BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 15-02-020 (Filed February 26, 2015)

COMMENTS OF THE INDEPENDENT ENERGY PRODUCERS ASSOCIATION ON THE RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS SUBMITTED BY THE LOAD-SERVING ENTITIES

INDEPENDENT ENERGY PRODUCERS ASSOCIATION
Steven Kelly, Policy Director
1215 K Street, Suite 900
Sacramento, CA 95814
Telephone: (916) 448-9499
Facsimile: (916) 448-0182
Email: steven@iepa.com

GOODIN, MACBRIDE, SQUERI & DAY, LLP
Brian T. Cragg
505 Sansome Street, Suite 900
San Francisco, CA 94111
Telephone: (415) 392-7900
Facsimile: (415) 398-4321
Email: bcragg@goodinmacbride.com

Attorneys for the Independent Energy Producers Association

Dated: August 18, 2017

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In response to 2017 Renewables Portfolio Standard (RPS) Procurement Plans submitted by Load-Serving Entities (LSEs) on July 21, 2017, the Independent Energy Producers Association (IEP) offers its comments. IEP begins with an overview of its recommendations to the Commission on the 2017 RPS Plans. We then provide background information that helps form the basis of IEP's recommendations, including comments on assumptions in the RPS Plans that create unwarranted barriers to timely and cost-effective procurement of incremental new RPS resources forecasted to be needed to meet state RPS and Greenhouse Gas (GHG) emissions-reduction policies.

I. IEP RECOMMENDATIONS

In response to the 2017 RPS Plans submitted by the LSEs for the Commission's review,[1] IEP recommends that the Commission:

[1] Pub. Util. Code § 399.13(c) directs the Commission to review and accept, modify, or reject each electrical corporation's renewable energy resource procurement plan prior to the commencement of renewable energy procurement. All statutory references are to the Public Utilities Code.

- *Direct* the Energy Division to report, no later than October 30, 2017, on whether the draft 2017 RPS Plans individually and collectively (a) reasonably balance expectations of load shifts among LSEs and (b) support state policy objectives in light of California Energy Commission (CEC) demand forecasts and preliminary Integrated Resource Plan (IRP) modeling.
- *Modify* the 2017 RPS Plans of Commission-jurisdictional LSEs (upon completion of the Energy Division study referred to above) as follows:
    - **Direct each LSE to procure RPS-eligible renewable resources at levels that exceed the minimum quantities specified in Section 499.15(b)(2) to reduce the corrosive effects of "excess" procurement.**[2] The Commission has the authority to direct jurisdictional LSEs to increase their RPS procurement above the minimum levels indicated in their 2017 RPS Plans. Due to various factors discussed below, near-term procurement of RPS resources is warranted. The Commission should direct its jurisdictional LSEs to increase their RPS procurement amounts above the statutory minimums.
    - **Allocate all costs *and* benefits associated with jurisdictional LSE RPS procurement to all beneficiaries on a non-bypassable basis.** The threat of future load departure should not be a barrier to timely procurement by the electric utilities. Delaying near-term procurement,

[2] Section 499.15(b)(3) enables the Commission to require the procurement of eligible renewable energy resources in excess of the quantities specified in § 499.15(b)(2). In addition, § 499.13(a)(4)(D) enables the Commission to adopt an appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the RPS to mitigate the risk that renewable projects planned or under contract are delayed or cancelled.

particularly in light of the diminishing availability of existing federal tax credits, could increase the costs of meeting state RPS and GHG emission-reduction goals. The Commission should authorize near-term procurement of RPS resources, and the costs *and* benefits of jurisdictional LSE RPS procurement should follow the load on whose behalf it was procured at the time of the procurement.[3]

II. BACKGROUND

The California RPS statutes impose an obligation on the Commission to implement a program in which jurisdictional LSEs serve their retail load during specified compliance periods with a minimum percentage of energy from eligible renewable resources. Currently, the RPS obligation is 33 percent of annual retail sales by 2020, increasing to 50 percent of annual retail sales by 2030. Moreover, beginning in 2021 LSE must procure at least 65 percent of the energy used for purposes of RPS compliance from long-term contracts of ten years or more or from ownership rights.[4] In addition, the legislature is considering a bill that would impose a 52% RPS obligation by the end of 2027 and a 60% RPS obligation in 2030.[5]

A. Forecasts of RPS Need

1. Energy Demand Forecasts

The Commission implements the RPS in light of official forecasts of energy demand over the next 10 years and modeling of various planning outcomes. The *California Energy Demand Updated Forecast, 2017-2027*, released January 2017 (CEDU 2016), provides

