LIPs. Due to the complexity and time requirements of this work, OhmConnect hired a consultant to develop its draft evaluation plan, incorporate feedback from the Demand Response Measurement & Evaluation Committee (DRMEC), develop a final evaluation plan, develop a draft load impact evaluation report, incorporate feedback from parties and the Energy Division, and develop a final load impact evaluation that exceeded 120 pages in length. By any standard, this is a disproportionate amount of work for what was likely a relatively small amount of capacity. In addition, the amount of work required of the Energy Division to review and assess the evaluation was likely significant; if the Energy Division, as can be expected, receives several load impact evaluations per year in 2020 and beyond, this workload will only multiply.

viii. LIPs are Silent on Enrollment Forecasts.

The LIPs provide no guidance on forecasting enrollments. DRP enrollment projections are a core component of each load impact evaluation because, when multiplied by the average per-customer ex ante load impact, they have a direct impact on the QC value of a DRP's portfolio. As can be observed in the critical responses to OhmConnect, Inc.'s 2018 Load Impact Evaluation, enrollment projections can be highly contentious. The challenge faced by a DRP in this situation is trying to put forth an enrollment projection that is consistent with its customer enrollment experience while providing evidence to support it in the eyes of other parties and the Energy Division. Unfortunately, there are no clear criteria for what constitutes a reasonable or realistic enrollment forecast, so it seems possible that some parties may never be completely satisfied by any DRP's enrollment forecast. More importantly, the lack of these criteria puts the Energy Division in a difficult position of having to judge whether a DRP's enrollment forecast is achievable, despite having little or no experience in DR customer enrollment or operations.

C. The Flexibility Provided by the LIPs Results in Less Transparency.

The LIPs provide a significant amount of flexibility to those performing the load impact evaluations to decide the most appropriate way to determine the ex post and ex ante load impacts of DR resources which, in turn, have a direct impact on the QC value awarded by the Energy Division. On its surface, this flexibility may appear to be a positive characteristic but, in practical terms, it creates a great deal of ambiguity that limits DRPs' ability to predict how the Energy Division will ultimately translate a load impact evaluation to a QC value. For example, it would be reasonable to expect that ex post load impacts for customers with a history of DR participation would be calculated using a regression analysis because there would likely be several DR events to act as data points. Conversely, it might not be practical to use a regression to determine the ex post load impacts of new customers with no history of DR participation. Further complicating this issue is how to determine load impacts of a group of customers in which some have a history of DR participation and some do not. These complexities make Energy Division assessment of load impact evaluations and assigning QC values highly subjective. In the end, it is possible that a DRP expends a substantial amount of resources on developing a load impact evaluation only to have its QC not resemble the projected ex ante impacts.

D. Upfront Validation of DR Capability is Necessary but should be More Streamlined.

The Joint Parties recommend using an approach similar to that recently approved for DRAM. D.19-07-009 approved and D.19-12-040 affirmed a set of guidelines for data to be provided by DRAM bidders to IOUs when responding to a DRAM solicitation to demonstrate they can deliver the capacity contained in their DRAM bids. These guidelines have already been approved by the Commission for the IOUs to validate the QC value of DRAM bids and the year-ahead and month-ahead supply plans of winning DRAM bidders. As such, they can also serve as a reasonable basis for DRPs to support their claimed QC values in the RA market. This approach is not perfect in that it continues to rely on the judgment of the Energy Division, but it is more transparent than the LIPs and significantly more administratively efficient. Also, the inputs are clear and DRPs will hopefully see a direct correlation between the Energy Division's comfort with a proposed QC value and the quality and robustness of the inputs.

The Joint Parties' Proposal deliberately does not define invoicing requirements, damages provisions for underperformance or contract default, a dispute resolution process, or failure-to-invoice penalties. It is the Joint Parties' expectation that each LSE will prefer to have discretion in how to individually address each of these issues within the RA contracts they execute. However, the Joint Parties are open to the adoption of standardized rules governing these contract components and again suggest that the existing DRAM rules are a good starting point.

