BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements.	Rulemaking 16-02-007 (Filed February 11, 2016)

COMMENTS OF THE CALIFORNIA WIND ENERGY ASSOCIATION ON INPUTS AND ASSUMPTIONS FOR DEVELOPMENT OF THE 2019-2020 REFERENCE SYSTEM PLAN

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On behalf of the California Wind Energy Association

January 4, 2019

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I. INTRODUCTION AND SUMMARY

Pursuant to the November 29, 2018, Ruling of Administrative Law Judge ("ALJ") Julie Fitch and ALJ Fitch's December 6, 2018, Ruling extending the comment deadline, the California Wind Energy Association ("CalWEA") submits these responses to the questions posed in the Ruling regarding the modeling inputs and assumptions to be used in the development of the Reference System Plan ("RSP") for the 2019-2020 cycle of the Integrated Resource Planning ("IRP") process. We comment only on the Proposed Inputs and Assumptions for 2019 RSP Development (Attachment A) and not the Proposed Approach for estimating Criteria Pollutant Emissions (Attachment B).

In summary, our major concerns with the proposed inputs and assumptions are:

- The base case assumptions should not continue to assume the indefinite continued operation of existing renewable resources without long-term contracts because many of these resources are at risk of retirement for lack of sufficient revenues and because they may be double-counted in LSE portfolios.
- The model should consider that repowering existing wind projects with new technology will dramatically improve capacity factors and extend project life.
- Because SERVM found more than three times the curtailment that RESOLVE found, and because of the importance of curtailment in developing an optimal, least-cost portfolio, RESOLVE must be adjusted in the next IRP cycle to improve its accuracy with regard to curtailment.
- The Commission should confirm that BTM-PV resources will be treated as candidate resources, given some ambiguity in Attachment A.

- The export limit should be based either on the historical figure of zero, west-wide production simulation studies, or a more reasonable figure of 2,000 MW, as well as a proper hurdle rate based on CAISO TAC charges.
- To test the validity of assumptions regarding Northwest hydro in the RESOLVE model, the Commission should direct all LSEs with recently executed contracts for zero-GHG imports to provide data on actual hourly and monthly historical imports into the CAISO.
- The percent failure rate for approved contracts for existing resources should be lower than 15 percent, and the rate should be higher than 15 percent for approved contracts with LSEs with insufficient track records or credit ratings.
- The Commission should review and update CREZs with regard to the balance of Full-Capacity Deliverability Status ("FCDS") and Energy-Only ("EO") resources within each CREZ, given a new CAISO methodology for assessing the deliverability of wind and solar resources.
- Assumptions for storage should include operational characteristics that track the assumptions in individual LSE plans and procurement. Storage that is not used to follow the system operator's dispatch signals does not provide the same system benefits as storage that follows dispatch signals.
- Either the year 2040 or 2045 should be included in the IRP in order to chart an optimal path to decarbonization and to properly evaluate the benefits of large, capital-intensive resources, such as pumped storage.

II. RESPONSES TO QUESTIONS

1. Base case selection. Please comment on the recommended base case assumptions outlined in Section 1 above. What assumptions would you modify and why?

CalWEA is surprised and disappointed to see that the proposed base case assumptions continue to include the indefinite continued operation of existing renewable resources, as well as gas resources, whether or not they are under long-term contracts, when, in fact, many of these resources are at risk of retirement for lack of sufficient revenues.[1] Most 1980s-vintage wind projects are either in the last few years of their 1980s-era "QF" contracts,[2] are operating under

[1] Consider, for example, the purpose of AB 893 (as amended 8/23/18), which would have mandated procurement "to ensure that existing renewable energy resources stay online and that new or repowered renewable energy resources are contracted by 2019 to ensure California stays on track to meet the 2030 greenhouse gas emissions target." This bill, promoted by CalWEA and the geothermal and biomass industries, was promoted in recognition of the risk that these resources will not continue to operate without additional support.