[3] IEP recognizes an issue related to non-compliance of RPS obligations by LSEs that are not subject to the Commission's jurisdiction. IEP does not address that matter here except to observe the regulatory treatment of existing Community Choice Aggregators (CCAs) does not need to be identical to the treatment of future CCAs. The threat of future departing load and CCA formation does not absolve the electric utilities of the responsibility to serve their customers.
[4] Section 399.13(b).
[5] Senate Bill 100 (De Leon), amended July 18, 2017.

the most recent officially adopted 10-year forecast of electricity demand statewide and for major utility planning areas within the state. The CEDU 2016 forecasts of electricity demand are net of energy efficiency and conservation. With regard to forecasts of changing energy demand, the CEDU 2016 concludes:

> *Annual* growth rates from 2015-2026 for the *CEDU 2016* cases average 1.42 percent, 1.05 percent, and 0.66 percent in the high, mid, and low cases, respectively, compared to 0.93 percent in the *CED 2015* mid case.[6]

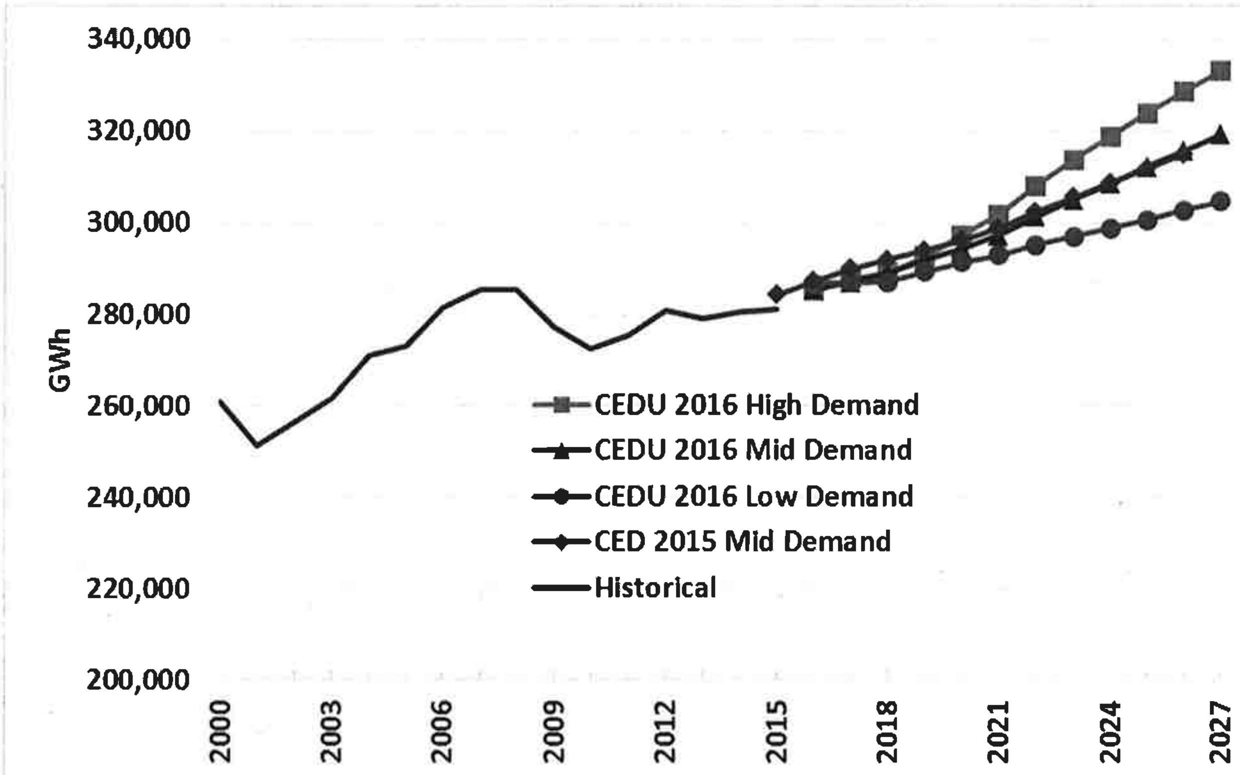
Specifically, the CEDU 2016 forecasts an increase in energy demand between 2015 and 2027 of 51,766 GWh in the High Energy Demand case, 37,922 GWh in the Mid Energy Demand case, and 23,305 GWh in the Low Energy Demand case.[7] The CEDU 2016 Report depicts the forecast of statewide baseline annual electricity consumption as follows[8]:

