**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 WIND ENERGY ASSOCIATION ON ORDER INSTITUTING RULEMAKING TO DEVELOP AN ELECTRICITY INTEGRATED RESOURCE PLANNING FRAMEWORK AND TO COORDINATE AND REFINE LONG-TERM PROCUREMENT PLANNING REQUIREMENTS**


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***On behalf of the California Wind Energy Association***


March 21, 2016

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OF THE STATE OF CALIFORNIA**

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## I. INTRODUCTION & SUMMARY

Pursuant to the Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements ("OIR") issued by the Commission on February 19, 2016, the California Wind Energy Association ("CalWEA") provides these comments on the scope of the OIR and the prioritization and sequencing of issues in the proceeding.

In summary, CalWEA recommends the following:

- **IRP Process --** The Commission should adopt a process by 2017 that will produce a detailed, executable IRP by the earliest possible date. The Commission should build on its work in other related resource proceedings, which is ongoing and unfinished. This work includes many components that will be prerequisites to conducting any single, comprehensive analysis leading to an optimized portfolio of resources. Therefore, the emphasis in this proceeding should be on "adopt[ing] a process by 2017" that will produce a detailed, executable IRP by the earliest possible date. That process should include the following actions by the Commission, in this priority and sequence:

  1. Adopt "California Pathways" as the initial high-level IRP and high-level electricity sector IRP and, based on that plan, develop a high-level IRP for each jurisdictional LSE operating within the CAISO. Such plans will ensure that the

LSEs' planning and procurement efforts are on track to meet the ARB's electricity sector GHG emissions-reductions targets while the Commission develops more detailed IRP processes.

2. Develop and adopt a detailed IRP framework for coordinated application to all LSEs and each resource proceeding related to IRP. To do this, the Commission should plan to examine its work in each relevant proceeding and identify any inconsistencies in their individual components (methods, assumptions and values), with the goal of developing a single harmonized IRP analytic framework for use in all proceedings going forward.
3. On a parallel path with 1 and 2, continue work on properly developing the various assessment values that will constitute the IRP framework. Developing the assessment values (such as capacity values and curtailment costs) is an equally high priority to 1 and 2 because these values will be integral to the IRP framework and thus are prerequisites to IRP. Moreover, they will strongly influence the procurement decisions that will continue to be made as the IRP procurement framework is put into place.
4. Develop optimized component resource portfolios for 2030, beginning with the RPS portfolio. Planning and procuring for the target year, rather than intervening years, will provide a long-term optimal portfolio that will also provide for the flexibility and lead-time that is necessary for rational planning and procurement.
5. Require the LSEs to submit IRP implementation plans for each component of their portfolio based on the Commission's adopted IRP framework and optimized component portfolios.
6. Determine whether the component IRP frameworks should be merged into a single IRP and executed by the LSEs as an all-source procurement, or whether California Pathways should be updated to guide resource-specific planning and procurement.

- **Cost Allocation --** To the extent that an LSE does not procure resources consistent with the optimal 2030 resource portfolio as identified in the integrated resource plan components, the LSE should be charged for its fair share of the resulting incremental costs. The Commission should pass along CAISO-allocated costs to LSEs on the basis of cost-causation, not on a load-share basis, and should address other costs through the Cost Allocation Mechanism or other mechanism, as SB 350 anticipates.

- **Greenhouse Gas Emissions Accounting --** If the IRP requirements are implemented as CalWEA recommends, above, then the lion's share of GHG emissions will have been accounted for. The Commission should address any issues that may not have been sufficiently explored, such as minimum generation levels for gas-fired facilities and GHG emissions related to ancillary services.

- **Other Specific Items Addressed in the OIR Scope --** The OIR lists and discusses "Resource Valuation and/or Selection Methodology," "Demand-Side and Distributed Energy Resource Cost-Effectiveness," and "Grid Integration" as distinct items that may need to be coordinated with the IRP proceeding. All of these issues are vital parts of the IRP process and should be incorporated into the IRP framework as discussed in these comments.

- **Cost Containment –** Achievement of the 50% RPS is necessary to cost-effectively achieve the state's GHG goals. Therefore, the Commission should provisionally deem that RPS costs will be contained as required, subject to the Commission's successful implementation of LCBF/IRP.

Each of these points is discussed further below.

## II. PRIORITIZATION AND SEQUENCING OF TOPICS AND ACTIVITIES

### A. Adopt A Process By 2017 That Will Produce A Detailed, Executable IRP By The Earliest Possible Date

As the OIR states, "SB 350 mandates that the Commission adopt a process by 2017 for all jurisdictional LSEs to submit IRPs to ensure that the LSEs' planning and procurement efforts are on track to meet, among other provisions, the electricity sector's GHG emissions reductions targets to be established by the California Air Resources Board." As the OIR also states, SB 350 also includes requirements for portfolio optimization in IRP, including requirements that the Commission identify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner, relies on zero carbon-emitting resources to the maximum extent reasonable, and is designed to achieve any statewide greenhouse gas emissions limit pursuant to the California Global Warming Solutions Act of 2006 or any successor legislation. (OIR at p. 12)

The OIR correctly acknowledges that the new legislative IRP requirements "represent a logical evolution" that builds on the Commission's work in previous LTPP proceedings and other related resource proceedings. (OIR at 2.) It is also essential to recognize that this work – which is ongoing and unfinished -- includes many components that will be prerequisites to conducting any single, comprehensive analysis leading to an optimized portfolio of resources to serve an LSE's load, as contemplated by the OIR. (OIR at p. 13.)

