**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

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| 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<br>(Filed February 11, 2016) |

# COMMENTS OF THE CALIFORNIA ENERGY STORAGE ALLIANCE ON ADMINISTRATIVE LAW JUDGE'S RULING SEEKING COMMENT ON PROPOSED REFERENCE SYSTEM PLAN AND RELATED COMMISSION POLICY ACTIONS

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In accordance with the Rules and Procedure of the California Public Utilities Commission ("Commission"), the California Energy Storage Alliance ("CESA") [1] hereby submits these comments on the *Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Plan and Related Commission Policy Actions*, issued on September 19, 2017 ("Ruling").

[1] 8minutenergy Renewables, Able Grid Energy Solutions, Adara Power, Advanced Microgrid Solutions, AES Energy Storage, AltaGas Services, Amber Kinetics, American Honda Motor Company, Inc., Bright Energy Storage Technologies, BrightSource Energy, Brookfield, California Environmental Associates, Consolidated Edison Development, Inc., Customized Energy Solutions, Demand Energy, Doosan GridTech, Eagle Crest Energy Company, East Penn Manufacturing Company, Ecoult, EDF Renewable Energy, ElectrIQ Power, eMotorWerks, Inc., Energport, Energy Storage Systems Inc., GAF, Geli, Green Charge Networks, Greensmith Energy, Gridscape Solutions, Gridtential Energy, Inc., Hitachi Chemical Co., IE Softworks, Innovation Core SEI, Inc. (A Sumitomo Electric Company), Johnson Controls, LG Chem Power, Inc., Lockheed Martin Advanced Energy Storage LLC, LS Power Development, LLC, Magnum CAES, Mercedes-Benz Energy, National Grid, NEC Energy Solutions, Inc., NextEra Energy Resources, NEXTracker, NGK Insulators, Ltd., NICE America Research, NRG Energy, Inc., Ormat Technologies, OutBack Power Technologies, Parker Hannifin Corporation, Qnovo, Recurrent Energy, RES Americas Inc., Sempra Renewables, Sharp Electronics Corporation, SolarCity, Southwest Generation, Sovereign Energy, Stem, STOREME, Inc., Sunrun, Swell Energy, Viridity 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 commends the Commission and the Energy and Environmental Economics ("E3") team for their work in laying out the state's first ever Integrated Resources Plan ("IRP") process and conducting a complex modeling exercise to optimize resource additions that meet Renewable Portfolio Standard ("RPS"), greenhouse gas ("GHG") emission, and grid reliability objectives, in addition to accounting for other miscellaneous requirements provided in Senate Bill ("SB") 350, such as energy efficiency, transportation electrification, and disadvantaged communities ("DACs"). CESA understands that this is a complex effort that will become increasingly difficult as the number of load-serving entities ("LSEs") grows.

Overall, CESA generally supports the Commission's modeling results, process, and policy actions. In these comments, CESA highlights several key limitations of the RESOLVE model, which are important and affect how certain resources such as energy storage are represented as being needed or selected. These limitations include the energy storage capital cost assumptions, the inability to model the potential economic retirement of existing gas-fired generation, the cost of renewable curtailment, and the viability of relying on curtailment as a grid integration solution.

At the same time, CESA does not wish to delay timely policy actions and authorization of near-term resource procurement to take advantage of the expiring Federal investment tax credit ("ITC") and production tax credit ("PTC"). While many stakeholders may disagree on the assumptions, scenarios, or policy actions, the one key takeaway of the 2017 IRP process has been that near-term renewables procurement is prudent and represents cost-effective investments to reach the state's RPS and GHG goals. At the beginning of the 2017 IRP, the Commission positioned this first iteration of the IRP as a trial run that would lay out the IRP process for the first time, develop linkages between planning and procurement as well as across agencies, and understand whether and how E3's RESOLVE modeling tool could be used to guide resource investment decisions. CESA supports these objectives – but the modeling results have elucidated the need to drive near-term renewables procurement, and therefore urges the Commission to move forward from modeling analysis to timely policy actions and procurement authorizations. The modeling limitations that CESA highlights are intended to provide modest suggestions on how the Reference System Plan can be adjusted, to serve as recommendations for modeling in the next IRP cycle, and to guide interim policy actions until the next IRP cycle begins.

In other words, CESA recommends that the Commission now focus its attention on how to link these planning efforts to procurement vehicles through timely policy actions. CESA's comments here can be summarized as follows:

- Energy storage cost assumptions are improved but still show a capital cost range and still-too-high forecasts through 2030, which should be addressed by adopting the low battery cost sensitivity as the Reference System Plan.

- The case for early renewable procurement is compelling due to the expiring ITC/PTC, which paired energy storage resources can take advantage of as well, and the Commission should thus authorize near-term procurement.

- The RESOLVE model is limited in that it does not reflect the true costs of keeping the existing gas fleet online and thus the study on natural gas fleet impacts is reasonable and important as it informs grid reliability and resource investment decisions going forward.

- The Commission critically omits any policy action on bulk storage, but given their economic selection in the 30 million metric ton ("MMT") scenario and the Legislature's expressed intent to push for a higher RPS goal, continued studies and establishment of a forum to discuss joint procurement pathways is justified.

- The value of resilience benefits should be incorporated in the procurement stage of the IRP given that RESOLVE only models "representative days" that may not sufficiently put weight on extreme event conditions, which are occurring with greater frequency.

- Intra-hour production cost modeling should be conducted for a single study year rather than hourly production cost modeling for two study years, if resources/time are constraints.

## II. ENERGY STORAGE COST ASSUMPTIONS.

Considering the fact that the Reference System Plan will be used as guidance for the LSEs to develop and file their IRPs and for the ultimate determination of whether to authorize resource procurements, resource cost assumptions are a critical input into any grid planning effort. In line with comments submitted by the California Independent System Operator ("CAISO") in the California Energy Commission ("CEC") docket for the environmental review of the Puente Power Project,[2] the best means to discover the most up-to-date resource cost data is through a competitive solicitation. CESA agrees, but notes that for the purposes of grid planning, such resource cost data is generally not publicly available. Yet, resource cost data is critically important in guiding LSEs in their own grid planning efforts as well as for the Commission in providing guidance on the types of resources that need to be procured to provide capacity, ancillary services, transmission/distribution deferral, or whatever other grid services are being sought. While the ultimate amount of each resource type procured may be a range as new resource cost and capability information is discovered during the competitive solicitation process, directional guidance from the Commission is needed through robust grid modeling and planning. Thus, to the greatest extent possible, the IRP should incorporate the latest resource cost data and forecasts that are publicly available to ensure that the guidance and policy recommendations from the Commission properly reflect the true range of cost-effective resources available to address various grid reliability needs and policy objectives.

CESA focuses here specifically on the energy storage cost assumptions used as inputs to the RESOLVE model. Overall, CESA appreciates and supports the revised battery storage cost

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[2] *California Independent System Operator Corporation Post-Hearing Comments*, California Energy Commission Docket No. 15-AFC-01, filed on September 29, 2017. http://docketpublic.energy.ca.gov/PublicDocuments/15-AFC-01/TN221345_20170929T153404_CAISO_Comments_regarding_Puenete_Power_Project.pdf

revisions in response to stakeholder comments[3] and new information provided in DNV GL's *Battery Energy Storage Study for the 2017 IRP*.[4] The mid and low prices ($523/kWh and $290/kWh, respectively) for battery storage in 2018 under the revised assumptions are generally more representative of the actual range of energy storage costs in the market today. However, CESA believes that the high-end prices ($777/kWh) are still far too high as compared to the costs at which the industry is deploying energy storage projects today and thus do not correctly inform LSEs by presenting a wide range of energy storage costs with a high price bound.

In addition to the DNV GL report cited as justification for the revised energy storage cost assumptions, CESA highlights the publicly available literature review on energy storage installed costs conducted by the Energy Storage Association ("ESA") as a reason why the high price bound used in the IRP modeling is not in sync with current industry trends and does not represent a true "sensitivity case", which should only be considered if it represents a potential future scenario. Using publicly available cost data sourced from IHS Research and GTM Research, ESA found the upper and lower bound of 2016 *installed* costs of lithium-ion battery storage to be between $453/kWh and $415/kWh,[5] which suggests that RESOLVE's mid-point estimate for 2018 lithium-ion battery storage should be approximated as the high-point estimate for capital costs for energy. Even then, using the mid-point estimate as the high-end of the price

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[3] *Opening Comments of Pacific Gas and Electric Company to Administrative Law Judge's Ruling Seeking Comment on Staff Proposal on Process for Integrated Resource Planning*, filed on June 28, 2017, pp. 27-28; *Comments of the California Energy Storage Alliance on the Administrative Law Judge's Ruling Seeking Comment on Staff Proposal on Process for Integrated Resource Planning*, filed on June 28, 2017, pp. 16-17.

[4] Ruling Attachment B, *RESOLVE Documentation: Inputs & Assumptions*, pp. 42-44.

[5] Energy Storage Association, *Including Advanced Energy Storage in Integrated Resource Planning: Cost Inputs and Modeling Approaches v1.1*, November 2016, p. 5. http://energystorage.org/system/files/attachments/irp_primer_002_0.pdf

range for lithium-ion battery storage may be overstating costs given the current downward trajectory of battery costs.