[6] California Energy Demand Updated Forecast, 2017-2027, January 2017 (CEC-200-2016-016-CMF), p. 3 (emphasis added). While continuing to forecast an increase in demand, the CEC Draft Staff Report for 2018-2028 indicates a slightly lower increase. The draft report states, "All three new forecast cases are lower than the CEDU 2016 mid case at the beginning of the forecast period with the addition of new efficiency program impacts and more PV adoptions, with the new high case pushing above CEDU 2016 by 2022. By 2027, sales in the CED 2017 Preliminary mid scenario are projected to be around 7,300 GWh (2.6 percent) lower than in the CEDU 2016 mid case. Annual growth from 2015–2027 for the CED 2017 Preliminary scenarios averages 0.70 percent, 0.32 percent, and -0.02 percent in the high, mid, and low cases, respectively, compared to 0.52 percent in the CEDU 2016 mid case." This forecast has not yet been adopted by the CEC.

[7] CEDU 2016, Table 1, p. 14. IEP calculated the difference using the CEDU 2016 High Energy Demand, Mid Energy Demand, and Low Energy Demand inputs comparing 2015 with 2027.

[8] CEDU 2016, Figure 1, p. 15.

California Energy Demand Updated Forecast 2017-2027
Figure 1: Statewide Baseline Annual Electricity Consumption



IEP converted the forecasted incremental energy demand into an estimated range of nameplate RPS capacity needed to supply the energy. Assuming passage of SB 100, which imposes a 52 percent RPS by the end of 2027, and an incremental energy need of 50,000 GWh, as forecasted in the High Energy Demand scenario, an additional 3,710 MW of incremental baseload renewables (*e.g.,* geothermal, biomass) are needed or, alternatively, 9,894 MW of incremental intermittent renewables (wind, solar) are needed.[9] Even assuming a Low Energy Demand scenario, the data suggests that approximately 1,641 MW of incremental, additional

[9] To forecast the amount of renewable procurement (MW) needed to meet the forecasted energy demand (GWh), IEP assumed a capacity factor of 80% for baseload resources and a capacity factor of 30% for intermittent resources. Assuming 100% of the need is met through baseload resources, the calculation in the High Energy Demand Scenario is as follows: 50,000 GWh / 8760 (hrs) * 0.80 (capacity factor) = 7,135 MW * 0.52 (RPS) = 3,710 MW. Assuming 100% of the need is met through intermittent resources, the calculation in the High Energy Demand Scenario is as follows: 50,000 GWh /8760 (hrs) * 0.30 (capacity factor) = 19,026 MW * 0.52 (RPS) = 9,894 MW. To calculate the need for the Low Demand Energy scenario, IEP replaced 50,000 GWh with 23,000 GWh and performed the same calculation.

baseload renewable capacity are needed in 2027 or, alternatively, approximately 4,376 MW of incremental, additional intermittent renewable capacity are needed to meet the 52 percent RPS obligation in 2027 assuming adoption of SB 100.

2. Preliminary IRP Modeling

Preliminary IRP modeling results also indicate a compelling need to move to procure incremental new RPS resources. For example, to achieve the state's aggressive GHG emission-reduction targets while meeting a 50% RPS by 2030, the preliminary RESOLVE modeling results suggest that it would be cost-effective to promote the delivery of energy from new, incremental RPS resources by no later than 2022 to take advantage of existing federal tax incentives before they expire or diminish. Moreover, the preliminary IRP modeling results indicate that additional RPS resource production beyond the 50% 2030 target likely will be needed to achieve the state's GHG emission-reduction goals by 2030.[10]

III. COMMENTS ON KEY FACTORS AFFECTING LSE PLANS

Even though official energy demand forecasts and preliminary IRP modeling results indicate growing demand and increasing need for new renewables, the 2017 RPS Plans of the investor-owned utilities (IOUs), Energy Service Providers (ESPs), Community Choice Aggregators (CCAs) collectively propose little, if any, additional RPS procurement in the near term to meet this need. For example:

- Southern California Edison Company (SCE) sees no need for renewable energy at this time to satisfy its RPS program targets.[11] Under the 50% by 2030 target using SCE's assumptions, SCE forecasts a net short position in 2027 without the

[10] Preliminary RESOLVE Modeling Results for Integrated Resource Planning at the CPUC, July 19, 2017. See slide 43 regarding the amount of incremental RPS additions modeled for 2022. See slide 55 regarding modeling outcomes that suggest need for incremental renewables exceeding the 50% RPS by 2030 to achieve GHG emission-reduction goals by 2030.