The proposed guidelines are:

- DRPs should provide the following details to the Energy Division with its proposed QC value:
    - Customer Class (or percent of mix): Residential, Non-residential

- Nature of Load Being Aggregated: e.g., whole house, HVAC load, storage, building load, pumps, electric vehicles, or other (describe)
- Dispatch Method: automated via cloud control, or other (describe)
- Projected Number of Service Accounts (including a breakdown of the active and registered number of Service Accounts within the total projected service account numbers)
- Projected Aggregated Load (if storage based, projected aggregated capacity)
- Projected Percentage of Load Impact or Reduction (if storage based, projected percentage of capacity delivered)
- Supporting Historical Performance Data for Projected Percentage of Load Impact or Reduction (from a prior test or market dispatch for a demand response resource with similar characteristics as Customer Class, Nature of Load Being Aggregated, and Dispatch Method). Where historical data are not available, the Provider should reference suitable publicly available performance data that best represents the anticipated performance of the resource. Along with the supporting performance data, the following details for the resource associated with the supporting performance data should be provided to establish similar characteristics:
  - Customer class (or percentage mix): Residential, Non-residential
  - Nature of load being aggregated: such as, whole house, Air Conditioning load, storage, building load, pumps, Electric Vehicles, or other (describe)
  - Dispatch method: automated via cloud control, or other (describe)
  - Number of Service Accounts
  - Aggregated load (if storage based, aggregated capacity)
  - Percentage of load impact or reduction delivered (if storage based, percentage of capacity delivered.)
- Estimated Qualifying Capacity = Projected Aggregated Load x Projected Percentage of Load Impact or Reduction

- QC estimates should be provided for, at minimum, the RA measurement hours and are expected to align, at minimum, with the California Independent System Operator ("CAISO") Availability Assessment Hours.

- The same baseline must be used for estimation of QC for the monthly supply plan, the energy settlement at CAISO and invoicing of the Demonstrated Capacity ("DC") for the applicable month.
- To the extent the projected percentage load impact for capacity delivered in Projected Percentage of Load Impact or Reduction deviates from the supporting data in Supporting Historical Performance Data for Projected Percentage of Load Impact or Reduction, the DRP should provide supplemental information to explain the reasonableness of the resulting Estimated QC.
- To the extent the contract/resource consists of heterogenous combination of load types (in terms of Customer Class, Nature of Load Being Aggregated, Dispatch Method characteristics), the DRP could subdivide the portfolio and provide the above information for each component and apply a weighted average to provide the Estimated Qualifying Capacity.
- The above information should be provided for each month of the year.

The Joint Parties propose that each DRP provide, on a rolling basis, the data specified by these guidelines to the Energy Division at least once per year along with the claimed QC value of their portfolio. To allow DRPs the flexibility to participate in RFOs throughout the year and to maintain an accurate QC value, there should be a quarterly or at least semi-annual timeline by which DRPs can update their portfolios to reflect new or departed customers. The Joint Parties propose the following quarterly timeline:

Milestone	Quarter 1	Quarter 2	Quarter 3	Quarter 4
DRP submits QC data to ED	2/1	5/1	8/1	11/1
ED requests supplemental data as needed	3/1	6/1	9/1	12/1
DRP provides supplemental data	3/15	6/15	9/15	12/15
ED issues final QC value	3/31	6/30	9/30	12/31

III.
PROPOSED RULES FOR OTHER ASPECTS OF THIRD-PARTY DR

In addition to the proposed QC counting rules above, there are several other important aspects of third-party DR that needs to be defined to create the conditions for a robust RA market third-party DR. The implementation of the DRAM has surfaced these issues and provided a good learning experience for IOUs, DRPs, and the CAISO. Many of the solutions developed for third-party DR in the DRAM can be applied to the "mainstream" RA market as well. In most instances, the Joint Parties use the guidelines provided in Appendix B of D.19-12-040, with some modifications, as a basis for the following recommendations.

