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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years.	R.17-09-020 (Filed September 28, 2017)

COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON PROPOSED DECISION ADOPTING LOCAL CAPACITY OBLIGATIONS FOR 2020-2022, ADOPTING FLEXIBLE CAPACITY OBLIGATIONS FOR 2020, AND REFINING THE RESOURCE ADEQUACY PROGRAM

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I. INTRODUCTION

Pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Pacific Gas and Electric Company ("PG&E") respectfully submits these opening comments ("Comments") on the proposed *Decision Adopting Local Capacity Obligations for 2020-2022, Adopting Flexible Capacity Obligations for 2020, and Refining the Resource Adequacy Program*, mailed on May 24, 2019 ("Proposed Decision").

As described in Section II of these Comments, PG&E generally supports the Proposed Decision, with the exception of the Commission's treatment of the issue set forth in Section II.B related to an unjustifiable potential risk to investor-owned utilities ("IOUs") resulting from a load serving entity's ("LSE") enrollment schedule deviating from its implementation plan. Notwithstanding PG&E's general support for the Proposed Decision, Section II.C of these Comments demonstrates that the record compels adoption of some of PG&E's initial proposals in Track 3 that are entirely omitted from the Proposed Decision. In order to correct the Proposed Decision with respect to these issues, PG&E encourages the Commission to implement the modifications described herein and revise the findings of fact, conclusions of law, and ordering paragraphs as shown in bold underline and strikethrough in Appendix A.

II. DISCUSSION

PG&E supports much of the Proposed Decision, including the Commission's approval of the local capacity requirements for 2020-2022 and flexible capacity requirement for 2020, among other things. Section II.A below sets forth PG&E's supportive comments and minor suggested improvements with respect to the Proposed Decision's discussion, findings, conclusions, and orders specifically related to Effective Load Carrying Capacity ("ELCC"), the establishment of a working group for seasonally varying local capacity requirements, and the workshop process to develop counting methodologies for hydroelectric and use-limited fossil resources.

While the majority of the Proposed Decision is well-supported by the record, the Proposed Decision contains critical errors related to (1) the potential risk to IOUs if an LSE's enrollment schedule deviates from its implementation plan and (2) failure to adopt some of PG&E's initial Track 3 proposals, as described in Sections II.B and II.C below, respectively. These errors must be corrected for the Proposed Decision to appropriately reflect and be supported by the record. Correcting these errors in the Proposed Decision will resolve any deficiencies and allow for a Commission decision adopting the Proposed Decision expeditiously.

A. The Commission Should Adopt, with Slight Modifications, the Proposed Decision's Discussion, Findings, Conclusions, and Orders Related to Effective Load Carrying Capacity, the Establishment of a Working Group for Seasonally Varying Local Capacity Requirements, and the Workshop Process to Develop Counting Methodologies for Hydroelectric and Use-Limited Fossil Resources

1. Effective Load Carrying Capacity

The Proposed Decision determines that the ELCC for energy storage should be valued at 100% of its nameplate capacity in all months and proposes allocating any monthly ELCC greater than 100% to solar resources only. While, in theory, multiple resources other than solar resources can charge energy storage, allocating this excess ELCC across multiple other resources (while correct) would likely be untenable; thus, the Proposed Decision's approach is reasonable. Accordingly, PG&E encourages the Commission to adopt the Proposed Decision's resolution of this issue.

PG&E notes, however, that the Commission's Energy Division ("Energy Division") originally calculated monthly ELCCs for energy storage that are *less than* 100% in the summer months. To avoid overestimating the capacity benefit of energy storage in these months, PG&E suggests that Energy Division assign these smaller calculated ELCCs to energy storage and not simply at 100% across the board. Furthermore, PG&E again strongly recommends including Helms Pumped Storage in the methodology for future calculations. There is no basis to assume that Helms Pumped Storage will not be a part of the resource portfolio in the near future and excluding it will likely inflate the capacity value of energy storage.