[11] Southern California Edison Company's 2017 Renewables Portfolio Standard Procurement Plan, p. 4.

use of its RPS bank and a net long position through 2030 using its RPS bank. Alternatively, using the Commission's assumptions, SCE forecasts a net short starting in 2024 without the use of its bank and a net short position starting in 2030 with the use of its bank.[12] *SCE is not proposing to hold a 2017 RPS solicitation.*

- Pacific Gas and Electric Company (PG&E) indicates that it does not have an incremental need for RPS resources until after 2030.[13] *PG&E is not proposing to hold a 2017 RPS solicitation.*
- San Diego Gas & Electric Company (SDG&E) states that it anticipates meeting its RPS requirements for each compliance period through 2030 with procurement already under contract.[14] *SDG&E is not proposing to hold a 2017 RPS solicitation.*
- CCAs as a whole report little need for additional renewables due to forecasts of stable load, only moderately increasing for some CCAs. Aside from 860 MW of contracted capacity reported by three CCAs, the majority of CCAs report that they can meet their RPS compliance obligations through contracts with existing resources.[15] *Little incremental development of new RPS resources is contemplated by the CCA sector.*

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[12] Southern California Edison Company's 2017 Renewables Portfolio Standard Procurement Plan, p. 9.
[13] Pacific Gas and Electric Company's Draft 2017 Renewable Energy Procurement Plan, p. 1.
[14] San Diego Gas & Electric Company's Draft 2017 Renewables Portfolio Standard Procurement Plan, p. 19.
[15] Individual exceptions to this overall observation of CCA RPS Plans occur. For example, Marin Clean Energy reports contracting on a long-term basis with 626.5 MW of RPS-eligible capacity not yet in commercial operation; Peninsula Clean Energy Authority reports contracting on a long-term basis with 240 MW of RPS-eligible capacity which is not yet in commercial operation; and Silicon Valley Clean Energy reports contracting with one RPS-eligible project of unknown size which is not yet in commercial operation. Collectively, these CCAs have contracted with at least 866 MW of new RPS-eligible resources. The extent to which these incremental resources will become operational over the next five years is unknown, but IOUs have historically assumed a not-insignificant

- ESPs as a whole report little, if any, need for additional renewables due to relatively stable load over the forecast period. Moreover, few ESPs report contracting on a long-term basis with RPS-eligible resources not yet in commercial operation. *Little incremental development of new RPS resources is contemplated by the ESP sector.*

As a practical matter, the LSEs' determination of no need is a function of the Commission's defaulting to the minimum RPS energy procurement obligations and the electric utilities' forecast of departing load, which depresses forecasts of future energy demand and the level of renewable generation needed to meet minimum RPS procurement obligations. In combination, these factors result in IOU forecasts of "excess" procurement in early years, which they propose to apply in later compliance periods. In essence, the lower the minimum procurement obligation set by the Commission and the higher the forecasted departing load assumed by the LSEs, the greater the excess procurement planned to be applied to future compliance periods. This planning and forecasting practice defers the procurement of low-cost, GHG-free energy from RPS resources that, if procured promptly, could avail themselves of federal tax credits that lower the costs of RPS procurement.

The electric utilities' determination that they have no need for incremental RPS procurement stems largely from (a) assumptions regarding departing load and (b) assumptions about minimum procurement obligations, which lead to forecasts of "excess" RPS procurement that may be banked for future use. IEP will address each of these assumptions in greater detail.

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failure rate for renewable energy projects. Moreover, it is unclear whether these existing contractual obligations will be sufficient to serve any increase in CCA load projected by the IOUs.

A. Risk of IOU Load Departure Due to CCA Formation

Actual CCA formation does not eliminate statewide energy demand; it simply shifts load from one LSE to another LSE. Moreover, the risk of *future* load departure does not eliminate or lower the utility's obligation to serve the load that it has at the time procurement decisions are made.

Whether IOU assumptions of departing load are matched by the CCA/ESP assumptions of increasing load is unclear.[16] Load departure over the next decade due to CCA formation is estimated to range from 40 to 85 percent of an IOU's existing load.[17] PG&E's 2017 RPS Plan indicates that its forecasted demand is a function of uncertainty about future bundled retail sales.[18] While the IOUs appear to forecast relatively high levels of load departure to CCAs, IEP sees little indication that the CCAs' forecasts of future energy demand within their portfolios match the IOUs' forecasts of load departure.