A. Recommendations.

i. Test Events.

DRPs with RA contracts should be required to conduct two events per year, regardless of the duration of the contract. Proposed test event parameters are similar to those in D.19-12-040, Appendix B, Section 1, but with a few modifications.

- The dispatch must be during RA measurement hours which are expected to align with the CAISO Availability Assessment Hours.
- The first event must occur within the first two months of the contract delivery period
- One of the dispatch months must be August.
- Each test event must be for the full capacity of the contract.
- A test event can be foregone if a full-capacity market event occurs with at least one hour of the event falling within the RA measurement hours.
- Each test or market event (in lieu of a test event) must be two consecutive hours in duration with the invoice capacity reflecting the average performance over the two hours.
- A combined market and test event may be used to satisfy the two-hour requirement if the CAISO market dispatch is for less than two hours.

ii. Customer Movement.

Customer location movement between resources within a month is prohibited, except under the following circumstances:

- Newly enrolled customers can be added to a resource.
- A customer who ends its relationship with a DRP may be dropped from a resource.

- If the above changes make a resource trigger the 10 MW telemetry requirement, or have it drop below the 100-kW minimum Proxy Demand Resource size, resources may be split or combined mid-month to continue to meet CAISO market requirements.

iii. Double-Counting.

Seller must avoid any potential double counting of customer performance associated with service account movement permitted by the exemptions when invoicing DC.

iv. Baselines.

The baseline method used for energy settlement at the CAISO must be the same as the baseline method used to invoice DC. The baseline method used to invoice DC must be the same as the baseline method used for estimating the QC on the supply plan applicable to the invoiced month.

v. Data-Related Communication Protocols.

- Each IOU and DRP shall designate a point of contact for all data delivery inquiries and notify the Commission's Energy Division, IOUs, and DRPs of any changes to this point of contact.
- Each IOU shall facilitate a monthly call for DRPs to report data issues.
- All DRPs shall perform troubleshooting prior to notifying an IOU of any data issues including: a) verifying the Application Programming Interface data request was correctly formatted; b) verifying the DRP's customer lists are updated including removing customers whose service accounts have been closed; and c) verifying that missing data is not a result of a planned or unplanned outage where the IOU has notified the DRP.
- DRPs shall notify the IOU of data error using a standardized data template. Again, this should provide efficiencies for the IOUs in determining the root causes of issues and resolving the issues and for DRPs in reporting the issues.
- The IOU shall confirm receipt of inquiry within two business days and provide an estimated time of resolution of the inquiry.
- The IOU shall update the DRP on a regular basis and when the estimated time of resolution could change.
- The IOU shall confirm resolution of the inquiry and data delivery.

B. Track 2 Question 4(b)(iv): How Should Load-Modifying Demand Response be Counted?

The Joint Parties provide no specific proposal in response to this question. As a general principle, any non-market-integrated DR such as critical peaking pricing ("CPP") and real-time rates should be included in the load forecast. In addition, should the Commission adopt any of the load-shift DR products recommended in the Load Shift Working Group Report, it will be necessary to address the capacity value of these resources.[8] Some of these resources may be best suited to treatment as Load Modifying Resource ("LMR") DR and some may work best as Supply Resource DR.

For some new technologies, there may be good reason to provide a QC value even if those technologies are not integrated into the CAISO market. For example, through the Self-Generation Incentive Program ("SGIP"), the Commission will facilitate the deployment of thousands of behind-the-meter ("BTM") storage devices at homes affected by PSPS events. These storage devices could provide highly valuable RA in local areas capable of responding precisely to dispatch signals with power exports. However, these systems are not eligible to be Proxy Demand Resources ("PDR") because PDRs do not allow energy exports, which can reduce the available capacity of these batteries by 80% or more. Thus, it may be necessary to treat these resources as LMR DR subject to all of the availability and operational requirements for DR receiving RA value.

