BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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RE: IN THE MATTER OF THE PROPOSED AMENDMENTS TO RULES REGULATING ELECTRIC UTILITIES, 4 CODE OF COLORADO REGULATIONS 723-3, RELATING TO ELECTRIC RESOURCE PLANNING, THE RENEWABLE ENERGY STANDARD, NET METERING, COMMUNITY SOLAR GARDENS, QUALIFYING FACILITIES, AND INTERCONNECTION PROCEDURES AND STANDARDS.	)))))))))))	**PROCEEDING NO. 19R-0096E**

OPENING COMMENTS OF THE COLORADO SOLAR AND STORAGE ASSOCIATION AND THE SOLAR ENERGY INDUSTRIES ASSOCIATION

MARCH 29, 2018

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The Colorado Solar and Storage Association ("COSSA" previously known as the Colorado Solar Industries Association or "COSEIA") and the Solar Energy Industries Association ("SEIA"), jointly submit these Opening Comments in response to the Colorado Public Utilities Commission ("CPUC" or the "Commission") Notice of Proposed Rulemaking ("NOPR") issued via Decision No. C19-0096E (mailed February 27, 2019).

1 Introduction & Summary

COSSA and SEIA are pleased to have the opportunity to work with the Commission to improve its electric rules in several critical areas that significantly impact the solar industry. We appreciate the Commission's hard work on these rules over the last 14 months and recognize that this is a massive undertaking. COSSA and SEIA have anticipated this rulemaking for over a year and have put significant resources into researching best practices from other jurisdictions, crafting proposed redline rules, submitting detailed comments through Proceeding No. 17M-0694E, and participating in many stakeholder group meetings and workshops. The NOPR represents progress in bringing the Commission's electric resource planning ("ERP") rules into the modern era and paving the way towards a transition to low-cost, carbon-free electricity. Rules that require consideration of early retirements, based in part on emissions profiles, are a significant step towards modernization of the electric grid that COSSA and SEIA fully support. Efforts to increase transparency on utility integration studies and modeling will also help to attract low-cost competitive renewable energy bids.

However, with regard to smaller scale retail distributed generation ("Retail DG") and community solar gardens ("CSGs"), COSSA and SEIA have significant concerns that several of the proposed rules move Colorado away from substantive policy goals set by Governor Polis and will fail to stimulate underserved market segments, including low-income and commercial customers. Rather than increase the opportunity for incrementally more clean distributed renewable energy resources, several proposed rules could slow adoption of distributed generation, decrease customer access, discourage adoption of onsite storage and significantly frustrate customer efforts to self-generate.

We encourage the Commission to consider the opportunity in front of us. With distributed renewable generation paired with storage, right now, through these rules, our state has the potential to reach farther and help all customers manage bills through facilitating policies to enable customer-sited distributed energy resources ("DERs"). Retail DG is the state's single best tool for allowing Colorado consumers to achieve their own 100% goals, and lead Colorado to a clean energy future. In order to reach these goals, the industry needs the Commission's help to modernize programs and interconnection standards that dramatically streamline the adoption of more renewable energy by Colorado consumers.

The Retail DG market is also critical for Colorado's economy and a significant driver of high quality jobs. According to the recent National Solar Jobs Census, The Solar Foundation's annual report on solar industry employment, Colorado employs a total of 6,847 workers.[1] Of this total, 4,569 are installers with only 467 of those jobs related to utility-scale projects and the remainder working in the residential and non-residential DG sector.[2]

With our proposed additions and modifications described throughout this document, the Commission can facilitate dramatically more customer options in the coming years, continue to drive economic and related job growth, and assist the administration's drive to 100% renewable energy.

Specifically, while several of the proposed net metering ("NEM") rules create certainty for customers and the DG solar industry in today's rate environment, other draft rules concerning NEM create uncertainty and confusion that is likely to chill consumer and broader investment in onsite solar in Colorado. First, under time-of-use ("TOU") rate structures which are widely regarded as a natural progression in rate design and likely to proliferate in the coming years, proposed rules that require "bucketing" for some customers could significantly devalue both existing and future onsite solar investments. Second, while COSSA and SEIA appreciate the Commission's proposals to ensure that customers outside of a utility incentive program are able to keep their renewable energy credits ("RECs"), we fear that allowing Investor-Owned Utilities ("IOUs") to count DG production for compliance purposes will have unintended consequences on the value of such RECs and may not be consistent with legal requirements. Third, the NOPR does not address our significant concerns raised during the stakeholder process regarding how utilities implement the 120% rule, which has had the impact of limiting customers' ability to generate even 100% of their energy needs onsite. While COSSA and SEIA discuss other

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1 *Solar Jobs Census 2018*, The Solar Foundation. *Available at:* www.solarstates.org/#state/colorado/counties/solar-jobs/2018.