As a first order of business, the Commission needs to ascertain whether the *decrease* in the retail sales forecasted by the IOUs due to CCA formation over the next decade is balanced by an equivalent *increase* in the forecasted retail sales of CCAs. IEP is concerned that the load forecasted to depart from the IOUs over the next decade due to CCA formation is not being reflected by the CCAs in their 2017 RPS Plans. If this is true, then there is a RPS planning and procurement "gap" that must be remedied. For that reason, IEP recommends that the Energy Division be directed to report, no later than October 30, 2017, whether LSE load forecasts (a) collectively align and (b) match statewide forecasts.

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[16] Information related to each LSE's forecast of departing load and retail sales is treated as confidential for the most part.

[17] "Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework," Staff White Paper, California Public Utilities Commission, May 2017, p. 3.

[18] Pacific Gas and Electric Company's Draft 2017 Renewable Energy Procurement Plan, p. 19.

B. <u>Minimum Procurement Obligation</u>

The RPS statutes direct the Commission to implement the RPS by requiring Commission-jurisdictional LSEs to use RPS-eligible energy to meet a minimum percentage of annual retail sales.[19] The Commission has the authority to establish levels of RPS energy procurement that exceed the minimums prescribed in statute.[20] The Commission is authorized to establish rules permitting retail sellers to apply excess procurement accumulate in one compliance period to a subsequent compliance period, a practice known as "banking."[21]

Excessive banking can have corrosive effects on RPS policy and GHG emissions reduction. Banked Renewable Energy Credits (RECs) cannot be counted by an LSE until retired; thus, the actual use of renewable energy in real-time is likely higher than reported or, alternatively, there is a risk of double-counting. As revealed in the IOU 2017 RPS Plans, excessive amounts of banked RECs that derive from energy produced today are reserved for RPS compliance in the future, creating a barrier to the incremental RPS procurement identified in the preliminary RESOLVE studies.

The Commission should restrict this practice. To rectify the corrosive effects associated with excessive banking, the Commission should establish minimum procurement obligations that encourage LSEs to retire a higher percentage of their RECs in the year or compliance period in which they were produced, thereby increasing the incentives for incremental procurement of new RPS resources during a period when the federal tax incentives

[19] Section 399.15(a) states, "In order to fulfill unmet long-term resource needs, the commission shall establish a renewables portfolio standard requiring all retail sellers to procure a *minimum quantity* of electricity products from eligible renewable energy resources a specified percentage of total kilowatt-hours sold to their retail end-use customers each compliance period to achieve the targets established under this article." Section 399.15(b) states, "The commission shall implement renewables portfolio standard procurement requirements as follows: (1) Each retail seller shall procure a *minimum quantity* of eligible renewable energy resources for each of the following compliance periods. . . ." (Emphasis added.)

[20] Section 399.15(b)(3) states, "The commission may require the procurement of eligible renewable energy resources in *excess of the quantities* specified in paragraph (2)." (Emphasis added.)

[21] Section 399.13(a)(4)(B).

provide the highest value to consumers. In establishing higher minimum levels of retail sales met through energy from RPS resources, the Commission will advance RPS policy and GHG emissions-reduction policy simultaneously, while positioning ratepayers to benefit from the diminishing availability of existing federal tax incentives.

C. <u>Benefit of Timely Procurement: The Value of Federal Tax Incentives</u>

The overall conclusion presented by the LSEs' 2017 RPS Plans is that there is no need for incremental RPS procurement in the near term. This conclusion is particularly disconcerting because the existing, but diminishing, federal tax incentives can significantly lower the cost of RPS resources that the latest energy modeling indicates will be needed soon to meet policy goals.

In commenting on the 2016 RPS Procurement Plans last year, IEP presented an analysis that assessed the impact of existing federal tax incentives on the costs of new, incremental renewables. IEP re-submits that analysis here because it is still relevant to the Commission's consideration of the 2017 RPS Plans. See Attachment A, *MRW Analysis—Value of ITC, PTC and Lower-Cost of Capital (August 29, 2016).*

Based on the 2016 RPS Calculator, the MRW Analysis reveals that the federal tax incentives reduce the levelized cost of energy (LCOE) for solar and wind resources significantly. For example, for projects qualifying in 2019, a 34% reduction in solar PV levelized costs and a 15% reduction in wind levelized costs would be anticipated. Even taking into account declines in future technology cost, the analysis shows higher costs of solar and wind in 2022 than in 2019 (25% and 13% higher, respectively). As a result, the MRW Analysis estimates that for every 1,000 MW of resources contracted at the 2022 LCOE instead of the 2019 LCOE, annual costs would increase by $54 million per year for solar PV ($1 billion over 20 years) and $30 million per year for wind ($600 million over 20 years).