Therefore, the emphasis in this proceeding should be on "adopt[ing] a process by 2017" that will produce a detailed, executable IRP by the earliest possible date. That process should include the following series of actions by the Commission, in this prioritization and sequence:

1. Adopt "California Pathways" as the initial high-level IRP and, based on that plan, develop a high-level IRP for each jurisdictional LSE operating within the CAISO.
2. Develop and adopt a detailed IRP framework for coordinated application to all LSEs and each resource proceeding related to IRP.
3. On a parallel path with 1 and 2, continue work on properly developing the various assessment values that will constitute the IRP framework.
4. Develop optimized component resource (i.e., RPS, energy efficiency, demand response, etc.) portfolios for 2030, beginning with the RPS portfolio.
5. Require the LSEs to submit IRP implementation plans for each component of their portfolio based on the Commission's adopted IRP framework and the optimized component portfolios.
6. Determine whether the component IRP frameworks should be merged into a single IRP and executed by the LSEs as an all-source procurement, or whether California Pathways should be updated to guide resource-specific planning and procurement.

Each of these steps is discussed below.

1. <u>Adopt "California Pathways" as the initial high-level IRP and high-level electricity sector IRP and, based on that plan, develop a high-level IRP for each jurisdictional LSE operating within the CAISO</u>.

Significant effort and resources went into the 2015 "California Pathways" project, which was collaboratively sponsored by this Commission, the Air Resources Board, the CAISO, and the Energy Commission, and was performed by Energy & Environmental Economics with support from the Lawrence Berkeley National Laboratory.[1] This study evaluated the feasibility and cost of a range of greenhouse gas ("GHG") scenarios for 2030, achieving GHG reductions of 25-36% below 1990 levels, addressing all economic sectors and their interactions.[2]

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[1] See https://ethree.com/documents/E3_PATHWAYS_GHG_Scenarios_UCDavis_CCPM_final.pdf.

[2] California Pathways looked at achieving GHG reductions in the 25-36% range by 2030, while the ARB has established a goal of achieving 40% reductions by 2030. If California Pathways were adopted as the initial IRP, the discrepancy in targets could be addressed by adopting the "early deployment" scenario (36% reduction), with a commitment to update the plan as soon as possible with a 40% reduction goal.

This extensive research and modeling effort – which will not likely be reproduced any time soon – should be adopted as California's initial multi-sector IRP along with a plan to conduct periodic updates of the study to include opportunities for public comment. This plan, adopted by the Commission, can well serve as the basis for a high-level electricity sector IRP, and serve as the basis for Commission-developed high-level plans for each of its jurisdictional LSEs that operate within the CAISO, after opportunities for public comment. These plans will ensure that the LSEs' planning and procurement efforts "are on track to meet … the electricity sector's GHG emissions reductions targets to be established by the California Air Resources Board" (OIR at p. 12) while the Commission develops more detailed IRP processes.

2. Develop and adopt a detailed IRP framework for coordinated application to all LSEs and each resource proceeding related to IRP.

The Commission asks whether integrated resource planning should be undertaken on a system-wide basis and/or by individual LSEs. (OIR at p. 14.) For both the high-level and executable plans, a single Commission-developed IRP for all CAISO-participant-LSEs is appropriate for several reasons. First, a single plan makes sense for entities that operate within the same interconnected balancing area that provides opportunities for cost-shifting (the procurement decisions of one LSE can affect the system costs that others will end up paying for).[3] Second, the development and implementation of a single Commission-driven plan will be more transparent and efficient for all parties, as compared to developing, reviewing and attempting to coordinate multiple plans. Third, a public plan would provide the public with greater confidence that procurement based on the plan will best promote the achievement of critically important statewide goals. That is, the Commission should be in the driver's seat with regard to the development of the plan; the role of each LSE should be to implement their portion of the plan.

A consistent IRP framework using uniform assumptions and values should be developed and applied to each resource proceeding related to IRP until such time as one or more may be fully integrated. To do this, the Commission should plan to examine its work in each relevant proceeding and identify any inconsistencies in their individual components (methods, assumptions and values), with the goal of developing a single harmonized IRP analytic framework for use in all proceedings going forward. (However, all components may not be

[3] See section II.B, below.

applicable in all proceedings due to the different natures of each resource type, e.g., energy efficiency, distributed resources, storage, renewable and conventional resources.)

The development and use of a common framework across proceedings will go a very long way toward "comprehensive resource optimization" (OIR at p. 13) because all decisions will be made on a consistent basis. Moreover, until this harmonization across proceedings occurs, it will not be possible to merge any or all of these proceedings into a single "all source" planning and/or procurement effort (assuming that this will be practical).