2 *Id.*

concerns with the proposed NEM Rules below, the above list reflects the solar community's most pressing concerns with proposed changes to the NEM policy.

Interconnection is another critical area to ensure that utilities do not create unnecessary barriers to the deployment of DG resources. Safety and reliability should be the primary concerns of utilities and regulators in crafting sound interconnection procedures. However, after almost two decades of experience with onsite solar interconnections with limited safety or reliability issues, plus the widespread proliferation of advanced inverter technologies, many of Colorado's interconnection rules are overly conservative and not in line with best practices. COSSA and SEIA raised these issues throughout Proceeding 17M-00694E and reiterate specific barriers and suggested solutions below.

Further, two years have passed since the solar industry first requested changes to interconnection rules to incorporate the unique characteristics of onsite energy storage systems. Since that time the state legislature passed Colorado Senate Bill ("SB") 18-009, which requires the Commission to craft interconnection rules that "limit barriers to the installation, interconnection, and use of customer-sited energy storage systems in Colorado."[3] SB 18-009 also requires that "utility approval processes and any required interconnection reviews of energy storage systems shall be simple, streamlined, and affordable for customers."[4] COSSA and SEIA believe that the proposed interconnection rule changes do not go far enough in implementing SB 18-009's requirements, set the state behind other forward-looking states and miss a long-awaited and politically supported opportunity.

Proposed CSG rules appear to be intended to expand access to underserved segments of the market, which COSSA and SEIA fully support. However, CSG developers are deeply

3 Colo. Rev. Stat. ("C.R.S.") § 40-2-130(3)(a).
4 *Id.* at (3)(c).

concerned that simply requiring a 50% carve-out for residential, small commercial and agricultural customers, without additional reforms that reduce barriers to market participation, will have the effect of making CSG projects less financeable, less affordable and less likely to materialize. This is especially troubling given information recently shared with stakeholders regarding Xcel's proposal to uncap its Renewable*Connect product, which would create additional unfair competitive advantages to the state's largest IOU that directly competes with CSG providers. In the below comments COSSA and SEIA urge the Commission to consider additional reforms so that the goal of expanding access to CSGs can be realized.

As utilities begin creating competing products with DG programs, such as Renewable*Connect, COSSA and SEIA are concerned about anti-competitive threats that can crowd out the private sector, despite legislative efforts to increase competition. This is all the more important when considering that utilities both currently select their competitors for these programs in requests for proposals ("RFPs") for CSGs and Large Solar*Rewards and through standard-offers in other programs. Further utilities' absolute control of the interconnection process without penalty or repercussions for delays and errors further skews the playing field in their favor. The industry supports a robust market for all companies to serve customers, including the utilities.

COSSA and SEIA recognize and applaud the Commission's efforts in crafting its NOPR, and are appreciative of this opportunity to help modernize the rules to advance clean energy development and create equity between utilities and alternative providers. We sincerely appreciate the Commission's intentions and efforts and wish to work with the PUC, its staff and other stakeholders to develop rules that will move Colorado forward towards a competitive, low-cost and carbon-free energy future. To that end, we also suggest additional workshops and hearings with the Commissioners on individual topic areas to ensure that these widely varied and complex issues can be fully discussed, addressed and investigated.

This introduction highlights the COSSA and SEIA's top issues. However, in the sections below, COSSA and SEIA provide detailed input on each proposed rule section and provide answers to many of the questions posed in the NOPR. Time did not permit us to provide detailed redline rule changes with this filing, but it is our hope and intention to submit redlines (perhaps in conjunction with other stakeholders) in the coming weeks.

2 <u>Net Metering Rules (Proposed Rules 3675-3682) and Associated Issues</u>

The proposed rules properly reinforce net metering as the primary mechanism by which customers with onsite solar are able to self-generate regardless of their participation in a utility's incentive program. These changes are consistent with Colorado law and also provide customers a mechanism to self-generate utilizing certain types of qualifying facilities under federal law.

It goes without saying that any person has the right to refuse to purchase any service or product. Moreover, there is an inherent right, embedded in human history, to self-supply. Federal law makes this right explicit with regard to electricity through the Public Utility Regulatory Policies Act ("PURPA"), which provides all customers the right and ability to self-generate and interconnect to a utility's system.[5] The right to self-generate is a natural extension of common law property law principles that ensure that property owners are entitled to make productive use of their property.[6] Because self-supply furthers Colorado's carbon reduction and renewable energy goals, the businesses that facilitate renewable self-generation should be

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5 *See* 18 C.F.R. § 292.306.