2. Establishment of Working Group for Seasonally Varying Local Capacity Requirements

The Proposed Decision correctly determines that PG&E's proposal for a working group to "specifically 'examine the relationship between local RA requirements, RA resource obligations, changes to NQC in forward years, how RA performance is assessed, and how local RA backstop procurement occurs or does not occur from uncured deficiencies'" is reasonable and directs Energy Division to establish a working group prior to the development of the 2021-2023 local RA requirements.[1] Given the expected timing of the Proposed Decision, PG&E also proposed that seasonally varying local capacity requirements be established beginning with the 2021 RA compliance year.[2] PG&E interprets the working group directed by the Commission to be the appropriate venue for discussion of seasonally varying local capacity requirements, as proposed by PG&E, and encourages the Commission to make this explicit in the Proposed Decision. To that end, PG&E requests that the Commission adopt all discussion, findings of fact, conclusions of law, and ordering paragraphs related to the establishment of this working group and clarify that the working group will discuss PG&E's proposal for seasonally varying local capacity requirements, as shown in Appendix A.

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[1] Proposed Decision, pp. 8-9, Finding of Fact 2, Ordering Paragraph ("OP") 4.

[2] *Track 3 Proposals of Pacific Gas and Electric Company (U 39 E)*, dated March 4, 2019 ("PG&E Track 3 Proposals"), pp. 2, 6-8.

3. Workshop Process to Develop Counting Methodologies for Hydroelectric and Use-Limited Fossil Resources

The Proposed Decision properly orders Energy Division to convene a working group to revisit the qualifying capacity ("QC") counting methodologies for hydroelectric and use-limited fossil resources.[3] The QC methodology for hydroelectric resources must balance hydrological conditions, weather patterns, Federal Energy Regulatory Commission licensing requirements, the availability of water storage levels and other potential operational constraints.[4] Further, the Commission appropriately recognizes the challenges of fossil resources with operational or regulatory limitations, including the difficulty in determining how best to reflect such limitations in the QC methodology for fossil resources.[5] In order to begin addressing these challenges, PG&E urges the Commission to adopt all discussion, findings of fact, conclusions of law, and ordering paragraphs in the Proposed Decision related to the QC counting methodologies for hydroelectric and use-limited fossil resources.

B. The Proposed Decision Should Be Clarified to Ensure IOUs Are Protected from Unpredictable Changes to LSE Implementation Plans

PG&E supports the Commission's effort to improve predictability of load and RA requirements by implementing a binding notice of intent ("BNI").[6] Notwithstanding these efforts, however, there may still be an unjustifiable risk to the incumbent utilities, given that implementation plans are not binding. As a result, revisions to the Proposed Decision are necessary to provide protections from unpredictable changes to LSE implementation plans.

The Proposed Decision rightly excludes changes to implementation plans in its definition of "load migration."[7] Ideally this, in addition to the BNI, will discourage changes to implementation plans and increase the predictability of load. Yet, a potential risk to the IOU appears to remain if an LSE enrolls its customers earlier than announced in its implementation plan and the incumbent utility is left to bear a higher resource adequacy ("RA") requirement than

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[3] Proposed Decision, OP 17.
[4] PG&E Track 3 Proposals, pp. 10-11.
[5] *See* Proposed Decision, p. 43.
[6] Proposed Decision, OP 13.
[7] Proposed Decision, Conclusion of Law 11, OP 12.

necessary, potentially shifting costs to customers.

To remedy this issue, PG&E requests clarification of the proposed plausibility review triggers on pages 30 to 31 of the Proposed Decision to ensure they mitigate the risk to an IOU if an LSE accelerates enrollment from what was outlined in its implementation plan. To the extent this risk is not adequately addressed and mitigated in revisions to the discussion portion of the Proposed Decision, PG&E requests the revisions to the Proposed Decision set forth in Appendix A hereto to allow the incumbent utility to adjust its forecast when an LSE unexpectedly changes its enrollment schedule, given that this is a change that the incumbent utility cannot reasonably predict.