In developing the common IRP framework, the Commission should begin with the areas where optimization and integration efforts have already begun and seek to accelerate, complete and expand those efforts. The Commission can build on its efforts to coordinate the RPS, LTPP and TPP processes where the Commission, Energy Commission and the CAISO are striving to use a single set of assumptions and common data to perform their analyses of the need for generation and transmission resources.[4] To inform LTPP and TPP assumptions regarding future renewable energy additions, the capabilities of Energy Division's "RPS Calculator" have been substantially improved to be able to generate a range of "reasonably possible" renewable energy futures.[5] However, these processes have not yet been sufficiently coordinated. For example, recently proposed LTPP assumptions do not yet reflect scenarios generated by the RPS Calculator.[6] Similarly, the Commission has just recently instructed the investor-owned utilities (IOUs) to develop a consistent methodology for determining the capacity value of RPS resources and to benchmark that methodology to those used in the RPS Calculator and the Resource Adequacy proceeding.[7]

All of these efforts, and many others, will be necessary components of IRP. The first order of business, therefore, is to build the IRP framework to be applied consistently to all proceedings, beginning with what has been learned and done to date. This effort should start and

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[4] See, e.g., CPUC R.15-02-020, Administrative Law Judge's Ruling Seeking Post-Workshop Comments (April 13, 2015).

[5] CPUC R.15-02-020, Administrative Law Judge's Ruling (1) Issuing An Energy Division Staff Paper On Incorporating Land Use And Environmental Information Into The RPS Calculator And Developing And Selecting RPS Calculator Portfolios; (2) Entering The Staff Paper Into The Record, And (3) Setting A Comment Schedule (August 28, 2015), Attachment A.

[6] See R.13-12-010, CalWEA Comments on LTPP Assumptions & Scenarios (2-22-16) at p. 6.

[7] See R.15-02-020, ALJ Ruling Accepting into the Record Revised Energy Division Staff Paper on the Use of Effective Load Carrying Capability for RPS Procurement and Setting Schedule (March 9, 2015).

conclude as early as possible because of the need for continued resource procurement to meet RPS and any other resource goals in an efficient and reliable fashion, and because the IRP framework should be in place in time for the likely and potentially imminent announcement of the retirement of Diablo Canyon. Without a new framework in place, LSEs will continue to use their disparate and generally ad hoc procurement processes to procure a significant amount of new renewable and conventional resources in a non-optimal fashion.

3. On a parallel path with 1 and 2, continue work on properly developing the various assessment values that will constitute the IRP framework.

While this step logically follows the previous two steps, it is essential to put equally high, if not higher, priority on it for two reasons: (a) the assessment values will be integral to the IRP framework and thus are prerequisites to IRP, and (b) these values will strongly influence the procurement decisions that will continue to be made as the IRP procurement framework is put into place, particularly in the RPS process and likely others.

The Adjusted Net Market Value ("ANMV") formula from the Commission's RPS Procurement Plan decisions seeks to compare renewable resources with different characteristics and is the essence of least-cost, best-fit ("LCBF") bid analysis – an optimization process that is reflected in the RPS Calculator and could also serve as the basis for integrated resource planning and procurement:[8]

**ANMV = ( E + C + S ) – ( P + T + G + I ), where**

E = Energy value
C = Capacity value
S = Ancillary services value
P = Post-TOD PPA price
T = Transmission cost adder
G = Congestion cost adder
I = Integration cost adder

[8] It is important to understand that "least cost" is not separate from "best fit." These value components are part of a single optimization equation that has two components: an "objective function" that considers all costs and benefits ("least cost") and "constraints" that account for limits and costs due to practical considerations ("best fit"). The optimization equation produces a single optimized result accounting for all costs, benefits and constraints; i.e., "least cost best fit." We note that optimization is commonly used in grid operations, where the objective is to seek "least cost" electric power system operations subject to "best fit" assumptions that are primarily represented in the same optimization problem in the form of either constraints or "penalty" costs.

Some parties (increasingly including CalWEA) have been unsatisfied with the RPS procurement process due to concerns that many of the indirect costs and benefits of various resources have never been properly and transparently accounted for in the ANMV equation, leaving these elements to be considered in the qualitative "best fit" portion of the LCBF process. While this was less important in the past, when the indirect costs and benefits of the various renewable resources were low, these values have dramatically changed as the system penetration of renewables has increased and updated quantifiable values can be expected to affect procurement decisions.[9] Yet, utility procurement has substantially outpaced the Commission's efforts to update these values. Specifically, the Commission has fallen behind in determining or updating the following values:

- **Integration cost adder ("ICA")** – The ICA encompasses the fixed and variable costs associated with the intra-hour system flexibility necessary to integrate renewable resources into the electricity system (i.e., regulation, load-following and ramping costs). The requirement to include indirect cost impacts in the LCBF bid evaluation process was included in the initial RPS legislation adopted in 2002 and the Commission initially established the ICA value at zero in 2004.[10] Yet, more than 10 years later and after the addition of over 10,000 MW of renewable energy resources to the system, the Commission still has not developed a methodology for determining the ICA, having adopted only a temporary placeholder value in 2014 reflecting the results of studies specific to other states, not the present and unique circumstances in California.[11] Stakeholder frustration with the lack of progress on a meaningful ICA led to a legislative addition to the RPS statute explicitly defining the ICA and setting a deadline of December 31, 2015, for the Commission to approve a methodology for it.[12] To date, the Commission has still not developed a methodology for the ICA; thus it remains in limbo.[13]

- **Capacity value** – Similarly, in 2011, as part of the legislation that raised the RPS to 33%, the Commission was required to determine the capacity value of wind and solar energy using the "effective load carrying capacity" ("ELCC")

[9] These decisions are critically important to the wind industry, as the relative value of wind energy is likely to increase as these values are updated. Meanwhile, existing PURPA contracts are expiring, and the federal tax benefits necessary to repower are expiring – thus, time is of the essence.

[10] CPUC D.04-07-029.

[11] CPUC D.14-11-042 (November 24, 2014).

[12] PU Code Sec. (a)(4)(A)(v).

[13] See R.13-12-010, March 27, 2015, Ruling of ALJ Gamson and subsequent rulings on the topic.

methodology to establish the contribution of these resources toward meeting resource adequacy ("RA") requirements.[14] Five years later, the Commission hopes to finally adopt ELCC-based values for RA purposes this year but, while it has begun a process to implement ELCC for use in the procurement process, it is not clear whether ELCC values will be ready in time for the 2016 procurement cycle.[15] The OIR's reference to the Commission's current efforts as a "refinement" of capacity values (OIR at p. 18) is an understatement; the Commission has recognized that the ELCC approach "is a more reliable and accurate measure" of renewable energy capacity value than the methodology currently in use, and that the inaccuracies of the current approach "are magnified as renewable penetration increases."[16]

- **Curtailment costs –** While the significant potential cost of curtailed energy due to overgeneration conditions was identified as a major issue in RPS Calculator results more than a year ago,[17] the cost of curtailed energy is not recognized in the LCBF procurement process, nor has the Commission identified it as a problem that needs to be corrected (although the issue of curtailment was briefly mentioned in the OIR (OIR at p. 20). In an Attachment to these comments, CalWEA explains in detail how it is that this major cost is currently falling through the cracks. Consistent with the findings of the Calculator, CalWEA expects that the cost of curtailment will dwarf the ICA.

These values are relevant to proceedings other than the RPS; for example, distributed-generation-related and storage proceedings should clearly be taking curtailment into account. In order to conduct "least-cost/best-fit" results in the near term, and IRP results in the longer term, it is critically important that the Commission update these values in transparent processes as soon as possible.

4. <u>Develop optimized component resource (i.e., RPS, energy efficiency, demand response, etc.) portfolios for 2030, beginning with the RPS portfolio.</u>

As soon as the IRP framework has been developed, and the most important LCBF/IRP values have been determined, the Commission should generate and adopt an optimized portfolio for the target year (2030, while ensuring consistency with the trajectory to 2050 as done in

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[14] PU Code Sec. 399.26(d).

[15] See R.15-02-020, ALJ Ruling Accepting Into the Record Revised Energy Division Staff Paper on the Use of ELCC for RPS Procurement and Setting Schedule (March 9, 2016) at p.3 (Schedule).

[16] *Id.* at Attachment A, p. 2-3.

[17] See Resource Valuation presentation in the February 2015 RPS Calculator Workshop Materials, which can be found at http://www.cpuc.ca.gov/RPS_Calculator/.

Pathways) for each component of the utility portfolio. Planning – and procuring – for the target year, rather than intervening years, will provide a long-term optimal portfolio that will also provide the flexibility and lead-time that is necessary for rational planning and procurement. The plan should be updated in a biannual cycle, reflecting the market data generated in recent procurement activities.

The adopted plan for each portfolio component would then serve as the basis for LSE procurement. For the RPS, planning for 2030 is already occurring through the RPS Calculator, which includes projected curtailment costs, although it is lacking robust ICA values since the development of the ICA is still in progress.

5. Require the LSEs to submit IRP implementation plans for each component of their portfolio based on the Commission's adopted IRP framework and optimized component portfolios.

With an optimized plan for each segment of the portfolio, with all plans having been coordinated through a common framework and assessment values, it would not be necessary for each LSE to submit their own IRPs. Rather, they would submit plans to implement their portion of the system-wide IRP on an annual basis. The Commission should provide the LSEs with some year-by-year flexibility to achieve the 2030 plan, as long as annual and cumulative procurements are consistent with it. This will enable the flexibility needed to respond to market conditions and to procure "lumpy" additions to the portfolio. While LCBF analysis would still be used to compare resources of the same type (e.g., different technologies or locations using the same renewable resource, or different types of storage), procurement would be guided by the overall 2030 plan. For example, if the 2030 portfolio shows 50% of resource X, 40% of resource Y, 10% of resource Z, and a certain amount of storage, the LSEs would seek to procure that mix in the intervening years (perhaps on a pro-rata basis each year, but providing for flexibility).