[2] Virtually all wind energy projects that were operating in California prior to the adoption of the RPS in 2002 were "qualifying facilities" ("QFs") operating under "standard offer" contracts pursuant to

short-term contracts, or are selling directly into the CAISO market.[3] These contracts or prices are insufficient to support the repowering of – or even capital repairs for – these aging facilities. As a result, these projects are at risk of deterioration and shutdown.

Calpine Corporation ("Calpine") has submitted in this docket the results of a modeling run that tested the retention of existing geothermal resources by eliminating these resources from the baseline and found that these resources are not selected until 2030.[4] CalWEA has submitted in this docket the results of a modeling run that removed from the base case all legacy wind resources not under long-term contracts and introduced them as repowered wind resources in the supply curve as candidate resources. The results showed 1,115 MW of repowered wind resources were selected as part of the optimal resource portfolio in the 42 MMT Reference Case, resulting in ratepayer benefits of $36 million/year.[5] For the 2019-2020 cycle, which will modify many of the previous assumptions, it is essential that existing resources without long-term contracts be modeled as candidate resources to more accurately portray whether or not they will actually continue to operate.

An additional essential reason to exclude existing, uncontracted resources from the base case is that, as was discussed at the October 31, 2018, workshop, it appears that existing wind and other existing renewable resources are included in the proposed portfolios of Community Choice Aggregators ("CCAs") and Energy Service Providers ("ESPs"). If these resources are included in the base case, they will be double counted in CCA portfolios.

Therefore, the base case should include only those existing resources that are specifically included in individual IRPs of the load-serving entities ("LSEs"), for the specified duration of their contracts. The fact that a resource may be included in the CAISO's Master Generating Capability list offers no assurance that these resources will continue to operate. Alternatively,

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California's implementation of the federal Public Utility Regulatory Policies Act (PURPA) of 1978. Most of these contracts were 30 years in length. Approximately 1,700 MW of QF wind contracts will have expired between 2014 and 2020, as detailed in CalWEA Attachment 1.

[3] Average prices in the CAISO market in SP-15 averaged 2.8 cents/kWh between mid-2016 and mid-2017. Scheduling and other fees are subtracted from these prices.

[4] *See* R.16-02-007, "Comments of Calpine Corporation on Proposed Reference System Plan and Related Commission Policy Actions" (October 26, 2017) at p. 6.

[5] *See* R.16-02-007, "Comments of the California Wind Energy Association on Proposed Reference System Plan and Related Commission Policy Actions" (October 26, 2017) at p. 4.

existing renewable resources could be handled as is proposed for existing natural gas resources: namely, they could be retired economically with RESOLVE's optimization function.

2. **Baseline resources. What changes would you make to the assumptions in Section 3 of Attachment A with respect to baseline resources? Explain.**

To remedy the problem discussed in response to Question 1, all existing wind, biomass, solar and geothermal resources not under long-term contract should be considered candidate resources.

CalWEA repeats here recommendations that we have previously made about how to model existing wind resources.[6] Approximately 1,000 MW of existing wind resources have not recently been repowered with new technology. See Attachment A for a list of these projects.[7] CalWEA is not aware of any publicly available data sources for the operating costs of existing, aging wind projects. Moreover, costs will vary depending on turbine type, age, and wind regime (e.g., wind turbulence) of the project, among other factors. However, in general, essentially all turbines installed in the 1980s that remain operational[8] are mechanically sound, although their electronic control systems are dated.[9] Most of these turbines continue to operate past 30 years of age, albeit with relatively high operations and maintenance costs, relative to modern turbines, and capacity factors ranging from the high teens to 30%-range. These "work horse" turbines are generally repairable to the extent that replacement parts can be found or fabricated and are not cost prohibitive. However, it would be unreasonable to assume more than a 45-year life.

In contrast, beginning in the 1990s, turbines began to be designed with lifetimes to match expected contract lengths of 20-25 years with a five-year margin beyond that (25-30 years in total). These variable-pitch machines, with smaller gears and bearings, are more difficult to

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[6] Energy Division should review previous filings of biomass and geothermal interests for similar information, or contact these interests directly.