C. The Commission Should Revise the Proposed Decision to Address a Number of PG&E's Initial Proposals in Track 3

The Proposed Decision fails to address a number of PG&E's initial Track 3 proposals that are clearly supported by the record and ripe for resolution. While PG&E understands that the large number of parties and issues involved in Track 3, and the relatively compressed timeline for issuance of the Proposed Decision after submission of initial proposals, may have prevented the Commission from addressing all of PG&E's proposals, it is clear that the record contains adequate support for the Commission to address PG&E's proposal on these issues at this time. As a result, PG&E urges the Commission to revise the Proposed Decision to address the PG&E initial Track 3 proposals as outlined below.

1. The Commission Should Revise the Proposed Decision to Provide That the Combining of Traditional Demand Response and Energy Storage is to be Measured in Aggregate Using Relevant Methodologies

In its opening testimony, Southern California Edison Company ("SCE"), similar to PG&E's Track 3 proposal,[8] indicated that, when energy storage is paired with demand response, "[t]o the extent there are proposals to separately measure pieces of a BTM resource, they should be carefully evaluated to ensure that they capture the actual load reduction delivered to the grid

[8] *See* PG&E Track 3 Proposal, p. 4.

(i.e., the sum of all parts should not be greater than the actual load reduction delivered to the grid)."[9] PG&E supports this proposal and requests that the Commission revise the Proposed Decision as shown in Appendix A to provide that the combining of traditional demand response and energy storage is to be measured in aggregate using consistent methodologies so that any QC is a reflection of actual load reductions.

2. The Commission Should Revise the Proposed Decision to Order that Qualifying Capacities for Third-Party Demand Response Provider Resources Be Based on Observable and Verifiable Event Performance Data

On May 31, 2019, the Commission issued a proposed decision for the Demand Response Auction Mechanism ("DRAM")[10] which includes an interim solution for determining the QC value for third-party demand response ("DR") resources. PG&E maintains, however, that determining the QC value for DRAM should be addressed in a holistic manner with other resources that provide RA value. Accordingly, PG&E views this proceeding as the appropriate venue to address the QC value for DRAM resources.

PG&E continues to advocate that the QC of DRAM resources be based on observable and verifiable event performance data and, to that end, supports SCE's proposal. SCE proposed the QC of DRAM resources be determined either through a generic load impact (through the current load impact protocols) or through a seller-determined QC paired with back-end controls (i.e., testing and dispatch performance data to validate the stated QC).[11] In support, PG&E provided evidence that the current methodology of establishing the QC value based on the contract capacity for third-party demand response provider ("DRP") resources is: (1) inherently flawed for resource planning purposes; (2) intended to be an interim methodology approved through 2019 because it was believed that penalties under the California Independent System Operator Corporation

[9] *Southern California Edison Company's Track 2 Testimony in Rulemaking 17-09-020*, dated July 10, 2018, p. 29, lines 19-24.
[10] Application 17-01-012 et al., Proposed *Decision Addressing Auction Mechanism, Baselines and Auto Demand Response for Battery Storage*, mailed May 31, 2019.
[11] *Southern California Edison Company's (U 338-E) Track 3 Proposals*, dated March 4, 2019, pp. 8-9.

("CAISO") tariff (including the RA Availability Incentive Mechanism ("RAAIM") and contract provisions are adequate incentives for DRPs to correctly state the QC of their resources, which Energy Division's final evaluation report contradicts;[12] (3) inconsistent with the standards by which the IOUs are being held;[13] and (4) creating an unlevel playing field between IOU DR resources and third-party DRP resources.[14]

Several parties responded to SCE's proposal.[15] As a result, the record contains adequate evidence for the Commission to adopt SCE's proposal on this issue, and PG&E requests that the Commission revise the Proposed Decision as shown in Appendix A to order that QCs for third-party DRP resources be based on observable and verifiable event performance data.

