BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

INFORMAL COMMENTS OF THE CALIFORNIA ENERGY STORAGE ALLIANCE ON THE DRAFT SOURCES FOR 2019-2020 IRP DEMAND-SIDE RESOURCES DOCUMENT

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Pursuant to the July 10, 2018 from the California Public Utilities Commission ("Commission") Energy Division staff soliciting comment on the draft *Sources for 2019-2020 IRP Demand-Side Resources* ("Draft Sources") document, the California Energy Storage Alliance ("CESA")[1] hereby submits these informal comments.

[1] 8minutenergy Renewables, Able Grid Energy Solutions, Advanced Microgrid Solutions, AltaGas Services, Amber Kinetics, American Honda Motor Company, Inc., Axiom Exergy, Brenmiller Energy, Bright Energy Storage Technologies, Brookfield Renewables, Carbon Solutions Group, Centrica Business Solutions, Consolidated Edison Development, Inc., Customized Energy Solutions, Dimension Renewable Energy, Doosan GridTech, Eagle Crest Energy Company, East Penn Manufacturing Company, Ecoult, EDF Renewable Energy, ElectrIQ Power, eMotorWerks, Inc., Enel, Energport, ENGIE, E.ON Climate & Renewables North America, esVolta, Fluence Energy, GAF, General Electric Company, Greensmith Energy, Ingersoll Rand, Innovation Core SEI, Inc. (A Sumitomo Electric Company), Iteros, Johnson Controls, Lendlease Energy Development, LG Chem Power, Inc., Lockheed Martin Advanced Energy Storage LLC, LS Power Development, LLC, Magnum CAES, Mercedes-Benz Energy, NantEnergy, National Grid, NEC Energy Solutions, Inc., NextEra Energy Resources, NEXTracker, NGK Insulators, Ltd., NRG Energy, Inc., Parker Hannifin Corporation, Pintail Power, Primus Power, Range Energy Storage Systems, Recurrent Energy, Renewable Energy Systems (RES), Sempra Renewables, Sharp Electronics Corporation, SNC Lavalin, Southwest Generation, Sovereign Energy, Stem, STOREME, Inc., Sunrun, Swell Energy, True North Venture Partners, Viridity Energy, VRB Energy, Wellhead Electric, and Younicos. The views expressed in these Comments are those of CESA, and do not necessarily reflect the views of all of the individual CESA member companies. (http://storagealliance.org).

I. INTRODUCTION.

CESA appreciates the opportunity to provide informal input on the potential data sources to be used for resource modeling in RESOLVE in the 2018-2019 Integrated Resource Planning ("IRP") cycle. Overall, CESA supports the Commission's efforts to consider key modifications to IRP modeling to ensure that distributed energy resources ("DERs") such as behind-the-meter ("BTM") energy storage and smart electric vehicle ("EV") charging are optimized as potential candidate resources. However, as Commission staff and the E3 team are likely aware, forecasting and optimizing BTM resources can be challenging given their interactions with retail rates and customer-sited services, which may not be entirely visible to system planners and may vary by customer load profile and characteristics. In addition, customer-sited resources differ from system resources in that they have the potential to avoid new infrastructure costs, such as new transmission and distribution investments. In these informal comments, CESA thus supports the Commission making certain manageable modifications to IRP modeling to better represent the capabilities and benefits of DERs but notes that certain modeling enhancements may have to await methodological or technical developments in other proceedings and agencies.

II. RESPONSE TO QUESTIONS.

Below, CESA provides our select responses to the questions posed by Commission staff from the Draft Sources document related to customer-side energy storage, EVs and EV chargers, demand response ("DR"), distribution deferral capacity and cost, and the miscellaneous/general questions.

Question 4: What data sources should be considered to forecast BTM energy storage adoption?