6 *See* John Wellinghoff & Steven Weissman, *The Right to Self-generate as a Grid-Connected Customer*, 26 Energy L.J. 305, 309 (2015) ("Property is more than the mere thing which a person owns. It is elementary that it includes the right to acquire, use, and dispose of it. The Constitution protects these essential attributes of property."); *2700 Irving Park Bldg. Corp. v. City of Chicago*, 69 N.E.2d 827, 832 (Ill. 1946) ("The right of every owner of property to use it in his own way and for his own purposes existed before the adoption of the constitution, and is guaranteed by that instrument."); *see also* Black's Law Dictionary 1232 (7th ed. 1999) (defining property as "[t]he right to possess, use, and enjoy a determinate thing").

encouraged. Furthermore, the Commission should ensure that utilities do not leverage their monopoly power to the detriment of companies that help facilitate customer self-generation or a customers' rights to produce their own power.

The NOPR's proposals to move the NEM rules out of the Renewable Energy Standard ("RES") rules and to clarify rules that prohibit separate rate classes for NEM customers are positive developments, which the Commission should adopt. However, two of the proposed modifications to the Commission's current rules, which appear to be intended to modernize the NEM rules, may have severe unintended consequences that are deeply concerning to the solar industry.

First, the section regarding NEM credits under a TOU rate design appear to require that excess generation credits only be used to offset like-kind consumption in the same TOU period for certain "cash-out customers." This requirement would essentially forbid the monetization of NEM credits for a significant portion of NEM customers making it impossible for them to utilize all of their excess generation credits and severely devaluing investments in onsite solar.

Second, while technically contained in the proposed RES rules, the NOPR attempts to codify today's current practice that forbids utilities from taking RECs from NEM-only customers that are outside of an incentive program. However, the proposed rules also attempt to allow the utility to count eligible energy produced by a NEM system for compliance with the RES. This proposal would essentially require a double counting of RECs, would devalue those RECs in such a significant way that it could be considered a partial regulatory taking and would lead to a fundamentally anti-competitive situation. This is because the proposed rule change would result in a situation whereby customers could only obtain attractive and aluable RECs that are actually paired with renewable energy, through a utility's program.

COSSA and SEIA's third critical concern regarding the NEM rules is that they lack any clarification around the 120% rule for sizing Retail DG. COSSA and SEIA support the 120% rule in concept, consistent with state law. However, as explained in stakeholder comments, the rule has consistently been misapplied and used as a barrier to self-generation due to the way utilities have chosen to implement it. Without clarifications this practice is likely to continue to create artificial limitations on a customer's right to self-supply.

2.1 The Proposed NEM Rules Can Significantly Harm Customers on Time-of-Use Rates

As noted in a 2016 comprehensive settlement regarding three Public Service proceedings, the current Commission's NEM Rule, "Rule 3664(b) was adopted at a time that did not contemplate TOU rates."[7] Specifically, the current Rule 3664(b) requires,

> If a customer with retail renewable [DG] generates renewable energy pursuant to paragraph 3664(a) in excess of the customer's consumption, ***the excess kWh*** shall be carried forward from month to month and credited at a ratio of 1:1 ***against the customer's retail kWh consumption*** in subsequent months." (Emphasis added).

This Rule requires utilities to track and credit excess generation in kWh, which works just fine when all kWh are sold at the same retail rate.[8] However, under more modern rate structures, like TOU rates, not all kWh are valued equally and so tracking pure kWh (as opposed to dollar credits) can lead to unintended consequences and could dramatically devalue solar investments.

To be clear, as stated in previous Commission filings, TOU rates are generally ***not*** beneficial to the onsite solar value proposition, as they tend to make NEM less financially attractive. However, COSSA and SEIA understand that there are significant public policy benefits to TOU rates in potentially reducing long-term capacity related costs and sending better

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[7] Proceeding No. 16AL-0048E, *Non-Unanimous Comprehensive Settlement Agreement* at p. 40 (August 15, 2016).

[8] This process also works with tiered rates because a kWh credit can be used to offset Tier 2 kWh consumption.

price signals to customers. To this end, the solar industry has worked with both Public Service and Black Hills to ensure that their TOU offerings include monetization of NEM credits. This is because "monetization" of NEM credits as opposed to "bucketing" is the only way that TOU rates make onsite solar viable in today's market.