[7] CalWEA submitted this same list as part of its October 26, 2017, IRP comments, and again as part of our April 23, 2018, Informal IRP comments on supply-side resources. Since this time, we are aware that plans to repower at least 70 MW of the listed projects have been announced.

[8] These are Danish-made turbines; nearly all, if not all, U.S. Windpower machines installed in the 1980s are no longer operating.

[9] UC Davis/DNV-GL will soon successfully complete a project funded by the Energy Commission (EPC-16-019) to research, develop and demonstrate cost-effective communications and control systems for aged turbines that will enable these turbines to be remotely dispatched and controlled in response to real-time and forecasted market prices, curtailment orders, forecasted wind production and other factors.

repair. Against this backdrop, based on input from CalWEA member companies that own and operate many of these vintage resources, CalWEA believes that the following average figures would be reasonable for use in the RESOLVE model:

- A reasonable assumption for the average cost of operating a 1980s-vintage wind project is \$0.05/kWh (with a range of \$0.04-\$0.065/kWh). Costs would be lower where capital costs have been paid off and/or capacity factors are higher, and higher where debt remains (many projects have been purchased from their original or later owners within the past decade) and where capacity factors are lower. Large, periodic maintenance costs are included in these figures.
- A reasonable assumption for the average cost of operating 1990s-vintage wind projects is perhaps 25% less than above, given higher capacity factors.

The model should consider that repowering existing wind projects with new technology will dramatically improve capacity factors and extend project life. The cost and production profile of repowered California wind projects should be presumed to be the same as the cost of building new, greenfield wind projects in California. On the one hand, these projects do not incur the early-stage risk-capital outlays associated with a greenfield project, including siting, permitting and interconnection-deposit costs. On the other hand, the very small size of these projects, as indicated in Attachment A, creates a lack of economies of scale.[10] Therefore, many fixed costs (e.g., re-permitting, transactions, certain construction costs and, potentially, interconnection costs) must be spread over many fewer megawatts. While there are many site/project-specific factors that create variability in the costs of both greenfield and repower projects,[11] in general, the model should assume the same cost for small repowers as assumed for new greenfield projects. A reasonable assumption for the average operating cost of a repowered project would be 105% of the operating cost of a new, larger greenfield wind project. This, again, is due to fixed and non-scalable costs associated with small projects, such as service trucks, buildings and personnel.

[10] A large majority of these wind projects (representing about half of the total capacity) is under 30 MW in size. Some 20 projects are under 10 MW in size.

[11] For repowers, these factors include substation conditions and interconnection requirements, terrain, project size, and impacts on neighboring projects.

3. **For planned resources with Commission- or CCA-board-approved contracts, for which the Commission may need to seek additional information as described in Section 3 of Attachment A, in the base case:**

    a. **Is the existence of an approved contract a reasonable determinant for inclusion in the baseline? Why or why not?**

Yes. For existing resources, there is a high likelihood that the resource will continue to operate for the duration of the contract. For new resources, there is a reasonable likelihood that the project will be constructed.

    b. **Is it reasonable to assume a 15 percent failure rate for these approved contracts? If not, what are the sources of uncertainty for these types of resources and how should the Commission plan and account for that uncertainty?**

A 15 percent failure rate is too high for an approved contract with an existing resource; the figure should be no more than 5 percent for such resources. For new projects, failure rates should track historical rates for each LSE type. Where there is not a sufficient track record for CCAs and ESPs, a failure rate significantly higher than the 15% used for the investor-owned utilities ("IOUs") should be assumed where the entity does not have a credit rating from a major ratings institution, since the lack of a credit rating could negatively affect project developers' ability to secure financing.

    c. **Provide data sources that speak to contract success rates.**

Each LSE (or representatives of each LSE type) should provide data to justify a contract success rate above what is generically assumed.