Given that forecasting methodologies require significant consensus-driven discussions and collaboration in regular technical working group processes, CESA believes that the forecasting questions may be best addressed at the California Energy Commission ("CEC") and its Demand Analysis Working Group ("DAWG"). CESA understands that BTM energy storage was included in the Integrated Energy Policy Report ("IEPR") for the first time in the final 2017 forecast. The CEC staff has previously indicated in the Distribution Forecasting Working Group in the Distribution Resource Planning ("DRP") proceeding that they are seeking to improve forecasting methodologies, including considering a "bottom-up" approach proposed by CESA based on economic payback and returns.[2]

In the interim, CESA supports the Commission's use of the Self-Generation Incentive Program ("SGIP") as the primary data source for forecasting BTM energy storage deployments and operational profiles. The SGIP data contains information on rated kW and kWh capacity, customer sectors, location, and usage shapes for SGIP-funded projects. Given the semi-public nature of SGIP data, the Commission and E3 team will likely have access to a rich dataset in the annual impact evaluation reports, though data quality is lacking in certain areas. The CEC's IEPR forecast already leverages SGIP data to some degree by estimating and projecting average annual additions based on previous levels of SGIP-funded energy storage deployment. Thus, by using the IEPR forecast, the Commission and E3 should already be using SGIP as a primary data source.

However, the IEPR forecast for BTM energy storage faces several limitations. First, the program is expected to retire in 2020, so it is unclear if the current assumed trajectory for growth based on SGIP deployment is a reasonable forecast. This issue may not be addressable using the

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[2] See *Distribution Forecasting Working Group: Energy Storage Assumptions & Forecasts*, presented by CESA on May 16, 2018. http://capabilities.itron.com/DFWG/documents/2018-05-16%20DFWG%20-%20CESA%20Presentation%20on%20Energy%20Storage%20Assumptions%20and%20Forecasts.pdf

current forecasting methodology. Instead, going forward, CESA hopes to work with the CEC on developing a "bottom-up" approach whereby BTM energy storage deployment is driven by economic payback and returns to customers based on their load profiles and bill savings. Second, the assumed operational profile where the CEC assumes a 90% peak discharge impact relative to the nameplate capacity of the BTM energy storage system may not accurately reflect their operations. This challenge may be addressed through the use of representative profiles from the SGIP project data, but CESA cautions that such discussions may be best had in the DAWG, rather than this IRP Modeling Advisory Group. Therefore, at the moment, CESA supports the use of the IEPR for the BTM energy storage forecasts.

Other potential data sources for BTM energy storage forecasts include: the 2019 building energy efficiency standards that may encourage some energy storage adoption with new home and building construction to comply with zero net-energy ("ZNE") requirements; supply-side procurement of BTM energy storage through the Demand Response Auction Mechanism ("DRAM") and through Local Capacity Requirement ("LCR") Request for Offers ("RFOs"); and load-modifying DR programs.

<u>**Question 5**</u>**: What assumptions should be made about how BTM energy storage responds to price signals, either wholesale or utility rates? What data sources should be considered for developing BTM energy storage charge and discharge shapes? Will the price signals and resulting dispatch accurately capture the potential future value of BTM storage? If candidate BTM energy storage is modeled as responding to rates, what assumptions regarding future rate structures would need to be made?**

The Draft Sources document notes that customer-sited energy storage may be modeled in the 2019 IRP as either responding to wholesale price signals or maximizing customer bill reduction. Because the latter will require additional RESOLVE development (in addition to further work at the DAWG), CESA agrees that BTM energy storage should be modeled for wholesale price signals. CESA understands that maximizing customer bill reduction is important to the deployment of BTM energy storage at customer sites, but for the purposes of identifying and selecting BTM energy storage resources as potential candidate resources, RESOLVE may be better positioned to have BTM energy storage resources respond to wholesale price signals. The provision of DR is already represented in RESOLVE. Additionally, with the Commission intent on integrating its DR programs and portfolios into the California Independent System Operator ("CAISO") market, CESA believes that customer energy storage dispatched in response to wholesale signals will be captured through the selection of energy storage as DR resources in RESOLVE. Based on a previous webinar meeting, the Commission and E3 explained that DR resources and energy storage resources will be modeled separately, which CESA supports given the operational and performance differences of energy storage in being able to provide real-time market participation and providing fast-response without customer attrition. In addition, BTM energy storage resources participating in the CAISO market will likely be captured in selecting energy storage as a DR resource in RESOLVE because these resources are predominantly configured as non-export systems that provide Resource Adequacy ("RA") capacity or other wholesale domain services via DR. BTM energy storage resources are capable of contributing to reserve requirements for spin, frequency response, regulation, and load following, but current regulations and market participation models do not allow for the provision of these services.