3. The Commission Should Revise the Proposed Decision to Adopt a Multi-Year Load Forecast to be Submitted by all Commission-Jurisdictional Load Serving Entities

PG&E proposed that the Commission adopt a multi-year load forecast to be submitted by all Commission-jurisdictional LSEs and used in determining the local RA requirements for each of the three forward years.[16] In support of this proposal, PG&E notes that community choice aggregators or energy service providers that will expand their service in 2021 or beyond shall be

[12] This methodology was approved in Decision ("D.") 16-06-045, pp. 41-42, which states that the exemption should be reviewed based on the findings of ED's final evaluation report, issued on January 4, 2019 in Application 17-01-012 et al, in the *Administrative Law Judge's Ruling Issuing Evaluation Report of the Demand Response Auction Mechanism Pilot, Noticing January 16, 2019 Workshop, and Denying Motion to Require Audit Reports in the Evaluation Report*. Specifically, the report states on p. 109: "During the DRAM pilot, CAISO RAAIM penalties and replacement capacity requirements under the CPUC's RA program have not effectively incentivized performance." In addition, p. 78 states: "IOU DRAM contracts with DRPs did not include explicit, universal penalties for non-compliance with contract obligations, although there was some discretion available to IOUs to impose penalties in certain cases."

[13] The QC for IOU DR programs is based on Commission-approved load impact evaluation protocols that require the use of observed and verified past event performance data.

[14] PG&E Track 3 Proposals, pp. 4-5.

[15] *Comments of the California Large Energy Consumers Association on Resource Adequacy Track 3 Proposals*, dated March 22, 2019 ("CLECA Comments"), p. 9; *San Diego Gas & Electric Company (U 902 E) Opening Comments on Track 3 Proposals*, dated March 22, 2019 ("SDG&E Comments"), pp. 15-16; *NRG Energy, Inc. Opening Comments on Track 3 Proposals*, dated March 22, 2019, p. 15; *Comments of Pacific Gas and Electric Company (U 39 E) on Track 3 Proposals and Workshops and Energy Division's Effective Load Carrying Capacity Proposal*, dated March 22, 2019, pp. 16-17.

[16] PG&E Track 3 Proposals, p. 6.

assigned their RA obligations based on their 2020 load forecast. This disconnect could result in the IOUs procuring on behalf of load that they ultimately will not serve. Several parties to this proceeding support PG&E's proposal.[17] As a result, the record contains adequate evidence for the Commission to adopt PG&E's proposal on this issue, and PG&E requests that the Commission revise the Proposed Decision as shown in Appendix A to require LSEs to submit their three-year load forecast as part of the August mandatory load forecasting update for the 2020-2022 local RA requirements only. On a going forward basis, if needed, LSEs should be required to submit their multi-year load forecasts in the month of April as part of the existing RA timeline and serve only the load for which they have planned.

III. CONCLUSION

PG&E appreciates the opportunity to provide these opening comments and urges the Commission to modify the Proposed Decision as set forth above and in Appendix A.

Respectfully Submitted,

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[17] CLECA Comments, pp. 5-6; *Comments of the Alliance for Retail Energy Markets on Track 3 Proposals*, dated March 22, 2019, p. 7; SDG&E Comments, p. 3.

APPENDIX A

PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDERING PARAGRAPHS

Findings of Fact

1. The CAISO recommended the existing capacity needed for all local areas is 23,643 MW for 2020, 23,635 MW for 2021, and 22,598 MW for 2022.

2. It is reasonable to convene a working group to evaluate the LCR process prior to the development of the 2021-2023 local RA requirements. **It is reasonable for the working group to discuss PG&E's proposal that seasonally varying local capacity requirements be established beginning with the 2021 RA compliance year.**

3. The CAISO recommended system-wide flexible capacity requirements ranging from 11,812 MW in July to 18,025 MW in February.