6. Determine whether the component IRP frameworks should be merged into a single IRP and executed by the LSEs as an all-source procurement, or whether California Pathways should be updated to guide resource-specific planning and procurement.

Once all proceedings are governed by the same IRP framework, and share the same methodologies, assumptions and assessment values, we then essentially have an IRP, even if procurement takes place in separate resource proceedings. The Commission should not assume that we also need a single IRP process to generate an overall electricity sector IRP and to conduct all-source procurement and, in any case, will be a ways off given the preliminary work that is required, as described above. The practical challenges alone of developing an IRP and conducting all-source procurement may be daunting.

An alternative would be to periodically update the multi-sector California Pathways study (or some facsimile) to serve as the overarching IRP, and the high-level IRP for the electric sector. While comment opportunities should be provided, the advantage of this approach is its multi-sector nature (the GHG goals in the electricity sector will be strongly affected by the other sectors) and the practical need to conduct more complex modeling to derive an IRP (particularly a multi-sector IRP). The assumptions, methods and assessment values used in California Pathways must, however, be harmonized with what is used in the Commission's IRP framework.

As noted above, the IRPs filed by LSEs should be IRP implementation plans, not IRPs. Further, while the OIR notes at one point that "this proceeding will then address the scope of the integrated resource plans to be filed with the Commission beginning in 2017" (OIR at p. 4), the statute does not require plans to be filed in 2017. Instead, and consistent with our recommendations above, the statute states, "Commencing in 2017, and to be updated regularly thereafter, the commission shall <u>adopt a process</u> for each load-serving entity, as defined in Section 380, to file an integrated resource plan, and a schedule for periodic updates to the plan …"[18] (Emphasis added.) Given the steps necessary before an IRP can be developed, as discussed in these comments, 2017 will be too soon for the LSEs to be filing IRPs.

Finally, as detailed above, we note that the Commission is far behind in implementing other statutory mandates such as the integration cost adder and ELCC – and has not addressed the major grid integration issue of curtailment at all. Addressing these issues must therefore rank higher on the priority list than new SB 350 requirements.

**B. Cost Allocation**

The new IRP requirement extends to all LSEs who serve load within the IOU service territories, including electric service providers (ESPs) and community choice aggregators (CCAs), as well as the small and multi-jurisdictional utilities (SMJUs). (OIR at p. 14.) This is

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[18] PU Code Section 454.52(a)(1).

appropriate, since most of these entities operate within the CAISO system, presenting opportunities for cost-shifting among them. The new IRP policies should prevent such cost shifting, and instead develop new cost-sharing mechanisms to address system integration costs.

CalWEA's recommendations above have assumed equal applicability of IRP to all LSEs. However, to the extent that an LSE does not procure consistent with the optimal 2030 resource portfolio as identified in the integrated resource plan components, the LSE should be charged for its fair share of the resulting incremental costs. These costs fall into two categories: costs that are allocated by the CAISO and are normally allocated based on cost-causation principles, and those that do not fall in that category.

1. CAISO-allocated costs

The CAISO allocates the cost of some ancillary services (such as ramping costs on an intra-hour and multi-hour basis) based on principles of cost causation. Thus, the CAISO associates these ancillary service costs with types of resources and load and allocates costs to specific LSEs accordingly. Unfortunately, the Commission has not passed these costs along to its LSEs in the same fashion (e.g., multi-hour ramp capacity responsibilities); rather, it has re-allocated total costs according to load share.[19] As CalWEA explained in 2014 comments, this practice eliminates the incentive for LSEs to reduce the costs that it imposes on the system.[20] Therefore, as part of IRP, the Commission must change this practice so that costs are passed through to LSEs as the CAISO has allocated them.

2. Other costs

There are other indirect costs of procurement, however, that will not be allocated by the CAISO or the Commission without new policy. The cost of curtailed energy is the most obvious example. Currently, as CalWEA explains in detail in the Attachment hereto, the curtailment and associated cost that a procured resource will impose on other resources is escaping analysis in the RPS LCBF analysis because it is not included in the LCBF framework, paid for in the power

[19] CPUC D. 14-06-050 (June 26, 2014).

[20] See R.11-10-023, CalWEA's Comments on the Proposed Decision Adopting Local Procurement and Flexible Capacity Obligations For 2015, and Further Refining the Resource Adequacy Program (June 16, 2014).

purchase agreement (assuming the pro forma terms are not revised), or factored into the bidder's price. As a result, the cost of curtailment – which, if not checked, could account for almost 9% of all renewable energy production by 2030 – will unexpectedly fall on many generators or other parties. CalWEA suspects that this phenomenon is likewise not currently being sufficiently appreciated in other proceedings, particularly those related to distributed (solar) generation. Curtailment costs must immediately be addressed in the RPS LCBF process, and must likewise be corrected across all proceedings in order for IRP to properly function.