Whether responding to wholesale dispatch instructions to provide RA or to retail price signals (*i.e.*, rate schedules), the potential full value of BTM energy storage resources may still not be captured. Price signal response is an important value stream for BTM energy resources, but as discussed in our previous comments,[3] energy storage resources are capable of multiple-use applications ("MUAs") to deliver multiple grid services from the same asset or portfolio of assets. BTM energy storage resources are also capable of MUAs to contract for other grid needs. Even then, there may still be value that is not captured by the deployment of energy storage for current, non-monetizable grid benefits, such as increased hosting capacity, renewables integration support, and grid resilience. RESOLVE should not strive to model all of these values for all resources, but it is important to note that response to price signals of BTM energy storage systems does not capture the "potential *full* value" as posed in this question.

CESA does not believe that RESOLVE needs to account for how BTM energy storage resources may respond to future rate structures. In general, CESA does not believe that future rate structures need to be modeled for any resources since TOU periods are unlikely to change until the mid-2020s according to D.17-01-006, which limits risk when planning out just a bit longer to 2030.[4] Furthermore, the 2018 Reference System Plan favored a solar-heavy portfolio by 2030, indicating that current trends with mid-day overgeneration followed by a steep ramp in the evening are only likely to get more pronounced. For the time being, the Reference System Plan seems to indicate the current or shortly forthcoming TOU periods with peak periods shifted to around the

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[3] *Informal Comments of the California Energy Storage Alliance on the Draft Sources for 2019-2020 IRP Supply-Side Resources Document*, filed on April 23, 2018. http://www.storagealliance.org/sites/default/files/Filings/2018-04-23%20CESA%27s%20Informal%20Comments%20on%20IRP%202019%20Draft%20Sources%20Document%20-%20FINAL.pdf

[4] *Decision Adopting Policy Guidelines to Assess Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payments*, D.17-01-006, issued on January 19, 2017, p. 7. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M172/K782/172782737.PDF

"Base TOU periods should continue for a minimum of five years (unless material changes in relevant assumptions indicate the need for more frequent Base TOU period revisions) and each IOU should propose new Base TOU periods, if warranted, at least every two general rate case cycles"

4-9 pm period. Finally, CESA believes it is currently speculative to forecast retail rates so far in advance.

<u>Question 6</u>: Do parties have suggestions on how to represent hybrid resources (e.g. storage and solar) in RESOLVE? Can this be modeled by reducing the capital cost of the storage resource and paired resource to account for costs savings from co-locating facilities and Investment Tax Credit (ITC) savings? If so, what data should the CPUC rely on to accurately capture cost reductions? How can the CPUC accurately estimate any reduction in savings caused by any operational constraints placed on hybrid resources by ITC rules or shared infrastructure?

At minimum, RESOLVE should represent hybrid resources with reduced capital costs from shared facilities (and the ITC in the case of energy storage paired with solar). CESA reiterates its previous comments here,[5] where the Commission could reference a study produced by the National Renewable Energy Laboratory ("NREL")[6] on how pairing energy storage resources with solar plants can impact the costs and benefits of these hybrid assets, depending on the configuration and the charge profile of the resource. Notably, the study found significant balance of system and inverter cost savings as well as a major benefit in the ITC that boosted the viability of DC-coupled solar-plus-storage systems. Similar to NREL's approach, the Commission and E3 could leverage its existing data inputs for the system, O&M, module, and balance of system costs for solar PV and energy storage resources to calculate assumed avoided cost based on the balance of system costs to eliminate one of the inverter costs in addition to other 'soft costs' for DC-coupled systems and just the engineering and site acquisition costs for AC-coupled systems. With Lazard providing