4. In D.06-06-064, the local waiver trigger price was adopted. An updated trigger price to reflect current market conditions is warranted.

5. If the local trigger price is updated, it is appropriate to raise the local RA penalty price to the equivalent local trigger price value.

6. It is reasonable to establish a transparent, formal local waiver review process, in light of the recent increase in local waiver requests.

7. In D.14-06-060, the Commission adopted flexible RA capacity requirements but did not explicitly address the penalty structure for LSEs that incur both flexible and system RA deficiencies.

8. In order to develop accurate load forecasts for aggregation and comparison purposes, it is critical to standardize the assumptions used to develop initial and final year ahead load forecasts.

9. Energy Division's proposal for a Binding Notice of Intent process will encourage effective forecasting in the year ahead process and discourage modifications to load forecasts for reasons other than unpredictable load migration. **An incumbent utility cannot reasonably predict when an LSE unexpectedly changes its enrollment schedule.**

10. Given LSEs' need to rely on investor-owned utilities as the source of customer-level load data for LSEs to develop their load forecasts, it is essential to establish clear data sharing and coordination guidelines.

11. Standardizing the data sharing process between IOUs and non-IOU LSEs will improve the efficient and effective transfer of data.

12. Energy Division's conflict resolution proposal is a reasonable mechanism to attempt to resolve discrepancies between LSEs prior to distributing initial year ahead requirements.

13. It is appropriate to revisit the counting methodology for hydro and use-limited fossil resources through a working group.

14. Given the transitional nature of the ELCC values adopted in D.17-06-027, it is reasonable to reconsider the ELCC modeling framework to include the effects of behind-the-meter photovoltaic generation.

15. Eliminating the Path 26 constraint may allow greater procurement flexibility for LSEs without significantly increasing the threat of violating constraints along Path 26.

16. It is appropriate for QCs for load modifying resources to reflect actual load reductions.

17. It is reasonable to require observable and verifiable event performance data in connection with determining the qualifying capacities for third-party demand response provider resources.

18. It is reasonable to require LSEs to submit their three-year load forecast as part of the August mandatory load forecasting update for the 2020-2022 local RA requirements. On a going forward basis, it is reasonable for LSEs to submit their multi-year load forecasts in the month of April as part of the existing RA timeline and serve only the load for which they have planned.

Conclusions of Law

1. The CAISO's recommended LCR existing capacity needed for 2020 – 2022 should be adopted.

2. Energy Division should establish a working group to evaluate the LCR process prior to developing local RA requirements for the 2021-2023 compliance year. **Among other things, the working group should discuss PG&E's proposal that seasonally varying local capacity requirements be established beginning with the 2021 RA compliance year.**

3. The CAISO's recommended systemwide FCR figures for 2020 should be adopted.

4. Raising the local trigger price to an annualized value of the 85th percentile of the monthly local RA prices for South of Path 26 is a reasonable figure.

5. The local penalty price should be raised to match the local trigger price.

6. Local waiver requests should be submitted via a Tier 2 Advice Letter to promote transparency and establish a formal process.

7. Where an LSE incurs an equivalent system RA deficiency and flexible RA deficiency, the system RA capacity should be penalized at the system RA penalty price, with no separate penalty on the flexible deficiency.

8. Where an LSE incurs a flexible deficiency that exceeds its system deficiency, the system RA penalty price should apply for the system deficiency and the flexible penalty price should apply to the flexible deficiency in excess of the system deficiency amount.

9. Load migration should be the only allowable reason for differences between initial and final year ahead load forecasts~~.~~**; provided that an incumbent utility should be permitted to adjust its forecast when an LSE unexpectedly changes its enrollment schedule.**

10. "Load migration" should be defined, for the purposes of the RA program, to mean both: (1) load effects resulting from one or more customers' retail electric service transferring directly from one LSE to another LSE in the same TAC area, and (2) load effects that an LSE cannot reasonably predict and include in an implementation plan or in an initial year ahead load forecast.