C. Track 2 Question 4(b)(v): Are Modifications to the Load Impact Protocols Needed (*e.g.,* to Ensure Demand Response Resources Provide Local and System Reliability Benefits)?

For the reasons described above, third-party DR should not be subject to the LIPs for the purpose of determining its QC value. However, if the Commission determines that this practice should continue, the Joint Parties propose the following revisions to the LIPs and the load impact evaluation process.

i. The Accuracy of the LIPs for Determining the QC Value of Third-Party DR should be Assessed and any Necessary Changes Made to Improve it.

As discussed in greater detail above, the accuracy of the LIPs for determining QC values of third-party DR should be assessed and any necessary improvements made.

---

[8] *Final Report of the California Public Utilities Commission's Working Group on Load Shift*, January 31, 2019.

ii. The LIPs should be Revised to Require subLAP-Level Ex Post and Ex Ante Load Impacts.

Because most DR is market-integrated, the LIPs should be revised to report load impacts by subLAP. While this was not so when the LIPs were first created, Local Capacity Areas now conform with subLAPs. So, the practical effect of reporting load impacts by subLAP will only be to break out load impacts for the subLAPs that are not currently being reported. Additionally, QC values should be assigned to DRPs at the subLAP level.

iii. Common Data Must be Made Available.

IOUs or the Demand Response Measurement and Evaluation Committee ("DRMEC") must make available the common foundational data needed by all DRPs' evaluators to perform load impact evaluations. These data include temperature data, maps of zip codes to weather stations, the peak hour for each year, and the dates and times of PSPS events.

iv. Confidentiality Issues Must be Addressed.

The Commission must develop clear rules to protect the confidentiality of DRPs' data. In the absence of adequate protections, DRPs risk their proprietary information being shared with competing DRPs or IOU DR program staff. Specifically, the Joint Parties are very concerned about the confidentiality of the data used by DRPs to develop their load impact evaluations. Based on a brief review of OhmConnect's October 18, 2019 *2018 Load Impact Evaluation*, these proprietary data can include customer count, per-participant load impact, current and forecasted portfolio size, event frequency and duration, and customer location. Though the IOUs share these same data in their draft and final load impact evaluations, the IOUs are subject to heightened regulatory oversight of their DR resources as a public utility.

It is important to note that the LIPs were developed for the purpose of estimating the capacity value and determining the cost-effectiveness of regulated monopoly IOU DR programs. That environment has fundamentally changed with the proliferation of both DRPs as well as non-IOU LSEs such as community choice aggregators. In this new environment, DRPs are engaged in competitive activity with one another, so disclosure of market-sensitive information similar to what was shared by OhmConnect could cause harm to a DRP's competitive position.

The Joint Parties recommend that DRPs not be required to share draft and final load impact evaluations with parties other than the DRMEC and Energy Division. The DRMEC could review each DRPs' draft load impact evaluations and provide non-binding feedback directly to each DRP and the Energy Division. To protect competitively sensitive information, the Energy Division should require the same controls approved for DRAM bidders in Ordering Paragraph 22 of Decision 19-12-040, such that IOU DR program staff should not have access to DRPs' data when being reviewed by the DRMEC. Also, members of the DRMEC should sign non-disclosure agreements with each DRP.

v. Changes to Individual Protocols.

Protocol 8 (ex post): This protocol requires ex post impacts to be provided for "each day on which an event was called" and the "average event day" across the evaluation period. The number of scenarios DRPs are required to produce under this protocol should be substantially reduced. The average event day impact, while interesting, does not lend itself to the calculation of ex ante impacts for the purposes of QC because QC values are assigned on a monthly basis. Moreover, for weather-sensitive resources, a yearly average may not be very instructive. For these reasons, we recommend the Commission waive the requirement to calculate ex post impacts for the average event day.