In addition, LSEs that do not conduct procurement according to LCBF/IRP and conform to the optimal 2030 portfolio (procuring only those resources with the lowest price tag without regard to system impacts) should be subject to paying for the costs that such practices impose on other parties through the Cost Allocation Mechanism" ("CAM")[21] or some other mechanism, as SB 350 anticipates.[22] Given the lead-time required to achieve 2030 goals, each LSE would ideally be required to declare in advance whether or not it intends to procure its pro-rata share of the optimized 2030 portfolio.

We note, once again, the importance of quantifying all of the indirect costs, because only when indirect costs are properly accounted for will the efficient procurement path be known and can fair and appropriate cost-sharing among LSEs take place. So, again, it is important that these issues be assigned higher priority than the filing of IRP implementation plans by LSEs.

### C. Greenhouse Gas Emissions Accounting

SB 350 requires the Commission to address, in IRP, the "optimal integration of renewable energy in a cost-effective manner," relying on "zero carbon-emitting resources to the maximum extent reasonable." (OIR at p. 22.) If the IRP requirements are implemented as CalWEA recommends, above, then the lion's share of GHG emissions will have been accounted for in the electricity-sector portion of the California Pathways study (and any subsequent iterations), which to a significant extent provides for optimal renewable energy integration within a GHG constraint.[23]

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[21] See http://www.cpuc.ca.gov/General.aspx?id=6949.

[22] PU Code Section 454.51(c) and (d).

[23] Primarily, the Pathways study includes a diverse mix of renewable resources, which reduces integration costs (primarily curtailment costs). See note 1, supra, at slide 12.

However, in the Commission's IRP process, which should develop an IRP framework for application to each IRP-related procurement proceeding, the Commission can address issues that may not have been fully explored in Pathways. (Any findings can be fed into the updated Pathways study, in an iterative type of process.) This should include assumed minimum generation levels for gas-fired facilities, which levels may be able to be lowered under evolving CAISO operating practices. The Commission should also explore the addition of a GHG value to the ancillary services cost component of the ANMV equation in the RPS LCBF process, and to relevant equivalent processes in other proceedings. While CalWEA expects the GHG value that is associated with renewable energy integration to be relatively small and thus possibly inconsequential (because ancillary service costs generally are a small portion of the total ANMV), it should be addressed in order to be responsive to the requirements of SB 350.

### D. Other Specific Items Addressed in the OIR Scope

The OIR lists and discusses "Resource Valuation and/or Selection Methodology," "Demand-Side and Distributed Energy Resource Cost-Effectiveness," and "Grid Integration" as distinct items that may need to be coordinated with the IRP proceeding. As CalWEA sees it, all of these issues are vital parts of the IRP process. As described above, a uniform IRP framework with consistent methodologies, assumptions and values should be applied to all relevant proceedings. Thus, the "resource valuation and/or selection methodology" with consistent "grid integration" values should apply equally to the determination of "demand-side and distributed energy resource" as well as conventional and renewable energy evaluations. For example, rather than possibly incorporating the results of the Integrated Distributed Energy Resources proceeding into the IRP process (OIR at p. 19), the Commission should draw on that process and others to develop a consistent overarching IRP framework to be applied equally and transparently across all relevant proceedings as soon as possible.

### E. Cost Containment

The OIR raises the issue of RPS cost containment, as the Commission is required to contain RPS costs "at a level that prevents disproportionate rate impacts." (OIR at p. 21.) RPS cost containment was included in the 33% RPS legislation adopted in 2011. However, given the Legislature's and the Administration's 2015 commitment to achieve the greenhouse gas goals embodied in SB 350 and related Executive Orders, the RPS cost containment provisions included in statute at an earlier time represent a conundrum.

The California Pathways study demonstrates that the state must achieve an electricity sector portfolio with at least 50% renewable energy by 2030 to most cost-effectively achieve the state's 2030 and 2050 GHG goals. Given this fact, and the state's overall GHG goals, the Commission's focus should be on achieving the RPS at least total cost, which is the aspiration of both the RPS LCBF framework and a broader IRP framework spanning all proceedings. Therefore, CalWEA recommends that the Commission provisionally deem that RPS costs will be contained, subject to the Commission's successful implementation of LCBF/IRP.

## III. CONCLUSION

For the foregoing reasons, the Commission should adopt the recommendations for progressing towards an integrated resource planning process as set forth in these comments.