"Bucketing" refers to NEM requirements whereby only "on-peak" credits generated by excess generation can be used to offset "on-peak" consumption from the grid and only "off-peak" credits generated by excess generation can be used to offset "off-peak" consumption. In other words, credits are kept in their buckets and can only be used to offset like-kind consumption. This mechanism would be an extremely punitive change from today's NEM regime, in which all generation can be used to offset all consumption. Bucketing would result in many NEM customers having too many excess "off-peak" or "on-peak" credits that cannot be used at all. However, it would also not be fair to the general body of ratepayers under TOU rates to allow one off-peak credit to offset one kWh of on-peak consumption, as this fails to recognize that off-peak production is less valuable to the system than on-peak production. The solution to this conundrum is "monetization" of NEM credits.

"Monetization" refers to doing away with a bank of "kWh" credits to offset future "kWh" consumption and instead converts excess kWh into a bank of credits with a cash value, though that value can only be used to offset future bills and ***is not ever paid out to the customer***.[9] Essentially under a "monetization" methodology customers receive credits that are equal to the prevailing retail rate of electricity for whatever time period the electricity was generated. For example, if off-peak grid supplied energy cost \$0.08/kWh and on-peak grid supplied energy cost \$0.24/kWh (a 1:3 ratio), then any excess NEM generation that was sent back to the grid during

[9] Even a customer that chooses to be cashed out at the end of the year is only done so at the utility's avoided cost rate.

off-peak hours would result in a $0.08 credit towards future consumption. Similarly, any excess NEM generation that was sent back to the grid during on-peak hours would result in a $0.24 credit. In this way a NEM customer could use three excess off-peak credits to offset one on-peak kWh of consumption (3 x $0.08 = $0.24). Monetization thus preserves a NEM customer's ability to utilize all of their excess generation, but also ensures that the value of NEM credits are reflective of the value that the energy brings to the system when it is needed most.

Unfortunately, proposed rule 3679(b) appears to require "bucketing" during every month of the year for those customers that get a "cash-out" of excess energy at the end of the calendar year. Rule 3679(b) includes new language, which states, "[f]or customers taking retail service on time-of-use rates, the utility shall track when the excess energy was generated, apply the accumulated excess energy against the customer's retail kWh consumption for the same time periods that the excess energy was generated…" As noted above, this would result in many NEM customers have a perpetual bank of excess credits that could never be used. Proposed Rule 3679(d) contemplates "applying rolled-over kWh credits as dollar credits" but appears to only apply to customers that have elected to rollover their excess credits at the end of a calendar year.

COSSA, SEIA, and other solar advocates did agree to disparate treatment of "roll-over" and cash-out customers in the tri-proceeding settlement in 2016 in order to address Public Service's billing system concerns. The solar industry understood that with regard to cash-out customers, it would be difficult for utilities to convert a dollar bank utilized during the calendar year back into a kWh value to use for paying out avoided cost rates at the end of the year. The compromise at that time was to allow a version of bucketing (colloquially referred to as "the chocolate fountain") for cash-out customers, where higher value credits could be used to offset lower-value consumption, but this was intended as a temporary solution in order to allow Public Service to implement its R-TOU pilot program in a timely fashion.

Clearly utilities are able to track excess generation banks in kWh terms (as they have done for some time) and in dollar terms (as Public Service has done in recent years). Thus there is no reason that a utility billing system could not theoretically track both types of banks for "cash-out" customers. If both banks were tracked, the dollar bank could be utilized within a calendar year to allow monetization of excess credits from month to month and the kWh bank could be tracked separately. At the end of the year, the positive balance of the kWh bank (if any) could be cashed out at the avoided cost rate.

COSSA and SEIA understand and appreciate that utility billing systems may not be able to accommodate this change right away. But ultimately both types of NEM customers should be in a position to utilize all of their excess generation, as they are today. As such, COSSA and SEIA strongly urge the Commission to reject the proposed addition to Rule 3679(b). Instead, the Commission should modify Rule 3679(d) to apply to all types of NEM customers (not just "roll-over") and to eventually require monetization under TOU rates across the board. Further the Commission should eliminate the term "kWh credits" throughout the NEM rules and replace it with "dollar credits" since monetization is the method by which excess energy can be properly valued by time period and NEM customers are not unduly penalized.