Furthermore, CESA also refers the Commission to a recently released report from the International Renewable Energy Agency ("IRENA"), which completed a peer reviewed analysis of current energy storage costs as well as projections through 2030 using a methodology that identified economic and materials-based factors that could drive down costs with scale and innovation.[6] This new report is comprehensive and covers not just classes of energy storage technologies (*e.g.*, lithium-ion, flow batteries) but also specific chemistries and sub-classes of each type of technology. In it, IRENA estimates lithium-ion batteries have installed costs at $350/kWh in 2016,[7] which again points out how the high-end estimate used in RESOLVE does not reflect industry costs today. Energy storage cost forecasts may also require further examination and revision. In the IRENA report, lithium-ion battery chemistries are projected to have installed costs between $80/kWh and $340/kWh by 2030, which is well within the bounds of RESOLVE's low- and mid-point estimates for lithium-ion battery storage capital costs in 2030.[8] Therefore, CESA recommends that the Commission adopt the mid-point estimate in RESOLVE for lithium-ion battery storage costs as the new high-point estimate (*i.e.*, the new

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[6] International Renewable Energy Agency, *Electricity Storage and Renewables: Costs and Markets to 2030*, October 2017. pp. 126-129.
http://www.irena.org/menu/index.aspx?mnu=Subcat&PriMenuID=36&CatID=141&SubcatID=3879

[7] *Ibid*, p. 77.

Note: IRENA reports this cost estimate as reflecting that for the nickel cobalt aluminum (NCA) battery chemistry, which is one of the least expensive on the market. There are other lithium-ion battery chemistries that have higher cost estimates in 2016, according to IRENA. CESA observes, however, that the NCA battery chemistry is currently being used by a number of industry market leaders such as Tesla, LG Chem, and Samsung SDI, thus providing a reasonably fair representation of where the industry is currently in terms of installed costs.

[8] *Ibid*, p. 77.

high battery cost sensitivity) and adopt the low-point estimate in RESOLVE for lithium-ion battery storage costs as the new mid-point estimate (*i.e.*, the new Reference System Plan).

Finally, for lithium-ion battery storage, RESOLVE assumes that additional costs are included in Year 10 to replace the battery cell, with the replacement cost being the cost of the battery during the year of replacement.[9] However, CESA believes that this unnecessarily increases the investment cost for battery storage systems given that the capital costs used in RESOLVE likely already include warranty costs that ensure that the system has a 20-year life. At minimum, RESOLVE should remove the capital cost of battery storage in Year 10. This adjustment coupled with the lower capital costs for energy storage described above would bring levelized costs within the range of what is being deployed in the market today.

Lithium-ion battery storage is not the only type of energy storage technology where capital cost assumptions may need to be re-examined. For vanadium redox flow batteries, IRENA estimates the 2016 installed costs at around $360/kWh, with a drop to $120/kWh by 2030, suggesting that the low-point estimate in RESOLVE should be repositioned as the mid-point estimate for flow batteries. Moreover, while pumped storage was the technology focus of the bulk storage resource class, there are different cost assumptions and operating parameters reflective of other bulk storage resources such as CAES. With adjustments to the capital costs to reflect that of CAES, the Commission may be able to explore additional bulk storage options as well, which CESA also discusses here. PacifiCorp's 2017 IRP highlights cost and operational

[9] Ruling Attachment B, *RESOLVE Documentation: Inputs & Assumptions*, p. 43.

assumptions for several candidate pumped storage and CAES projects, which could inform modeling assumptions in RESOLVE.[10]

In summary, CESA believes that the Commission's energy storage cost assumptions could be improved using some of the resources identified above. CESA understands that the Commission is limited by the availability of cost data that can also be publicly cited to inform the record, and also understands that staff time and resources are limited to re-run the cases using updated cost assumptions. If, given the limited time remaining in this IRP cycle, it is not possible to make major changes to the assumptions, CESA recommends that the Commission adopt the low battery storage capital and levelized cost assumptions as part of the Reference System Plan. These cost assumptions better reflect industry cost trends today and serve as a reasonable proxy for CESA's recommended changes. Using these cost assumptions will be extremely important to serve as useful guidance for the LSEs in filing their IRPs.

## III. MODELING ANALYSIS.

The Commission coordinated with the CEC in aligning the statewide GHG targets with the IRP and appropriately incorporated the current policy trajectory in its modeling efforts. In general, CESA applauds the robust modeling conducted in the IRP, but highlights a few limitations of the model and potential considerations for modeling in the next IRP cycle. Importantly, CESA offers its views on the implications of the IRP modeling results as well.

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[10] Black & Veatch, *Bulk Storage Study for the 2017 Integrated Resource Plan*, prepared for PacifiCorp, August 19, 2016. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/Black_Veatch_PacifiCorp_Bulk_Storage_IRP_Study_Report-final_20160819.pdf

**<u>Question 1</u>: Please comment on the appropriateness of the baseline resources included in the RESOLVE model. What changes would you make and why?**

CESA finds the baseline resources used in the RESOLVE model to be appropriate as it reflects current policy trajectories, but there are two areas for future consideration regarding baseline resources.

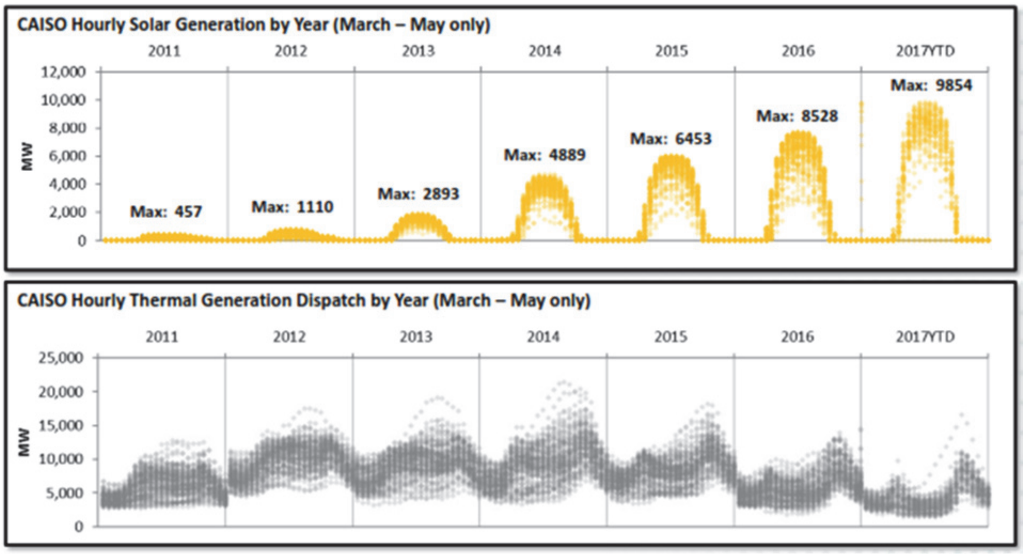
First, an additional consideration for the next IRP cycle is the inclusion of Assembly Bill ("AB") 2868 requirements in the baseline resources, which authorizes each of the investor-owned utilities ("IOUs") to propose applications for programs and investments of up to 500 MW of distributed energy storage incremental to the current AB 2514 requirements. Up to 25% of the proposed programs and investments may be for behind-the-meter ("BTM") energy storage resources. These applications will be filed in March 2018, which will provide greater clarity in how much distributed energy storage to include in the baseline portfolio, considering the IOUs have an authorized 500-MW cap but are not required to propose procurement or investments up to that maximum authorization.

Second, RESOLVE includes existing generators without expected future retirements in the baseline of resources and "assumes that thermal generators will remain online in perpetuity unless they have formally announced intentions to retire."[11] However, as noted in the Ruling and the Commission policy actions as well as by comments by parties, some of these generators may be forced to retire early in a future with significant zero or negative pricing being driven by the continued additions of renewables, especially given that several are on short-term Reliability Must-Run ("RMR") contracts that inhibit their long-term financial viability. The best proxy,

[11] Ruling Attachment B, *RESOLVE Documentation: Inputs & Assumptions*, pp. 16-17.

given the modeling tools available at the moment, to reflect these market conditions is the ability to select an assumed plant lifetime and to test sensitivities around retirements as early as 10 years.

Indeed, recent price and dispatch data released by the CAISO spanning 2012-2017 appears to indicate that as more and more solar comes online, gas resources tend to be dispatched less and less, likely in response to the prevalence of low and negative pricing during solar production as shown below.




*Source: E3, presented at the EPIS Electric Market Forecasting Conference on September 7, 2017*

Given this trend, the Commission may also wish to consider having the early gas retirement scenario as the baseline case. Alternatively, the cost to ensure that this baseline fleet of gas plants remains online through 2030 should be included in the baseline cost of those resources.

**<u>Question 2</u>: Comment on the appropriateness of the three major scenarios modeled by staff (Default Scenario, 42 MMT Scenario, and 30 MMT Scenario)?**

CESA finds the three major scenarios modeled by Commission staff to be appropriate. These scenarios represent the current policy trajectory and fall within the bounds established by the California Air Resources Board ("CARB") and its Draft Scoping Plan.