Respectfully submitted,

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***On behalf of the California Wind Energy Association***

March 21, 2016

**Curtailment: The Missing Link Toward a More Diverse RPS Portfolio**

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February 19, 2016

The models being used by the CPUC and the CAISO to project cost-effective 50% RPS resource scenarios for meeting California's 2030 goals consistently show a need for several thousand megawatts of additional wind energy capacity, both in California and across the West.[24] In addition, these models assume that California's fleet of 1980s-vintage wind projects not only continue to operate but increase their energy production, if not capacity.[25] Given the low and still-falling costs of solar energy, a primary driver of the cost-competitiveness of wind energy in these models is the finite capacity of the system to accommodate the output profile of solar: there is only so much demand for power during daytime hours. This concentrated output profile is expected to lead to very significant curtailment of solar energy at high solar penetration levels.[26]

Importantly, however, these models make a critical assumption that may not always track current utility practice: that generators are paid for their curtailed energy at the full contract price.[27] That is, the models assume that the cost to curtail excess renewable generation will be included in the least-cost, best-fit (LCBF) analyses leading to utility procurement decisions, with the result that solar energy becomes less cost-effective and resources with complementary output profiles become more competitive as solar penetration increases. The problem is that curtailment costs are not, in fact, being fully included – if included at all – in utilities' procurement analyses of proposed bids. As a result, solar continues to dominate utility procurements.

Curtailment costs are being overlooked or under-estimated for a number of reasons. First, overgeneration-related curtailments are of little or no concern to the buyer. This is because the CAISO orders curtailment for the purpose of maintaining system reliability when supply is expected to unavoidably exceed demand. The investor-owned utilities' pro forma power purchase agreements (PPAs) – and therefore presumably most, if not all, of their signed contracts

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[24] For example, E3's Draft Renewable Portfolios for CAISO SB 350 Study presented at a February 8, 2016, CAISO workshop showed a range of 1,500-3,000 MW of incremental California wind, plus an additional 2,000 – 5,000 MW of regional wind (not including wind RECs alone), under various scenarios. See also E3's Update on the 2015 Special Study presented at a June 29, 2015, CPUC-CAISO Webinar.

[25] Statement of E3's Arne Olson in response to a question posed at the February 8th CAISO workshop.

[26] Marginal curtailment for solar PV was found to be 65% in a solar-heavy 50% RPS scenario in E3's Investigating a Higher Renewables Portfolio Standard in California (January 2014), at p. 15; similar results were found in E3's more recent Western Interconnection Flexibility Assessment, where almost 9% of all renewables are shown to be curtailed on average in a high-solar case (slide 30).

[27] *Supra* note 1 (SB 350 Study) at slide 10.

– generally provide that the utilities will not pay for any reliability-related curtailments ordered by the CAISO. So those costs are shifted to the seller and are of no concern to the utility buyer (although the utility should not be counting on obtaining the RECs from projected curtailment periods for RPS compliance purposes).

Second, from the seller's perspective, it is not clear whether bidders -- particularly the solar projects that will, by far, be hit the hardest by curtailments -- are factoring in any reliability-based overgeneration curtailment into their pricing. If bidders are factoring anything in, it would almost certainly be no more than the bidder's individual share of the average curtailment level expected under the CAISO's practice of uniformly curtailing generators during overgeneration conditions, not the total curtailment that all generators (both existing and planned) will suffer as a result of the bidder's marginal contribution to the need for curtailment.

Nor is there any accounting in the LCBF RPS procurement process for this curtailment cost-shift to other generators. If curtailment will be borne, on average, by generators and not by the utility or its customers, it's not really an indirect cost of concern to the LCBF evaluation. (Ratepayer groups and utilities might be concerned, however, that, when that curtailment begins to mount, solar project owners will seek to get that curtailment paid for.)

But how much curtailment should be expected by all generators? How can developers accurately predict how much solar energy will be procured by California's utilities as well as all other load-serving entities on the CAISO grid (and as that grid may be expanded)? As importantly, if not more so, bidders would need to factor in the curtailments they will bear as a result of rooftop solar installations, which themselves are expected to bear no curtailment at all, as they are not subject to curtailment by the CAISO. The CPUC's recent net-metering decision, widely viewed as very favorable for rooftop solar installers, will likely produce more than the 10,000 MW of rooftop solar that has been included in recent forecasts. Further, it is difficult to project future levels of demand-response (including midday EV charging) or energy exports that might reduce curtailment.

This situation is a conundrum for any bidders who are thinking about how to factor in future curtailments into their bid prices (even if only the average curtailment they will suffer), since it is virtually impossible to accurately predict curtailment levels over time. And a conservative assumption will result in a losing bid, if other bidders do not project similarly high curtailment levels.

The result is a common-pool resource problem[28] in which everyone has access to a resource and, by using it, additional costs are imposed on other users of the resource. In this case, the grid's limited ability to absorb generation becomes saturated at certain times due to a combination of limited demand and high solar generation, resulting in a curtailment order to all generators. Fixed-output renewable energy generators – again, primarily solar generators – will be in for an unpleasant surprise as unpaid curtailments begin to mount.

[28] More specifically, the grid can be thought of as an open-access resource.

To resolve this common-pool problem, two main fixes are needed:[29] ***(1) generators must be paid for overgeneration-related curtailment***, and ***(2) the remaining marginal curtailment that will be imposed on existing and planned generation must be accounted for in the analyses leading to procurement decisions.*** In this way, procurement decisions will take into account the "overuse" of the grid, and that overuse will occur only when it is cost-effective to do so – i.e., only when, even with expected overall curtailment, the procured resource is still cost-effective.[30] There is one problem. To date, the utilities' pro forma PPAs have attempted to assign CAISO-ordered overgeneration-related curtailment costs to the generator; only going forward will the fix described above cause these costs to be felt by the purchasing entities. Therefore, the overgeneration that will be felt by existing generators is not pain that will be felt by the purchaser or its retail customers, and thus does not strictly fit in the LCBF analysis of future procurement options.