4. **For planned resources without approved contracts in the base case:**

    a. **What criteria should the Commission use to evaluate whether it is reasonable to assume that a planned resource will be completed?**

The only resources that should be considered "planned" and included in the base case are resources that are under development, as described in Attachment A. Any other planned resources are purely speculative, particularly given the early development stages of most

CCAs.[12] Moreover, there are indications that some CCAs' filed plans do not represent their actual internal resource planning, as some CCAs have indicated that the IRPs they filed with the Commission for the 2017-2018 cycle do not represent their "full," "strategic," or "internal" IRPs, which will be developed separately.[13]

More generally, the Commission's IRP process will provide little insight into an optimal portfolio unless all resources beyond those in development are optimized in the modeling process.

b. Is it reasonable to assume a 50 percent failure rate for these types of resources? If not, what are the sources of uncertainty for these types of resources and how should the Commission plan and account for that uncertainty?

As previously indicated, none of these speculative resources should be included in the base case, and therefore the failure rate is moot.

c. Provide data sources that speak to contract or project success rates.

See previous response.

5. As described in Section 3.1 of Attachment A, the 2019-2020 IRP version of RESOLVE will be capable of retiring baseline thermal resources economically within the optimization process. Fixed operations and maintenance costs of baseline thermal resources will be added to RESOLVE's optimization logic, such that existing thermal generators may be retired by the model, subject to reliability constraints, if it is cost-effective to do so. Provide suggestions for data sources that could be used for the fixed operations and maintenance costs of baseline/existing thermal resources.

No response at this time.

6. Candidate resources. Section 4 of Attachment A outlines the proposed candidate resources from which the model can choose for the development of new resources beyond the baseline.

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[12] For example, as Energy Division staff found in aggregating LSE portfolios, the aggregated portfolio substantially oversubscribed available renewable resources in each CREZ and over-relied on resources with full capacity deliverability status, as opposed to energy only resources. *See* Energy Division Staff, *IRP Workshop on Production Cost Modeling, Aggregated LSE Portfolios, and Portfolios for the CAISO Transmission Planning Process*, October 31, 2018, at 46-47.

[13] *See* Comments of Southern California Edison Company (U 338-E) on Load-Serving Entities' Integrated Resource Plans, R.16-02-007, September 12, 2018, at 7-11.

a. General: Comment on the appropriateness of all of the resource types proposed to be modeled.

First, as discussed in response to Questions 1 and 2, existing resources should be treated as candidate resources, rather than being included in the base case.

Second, the Commission should review and update CREZs with regard to the balance of FCDS and EO resources within each CREZ. CAISO has recently proposed a new methodology for assessing the deliverability of wind and solar resources in response to the CPUC's adoption of the ELCC methodology for determining the RA capacity of wind and solar resources.[14,15] Based on the CAISO's new deliverability assessment methodology, the number of projects that will receive FCDS designations in virtually all CREZs (particularly solar-heavy CREZs) is likely to increase significantly. CAISO intends to apply this new methodology to its Transmission Planning Deliverability ("TPD") allocation of queued interconnecting resources up to Cluster 10 in the first quarter of 2019. The Commission should request that the CAISO apply the new methodology to all CREZs for use in the 2019-2020 IRP cycle.

b. Storage: Does the proposed approach for modeling energy storage in RESOLVE adequately reflect the latest available storage technologies? What energy storage technology types would require significantly different input values? Explain in detail how the inputs would vary.

The proposed approach states that both wholesale and behind-the-meter (BTM) battery storage will be included as candidate resources.[16] However, these resources could be operated in different modes, having significantly different system benefits and ratepayer value: 1) they could operate to maximize a plant's revenue (especially when paired with generation[17]); or

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[14] http://www.caiso.com/Documents/DraftRevisedDeliverabilityStudyMethodology.pdf. (Note that the CAISO document is incorrectly dated 12-11-08, which should be 12-11-18.)

[15] http://www.caiso.com/Documents/PresentationProposedRevisionsDeliverabilityMethodologyWebinarDec182018.pdf.

[16] Attachment A at p.31.

[17] Paired storage facilities that benefit from federal tax credits must charge the storage facility from the co-located renewable energy project, rather than from the grid, which severely limits the operation of the storage and the potential benefits it may provide.

2) they could operate to follow CAISO's dispatch signals (more likely if not paired with renewable generation[18]).