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[5] *Informal Comments of the California Energy Storage Alliance on the Draft Sources for 2019-2020 IRP Supply-Side Resources Document*, filed on April 23, 2018, p. 7. http://www.storagealliance.org/sites/default/files/Filings/2018-04-23%20CESA%27s%20Informal%20Comments%20on%20IRP%202019%20Draft%20Sources%20Document%20-%20FINAL.pdf

[6] Denholm, Paul, Josh Eichman, and Robert Margolis. *Evaluating the Technical and Economic Performance of PV Plus Storage Power Plants*, National Renewable Energy Laboratory, published on August 2017. https://www.nrel.gov/docs/fy17osti/68737.pdf

cost breakdowns for each resource, CESA believes such an approach may be possible to more reasonably represent the cost savings of hybrid solar-plus-storage resources.

For solar-plus-storage systems claiming the ITC, the Commission and E3 may consider creating different candidate resources for 75% charging from the solar facility and 100% charging from the solar facility, as well as different sizing and duration of paired energy storage resources relative to the nameplate capacity of the solar facility. Understandably, this is a difficult task without several representative profiles. At the moment, CESA has not identified such profiles but hopes to work closely with the IRP modeling team to identify solutions to model such different hybrid solar-plus-storage configurations.

There are several other hybrid energy storage configurations that should be modeled in the 2019 IRP as well. First, energy storage resources should be modeled to be added to existing gas-fired generation to reduce greenhouse gas ("GHG") emissions of the facility and also take advantage of cost savings from shared facilities and infrastructure. When an existing gas-fired facility is hybridized, it should become a new resource and the former gas-fired resource should be removed to ensure that the capacity is not double-counted. Second, energy storage resources should be capable of being paired with wind generating facilities as well. Finally, CESA believes that the paired energy storage technology should flexibly consider all types of technologies – not only including lithium-ion batteries but also flow batteries, thermal storage, and compressed air storage.

<u>Question 7</u>: In addition to the CEC IEPR Demand Forecast, what other public data sources should be considered for representing EV adoption forecasts in IRP? What sources best represent the Governor's goal of 5 million zero-emission vehicles on the road in California by 2030?

CESA does not have any additional data sources to recommend at the moment to inform the EV forecast in the IRP. CESA believes that the CEC has developed a comprehensive and robust EV forecasting methodology that uses choice models and propensity models (based on household and per-capita income factors and commute time) for light-duty EVs in different sectors. The CEC methodology appears to account for a broad range of factors that smartly feed into the forecast, including tax credits and rebate, HOV lane access, and vehicle/battery prices.[7] To align with the Governor's goal of 5 million zero-emission vehicles ("ZEVs") on the road in California by 2030, CESA recommends that the CEC's "aggressive" scenario be used as the baseline in RESOLVE, which results in a forecast of 5.3 million plug-in electric vehicles ("PEVs") by 2030. In this scenario, the EV battery price forecast of $73/kWh aligns with the forecast of publicly available information from Bloomberg New Energy Finance.[8] Furthermore, the IRP should also be striving to meet the state's policy goals. The Governor's goal is being used in other EV-related proceedings to justify the scope and scale of programs and investments, and similar minimum goal posts should be set for EV forecasts in the IRP.

A key gap in the EV forecasting efforts may be the impact of medium- and heavy-duty EVs, which has been a major focus of the Transportation Electrification Applications by each of the utilities. While these programs and investments have yet to be implemented, the Commission and the E3 modeling team should align and possibly adjust the EV forecast to account for new electric load coming from this segment of EVs.

<u>Question 8</u>: What data sources should be considered in developing EV charging shapes for IRP?