There is, however, a way to shift the CAISO-ordered overgeneration-related cost imposed on existing generators to the utility/ratepayer side of the ledger. This shift could occur through another type of curtailment, known as "economic" curtailment, which enables the utility to curtail generators when it makes sense for economic, as opposed to reliability, reasons. Many versions of past utility pro forma PPAs allowed for a limited number of unpaid hours of economic curtailment in order to respond to very low or negative market prices, since utilities would rather not pay the PPA price when they get little or nothing – or even have to pay – to offload the energy onto the grid in return. These contract provisions also enable the use of economic curtailment to back generators down to avoid an overgeneration situation. Moreover, utility contracts also generally allow for unlimited curtailment at the PPA price. In the normal course, one would expect the market price of energy to fall as supply began to exceed demand, which would introduce an incentive for a utility to utilize its economic curtailment rights to reduce supply before the supply-demand imbalance resulted in negative prices being applied to the utility's entire portfolio. But, it's quite possible that utilities would not avail themselves of the opportunity to avoid negative pricing by paying for economic curtailment if engaging in a strategy of foregoing their economic curtailment rights would push the supply-demand imbalance past the "tipping point," forcing the CAISO to declare an overgeneration condition and order curtailments, which the utility is not contractually required to pay for.

If, instead, utilities were required to utilize their economic curtailment rights under their existing contracts in order to avoid overgeneration events, it would (in addition to solving the overgeneration problem) remove the economic incentive to engage in the strategy noted above:

[29] These issues could be addressed in the CPUC's implementation of PU Code Section 399.13(a)(8), which was added to statute by SB 350 and states: "In soliciting and procuring eligible renewable energy resources, each retail seller shall consider the best-fit attributes of resource types that ensure a balanced resource mix to maintain the reliability of the electrical grid."

[30] Alternatively, increasing, but reasonable levels of unpaid overgeneration-related reliability curtailments could be assigned to each group of annual procurements (with the balance of curtailments paid). This would require selective curtailments, however, which would require the CAISO to give curtailment instructions to specific Scheduling Coordinators or generators, rather than the current practice of curtailing all generators uniformly.

namely, it would convert the overgeneration cost to a utility/ratepayer cost, rather than shifting it onto existing generators who could not reasonably have factored in expected levels of reliability-based overgeneration-related curtailment into their original PPA pricing, and who do not control the decision to engage in additional procurement of resources that cause increasing levels of overgeneration (their buyer, along with other buyers, do). Therefore, ***(3) the CPUC should order utilities to utilize their economic curtailment rights under their existing contracts to avoid overgeneration events.***[31]

Even if utilities don't pay existing generators for economic curtailment to avoid overgen, they should still factor the overall curtailment that is expected to result from their incremental procurements into their LCBF processes to achieve results going forward that are economically rational overall. The common-pool problem requires the problem to be resolved by directing procuring entities to look at the big picture.[32] Presently, stakeholders have very limited visibility into the LCBF processes; therefore, ***(4) the CPUC should require greater transparency and an explanation of how the impact of potential additional procurement on overall curtailment across all existing resources is being factored into the bid-evaluation process.***

Since the utilities likewise cannot perfectly forecast anticipated levels of curtailment, they could use a low- and high-range of curtailments to inform their decision-making. This range would be based on reasonably possible levels of CAISO exports to neighboring BAs, rooftop-solar penetration, demand-response programs, and time-of-use pricing incentives, etc. This analysis should also factor in the low or negative energy values that would be involved in CAISO exports (or sales within an expanded CAISO) of generation that would otherwise be curtailed. Procurement decisions could be based on a mid-range assumption, or could involve hedging any bets that curtailment levels will be on the low-end of the spectrum by procuring some renewable resources that would most cost-effectively reduce potential curtailments through resource diversity.

In this way, the models – which show that the most cost-effective 2030 50% mix will include substantial amounts of wind energy to complement a solar-dominant portfolio -- will come to fruition in actual utility procurements. Likewise, the state can avoid a common-pool problem that could lead to a dramatic loss of solar energy that would prevent the achievement of 50% goal and hurt all renewable energy generators, but ultimately hit solar projects the hardest.

[31] E3 also concludes, in its Western Interconnection Flexibility Assessment (see note 3, supra, at slide 46), that "creating an environment in which renewables can be curtailed routinely on an economic basis is necessary to avoid emergency conditions & reliability events."

[32] To the extent that Electric Service Providers (ESPs) and Community Choice Aggregators (CCAs) do not employ this type of LCBF process and continue to purchase solar without paying to avoid curtailments, the investor-owned utilities (IOUs) should be able to charge them for the higher direct costs that they incur to avoid overgeneration curtailments pursuant to PU Code Sec. 454.51.