Protocol 17: This protocol states that ex ante load impacts should be informed by ex post load impacts whenever possible, and if ex post estimates or models are not used, an explanation should be provided. A clear set of conditions are needed for when using ex post load impacts is not practical. For instance, when a DRP's portfolio in the upcoming RA delivery year is expected to be significantly larger or smaller than the prior year (in which case ex post load impacts are meaningless), or when a DRP has enrolled or expects to enroll customers with no DR participation history with that DRP. In the latter instance, a customer's participation history with prior DRPs is moot because the current DRP will not have access to the customer's prior event data.

Protocol 4 (ex post)/Protocol 18 (ex ante): These counterpart protocols (one for ex post load impacts and the other for ex ante load impacts) require that the mean change in energy use per hour (kWh/hour) for each hour of the day be estimated for each day type and level of aggregation defined in the following Protocol 8 (ex post) or Protocol 22 (ex ante), respectively. To the extent that a DRP's portfolio will only be used for RA, the relevance of requiring these calculations for all 24 hours for each day type is unclear when the Availability Assessment Hours (AAH) for System and Local Resource Adequacy are only 4:00 p.m.-9:00 p.m. DRPs should be required to only perform these analyses based on the AAH at minimum, with an option to perform them for more hours of the day.

Protocol 5 (ex post)/Protocol 19 (ex ante): These counterpart protocols require that mean change in energy use per year be reported for the average across all participants and for the sum of all participants on a DR resource option for each year over which the evaluation is conducted. Annual averages are not necessary for the assignment of QC—these are always monthly values—and are not indicative of highly seasonal resources. Compliance with Protocols 5 and 19 in its entirety should be waived for load impact evaluation performed solely for determining the QC value of third-party DR.

Protocol 22: The number of scenarios required by this protocol should be substantially reduced if a DRP undertakes a load impact evaluation solely for the purposes of being given a QC value. This protocol specifies the analyses required for each day type using CAISO and IOU 1-in-2 and 1-in-10 weather conditions. However, only the "monthly system peak day" calculated under IOU 1-in-2 weather conditions are needed to estimate the QC value for RA purposes. This should be the only scenario required by the protocol. Calculating the "average weekday" and the "typical event day" under 1-in-2 weather conditions and calculating anything under 1-in-10 weather conditions is not relevant to estimating the RA QC value. While we acknowledge that the 1-in-10 scenario is used by the CAISO in its local capacity technical studies, the CAISO does not use the outputs of the load impact reports in its own studies. Therefore, requiring DRPs to produce these scenarios is not directly useful for the CAISO.

Protocol 26: This protocol specifies the format and content of the load impact evaluation reports. One requirement of this protocol is that "a comparison of impact estimates derived from the analysis and those previously obtained in other studies and those previously used for reporting of impacts toward resource goals, and a detailed explanation of any significant differences in the new impacts and those previously found or used." It is reasonable to expect that a DRP's portfolio will likely change significantly from one year to the next, so this requirement is not relevant. In addition, it is not clear what value such a comparison would have in determining QC value even if a DRP's portfolio was fairly stable, so this requirement should be removed.

v. A Supplemental Process is Needed.

DRPs should have an opportunity to update their load impact evaluations later in the year to reflect updated customer portfolios and performance. Under the current process, load impact evaluations are performed once a year for the upcoming year and are based on ex post data from the prior year. This means that, in any given compliance month, the QC value of DR is based on two-year-old ex post data. For example, August 2021 QC values will be based on August 2019 performance and customer data. A DRP's customer base may differ substantially from year-to-year, including changes to reference loads as DRPs test new technologies, incentives, messaging, etc. in an effort to provide the greatest value to customers and improve performance.