The assumptions used in IRP about the way in which storage is operated should track the assumptions in individual LSE plans and as carried out in procurement. That is, specifying a "storage technology" is not enough; operational characteristics must also be specified. Storage that is not used to follow the system operator's dispatch signals would not offer the same system benefits (and could even impose system costs) and should not get credit for producing system benefits.

c. **Offshore Wind: Public data about offshore wind cost and potential in California may be limited and/or outdated. Comment on what data is currently available regarding offshore wind development in California and its possible limitations. If you are aware of new data expected to become available in the next year or two, for example through the work of the California Intergovernmental Offshore Renewable Energy Task Force, provide specific reference to that information.**

No response at this time.

7. **Should large periodic maintenance costs to utility-scale generators be included in IRP modeling? If so, what data sources should be used to estimate these costs? Please refer to Section 3.1.1 of Attachment A for more discussion of this issue.**

No response at this time, given that Section 3.1.1 relates to gas generation and not renewable generation.

8. **IRP modeling in 2017 optimized investment and system dispatch for four representative years: 2018, 2022, 2026, and 2030. The number of representative years represents a balance between precision and model runtime. In modeling for the 2019-20 IRP cycle RSP, Commission staff again proposes to limit the simulation to four years, replacing the 2018 Year with 2020, but continuing to include Years 2022, 2026, and 2030. Then, in the next IRP cycle, study years would become 2022, 2026, 2030, and 2034, with the subsequent cycle addressing Years 2024, 2026, 2030, and 2034 (and so on). This allows for continuity and comparison of assumptions and results across IRP cycles, while continuing to focus between 10 and 12 years in the future. Do you support this approach or recommend a different distribution of study years (i.e., updating the study years with each IRP cycle)? Explain your answer.**

CalWEA supports this proposal, but with the addition of 2040 or 2045 as noted next.

[18] *Ibid.*

9. **In order to analyze the Senate Bill (SB) 100 goal of 100 percent of retail electricity sales being supplied by zero-carbon resources by 2045, Commission staff are also considering using RESOLVE to run a limited number of scenarios on years beyond 2030. Considering the significant amount of modeling and run-time cost of each additional planning year, as well as potentially limited availability of data for years beyond 2030, what year(s) should be studied (e.g., 2035, 2040, 2045) and why?**

Given the state's decarbonization goals, it is critical to conduct near-term planning in view of those longer-term goals so that an optimal course to decarbonization, while maintaining reliability and affordability, can be charted. For example, if some existing resources are not selected in the near-term, but are optimal for the long-term portfolio, the Commission could plan to preserve those existing resources in the interim. It is also important to evaluate resources on a longer-term basis so that the benefits of large, capital-intensive resources, such as pumped storage and transmission, can be fully and properly evaluated. To do this, either the year 2040 or the year 2045 should be included in the IRP, at least as a sensitivity, based on a straight-line trajectory to the 2045 zero-carbon goal.

10. **Voluntary procurement of in-front-of-the-meter renewables beyond statutorily-required levels could impact the development of new renewable energy facilities. For example, many LSEs have programs that allow customers to choose a higher portion of renewables in their electricity supply than required by the RPS, which could result in a need to build additional new renewable energy facilities. Should RESOLVE include projections of voluntary planned procurement (but not yet contracted) when developing future resource portfolios? If so, what are publicly available sources of information that could be used to forecast the volume of such procurement?**

Voluntary procurement of renewables above required levels, if significant, potentially could affect the cost of renewables, both because it will require moving up the supply curve to potentially more costly resources and because it could affect the indirect system costs associated with renewable energy procurements. For example, if CCAs were to exceed mandated levels of renewables of certain type by purchasing, say, more solar, it could remove some of the most desirable sites from the supply curve and could increase overall curtailment levels that could affect RESOLVE's selection of the optimal portfolio. Therefore, RESOLVE should include projections of voluntary planned procurements, if significant, when developing future resource portfolios, at least as a sensitivity.