**<u>Question 3</u>: Provide any comments or reactions to the cost metrics analyzed and the estimated cost results.**

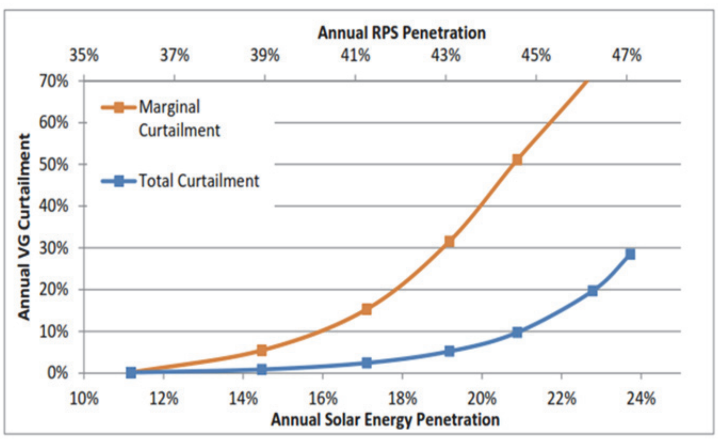
CESA supports the cost metrics analyzed, but additional yet-to-be quantified cost metrics include the value of grid resilience. In the context of seemingly increasing frequency of extreme weather and outage events, it may be reasonable to consider the benefits of resources that can avoid 1-in-10 or 1-in-100 events in the review of LSE IRPs and in developing the Preferred System Plan. RESOLVE uses a representative sample of 37 days of the year,[12] which is drawn from a sample of dates in 2007 to 2009 with different weights attributed to different days representing various weather and hydro conditions.[13] The concern with this averaging approach may be that it critically misses extreme weather and outage events (*e.g.*, methane leak at the Aliso Canyon natural gas storage facility, and wildfires) and therefore overlook the costs of these type events. While it is unreasonable to overbuild electric grid infrastructure to address these extreme events, the Commission should identify resources that can cost-effectively provide these resilience benefits in addition to other grid reliability and policy benefits, and appropriately consider a balanced and diverse portfolio that includes appropriately weighted future scenarios of extreme weather and other unforeseen events.

[12] Ruling, p. 7.

[13] Ruling Attachment B, *RESOLVE Documentation: Inputs & Assumptions*, p. 50.

**<u>Question 4</u>: Comment on the viability of renewable curtailment as a grid integration strategy.**

The viability of renewable curtailment as a grid integration strategy is a policy question as much as it is an economic question. To some degree, at relatively low levels, curtailment may often be a viable flexibility solution as it may be cost-effective to curtail renewable generation to address short imbalances in the grid rather than to upgrade grid infrastructure or to invest in an energy storage resource. However, there is a limit to which California can rely on curtailments to cost-effectively reach its RPS goals, considering marginal curtailment rates increase exponentially with higher renewables penetration. The cost of overbuilding renewables and the declining capacity factors of the marginal renewable unit will make investments in grid flexibility solutions viable, cost-effective, and necessary to achieve GHG objectives.




*Source: National Renewable Energy Laboratory (2015).*[14]

Additionally, there may be potential drawbacks in contracting for renewables by relying too heavily on curtailments as a grid integration solution. The Commission has noted that most current RPS contracts compensate developers at their production cost during curtailment regardless of whether its output is curtailed or delivered to the grid, which is how RESOLVE

[14] NREL (2015). *Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart*, p. 22. https://www.nrel.gov/docs/fy16osti/65023.pdf

models the cost of curtailment.[15] However, this assumption should be more closely investigated since RPS contracts also include "curtailment rights" with the IOUs that define the number of hours in which economic curtailment is allowed without compensation. If true and prevalent, this potential revenue loss from curtailment could lead to higher power purchase agreement ("PPA") prices to hedge against the risk of uncompensated curtailment.

It may be acceptable to rely on renewable curtailment as a policy for its cost-effectiveness in managing short-duration imbalances and oversupply conditions, but reliance on curtailment as a grid integration strategy may not support the other policy objectives to secure more GHG-free resources to meet peak load needs, and may only incentivize continued builds of renewable resources that will generate during times of overabundance rather than providing the policy and economic signals to somehow shape that generation. Curtailment of solar during the mid-day, for example, wastes an opportunity to provide clean ramping and peak capacity through distributed and bulk energy storage. Finally, as the cost of curtailment in the model is directly tied to the cost of renewable contracts, it is certainly subject to change if, for example, solar prices change. In general, CESA believes assumptions to the cost of curtailment need to be more closely examined.

**Question 5: Comment on the advisability of early procurement of renewables to take advantage of federal ITC and PTC availability.**

CESA strongly supports early procurement of renewables to take advantage of the ITC and PTC that are expected to expire over the coming years. RESOLVE demonstrated significant value for procuring renewable resources earlier than needed for RPS requirements to meet the state's GHG goals in a cost-effective manner.

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[15] Ruling, p. 12.

Importantly, a critical limitation of RESOLVE is that it models solar, wind, and energy storage resources separately, overlooking the potential cost, ancillary service, and capacity benefits of pairing solar with energy storage or wind with energy storage. In particular, energy storage resources may also take advantage of the full 30% Federal ITC if the storage facility is charged from the solar generation resource. The percentage of the ITC that can be claimed by the paired energy storage system declines proportionally down to a 75% minimum threshold for charging energy storage from the paired solar resource, below which point the energy storage system earn a 0% ITC. CESA notes this because it is not only solar and wind resources that have a limited opportunity for more cost-effective investments in RPS and GHG-free resources needed to meet the state's objectives, but there is also an opportunity for energy storage resources to benefit from the existing ITC to provide load following as well as clean peak capacity. Additionally, SB 338 (which was signed into law by Governor Brown last month) directs the Commission to consider how peak electricity demand can be met by GHG-free resources and distributed energy resources including energy storage. Taking advantage of energy storage pairing opportunities with solar will help the Commission simultaneously achieve a number of statutory objectives at a more reasonable cost to the benefit of ratepayers.

CESA recognizes that it may be too late to revise the RESOLVE model's operating assumptions and functionalities to incorporate these pairing opportunities and that this opportunity may be more directly addressed in the next IRP cycle or elsewhere.[16] However, the use of the low battery storage cost sensitivity should meanwhile be used to provide sufficient

[16] Generally, the Commission staff and E3 team should consider how RESOLVE could potentially consider hybrid resources in its resource selection. While the focus of these comments were on energy storage pairing opportunities with solar and wind resources, there are also opportunities to pair existing natural gas plants with energy storage to reduce the GHG and pollution impacts of the existing fleet, which may be a consideration during this transitory phase toward the state's 2030 and 2050 GHG goals.

proxy to represent these opportunities, as the ITC is substantially reduced in 2019. Because solar-plus-storage resources have fundamentally different generating profiles and would lead to drastically different portfolios if such paired resources were a large part of the portfolio mix, CESA recommends that these pairing opportunities be explored in LSE IRPs and during the procurement stage.

**<u>Question 6</u>: Comment on the impact of banked RPS procurement on this analysis.**

CESA has no comment at this time.

**<u>Question 7</u>: Comment on the impact of import/export constraints on this analysis.**

CESA has no comment at this time.

**<u>Question 8</u>: Comment on the results of the three long-lead-time resource studies summarized in this analysis: (a) Pumped storage, (b) Geothermal, and (c) Out-of-state wind.**

CESA appreciates the additional sensitivity analysis conducted by the Commission staff and E3 team to test the modeling impact of a new pumped storage resource with a six-hour minimum duration. In addition to pumped storage, CESA notes that there are other forms of very large-scale energy storage resources (collectively referred as "bulk storage" in these comments) available, such as CAES. While not directly modeled, these bulk storage resources could also provide needed reliability and system flexibility for a highly renewable future, and share many of the challenges that a pumped storage resource faces. With respect to pumped storage, RESOLVE found that changing the duration of pumped storage to six hours has no impact on the Default and 42 MMT scenarios – *i.e.*, no pumped storage was selected. As noted above perhaps a more significant assumption that could be driving the selection or non-selection of pumped storage or other bulk storage resources maybe due to the gas fleet assumptions used in the Reference System Plan. Appropriately factoring the cost of keeping those gas units online in the face of increasing negative pricing and or a scenario of early retirements may be prudent, and may result in the selection of more bulk storage resources in the 42 MMT scenario. CESA notes that a small increase in the amount of additional pumped storage capacity selected in the 30 MMT scenario, even under the assumption that certain gas plants will not retire in the immediate future.[17] However, CESA disagrees with the conclusion that this additional six-hour pumped storage sensitivity case analysis not be incorporated into the full scenario 42 MMT Reference System Plan analysis. At minimum, while the proposed Reference System Plan may not include pumped storage, it should indicate that bulk storage resources of all sizes, whether 300 MW or 1,500 MW, require a pathway for competitive procurement given that this energy storage resource sub-class uniquely provides valuable inertia and low-cost, long-duration energy storage capabilities that will provide critical diversity to California's daily grid operations.

In addition, the Commission declined the request from Brookfield Renewables to change the model to account for a longer lifetime of resources (*i.e.*, greater than 10-year horizon). CESA understands that the RESOLVE model is limited in this regard at this time and thus applies greater weight to the last modeled year (*i.e.*, 2030),[18] but modeling a resource with a lifetime of more than 50 years under an artificially short time frame will inflate its cost relative to alternatives.

As a case in point, the Los Angeles Department of Water and Power ("LADWP") built and permitted the Castaic Pumped Storage Plant, a 1,250-MW pumped storage facility completed in 1978 ("Castaic"). Castaic has been used continuously on an economic basis to provide essential energy, capacity, and system reliability resources to LADWP since then.

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[17] Ruling Attachment D, p. 2. *Case ##mmt_Ref_6h_ps_20170831*.
[18] Ruling Attachment D, p. 3.