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[7] CESA believes that some of the improvements to the EV forecasting can be done through the Demand Analysis Working Group ("DAWG") at the CEC, such as the increased choice that drivers now have (more than the 13 PEV models they assume to be available in the "aggressive" scenario) as well as the qualitative factors around more chargers being available, especially at multi-unit dwellings and low-income communities due to the Transportation Electrification Applications.

[8] "Lithium-ion Battery Costs and Market." Presentation by Claire Curry at Bloomberg New Energy Finance on July 5, 2017. p. 7. https://data.bloomberglp.com/bnef/sites/14/2017/07/BNEF-Lithium-ion-battery-costs-and-market.pdf

CESA supports the data sources identified for developing the EV charging shapes for IRP at this time, which is largely unchanged from the 2018 IRP approaches. Currently, there are a number of programs and investments that will likely be underway in response to the Transportation Electrification Applications that will deploy EV chargers and infrastructure beyond the home and workplace that will require the Commission to revisit these assumptions, but CESA understands that there is too little information at this time to inform the 2019 IRP.

Question 9: Are there any other data sources to consider that could inform the assessment of the potential value of smart charging in IRP?

One limitation of the EV charging load shapes is the lack of TOU impacts being incorporated into the IRP model. EV charging is not just governed by the charging requirements to meet a customer's driving needs, but it may also be incentivized through EV rate structures – some of which are whole-home rates. These rates are not modeled, and like with BTM energy storage, it may be too complex to model at this time. However, CESA appreciates that smart EV charging is currently modeled in the DR supply curve, which should capture some of the smart charging capabilities of EV chargers. Data on this may be available through the DRAM pilots and/or other DR programs.

Question 10: Are there other data sources that should be considered for baseline and candidate DR?

CESA generally agrees with the data sources considered for the modeling of DR baselines. CESA supports the usage of the actual data from the DR Load Impact Reports, bid procurement data, and DRAM performance data to the degree that they are available. CESA believes these data sources are comprehensively capture the current and future DR resources that will serve the grid and does not have further recommendations on data sources at this time. CESA does request that the IRP documentation include some overview of how the Lawrence Berkeley National

Laboratory's DR-PATH model is incorporated into RESOLVE for ease of understanding and accessibility into how DR is modeled in RESOLVE, rather than to have to track and process that separate source document independently. The various cost inputs in DR-PATH may require updating as new publicly available cost data from Lazard is published.

Question 11: Are there other methods that should be considered for modeling candidate DR? What would be the advantages or disadvantages of these proposed approaches?

CESA believes that the current method used to model the inputs described in the Draft Resources documents is generally acceptable as it computes complex optimizations in a reasonable runtime. CESA's only suggestion is to consider how RESOLVE can be enhanced to reflect a growing grid need for dispatchability and sub-hourly response. These issues are not limited to the modeling of DR, but there are several developments in the DR world that are relevant. The CAISO is currently finalizing the design of a new Proxy Demand Response ("PDR") resource in the Energy Storage and Distributed Energy Resources ("ESDER") Initiative to allow for sub-hourly dispatchability as a main component. There may be a disadvantage in significant model runtimes to an approach that conducts sub-hourly analysis. One way to address this issue would be to conduct sub-hourly analysis with a subset of days, instead of all of the ones selected.

Question 12: Could different methods, aside from the E3 proposal, be used for incorporating distribution-level impacts into IRP modeling?

CESA supports E3's proposal to model distribution-level impacts in IRP modeling where costs for identified distribution upgrade needs can be used to derive potential avoided distribution costs for distributed energy resources ("DERs"). E3's approach is a smart approach to create a "supply curve" of deferral needs that are translated to deferral value and decremented from the cost of the DER resource when the deferral need is met by the DER installed before distribution capacity upgrade. CESA believes that modeling DERs as candidate resources and for avoided distribution costs will ensure that RESOLVE is not biased against DERs because the current RESOLVE model focuses on system-level benefits.