The Commission should review LSEs' resource plans, supplemented as necessary with information requests to particular LSEs, to determine whether, overall, planned voluntary procurements of renewables are of a sufficient volume to warrant study. We note that, to date, a very small fraction of individual CCA customers opt for products with a higher renewable energy content, although some cities have elected to default their citizens into a higher-renewable-content product that could result in more material voluntary purchases.

11. How should the utilization of the LSEs' current and forecasted REC banks be represented in RESOLVE? Which of the modeling options described in Section 8.3.2 of Attachment A are most appropriate for the base case? What additional options should be considered?

CalWEA recommends that the Commission adopt Option 1B (Section 8.3.2 of Attachment A) for treatment of REC banks in RESOLVE because it will optimize the use of RECs. The Commission should investigate what it might do to improve the liquidity of the REC trading market in the CAISO footprint so that this optimization can be achieved.

12. Provide any additional comments on the appropriateness of the draft inputs and assumptions proposed for the 2019 RESOLVE model runs for IRP purposes. What changes would you make and why? Please include references to the appropriate section number of Attachment A.

CalWEA has four additional comments.

Additional Comment #1: Representative sampling of days. Appendix A, Section 6.1 (p. A-37) does not discuss whether the days selected for RESOLVE's simplified modeling will be adjusted. CalWEA strongly advises that the selected days be adjusted to improve RESOLVE's accuracy with regard to estimating curtailment in future IRP cycles.

The SERVM model results demonstrated that the RESOLVE model (which approximates a full production cost model such as SERVM) grossly underestimated the curtailment associated with the Reference System Plan. Specifically, SERVM found more than three times the curtailment that RESOLVE found -- 10,025-11,055 GWh (4% overall) vs. 2,923 GWh (1% overall) of curtailment, respectively, in 2030.[19] In light of these results and given the importance

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[19] R.16-02-007, Administrative Law Judge's Ruling Seeking Comment on Production Cost Modeling Ruling (September 24, 2018), Attachment B, "IRP Production Cost Modeling with the Reference System Plan and the 2017 IEPR: SERVM model results," slide 34 (September 13, 2018).

of curtailment in developing an optimal, least-cost portfolio, it is essential that RESOLVE be adjusted in the next IRP cycle to improve its accuracy with regard to curtailment.

Specifically, CalWEA recommends that the number of high-curtailment days be increased in RESOLVE or, at a minimum, the weight of the one high-curtailment day currently selected for RESOLVE should be increased.[20] Additionally, post-processing of the SERVM results should show curtailment by resource type, which would provide very important information to LSEs that are conducting procurement.

Additional Comment #2: BTM Storage as a candidate resource. CalWEA is pleased that behind-the-meter (BTM) PV will be considered as a candidate resource, as stated in Attachment A, Section 1.3 ("Key Data Source Updates"). However, Section 4.3, which was referenced there, does not include any further discussion, and Section 2.1.5 states that the 2019-2020 IRP scenarios "could include three options for BTM-PV adoption, each of which is based on the CEC's IEPR Demand Forecast" (low, mid and high).

It is very important that BTM-PV be modeled as a candidate resource, based on installation costs, so that IRP will fulfill its purpose of providing a consistent, technology-neutral evaluation to achieve the state's clean-energy goals while minimizing costs.

In the event that the Commission inappropriately continues to include BTM-PV in the baseline, it should not assume levels of BTM PV that the previous IRP results showed to be grossly non-cost-effective. The RESOLVE results for the initial IRP cycle showed that reducing BTM PV from the 16 GW presumed in the 42 MMT Reference case to 9 GW would save ratepayers $682 million/year.[21] The CEC IEPR's Low BTM PV forecast (IEPR High Demand Forecast), should be used if a CEC figure is going to be used until the Commission determines the successor NEM tariff in view of any location-specific values determined in the Distributed Resources Plan proceeding.[22] In addition, a sensitivity should be run to demonstrate the savings

[20] It is CalWEA's understanding that, for the first IRP cycle, only one or two high-curtailment days were included among the 37 days selected.