Originally, Castaic's role was to leverage differences between on-peak and off-peak energy prices to enable energy arbitrage savings. Now Castaic is being transitioned to help manage over-generation, including pumping at night and also during the middle of the day when solar generation is most abundant. According to Brad Packer, LADWPs Director of the Power and Fuel Purchase Division, "Castaic will be used more and more to support achieving our renewable energy goals, and with recent upgrades, we fully anticipate another 40 years of expected life." The use of Castaic as a renewable integration resource is highlighted in LADWP's most recent IRP.[19] Further, even under a potentially fully regionalized Western grid, "more pumped storage will be generally helpful for California."[20] LADWP notes that a key advantage of Castaic is that, even under a heat wave, it can consistently generate 5000 MWh per day – a valuable system resource when heat waves are tending to increase in frequency (now annually) and the duration of these heat waves is tending to get longer (from the usual three days to as long as 12-14 days). Given this capability, Castaic is more than a reliability resource for LADWP; it is a key resilience resource.

CESA therefore strongly urges the Commission to continue to study bulk storage resources in future IRP cycles and elsewhere and as scenarios and modeling assumptions change.

## IV. <u>ELECTRIC SECTOR GHG TARGET.</u>

Aside from the Default Scenario, the Commission used GHG targets based on CARB's Draft Scoping Plan as constraints on the electric sector in pursuit of the state's statutory requirements to reach 40% GHG emissions below 1990 levels by 2030. In turn, the RESOLVE

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[19] LADWP 2016 Final Power Integrated Resource Plan, pp. 26, 170. https://www.ladwp.com/ladwp/faces/wcnav_externalId/a-p-doc?_adf.ctrl-state=8hih21dxz_4&_afrLoop=386879388065696

[20] CESA interview with Brad Packer on October 23, 2017.

model used these constraints along with publicly available and vetted assumptions to develop a Reference System Plan portfolio and to generate a GHG Planning Price based on this portfolio as guidance on a consistent marginal cost of GHG abatement to be used across LSEs and to evaluate a range of resources.

**<u>Question 9</u>: Do you agree with the recommendation to utilize the 42 MMT Scenario for IRP planning purposes? Why or why not?**

CESA generally agrees with the Commission's recommendation to utilize the 42 MMT scenario and the associated resource portfolio as the proposed Reference System Plan to guide LSE development of their individual IRPs. CESA recommends that the final Reference System Plan be developed that more accurately factors in the cost of retaining the gas fleet online, and or considers a fast retirement scenario. The Commission reasonably views the Default Scenario, constrained by the 50% RPS, as the current policy trajectory and business-as-usual expectation of the electric sector, per SB 350. Furthermore, with the state generally on a path to reach a 50% RPS far earlier than 2030, it is reasonable for the Commission to "increase momentum from current policies" and provide additional market stimulation that generates additional GHG emissions reduction from the electric sector while balancing cost considerations to the ratepayer.[21] The Commission also importantly adds that the 42 MMT scenario approximates a straight-line path to the 2050 GHG emissions target,[22] which aims to reduce GHG emissions to 80% below 1990 levels by 2050.[23]

The Commission finds that the use of the 30 MMT scenario would lead to disproportionate costs in the electric sector, thus choosing not to use the 30 MMT case as the

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[21] Ruling, p. 16.
[22] *Ibid*, p. 17.
[23] Executive Order B-30-15 of Governor Jerry Brown. https://www.gov.ca.gov/news.php?id=18938

proposed Reference System Plan.[24] As noted above, the conclusions of the 42 MMT and 30 MMT should not be finalized until the costs of keeping the gas fleet online and/or a fast retirement scenario are considered, as well as the legislative intent of SB 338. The results from the 30 MMT scenario should not be dismissed, particularly given the Legislature's intent to potentially expedite RPS procurement as evidenced by the broad support (though not yet passage) of SB 100, SB 813, and AB 726.[25] SB 100, for example, would have pushed the state toward a more aggressive 50% RPS by 2026 and 60% RPS by 2030 if passed, which would have required the state to pursue a portfolio ranging between the 42 MMT scenario (translating to a 57% RPS by 2030) and the 30 MMT scenario (translating to a 71% RPS by 2030). In addition, with a 100% RPS by 2045 requirement in SB 100, the Commission would have had to more thoroughly consider the 30 MMT scenario to continue the state on a trajectory toward its hoped-to-be statutory objective.

CESA understands that the Commission cannot make policy determinations based on speculation as to whether SB 100 would pass this year or possibly pass next year. On the other hand, the 30 MMT scenario is useful in potentially guiding the Commission to consider certain near-term policy actions in light of this legislative environment. Pumped storage, for example, was economically selected in the 30 MMT scenario, along with 2,000 MW of out-of-state wind and 2,020 MW of geothermal resources, but would require near-term policy action that provides a procurement pathway to be online by 2030. Long-lead-time resources such as pumped storage and CAES require support from the Commission and the CAISO to develop joint procurement

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[24] Ruling, p. 17.

[25] Senate Bill 100: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100; Senate Bill 813: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB813; Assembly Bill 726: https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180AB726

pathways and shared cost recovery mechanisms given the size of these resources and the system-level benefits that they provide, thereby requiring multiple LSEs to participate in their procurement and cost allocation. In the landscape of emerging LSEs such as community choice aggregators ("CCAs"), the determination of these joint procurement and cost recovery mechanisms are especially important as no one LSE would bear the full cost of a resource that provides system-wide benefits for multiple LSEs. Without actually committing to procuring bulk storage resources at this time given that SB 100 has yet to pass, the 30 MMT scenario results combined with the legislative environment to increase RPS requirements presents a compelling case for the Commission to direct policy action on establishing procurement pathways for bulk storage resources.

Lastly, since the Commission is also required to consider DACs in the IRP process, the 30 MMT scenario and its associated portfolio should continue to be evaluated since the selection of this GHG constraint demonstrated a significantly higher impact on emissions in DACs than for any changes to individual assumptions and variables.[26] Any policy actions associated with the 30 MMT scenario should thus be considered.

At the very least, the potential for future legislation directing expedited RPS procurement and setting more aggressive RPS goals should solidify the Commission's case for using the 42 MMT scenario as the Reference System Plan.

## V. PROPOSED REFERENCE SYSTEM PLAN.

The Commission staff recommends a Reference System Plan using the portfolio of resources and GHG Planning Price associated with the statewide GHG planning target of 42 MMT for the electric sector.

[26] Ruling, pp. 11-12.

**<u>Question 10</u>: Do you support the use of the Reference System Portfolio associated with the 42 MMT Scenario as the model for LSE portfolio planning for their individual IRPs? Why or why not?**

CESA recommends that the Commission use the 42 MMT scenario under the low battery storage cost assumption as the Reference System Plan portfolio with the above noted changes to the assumed baseline gas resources that will be online in 2030; namely that they may retire faster than anticipated and/or reflect a higher cost to keep them online. As noted previously in these comments, the energy storage cost assumptions are still high relative to the range of costs seen in the market today.

**<u>Question 11</u>: Do you support transmitting Default Scenario and associated portfolio to the CAISO for use as the reliability base case in the TPP for 2018? Why or why not?**

CESA supports the Commission's recommendation to transmit the Default Scenario portfolio but under the low battery storage cost sensitivity to the CAISO as the reliability case for the 2018 Transmission Planning Process ("TPP"), as it represents the minimum that the state must accomplish while reflecting industry cost trends for battery storage resources. However, the CAISO raised valid points in the September 25-26, 2017 workshops that highlighted potential discrepancies in recommended transmission buildouts from the Reference System Plan and Preferred System Plan and the need to resolve these discrepancies. In addition, the CAISO highlighted how the Reference System Plan would have some geographic specificity by zone but not to specific locations as in years past. CESA agrees that these are all important points that must be addressed by the Commission.

**Question 12: Do you support transmitting the 42 MMT Scenario and associated portfolio to the CAISO for use as the policy-driven case in the TPP for 2018? Why or why not?**

CESA supports the Commission staff's recommendation to transmit the 42 MMT Scenario portfolio but under the low battery storage cost sensitivity to the CAISO as the policy-driven case for the 2018 TPP, as it represents the staff's recommended actions to achieve the state's long-term GHG goals while reflecting industry cost trends for battery storage resources.

**Question 13: Should the RETI 2.0 work or other available information be incorporated into the TPP recommendations for 2017? If so, how?**

CESA generally supports the use of available information from other proceedings and agencies to inform the Commission.

## VI. LSE ACTIONS REQUIRED IN RESPONSE TO REFERENCE SYSTEM PLAN.

The Commission proposes to link grid planning with procurement through the use of the Reference System Plan, GHG Planning Price, and GHG Emissions Benchmark as guidance for the LSEs in formulating their IRPs. CESA supports these actions and seeks to ensure that timely action and procurement is achieved by the LSEs.

**Question 14: Do you support the staff recommendation for how LSEs should utilize the GHG Planning Price in preparing their individual LSE IRPs? Why or why not?**

CESA supports the GHG Planning Price being used for each LSE's IRPs, as it would better align individual IRPs to some common set of assumptions and would allow for some consistency in the IRPs to make it easier for the IRPs to be aggregated into a Preferred System Plan that at least resembles the Reference System Plan.

**<u>Question 15</u>: Do you support the staff recommendation for how LSEs should utilize the Reference System Portfolio in preparing their individual LSE IRPs? Why or why not?**

CESA agrees that the Reference System Plan should be used as guidance for the LSEs filing their IRPs, but at the same time, as the Commission correctly note, the LSEs should be required to explain any deviations from the Reference System Plan. As the IRPs are vetted, it will help the Commission staff and stakeholders to understand why the deviations occurred (*e.g.*, different assumptions or modeling tools/techniques were used by the LSE).