11. "Load migration" should not include the following non-exhaustive list of events: changes to approved implementation plans, changes to customer class load profiles, changes to weather assumptions, changes resulting from the receipt of new or updated customer meter data, new service requests, losses due to disconnects or force majeure events, transfers of load out of the TAC area, or forecasting errors. **Notwithstanding the foregoing, an LSE's unexpected change to its enrollment schedule should not be excluded as a reason for the differences between initial and final year ahead load forecasts of the incumbent utilities.**

12. Energy Division's proposal for a Binding Notice of Intent process should be adopted.

13. A meet and confer requirement should be adopted whereby: (1) a meeting between LSEs that anticipate load migration shall occur in advance of the deadline for initial year ahead forecasts, and (2) in LSEs' initial year ahead forecast filings, LSEs should describe dates of meetings, any agreements, and any continued areas of disagreement.

14. Energy Division's proposal to standardize data transfer and handling should be adopted, with a modification to the proposed data provided.

15. Energy Division's conflict resolution proposal should be adopted.

16. Energy Division should convene a working group on counting methodologies for hydro and use-limited fossil resources.

17. Energy Division's revised ELCC proposal appropriately identifies the contribution of in-front-of-the-meter solar resources to grid reliability and reasonably captures the interaction effect between solar and storage. Energy Division's proposed ELCC values should be adopted.

18. The Path 26 constraint should be eliminated.

19. The combining of traditional demand response and energy storage should be measured in aggregate using consistent methodologies so that any QC is a reflection of actual load reductions.

20. Qualifying capacities for third-party demand response provider resources should be based on observable and verifiable event performance data.

21. Submission of three-year load forecasts should be part of the August mandatory load forecasting update for the 2020-2022 local RA requirements only. On a going forward basis, if needed, the multi-year load forecasts should be submitted in the month of April as part of the existing RA timeline.

O R D E R

IT IS ORDERED that:

1. The Commission approves 23,643 megawatts as the existing capacity needed for the Local Capacity Requirement for 2020.

2. The Commission approves 23,635 megawatts as the existing capacity needed for the Local Capacity Requirement for 2021.

3. The Commission approves 22,598 megawatts as the existing capacity needed for the Local Capacity Requirement for 2022.

4. Energy Division shall convene a working group to evaluate improvements and refinements prior to the development of the 2021-2023 local Resource Adequacy requirements. Among other things, the working group shall discuss PG&E's proposal that seasonally varying local capacity requirements be established beginning with the 2021 RA compliance year.

5. The California Independent System Operator's recommended Flexible Capacity Requirement for 2020, ranging from 11,812 megawatts (MW) for July to 18,025 MW for February, shall be adopted.

6. The local Resource Adequacy (RA) waiver trigger price of $40/kW-year, adopted in Decision 06-06-064, shall be updated to the annualized value of the 85th percentile of the monthly local RA prices for South of Path 26, or $51/kW-year.

7. The local Resource Adequacy (RA) penalty price of $3.33/kW-month shall be raised to the equivalent value of the newly-adopted local RA trigger price, or $4.25/kW-month.

8. Local Resource Adequacy (RA) waiver requests shall be submitted via a Tier 2 Advice Letter to the Commission with accompanying service to the service list (in redacted form, if necessary) of the RA proceeding open at the time of the request.

9. We clarify that if a load-serving entity (LSE) incurs both flexible and system Resource Adequacy (RA) deficiencies, the penalty shall be based on the following:

a. Where an LSE incurs equivalent flexible and system RA deficiencies, the system RA penalty price shall apply.
b. Where an LSE incurs a flexible RA deficiency that exceeds its system RA deficiency, the system RA penalty price shall apply to the megawatt amount of the system deficiency and the flexible RA penalty price shall apply to the flexible deficiency megawatt amount that exceeds the system deficiency.