[21] These figures are based on installation costs, not NEM-based costs, which would roughly double the cost. See *Ruling Seeking Comment on the Proposed Reference System Plan and Related Commission Policy Actions* (September 19, 2017), Attachment A, at PDF-page 202, and CalWEA's October 26, 2017, comments on that Ruling.

[22] While location-specific transmission and distribution ("T&D") deferral benefits (net of specialized distribution upgrades needed to accommodate high BTM penetrations) are not considered in RESOLVE, the RESOLVE model also does not consider the ratepayer impact of NEM, since the assumed cost of

from lower BTM-PV levels under the assumed NEM rate that underlies the BTM-PV base case assumption.

Additional Comment #3: Assumed import-export limits. Attachment A, Section 6.5, does not state what the assumed limits on CAISO import and export capability will be. Staff's previous assumption of a net export level of 5,000 MW is nearly 5,000 MW over the highest amount that has ever occurred. The "low export" 2,000 MW sensitivity is more reasonable, as CAISO has previously recommended. However, the current net export level is near-zero even though there are no institutional, regulatory, or technical barriers to exporting energy out of the CAISO. If there are limits, they are economic limits resulting from neighboring Balancing Authorities' valuation of energy from the CAISO footprint (due to cost of the energy, the wheeling-out cost, or the neighboring area's own minimum generation limits or other operating considerations). Therefore, the export limit should be based either on the historical figure of zero, west-wide production simulation studies,[23] or a more reasonable figure of 2,000 MW. In all these cases, the exports should also include the proper hurdle rate based on CAISO TAC charges.

Additional Comment #4: Modeling NW Hydro. Attachment A, Section 3.3 states, "A fraction of the total Pacific Northwest hydro capacity will be made available to CAISO as a directly scheduled import. The quantity will be based on the amount of specified hydro imported into California will be based on historical import data."

Extending comments that TURN made in this proceeding in the context of GHG accounting,[24] CalWEA is concerned that, particularly if LSE plans (beyond signed contracts) are incorporated as part of what is modeled (rather than projecting an optimal portfolio

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BTM PV was the estimated installation cost only; the ratepayer impact is likely to be far higher than any T&D net benefits associated with BTM PV.

[23] As stated in CalWEA's January 13, 2017, informal comments in this proceeding, these limits could be reasonably established by performing a WECC-wide study with proper hurdle rates for inter-BA transactions to determine maximum expected export values from California to neighboring BAs. One such value should be established for each study year and interpolation could be used to determine the maximum expected export value for non-study years. The maximum expected export values, thus determined, would then become export limits for the IRP studies.

[24] R.16-02-007, *Opening Comments of The Utility Reform Network on Greenhouse Gas Emissions Accounting Methods* (April 20, 2018), at p.3.

unencumbered by such plans), then the large hydro assumptions may not correspond with "average" hydro dispatch profiles in the future. As TURN explained,

> This result could occur because an LSE is not contracting for the full output of the plant but rather for a fixed quantity of deliveries that represents only a portion of total generation. The contracted quantities may be imported into California during selected hours (or months) of the year that do not approximate the average annual hydro generation profile. Assigning the default average profiles to deliveries under these contracts could result in a serious disconnect between actual and assumed imports.

CalWEA supports TURN's suggestion that, to test the validity of assumptions in the RESOLVE model, the Commission should direct all LSEs with recently executed contracts for zero GHG imports to provide data on actual hourly and monthly historical imports into the CAISO procured under each contract.

Respectfully submitted,

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On behalf of the California Wind Energy Association

January 4, 2019

VERIFICATION

I, Nancy Rader, am the Executive Director of the California Wind Energy Association. I am authorized to make this Verification on its behalf. I declare under penalty of perjury that the statements in the foregoing copy of "Comments of the California Wind Energy Association on Inputs and Assumptions for Development of the 2019-2020 Reference System Plan" are true of my own knowledge, except as to the matters which are therein stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on January 4, 2019, at Berkeley, California.

/s/ *Nancy Rader*
Nancy Rader
Executive Director
California Wind Energy Association