**<u>Question 16</u>: Do you agree with the above-described relationship between the Reference System Portfolio and the GHG Planning Price? Why or why not?**

CESA generally agrees with the relationship between the Reference System Plan portfolio and the GHG Planning Price.

**<u>Question 17</u>: Do you support the staff recommendation for calculating and assigning a GHG Emissions Benchmark for LSEs to use in preparing their individual LSE IRPs? Why or why not? Would you recommend an alternative means of developing a similar benchmark? Explain.**

CESA generally supports the Commission's recommendation to assign a GHG Emissions Benchmark to each LSE that is intended to help the LSEs in preparing their IRPs and serve as a reference point for reviewing the IRPs. Understandably, the challenge may be in dividing the GHG Planning Target for the electric sector by 2030 proportionally to CCAs, energy service providers ("ESPs"), and IOUs based on their projected 2030 load share, which is subject to major uncertainty. Since this is for informational purposes, the Commission should not have the GHG Emissions Benchmark assignment delay or distract from timely policy action and procurements, given the time-sensitive nature of the expiring Federal tax credits.

**<u>Question 18</u>: Do you support the staff recommendation for requiring IOUs filing Standard IRPs to submit revenue requirement and system average rate forecasts to evaluate the impact of IRP costs on ratepayer costs of the IRP process? Why or why not?**

CESA has no comment at this time.

**<u>Question 19</u>: Are there additional components that would need to be explored in order to develop a more comprehensive approach to conducting ratepayer impact analysis in later IRP cycles, for both IOUs and other LSEs? Explain.**

CESA has no comment at this time.

**<u>Question 20</u>: Do you agree with the proposed requirements for LSEs to address the impact of their IRPs and any planned procurement on disadvantaged communities?**

CESA agrees with the staff's recommendation that LSEs describe how it will plan for early priority on DACs. Consideration for DAC priorities may be most easily addressed in the procurement stage of the IRPs.

## VII. <u>COMMISSION POLICY ACTIONS.</u>

Five different policy actions are recommended by the Commission staff:

- Evaluate whether it is reasonable to revise renewable energy targets to achieve the portfolios indicated in the IRP Reference and Preferred System Plans.
- Coordinate with the CAISO to convene an intensive and rapid study of out-of-state ("OOS") wind generation and transmission costs and procurement options.
- Adopt marginal abatement prices that can be used by other Commission proceedings.
- Coordinate the CAISO to engage in a detailed study on natural gas fleet impacts.
- Develop a Common Resource Valuation Methodology ("CRVM").

Despite the wide-ranging results from the various modeling runs and sensitivity cases, early renewable energy procurement is one of the key takeaways from the RESOLVE modeling results. In the proposed Reference System Plan, the modeling results indicate that early renewable energy procurement is optimal in the short-term to take advantage of the expiring Federal PTC and ITC.

<u>**Question 21**</u>**: Should the Commission raise the RPS compliance requirement for 2030 and/or intervening years for all LSEs?**

**a. If so, to what percentage?**

**b. If so, in this proceeding or as a recommendation to be considered in the RPS rulemaking (or another venue: please specify)?**

CESA has no specific views on whether to or by how much the RPS compliance requirement should be raised. In general, CESA has observed that the long timeline of RPS procurement cycles as well as reluctance by the LSEs to procure additional RPS resources (in light of being in overcompliance at the moment) represents major barriers to conducted expedited procurement through this venue.

<u>**Question 22**</u>**: Should the Commission require additional renewable procurement outside of the RPS program?**

**a. Why or why not?**

**b. If so, how?**

**c. If so, at what level?**

**d. If so, from whom?**

Additional renewable procurement may need to be authorized through the IRP proceeding. Under Public Utilities ("P.U.") Code Section 454.52, the Commission has the authority to ensure that LSEs meet the statewide GHG emission reduction targets, and thus should take action accordingly to ensure that the state is able to take advantage of cost-effective investments that leverage Federal tax credits before they expire.

**<u>Question 23</u>: Should the Commission initiate activities with the CAISO or others to investigate further development of out-of-state wind?**

**a. Why or why not?**

**b. If so, what specific steps should be taken?**

**c. Should out-of-state wind be included in the special study or as part of a policy-driven scenario for TPP? Why or why not?**

CESA notes that the 2016-2017 TPP and 2017-2018 TPP have been in the process of conducting a 50% RPS Special Study to evaluate the transmission implications and constraints of OOS wind resources to meet a portion of the state's 50% RPS goals. This study efforts should build off or enhance, not duplicate, these efforts.

**<u>Question 24</u>: Should the Commission utilize the GHG Planning Price as an input to the IDER avoided cost calculator, as described in this ruling?**

**a. Why or why not?**

**b. Do you have specific recommendations for the appropriate methodology for use of the GHG Planning Price in IDER or other demand-side resource proceedings/activities? Describe in detail.**

CESA supports the use of the GHG Planning Price as an input to the avoided cost calculator in the Integrated Distributed Energy Resources ("IDER") proceeding, since D.17-08-022 correctly determined that the CARB's cap-and-trade allowance price containment reserve ("APCR") price represents the highest cost of compliance with the cap-and-trade requirements, but is not the same as the marginal carbon abatement price, for the purposes of the IRP, is derived from California's pursuit of its RPS and GHG policy objectives.

**<u>Question 25</u>: If the Commission were to engage in development of a CRVM:**

a. **What resource areas should be prioritized for incorporation into the CRVM?**

b. **Do you have specific recommendations for the appropriate structure of a CRVM? Include examples from other jurisdictions where possible.**

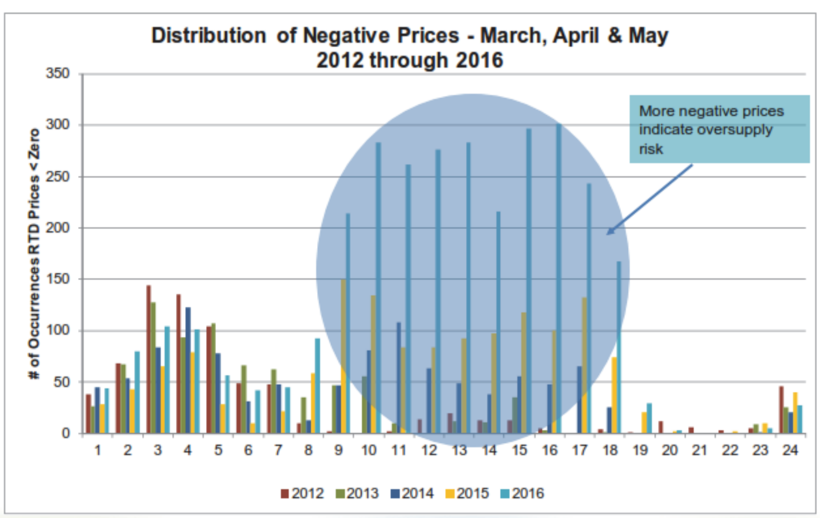
c. **What would be the appropriate application of such a method?**

The Commission is proposing the development of a Common Resource Valuation Methodology ("CRVM") to ensure that the costs and benefits used in the IRP planning and modeling are reflected in and linked to the bid evaluation and program funding authorizations that follow. As CESA notes later in our comments on the proposed Path to Future All-Resource Planning, the CRVM must ensure that energy storage resources are evaluated for the multiple benefits that it can provide from a single resource. The current IRP modeling does not incorporate the stacking of value streams, so the CRVM may be the best means by which to address these multiple-use benefits of energy storage resources. In addition, the Commission staff proposes to prioritize the CRVM for RPS resources since they are most likely to be authorized for near-term procurement. CESA supports this prioritization, but as noted in our comments on the proposed Path to Future All-Resource Planning, the CRVM should be developed to allow and appropriately value pairings of RPS resources with energy storage that can firm its renewable generation and shift deliveries to higher value time periods.

**<u>Question 26</u>: Should the Commission initiate activities with the CAISO or others to analyze the type and viability of the natural gas fleet? What activities should be undertaken and why?**

CESA strongly supports the Commission's recommendation to study the viability of the natural gas fleet, as RESOLVE does not capture individual plant costs, efficiency, bidding behavior, or any real-time market dispatch dynamics. Existing gas plants continue to be important for grid reliability purposes but are decreasing in capacity factor as more solar comes online and must be reconciled with the state's GHG and DAC policy objectives.

However, given a likely future of CAISO markets seeing frequent zero and negative pricing due to the significant levels of solar generation on the grid during the mid-day, there is an important question related to the economic viability of the existing gas fleet. Without the ability to recover costs in the market and the need for these plants during limited periods of the day, there is a concern that these existing resources may not be financially viable without economic support mechanisms even as these plants are needed for grid reliability. Thus, a financial analysis of the cost of keeping these gas plants online – *e.g.*, through expensive RMR contracts or multi-year Resource Adequacy ("RA") contracts (if approved in the future) – must be evaluated against other alternatives such as energy storage that can provide similar capabilities. In other words, RESOLVE assumes that all of the fixed costs of the existing gas plant are sunk and incorrectly assumes that these plants will therefore stay online through 2030 as a baseline resource, which may underestimate the total resource costs of the Reference System Plan portfolio that does not account for the ongoing costs of keeping these resources online.