Delay in the procurement of RPS resources in the near term diminishes the value of the federal tax incentives significantly. Renewable project developers need to start construction of their projects to qualify for the credits. To start construction, a project needs to be financed. To finance a project, renewable developers typically need a power purchase agreement (PPA). To obtain a PPA, renewable developers typically have to participate in a competitive, Least-Cost/Best-Fit procurement process. Accordingly, for RPS-eligible projects to qualify for 100 percent of the value of the federal tax incentives, *i.e.,* to begin construction by 2019, a RPS solicitation must occur early in 2018 with PPAs being executed no later than the end of 2018.

IV. <u>CONCLUSION</u>

If the 2017 RPS Plans are implemented as the LSEs propose, little, if any, RPS procurement needed to meet state policy and planning goals will occur over the next three to five years. Yet the financial and economic conditions present today, *e.g.*, the availability of federal tax incentives and the relatively low cost of capital, favor incremental RPS procurement in the near term. To take advantage of these favorable conditions, the Commission should set higher minimum procurement obligations as a percent of retail sales to absorb "excess" procurement and remove the barriers to procurement of new, incremental RPS resources. Specifically, when considering 2017 RPS Plans, the Commission should:

- *Direct* the Energy Division to report, no later than October 30, 2017, on whether the draft 2017 RPS Plans individually and collectively (a) reasonably balance expectations of load shifts among LSEs and (b) support state policy objectives in light of CEC Demand Forecasts and preliminary IRP modeling.

- *Modify* the 2017 RPS Plans (upon completion of the Energy Division study) as follows:
  - **Direct each LSE to procure RPS-eligible renewable resources at levels that exceed the minimum quantities specified in Section 499.15(b)(2) to reduce the corrosive effects of "excess" procurement.**
  - **Allocate all costs *and* benefits associated with Commission-jurisdictional LSE RPS procurement to all beneficiaries on a non-bypassable basis.**

Respectfully submitted this 18th day of August, 2017 at San Francisco, California.

GOODIN, MACBRIDE,
SQUERI & DAY, LLP
Brian T. Cragg
505 Sansome Street, Suite 900
San Francisco, California 94111
Telephone: (415) 392-7900
Facsimile: (415) 398-4321
Email: bcragg@goodinmacbride.com

By */s/ Brian T. Cragg*
Brian T. Cragg

Attorneys for the Independent Energy
Producers Association

ATTACHMENT A

MRW ANALYSIS:
Value of ITC, PTC and Lower-Cost of Capital
August 29, 2016

MRW & Associates

Confidential Memorandum

To: Steven Kelly, Policy Director
Independent Energy Producers Association

From: David Howarth

Subject: Value of ITC, PTC and Lower-Cost of Capital

Date: August 29, 2016

As requested, MRW & Associates (MRW) has completed an analysis to estimate the value of federal subsidies, including the investment tax credit (ITC) the production tax credit (PTC) and bonus depreciation, all of which are scheduled to phase out according to the terms of federal budget legislation passed in December 2015. If utilities go forward with proposed plans to delay RPS procurement, there is a risk that ratepayers miss out on benefitting from these federal subsidies. RPS procurement delay also increases the risk of higher financing costs in the event of an increase in interest rates from the current historic low rates. We investigated the impact of an increase in the cost of debt and weighted average cost of capital on wind and solar costs.

In order to capture the impact of the changes in federal subsidies and interest rates on renewable production costs, MRW relied on version 6.2 of the "RPS Calculator" provided to the public by the California Public Utilities Commission (CPUC).[22] The RPS Calculator is an extremely detailed model that incorporates a pro forma cash flow analysis to calculate the levelized cost of energy (LCOE) for a variety of generation technologies. The RPS Calculator is used to develop RPS resource portfolios for use in the Long-Term Procurement Planning (LTPP) proceeding and for the California Independent System Operator's (CAISO's) Transmission Planning Process (TPP). The model has undergone extensive vetting during its development for the CPUC and incorporates input assumptions that have similarly been subject to public review by various stakeholders. Although the values produced by the RPS Calculator may differ from the confidential prices for new renewable energy contracts, the model provides a basis for measuring the relative impact of the phase-out of federal renewable energy subsidies.