Rather than proposing a different approach, CESA seeks improvements/additions on E3's proposed approach or clarifications on their approach. First, how will E3 determine distribution costs that are incurred? Does this mean that certain "selectable" DERs will actually face higher costs on the distribution system in the supply curve? Second, timing of the DER deployment appears to be a factor in whether a DER can have their costs decremented by the avoided distribution cost. What are the assumptions that will be used for whether DERs can be deployed in time to meet the distribution upgrade need? Timing of resource deployment does not appear to be a factor in considering the selection of any supply-side or demand-side resource, but there is an element of timing that is introduced to be attributed with avoided distribution cost value. CESA proposes that timing not be a consideration as the Distribution Deferral Opportunity Report ("DDOR") already factors that in with the timing and technical screening criteria. Thus, all distribution grid needs identified in the DDOR should be assumed to be met by DERs and the selected DERs for the identified distribution grid need should be attributed an avoided distribution cost value.

<u>Question 13</u>: Are there other data sources that should be considered for estimates of avoided distribution costs and quantities, beyond the DRP-based analysis proposed by the IOUs in the June MAG?

CESA does not propose other data sources at this time and finds it is appropriate to use the Grid Needs Assessment ("GNA") and DDOR to develop the estimates of avoided distribution costs and quantities. CESA especially finds the approach to "bound" the analysis around the GNA for the high end of what DERs could potentially defer and the DDOR for the low end of what DERs could provide in distribution deferral services.

However, CESA wishes to understand from the investor-owned utilities ("IOUs") on whether the actual avoided distribution cost data will be usable in RESOLVE, as the GNAs filed by each IOU on June 1, 2018 does not currently include the traditional cost of mitigation. This data is important to calculating the avoided distribution cost. At the moment, only the quantity or percentage of the deficiency and the location of the deficiency at differing levels of granularity are made available. The stakeholders in the DRP proceeding (R.14-08-013) will likely need to address this issue, but without the traditional cost of mitigation, CESA believes that the Commission and E3 will not have the information needed to calculate these values.

<u>Question 14</u>: Are there different methods that can be used to apply data generated by DRP-based tools in IRP, aside from the methods proposed by the IOUs in the June MAG?

CESA does not have any suggested different methods that can be used to apply to data generated by the DRP-based tools in the IRP. Currently, the Integrated Capacity Analysis ("ICA") and Locational Net Benefits Analysis ("LNBA") methodologies do not appear to be ready for use in the IRP models.

<u>Question 16</u>: Should staff represent transmission avoided cost in IRP modeling? If so, how? Please provide a specific approach for deriving the costs and quantities and include suggested data sources for each.

The avoided transmission value of DERs should definitely be included in the IRP modeling. Failing to include avoided transmission in the modeling would create an inaccurate picture of the costs of distributed resources versus transmission-sited ones, since the ability to avoid new transmission investment is a significant benefit of distributed resources. For example, in the 2017-2018 transmission plan, the CAISO recently cancelled or revised 39 transmission projects with ratepayer savings of $2.6 million due to revised load forecasts "strongly influenced by energy efficiency programs and increasing levels of residential, rooftop solar generation."[9]

The Commission is currently developing a method for valuing transmission avoided cost as part of the LNBA working group of the DRP Proceeding, which has already done a significant amount of work on this issue, including soliciting parties' proposal and holding several working group meeting. Rather than duplicating this work or starting over with new proposals, CESA recommends the IRP proceeding adopt whatever method is eventually adopted via Commission Decision in the IRP proceeding. Taking a different approach would cause confusion and contrasting results by having two different methods for calculating the same value in two different proceedings. If a Decision in the DRP proceeding does not adopt a transmission avoided cost methodology prior to the time when it is needed for modeling in the 2019 IRP cycle, the Commission should delay optimizing DERs in the IRP until the following IRP cycle.

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[9] "Board approves 2017-18 Transmission Plan, CRR rule changes," CAISO News Release, March 23, 2018. http://www.caiso.com/Documents/BoardApproves2017-18TransmissionPlan_CRRRuleChanges.pdf

III. CONCLUSION.

CESA appreciates the opportunity to submit these comments and looks forward to working with the Commission going forward in this proceeding.

Respectfully submitted,

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