*Source: CAISO (2017)*

This study is therefore critically important to the development of the LSE's IRPs as well as the Preferred System Plan portfolio. A more accurate representation of the total resource costs is needed to avoid capacity deficiency issues. Already, the 2017-2018 TPP conducted a special study on the risk of early retirements of uneconomic plants, which found that capacity sufficiency issues start to emerge between 4,000 MW to 6,000 MW of retirement, especially with shortfalls in load following and reserves in the early evening after sunset.[27] Moreover, this study will be important in helping to identify the types of gas plants and attributes that are most needed for grid reliability and DAC impacts, better ensuring that the right gas plants are kept online for these purposes while retiring the ones that cost more and less effectively achieve these objectives. As a follow up to this study, the Commission should also evaluate the potential for energy storage resources, including bulk storage resources, to provide the energy and grid services that the state has typically acquired from the thermal fleet.

Finally, SB 338 directs the Commission to consider energy storage and preferred resources as a means to meet the net load peak in IRP planning, a role that has traditionally been performed primarily by gas plants.

## VIII. RESOURCE POLICY COORDINATION.

The Path to Future All-Resource Planning ("Path") is proposed by Commission staff as developing the next steps for specific resource areas given the IRP modeling results. CESA supports the Path as prudent means to draw certain key takeaways from the IRP proceeding to inform policy development and plan actions in resource-specific proceedings, such as for RA,

[27] *Risks of Early Economic Retirement of Gas-Fired Generation – Sensitivities of the 2016-2017 TPP Studies*, presented at the 2017-2018 Transmission Planning Process Stakeholder Meeting, p. 11. https://www.caiso.com/Documents/Day2_ISO-Presentation_2017-2018TransmissionPlanningProcess_PreliminaryReliabilityResults.pdf

demand response ("DR"), distributed resources planning ("DRP"), electric vehicles ("EVs"), and renewables. However, energy storage is critically missing in the proposed Path despite the Energy Storage proceeding (R.15-03-011) very actively discussing key issues that would support renewable integration, grid flexibility, and better and increased utilization of existing and new grid assets. In addition, the RA proceeding is not explicitly highlighted as part of the proposed Path.

**Question 27: Please comment on the slides in Attachment A titled "Path to Future All-Resource Planning" with respect to the following:**

**a. Are any of the conclusions, implications, or action items inappropriate?**

**b. Are any conclusions, implications, or actions missing that the Commission should consider? Explain.**

***Demand Response.*** CESA generally agrees with the staff's conclusions, and action items. The potential for Shift and Shimmy DR resources is significant based on Lawrence Berkeley National Laboratory's *2015 California Demand Response Potential Study Final Report on Phase Two* Results, but the development of these products or programs still require significant development, which will be underway soon in the new phase of the DR proceeding (R.13-09-011). Importantly, as the DR market shifts toward supply-side integration with the CAISO market, the IRP modeling results will be especially informative for providing guidance on DR targets and program budgets as the RESOLVE model adds enhancements to optimize demand-side resources that can provide Shift and Shimmy DR as well. To inform how RESOLVE should be modified to model these capabilities of DR resources, however, progress must be made in the DR proceeding to shape the framework on how such Shift and Shimmy DR resources would operate and be compensated.

***Distributed Resources Plan.*** CESA again generally agrees with the staff's conclusions, implications, and action items. The two main interactions between the IRP and DRP are on how grid integration costs and benefits are calculated at the distribution level can be aggregated up to the system level, and how the DER growth forecasts used in the DRP should feed into the IRP. As the methodologies being developed in the DRP are further developed to guide optimal siting of DERs on the distribution grid, the reduced grid integration costs at the distribution level should also feed into reduced system level grid integration costs.

***Electric Vehicles.*** CESA also generally agrees with the staff's conclusions, and action items. The potential of EV charging flexibility in reducing total system and renewable integration costs was evident in the IRP modeling results. However, it is unclear what actions the Commission will take in response to the IRP modeling results to inform EV program investment decisions and EV rate design discussions. The action items listed only include inter-agency coordination on state forecasts for EVs and the investigation of opportunities to electrify the transportation sector, but do not include how the IRP modeling results could actually inform EV program investment decisions and EV rate design discussions, which CESA believes may be due to RESOLVE not modeling the full capabilities of EV loads.

As the Commission moves toward the next IRP cycle, CESA thus recommends that the Commission more closely examine the way in which EVs and EV chargers are modeled in the IRP to better inform EV-related proceedings. As noted by the Commission and E3 staff, the IRP is limited in viewing demand-side resources such as EV loads as exogenous variables that can be adjusted for the number of light-duty EVs deployed, which in turn affect the magnitude of load, low/mid/high availability of workplace charging that affects the static shape of the load, and low/mid/high levels of "flexible charging" of EV loads to shape load within certain constraints.

CESA believes that additional modeling refinements must be made and different scenarios must be modeled to allow for the modeling of not only light-duty EVs but also medium-duty, heavy-duty, and off-road EVs,[28] as well as to allow flexible charging scenarios to be modulated between impacts from different TOU charging rates. The assumptions underlying the load shapes for home charging only versus home/workplace charging combinations must also be more closely examined because they may not be accounting for TOU rates for home charging, for example. Similarly, the Commission should investigate how different levels of workplace charging affects flexibility, as RESOLVE may not be fully accounting for the turnover rate of cars and the ability to modulate charging rates at different levels of workplace charging, which affects the degree to which EVs can provide ancillary services and flexibility.

Understandably, the 2017 IRP did not have the time and resources to develop all of the features to model demand-side resources such as EV loads in this way. In addition, the EV-related proceedings may need to develop the inputs and assumptions that would feed into the IRP modeling exercises to produce more actionable results. Therefore, a near-term action item for the Commission should be to develop the inputs and assumptions in the EV-related proceedings that would appropriately model static and dynamic EV load shapes under different TOU scenarios, which could then be fed into the next IRP cycle to provide more actionable results.

Furthermore, CESA recommends that the Commission explore in EV-related proceedings how and where EV infrastructure can be deployed to enable smart and flexible charging. EV charging flexibility can be unlocked with sufficient and smart daytime, workplace, and public-sector EV charging capacity, which can also be located at specific feeders or co-located with

[28] CESA understands that some electrification of medium- and heavy-duty vehicle fleets are incorporated in the "CARB Scoping Plan – Alt1" scenario, but the next modeling cycle could incorporate some of the projected deployments from the SB 350 Transportation Electrification Applications, which should be approved and underway with implementation by this point.

energy storage resources to relieve overly taxed distribution system sites. With most of the near-term focus of EV-related proceedings on deployment volume, CESA recommends that the IRP be used to inform the next phase of the EV and EV charging world to unlock the ability of these deployments to provide smart and flexible charging.

***Renewables.*** CESA agrees with the conclusion that significant renewable energy resource procurement is needed in the 42 MMT and 30 MMT cases, especially in the near term to take advantage of expiring Federal tax credits. Accordingly, the Commission appropriately recommends that the feasibility and advisability of large amounts of renewable energy procurement over a short timeline be evaluated. In particular, during the September 25-26, 2017 workshops, the Commission's lead staff representative in the RPS proceeding outlined the typical timeline for RPS Procurement Plans, competitive solicitations, and regulatory approval, which revealed a very tight window in which the Commission must make the determination on whether to use the RPS or IRP as the procurement mechanism and what the procurement target should be. Speed is of utmost importance, and thus it may be prudent to quickly advance to competitive solicitations (rather than deliberate on more analysis to determine whether this is prudent) using the procurement targets identified by the IRP modeling results and make the final decision on whether to contract and approve based on the actual bid results.

Furthermore, CESA supports reforms to the least-cost best-fit ("LCBF") methodology as a key action item in the RPS proceeding. While CESA is hesitant to have near-term renewable energy resource procurement slowed by LCBF reform discussions, there is an opportunity to use time of deliverability ("TOD") factors in the RPS procurement process to allow utilities to reasonably indicate the more desirable TOD periods for renewable energy resources. This adjustment to the LCBF methodology will support renewables that are paired with energy storage to deliver energy when it is needed, reduce renewable curtailment, and potentially improve the Effective Load Carrying Capability ("ELCC") value of renewables. Coordination with the RA proceeding will be needed on consideration of 'boosting' the ELCC value of solar and wind resources when paired with energy storage,

***Energy Storage.*** A critical omission of the Path is the consideration of action items for the Energy Storage proceeding (R.15-03-011), which is currently working on a number of policy issues that will have an impact on the IRP proceeding. Importantly, the Commission staff in this proceeding is developing a multiple-use application framework that will authorize a number of use cases where energy storage resources can provide multiple reliability and non-reliability services, which would allow this resource class to be more fully utilized and optimized to meet multiple grid service needs. This aspect of energy storage resources is not encapsulated in the resource investment decisions in RESOLVE, as it focuses on how energy storage resources can meet any one need to achieve the state's RPS, GHG, and grid reliability objectives. For example, most of the energy storage resources selected in RESOLVE are short-duration systems that provide load following, but that same resource may also be able to provide voltage support at the distribution level, allowing it to provide additional benefits and improve the cost-effectiveness of this resource class. However, rather than incorporating these multiple-use capabilities in a grid planning tool such as RESOLVE, which may be overly complex and difficult to capture the full grid service capabilities of an energy storage resource and may unreasonably prescribe what multiple-use applications energy storage resources should provide, the Commission should instead direct policy action for R.15-03-011 to continue to develop the multiple-use application framework and for the LSEs to allow for and consider multiple-use applications from energy storage resources in their procurement and bid evaluation processes. At the same time, it may be worthwhile to consider how RESOLVE could potentially model these multiple-use capabilities of energy storage resources in the next IRP cycle.