A DRP should have an opportunity to have the most up-to-date information be reflected in the QC values assigned to its resources for the following year. The Energy Division should allow DRPs to submit an optional "update" to their load impact evaluation in early fall of each year. For this update, the DRP would use the same methodology and models already vetted during the load impact evaluation process, but expand the underlying data set to include current year data through the end of August. This would avoid the need for a new review of the evaluation plan or draft updated load impact evaluation. The update would be a short supplement to the original final report - all existing models would simply be re-run using the more recent data set. Importantly, the Energy Division would update the QC values (if appropriate), based on the new data. Specifically, the updated data set would include:

- More recent customer composition data, including enrollment, reference loads, and adoption of AutoDR-enabling and energy storage technologies; and
- Performance data from the first eight months of the current year.

vi. A Standardized Load Impact Evaluation Timeline is Needed.

A standardized schedule is needed for the evaluation process. The Joint Parties recommend adoption of a modified version of the timeline approved by the Energy Division through its informal process conducted in late 2019 and early 2020. This proposed timeline includes the supplemental process described above:

Milestone	Date
DRP submits draft evaluation plan w/ DRMEC	2/28
DRMEC comments due on draft evaluation plan	3/20
DRP submits draft load impact evaluation due to DRMEC and Energy Division	4/10
DRMEC comments due on draft load impact evaluation	4/24
DRP submits final load impact evaluation to Energy Division	5/15
Energy Division DR and RA sections issue QC value to DRP	6/30
Initial RA Requirements assigned to LSEs	July
DRP submits update to Energy Division if necessary	9/10
Energy Division DR and RA sections issue revised QC value to DRP	10/1
LSEs submit RA year-ahead compliance filing to Energy Division	10/31

vi. Rules Governing the Energy Division's Assessment of Enrollment Forecasts are Needed.

DRP enrollment projections are a core component of each load impact evaluation because, when multiplied by the average per-customer ex ante load impact, they have a direct impact on the QC value of a portfolio. Unfortunately, there are no clear criteria for what constitutes a reasonable or realistic enrollment forecast.

Should the Energy Division consistently derate the enrollment forecasts and, by extension, the QC values of DRPs' portfolios, this could limit the growth of DR because it will not be commercially rational for DRPs to grow their portfolio beyond what the Energy Division has determined is the limit of the DRP's capability to deliver. Additionally, many DRPs do not enroll without corresponding commitment, and have demonstrated national track records of enrolling customers in portfolios specifically to meet contracted commitments. Enrollment efforts and expected results are strongly correlated to desired QC to meet contracts and would not separately be achieved. The enrollment projection evaluation process needs to take this into account. Clear guidelines are needed by which a DRP's enrollment forecast is assessed, and could include a list of information that the DRP must provide to substantiate their enrollment forecast.

vii. Representation on the DRMEC.

If the DRMEC is to have a role reviewing DRP draft evaluation plans and draft load impact evaluations, DRPs and non-IOU LSEs should be allowed representation on the DRMEC for the sake of fairness and transparency. Organizations representing the parties affected by the DRMEC's assessments with no direct financial interest in the outcome of the DRPs' load impact evaluations would likely be good candidates to join the DRMEC. As a representative of the DRP community, the Council is well-suited to join the DRMEC and already has a history of representing energy efficiency industry interests at the California Technical Forum ("Cal TF") and the California Energy Efficiency Coordinating Committee ("CAEECC"), so it would be an ideal candidate to represent DR industry interests in the DRMEC. Other potential candidates include the California Energy Storage Association, the California Solar & Storage Association, California Community Choice Association, and the CAISO.

IV.
CONCLUSION

The Joint Parties appreciates the opportunity to submit this Track 2 Proposal.

Dated: February 21, 2020

Respectfully submitted,

/s/ GREG WIKLER
Executive Director
On Behalf of
California Efficiency + Demand Management Council,
CPower, Enel X North America, Inc. and
Leapfrog Power, Inc.
1111 Broadway, Suite 300
Oakland, CA 94607
Telephone: 925-286-1710
E-mail: policy@cedmc.org