10. Load migration shall be the only allowable reason for differences between initial and final year ahead load forecasts~~.~~**; provided that an incumbent utility shall be permitted to adjust its forecast when an LSE unexpectedly changes its enrollment schedule.** This modification shall begin in the 2021 year ahead forecasting process.

11. "Load migration" is defined, for the purposes of the Resource Adequacy program, as both:

a. Load effects resulting from one or more customers' retail electric service transferring directly from one load-serving entity (LSE) to another LSE in the same Transmission Access Charge area; and

b. Load effects that an LSE cannot reasonably predict and include in an implementation plan or in an initial year ahead load forecast.

The adopted definition of "load migration" shall be effective upon the date of this decision.

12. "Load migration," for the purposes of the Resource Adequacy program, shall not include the following non-exhaustive events: changes to approved implementation plans, changes to customer class load profiles, changes to weather assumptions, changes resulting from the receipt of new or updated customer meter data, new service requests, losses due to disconnects or force majeure events, transfers of load out of the Transmission Access Charge area, or forecasting errors. **Notwithstanding the foregoing, an LSE's unexpected change to**

its enrollment schedule shall not be excluded as a reason for the differences between initial and final year ahead load forecasts for incumbent utilities.

13. Energy Division's Binding Notice of Intent proposal, as discussed in Section 3.5.3, is adopted. This adopted modification shall begin for the 2021 year ahead forecasting process.

14. A meet and confer requirement is adopted whereby:

a. A meeting between load-serving entities (LSEs) that anticipate load migration shall occur reasonably in advance of the filing deadline for initial year ahead forecasts, and

b. In each LSE's initial year ahead forecast filing, each LSE shall describe the dates of meetings with other LSEs to discuss load migration, any agreements, and any continued areas of disagreement.

15. A modified version of Energy Division's proposal to standardize data transfer and handling is adopted, as follows:

a. Community Choice Aggregators (CCA) and Electric Service Providers (ESP) must request from investor-owned utilities (IOU) any load data they will use in developing year ahead forecasts by January 15 of a given year (the year prior to the year for which they are developing forecasts);

b. IOUs must provide CCAs and ESPs with the requested load data by March 1;

c. At a minimum, the load data IOUs provide shall include the following:

i. Hourly meter data for the previous year for each individual account in each jurisdiction requested by the given ESP or CCA, and

ii. Hourly meter data for at least the two years preceding the previous year for each individual account in each jurisdiction requested by the given ESP or CCA, excluding any data that the IOU provided to the same CCA or ESP in an earlier year and that has not been corrected or otherwise updated since that earlier provision.

These requirements shall begin for the 2022 year ahead forecasting process.

16. Energy Division's proposal on conflict resolution, as discussed in Section 3.5.4.3, between load-serving entities is adopted. The adopted proposal shall be effective upon the date of this decision.

17. Energy Division shall convene a working group on counting methodologies for hydro and use-limited fossil resources.

18. Energy Division’s revised Effective Load Carrying Capacity (ELCC) proposal, as discussed in Section 3.7, and the resulting ELCC values shall be the approved ELCC factors in the Resource Adequacy program, as set forth in Appendix A. The adopted values shall be effective beginning with 2020 Resource Adequacy compliance year.

19. Energy Division shall convene a workshop on Effective Load Carrying Capacity methodologies.

20. The Path 26 constraint, adopted in Decision 07-06-029, shall be eliminated, effective upon the date of this decision.

21. The combining of traditional demand response and energy storage shall be measured in aggregate using consistent methodologies so that any qualifying capacity is a reflection of actual load reductions.

22. Qualifying capacities for third-party demand response provider resources shall be based on observable and verifiable event performance data.

23. LSEs shall submit their three-year load forecast as part of the August mandatory load forecasting update for the 2020-2022 local RA requirements only. On a going forward basis, if needed, LSEs shall submit their multi-year load forecasts in the month of April as part of the existing RA timeline and serve only the load for which they have planned.

2~~1~~**4**. Rulemaking 17-09-020 remains open.