Given that RESOLVE identified load following as the primary use case for energy storage resources being selected in the model, the Commission may also consider policy action on considering how best to procure energy storage resources to meet this identified need. There is no specific market product for load following services and the LSEs in the state, to CESA's knowledge, has not solicited for energy storage resources to provide this service specifically, instead procuring energy storage resources as part of the AB 2514 framework to provide RA capacity on the large part. Thus, the Commission should identify the appropriate procurement mechanisms for energy storage resources to meet this identified need. For example, the Commission may find that the RPS proceeding is the most appropriate as solar and wind resources paired with energy storage systems would address load following needs.

Finally, as noted previously in these comments, there is no policy action directed toward bulk storage resources even as new pumped storage resources were economically selected in the 30 MMT scenario. It is not clear why policy action is not directed for bulk storage resources when OOS wind resources were similarly only economically selected in the 30 MMT scenario. Even when 'forced in' in early 2026, the net benefit of OOS wind is only relative to the 30 MMT scenario without forcing OOS wind in 2026; the net costs of OOS wind relative to the Default Scenario and the 42 MMT scenario are still over $1 billion per year and $700 million per year, respectively.[29] Given the economic selection of pumped storage in the 30 MMT scenario, similar to OOS wind, CESA recommends that policy action be recommended for bulk storage resources

[29] Ruling Attachment A, *Proposed Reference System Plan*, pp. 103-104.

as well, such as through continued studies of the benefits of bulk storage resources and/or discussions on procurement pathways for bulk storage resources.

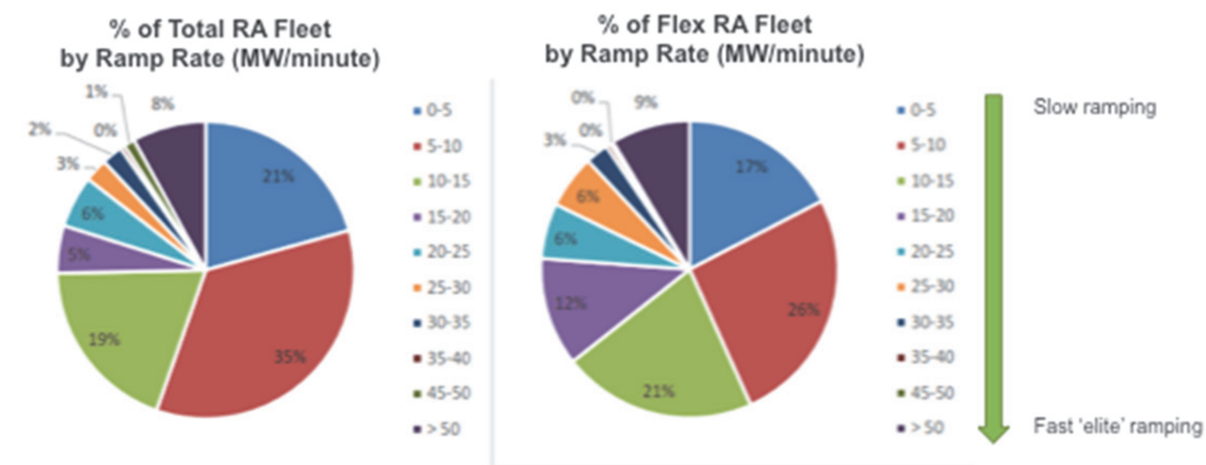
CESA also points to the CAISO's Bulk Storage Resource Special Study that have been updated in the 2016-2017 TPP and the 2017-2018 TPP. These special studies have been valuable in highlighting how pumped storage resources provide benefits in reducing curtailment, GHG emissions, and production costs. While the studies highlight how the net market revenues from this resource were not able to fully cover annual revenue requirements, the pumped storage resource likely provides additional system benefits in the form of reduced renewable overbuild, reduced production cost, and added inertia to the system (*i.e.*, which would reduce the need for additional ancillary services such as frequency response).[30] Continued study efforts may be helpful for the Commission to direct that consider different assumptions for the cost of curtailment or that seeks to quantify these other benefits and cost savings (*e.g.*, added inertia on the system), but more than that, CESA recommends that a forum be established that provides a pathway for bulk storage resources to have a pathway to joint procurement. Discussions on these procurement vehicles and cost allocation mechanisms are importantly needed.

Without any recommended policy actions, energy storage resources are critically overlooked and critically miss an opportunity to take the key conclusions and implications of the IRP modeling results to drive actionable next steps.

***Resource Adequacy.*** CESA recommends that the Commission urgently consider enhancements to the Flexible RA program to encourage the development of a fast, flexible fleet that the CAISO can use to reliably operate the grid in all hours, time scales (*e.g.*, sub-hourly,

[30] *CAISO Bulk Energy Storage Resource Case Study – Update to the 2016-2017 Transmission Plan Studies*, presented at the 2017-2018 Transmission Planning Process Stakeholder Meeting on September 21, 2017, pp. 18-29. https://www.caiso.com/Documents/Day2_ISO-Presentation_2017-2018TransmissionPlanningProcess_PreliminaryReliabilityResults.pdf

hourly, and three hours), and all circumstances throughout the year. Currently, California's system and local RA fleet is very similar to its flex RA fleet in terms of ramp rate. For example, under the current Flexible RA eligibility rules, a resource that can ramp instantaneously is being counted the same as a resource that requires three hours to ramp.




*Source: CAISO (2017)*[31]

## IX. PRODUCTION COST MODELING RELATED ISSUES.

The Commission staff proposes to conduct production cost modeling ("PCM") using the Strategic Energy Risk Valuation Model ("SERVM") to evaluate operational performance of the proposed Reference System Plan and the Preferred System Plan, verify satisfaction of the Planning Reserve Margin ("PRM") requirement, and to calculate the marginal ELCC values for use by individual LSEs to develop their individual IRPs. In Q1 2018, the Commission proposes to complete, share, and vet the PCM results with stakeholders.[32]

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[31] *CAISO Flexible Resource Adequacy Criteria and Must-Offer Obligation – Phase 2 Supplemental Issue Paper*, published on November 8, 2016, p. 7. https://www.caiso.com/Documents/SupplementalIssuePaper-FlexibleResourceAdequacyCriteria-MustOfferObligationPhase2.pdf

[32] Ruling Attachment E, *Production Cost Modeling Process to Review Integrated Resource Plan Portfolios*, p. 4.

CESA generally believes that PCM is important to the grid planning process as it ensures that the proposed resource mix reflects a reasonable measure of adequacy to provide reliable real-time grid operations. As a capacity expansion model that has yet to be benchmarked, RESOLVE optimizes for cost-effectiveness of resource additions that are also constrained by policy and grid reliability requirements (*e.g.*, load following reserves per hour), but it may not fully account for the granular operational complexities that occur at the sub-hourly and real-time levels, which may require a different set of resources in the Reference System Plan.[33] CESA notes that there is no capacity product at the moment that ensures that the CAISO market has a minimum quantity of load following in the 5-minute or 15-minute time frame, thus assuming that the CAISO's market will make efficient use of committed resources. Broadly, CESA is also concerned that the RESOLVE model takes an 'averaging approach' based on a sample of 37 representative days, which may overlook extreme weather and outage events (*i.e.*, the 1-in-10 standard) that appear to be occurring with growing frequency and magnitude.

The PCM by the Commission (and potentially by the CAISO and other stakeholders as well) is therefore very important to California's IRP modeling and grid planning process to validate the resource portfolio and ensure the right resource mix is procured to meet the grid's reliability and flexibility needs.

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[33] Ruling Attachment B, *RESOLVE Documentation: Inputs & Assumptions*, pp. 63-65.

CESA understands that RESOLVE uses an hourly load following and regulation requirement based on sub-hourly analysis that was done for one 33% and two 50% RPS cases in the CAISO system. However, CESA is concerned about how much renewable curtailment can be relied upon to meet these hourly requirements given contractual obligations for developers as well as the state's policy objectives. Due to the significant sub-hourly variability in renewable generation as observed by the CAISO at the July 24, 2017, Inverter-Based Generation Workshop (http://www.caiso.com/Documents/Agenda-Presentation-OperationalOpportunitiestoMinimizeRenewablesCurtailments.pdf), CESA suspects that intra-hour variability could be significant enough to make it infeasible to rely heavily on renewable curtailments to provide load following and regulation.

**<u>Question 28</u>: Please comment on any aspect of the staff proposal included as Attachment E to this ruling. Explain the reasoning behind any recommended revisions. Please organize your comments according to the major topics of the proposal.**

CESA supports the Commission's use of the SERVM model to benchmark the results of RESOLVE model, but has concerns and comments on the following:

- The hourly time steps of the SERVM model may overlook critical intra-hour flexibility issues that require fast-responding and fast-ramping resources (*e.g.*, energy storage, advanced inverters).
- Considering staff time and resources, it may be prudent to identify a single study year to conduct more intensive intra-hour PCM rather than two study years of hourly PCM.

First, the hourly time steps of the SERVM model may represent a critical limitation of the PCM process. RESOLVE also models at the hourly level constrained by the PRM and load following requirements, so it is unclear what additional information and insights would be provided. The staff proposal includes a first step in the PCM process in which staff will identify the differences in model granularity, but it appears that there will be no difference in the hourly time steps in which the proposed Reference System Plan will be modeled.