MRW analyzed two years for this assessment. The first year is 2019, which is the last year in which the solar ITC is at the full 30%. The second year is 2022, which is the first year in which the solar ITC reaches the minimum 10% level at which it is schedule to remain past 2022. The selected years bracket the year 2021, which is the year that SCE and PG&E have indicated they expect to resume RPS purchases. To investigate the value of the ITC, we analyzed costs for large

[22] http://www.cpuc.ca.gov/RPS_Calculator/

tracking photovoltaic (PV) systems. Although the ITC is also available to wind projects, it is more common for these projects to use PTCs. Thus, we analyzed the impact of PTCs on wind project costs. Bonus depreciation allows project owners to depreciate up to 50% of project costs in the first year, followed by the standard Modified Accelerated Cost Recovery System (MACRS) depreciation schedule.[23] Bonus depreciation is available to both solar and wind projects and phases out between 2017 – 2020.[24]

As discussed above, MRW ran different scenarios using the RPS Calculator that either included or excluded each of the subsidies or combinations thereof. Results are presented in levelized 2015 dollars. We determined the relative impact by comparing levelized costs across the scenarios. Table 1 presents a summary of results, with charts provided in Figures 1 and 2.

Table 1. Summary of Results, $2015

	Solar PV		Wind	
Cost Category ($/kW-yr)	**2019**	**2022**	**2019**	**2022**
Capital	$253	$236	$203	$194
Fixed O&M	$37	$36	$38	$38
Interconnection	$22	$21	$14	$13
Property Tax & Insurance	$17	$18	$15	$16
ITC/PTC/Bonus Depr.	($112)	($40)	($41)	$0
Total	$218	$272	$230	$260
Percentage Increase		25%		13%

As summarized in Table 1 and Figures 1 and 2, the RPS Calculator shows a significant increase in the levelized fixed costs of solar PV and windpower from 2019 to 2022, even though technology costs are assumed to decline over that period. Total levelized fixed costs for solar increase by 25% and wind costs increase by 13% between 2019 and 2022.

The largest driver of the increase in levelized costs is the reduction in the ITC for solar projects and the PTC for wind. In 2019, the ITC has the effect of reducing levelized solar PV costs by 32% while bonus depreciation reduces levelized fixed costs by 2%, for a combined impact of 34%. In 2022, there is no benefit from bonus depreciation, but the ITC still reduces the estimated levelized fixed cost by 13%.

By 2019, the wind PTC has already declined to the point that it has a smaller impact on levelized costs than the solar ITC. In 2019, the PTC has the effect of reducing levelized fixed costs by 12%. Adding a three percent reduction from bonus depreciation results in a combined 15% reduction in levelized costs in 2019. Since the PTC is scheduled to be completely phased out by 2022, levelized costs simply reflect a slight reduction in capital costs, which only partially offsets the loss in federal subsidies.

[23] The MACRS accelerated depreciation schedule provides significant financial benefits to project owners and tax equity partners, thereby reducing costs. Since MACRS is part of the tax code and not presently scheduled to sunset, we have not included MACRS in the analysis of the value of foregone federal subsidies.

[24] MRW modified version 6.2 of the RPS Calculator to update the input assumptions to reflect the extension of bonus depreciation for renewable energy projects, providing a 30% bonus in 2019 and no bonus depreciation in 2022.