Understandably, the Commission staff is constrained by time and resources in the 2017 IRP, which is the first iteration of the IRP process and requires the development and implementation of new tools and capabilities. As a result, the staff proposes to run PCM using SERVM for only two study years: 2022 and 2030. It is not clearly explained why the staff chose to model these two study years, but CESA recommends that the Commission focus on intra-hour PCM for a single study year rather than conducting hourly PCM for two study years in the interest of staff's limited time and resources. As noted above, CESA believes that intra-hour modeling will yield more insightful results and serve as a more useful 'check' or benchmark against RESOLVE's ability to ensure PRM and other reliability standards can be met in real-time operations. Granted, such intra-hour modeling will likely be significantly more intensive, as demonstrated by the California Energy System for the 21st Century ("CES-21") Project, which conducted 87,500 'full years' of simulated system operations and required high-performance computing resources.[34] Therefore, with a focus on a single study year, a more manageable level of granularity (*e.g.*, 15-minute intervals rather than 5-minute intervals as in the CES-21 project), and a reduced set of study cases for uncertainty (*e.g.*, reduced generation profiles and forecast errors), the Commission staff may be able to conduct intra-hour PCM to benchmark the proposed Reference System Plan. The use of a single scenario (*i.e.*, the proposed Reference System Plan) unlike the CES-21 project may also reduce the modeling intensity.

In selecting the single study year, the Commission may consider either 2022 or 2026, as RESOLVE clearly shows that 2018 will likely not see additional resources coming online (especially as it would be infeasible to procure and deploy additional renewable energy resources by that time) and that 2030 will be the year in which flexible resources such as battery storage are procured to meet the flexibility needs likely identified in 2026. In other words, according to the proposed Reference System Plan, with most of the changes to the resource mix coming in 2022 to take advantage of expiring Federal tax credits, it may be reasonable for the Commission to focus on the 2022 study year for its PCM efforts. The 2026 study may also be candidate for PCM due to the complete retirement of the Diablo Canyon Power Plant ("DCPP") by that time,[35] a baseload plant that may relieve some of the grid flexibility issues with its retirement. However, there may be a need for flexible resources in 2022 given the significant resource mix change that

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[34] *Flexibility Metrics and Standards Grid Integration: Role of Operating Flexibility in Planning Studies*. California Energy System for the 21st Century (CES-21) Final Report, filed on September 12, 2017, pp. 6-8.

[35] Ruling Attachment E, *Production Cost Modeling Process to Review Integrated Resource Plan Portfolios*, p. 8.

will occur between 2020 and 2026 as utility-scale solar resources taking advantage of the Federal ITC have a four-year window to complete construction of their project. Ahead of DCPP retirement, it may be necessary to ensure that potentially 9,000 MW of new utility-scale solar and 1,100 MW of additional in-state wind resources are able to be integrated.

Finally, CESA agrees that the Commission should prioritize PCM for the Default Scenario and other alternative cases that are needed as inputs for other state agencies' forecasting or planning efforts.[36] In recognition of the staff's limited time and resources, CESA views the need to model intra-hour production costs and operations as a greater priority and thus recommends that the Commission limit any PCM of alternative cases.

<u>**Question 29**</u>**: Please comment on the results and recommendations from the CES-21 grid integration project final report filed on September 12, 2017 in this proceeding. Note that the CES-21 project is complete and is not seeking comment to conduct additional work. The Commission seeks comment on:**

**a. The technical merits of the analytical framework used in the CES-21 project.**

**b. What aspects of the CES-21 project (*e.g.*, directional findings or recommendations, or the modeling techniques) can be used to improve the staff proposal in Attachment E, in the current or future IRP proceedings, and how?**

The CES-21 project has been positioned as providing directionally useful information, not precise results, on whether there is sufficient capacity and operating flexibility to meet the 1 day in 10 years reliability standard in 2026 and whether new planning standards are needed. Using assumptions from the 2016 Long-Term Procurement Plan ("LTPP") and the stochastic modeling capabilities of SERVM, it finds that the CAISO system has sufficient operating flexibility to meet demand in the 50% RPS scenario. Additionally, the report concludes that the

[36] *Ibid*, p. 5.

PRM is still a useful metric to assess adequacy, that new flexibility-related planning standards (*e.g.*, LOLE multi-hour, LOLE intra-hour) are not needed at this time, and that the capacity contribution from energy storage increases with more renewables on the grid.[37]

Most of all, CESA views the CES-21 project and its focus on flexibility needs and planning standards as an important consideration for the PCM process. The results on intra-hour flexibility needs are especially insightful and provide a reasonable basis for incorporating intra-hour PCM in the IRP process as well. For example, the CES-21 project observes that the absolute value of five-minute ramps in a given day add up to a significant amount of cumulative ramping across an entire year, which increases significantly as California advances toward higher RPS levels.[38] This observation highlights the magnitude of the intra-hour grid flexibility need and raises questions as to whether renewable curtailment can provide such significant levels of intra-hour flexibility, and if so, whether it is cost-effective at higher and higher RPS levels. With granularity of PCM at the hourly level as proposed by Commission staff, CESA is concerned that these operational grid flexibility challenges will be overlooked. Additionally, the report observes that load following needs have a non-linear relationship with load and renewables, an important insight as this relationship is not easily captured by the linear programming model of RESOLVE.

Similarly, for multiple-hour ramps, CESA has estimated that the projected 2030 net load curves will leave no room for inflexible generation and requires the CAISO to be equipped with highly flexible resources with low to zero minimum operating levels and fast-ramping, quick-

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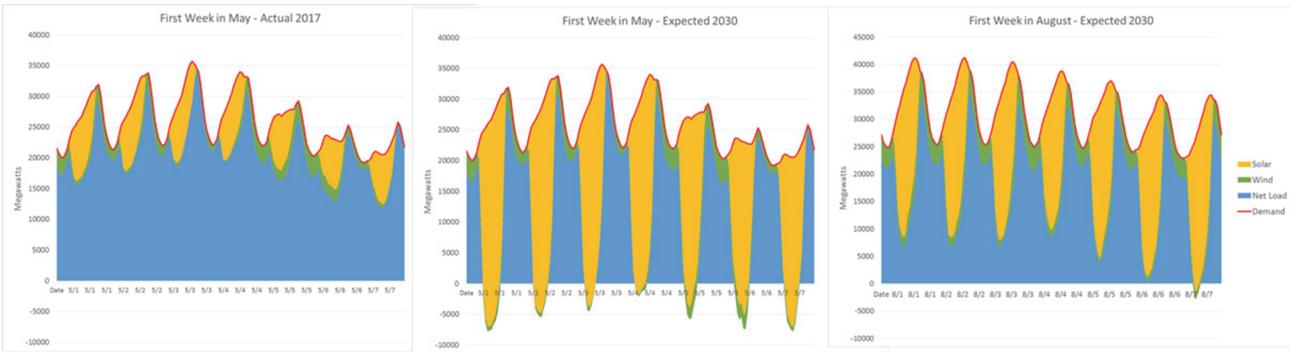
[37] *Flexibility Metrics and Standards Grid Integration: Role of Operating Flexibility in Planning Studies*. California Energy System for the 21st Century (CES-21) Final Report, filed on September 12, 2017. p. 12.

[38] *Ibid*, p. 31.

start capabilities to manage daily ramps – not only for the spring but also for the summer months. This analysis is supported by the CES-21 project that also demonstrated the need for resources for flexible ramping resources under a 50% RPS scenario.




*Source: CESA and LS Power analysis using CAISO OASIS 2016 data and IRP Proposed Reference System Plan*

In determining that no new flexibility-related planning standards are needed, the CES-21 project relies on assumptions related to operating practices, such as by allowing for some small Area Control Error deviations to maintain low costs for California's grid resource portfolio.[39] However, this tradeoff between intra-hour reliability and costs should be examined as the CAISO has recently highlighted challenges in meeting their Control Performance Standard ("CPS") performance target on a day-to-day basis, even as the 12-month rolling average for the CPS can be achieved.[40] Given the growing magnitude of intra-hour flexibility challenges observed today by the CAISO, it may be worthwhile to consider whether a new flexibility reliability standard should be developed based on sub-hourly PCM conducted in the IRP. Even as operational tools are available to manage projected intra-hour flexibility needs under 50% RPS and 42 MMT

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[39] *Ibid*, pp. 29, 32.

[40] *Operational Opportunities to Minimize Renewables Curtailments*, presentation by Clyde Loutan at the CAISO's Inverter-Based Generation Workshop on July 24, 2017, pp. 15-23. http://www.caiso.com/Documents/Agenda-Presentation-OperationalOpportunitiestoMinimizeRenewablesCurtailments.pdf

scenarios, the CAISO may also need the Commission to supply the right resource mix to be ensured that intra-hour flexibility can be provided without reliance on real-time operational tools, which should be relied upon more to handle certain shortfalls due to forecast error. In an era of increasing clean but variable generation, the reliance on the PRM alone as the grid reliability standard may not be prudent and thus CESA finds it important to explore this through sub-hourly PCM in the IRP process. From a developer perspective, a new flexibility-based reliability standard may also facilitate flexible capacity planning and encourage long-term contracting for flexibility capacity.

## X. CONCLUSION.

CESA appreciates the opportunity to submit these comments on the Ruling and looks forward to working with the Commission and stakeholders to ensure informative and actionable modeling results for the Reference System Plan.

Respectfully submitted,

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