Figure 1. Solar PV Levelized Fixed Costs, 2019 and 2022, $/kW-yr

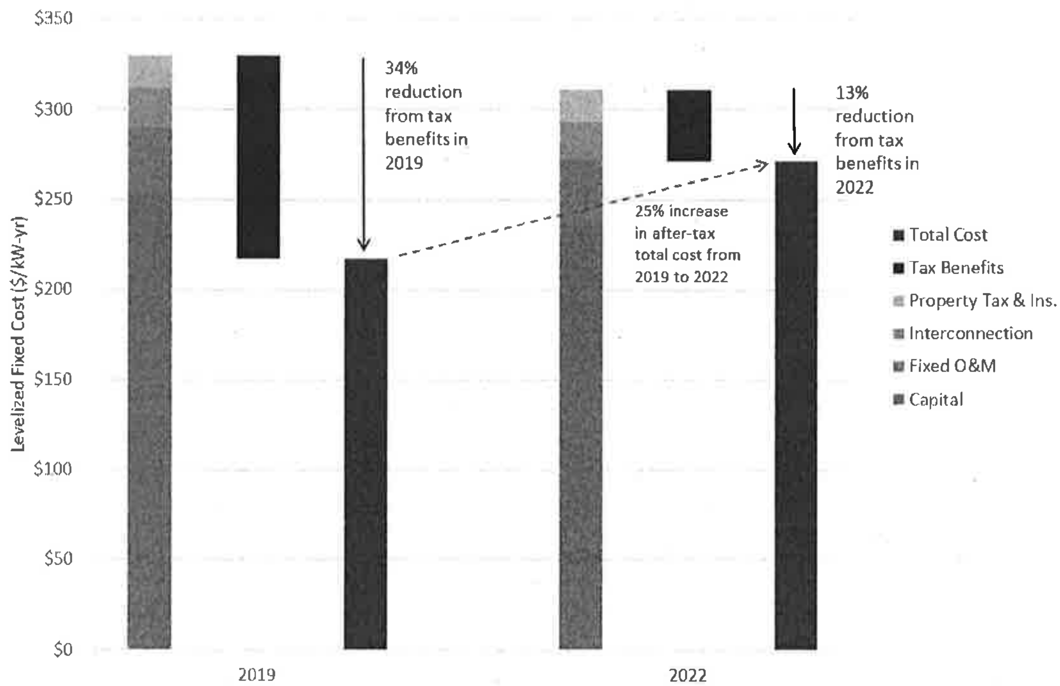
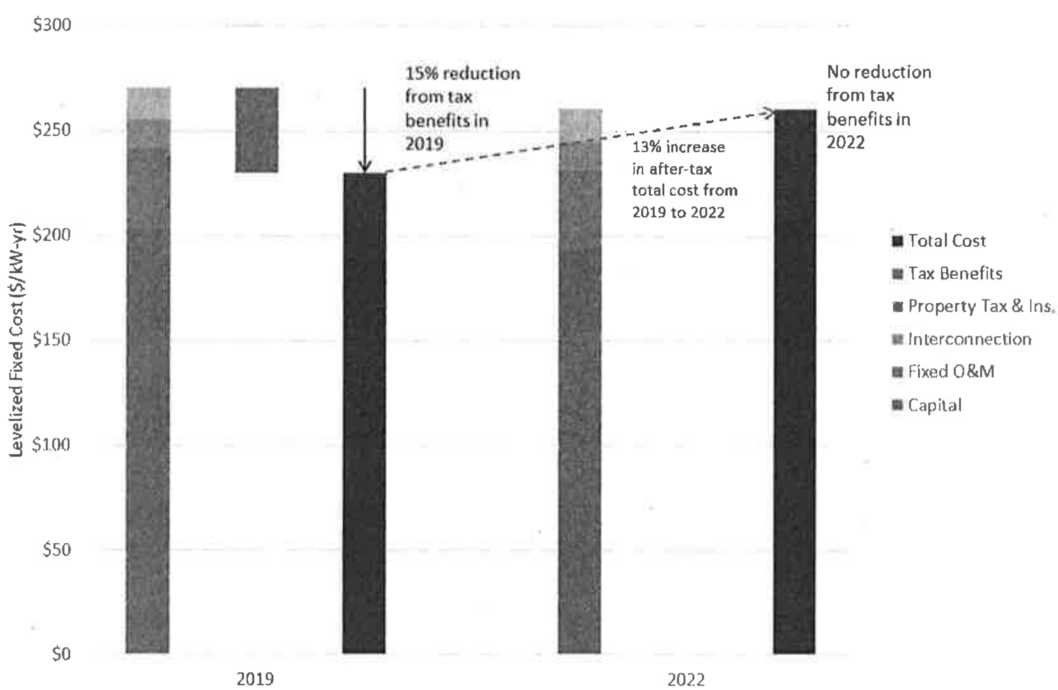


Figure 2. Wind Levelized Fixed Costs, 2019 and 2022, $/kW-yr



Given the capital intensive nature of solar and windpower projects, financing costs are a significant factor in the total cost of production for these technologies. Using the RPS Calculator to compare scenarios with a difference in the weighted average cost of capital (WACC) of one percentage point, we determined the increase in fixed costs ($/kW-yr) that would result. For a windpower project built in 2019, the RPS Calculator shows a $17/kW-yr increase in levelized fixed costs with a 1% increase in WACC. For a 250 MW windpower project, the increase would result in an additional $4 million per year in costs.

The results of a 1% increase in WACC for solar projects are similar. The RPS Calculator shows an increase in levelized costs of about $14/kW-yr for a solar PV project built in 2019. This increase would add about $3.5 million per year to the solar project costs.

VERIFICATION

I am the attorney for the Independent Energy Producers Association in this matter. IEP is absent from the City and County of San Francisco, where my office is located, and under Rule 1.11(d) of the Commission's Rules of Practice and Procedure, I am submitting this verification on behalf of IEP for that reason. I have read the attached "Comments of the Independent Energy Producers Association on the Renewables Portfolio Standard Procurement Plans Submitted by the Load-Serving Entities," dated August 18, 2017. I am informed and believe, and on that ground allege, that the matters stated in this document are true.

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

Executed on this 18th day of August, 2017, at San Francisco, California.

/s/ Brian T. Cragg

Brian T. Cragg

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