COSSA and SEIA would also note other jurisdictions that have grappled with this issue have also come down in favor of monetization. For example, under NEM in California, the financial credit for power generated by a customer-generator's onsite system in a TOU scenario is equivalent to the hourly retail electricity price. The credits are valued at the "same price per kilowatt hour" that customers would otherwise be charged for electricity consumed.[10] A customer producing power in excess of its onsite load may be eligible for "net surplus compensation."[11]

Similarly, in Washington D.C., for a customer-generator with an electric generating facility that has a capacity less than or equal to 100 kilowatts, if the electricity generated during the billing period by the customer-generator's facility exceeds the customer-generator's kWh usage during the billing period (*i.e.*, excess generation), the customer-generator's next bill will also be credited for the excess generation at the full retail rate *expressed as a dollar value* on the customer-generator's bill.[12]

In Massachusetts, the distribution utility companies calculate a NEM credit in the event of net excess generation. The actual calculation differs depending on the type of facility.[13] The State of Massachusetts produces a calculation guide for customers.[14] National Grid's NEM tariff is an example of the application of monetized crediting by time-of-use.[15]

2.2 Proposed RES Rules Properly Allow NEM-Only Customers to Keep RECs But Leave Them Valueless

While not contained in the proposed NEM rules, the NOPR proposes in the revised RES Rules 3654(a), 3655(a), 3655(d) to allow a utility to count un-incentivized NEM-eligible generation systems toward its RES compliance obligation even when it does not own the

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[10] See California successor NEM tariff adopted in Decision ("D.") 16-01-044, p. 13 (January 28, 2016). *Available at*: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf.

[11] Net surplus compensation payments were authorized by AB 920 (Huffman), Stats. 2009, ch. 376, and implemented by the Commission in D.11-06-016. *Available at*: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/137431.htm.

[12] See D.C. Mun. Regs. 15-903.5, Net Energy Billing and Crediting for Standard Offer Service Customers, https://www.dcregs.dc.gov/Common/DCMR/RuleList.aspx?ChapterId=284.

[13] See DPU 220 CRM 18.04, https://www.mass.gov/files/220_cmr_18.00_final_12-1-17_1.pdf.

[14] See Massachusetts Net Metering Guide. *Available at:* https://www.mass.gov/guides/net-metering-guide#2-net-metering-credit-calculation-and-billing.

[15] See National Grid Net Metering Provision, Section 1.06 Calculation of Net Metering Credits. *Available at:* https://www9.nationalgridus.com/non_html/Net%20Metering%20Provision_12.03.18.pdf.

associated RECs. While COSSA and SEIA appreciate the Commission's desire to maximize the value of onsite solar, we are deeply concerned that the proposed rule creates multiple legal challenges and will have the effect of de-valuing customer-owned RECs. In addition to the legal issues, COSSA and SEIA are concerned about negative competitive impacts of this proposal, which could make utilities the only entities capable of conveying marketable bundled energy-REC products to customers.

Colorado law requires the Commission to establish "a system of tradable renewable energy credits that may be used by a qualifying retail utility to comply with this [renewable energy] standard."[16] In other words, Colorado law requires RECs to be the mechanism by which utilities track compliance with the RES. RECs are defined by Proposed Rule 3001(mm) as, "a contractual right to the full set of non-energy attributes, including any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, directly attributable to a specific amount of electric energy generated from a renewable energy resource."

Under the proposed Rule 3654(a), even where there is no REC-transfer utilities would be allowed to count NEM-only systems for compliance with the RES. This on its face appears to violate the statutory requirement that RES compliance be based on a system of tradable RECs. If the utilities do not own the RECs, they would not be basing their compliance with the RES on RECs acquired from NEM-only systems. Further, if RECs are rendered valueless, as discussed below, they may no longer be "tradable" because no one would want to buy them. Because the statute requires system of "tradable RECs," rules that render RECs valueless would violate the legislature's intent.

Allowing both utilities and customers to claim the non-energy benefits of NEM-only generation also violates the Commission's current Rule 3654(m), which the NOPR does not

[16] C.R.S. § 40-2-124.

propose to alter. Rule 3654(m) states, "[f]or purposes of compliance with this RES, there shall be no "double counting" of eligible energy or RECs. RECs shall be used for a single purpose only, and shall be retired upon use for that purpose." As noted, above a REC includes "the full set of non-energy attributes." Allowing utilities to claim the non-energy attributes of the generation towards its RES compliance obligations *and* allowing a customer to retain the RECs, which would allow them to also claim they are generating renewable energy, would result in a double counting of RECs in violation of Rule 3654(m).

As noted above, allowing qualifying retail utilities ("QRUs") to count NEM-only generation for RES compliance would render a customer's RECs valueless and would result in an impermissible regulatory taking without just compensation. Many REC certification organizations and REC marketers will not certify a REC associated with energy that has already been used for compliance with a state renewable energy standard.[17] While retaining RECs whose energy is already being counted for QRU RES compliance may still legally allow a customer to claim that they are generating renewable energy, the REC itself would likely become un-tradable on the open REC-market because no one would certify, sell or buy the RECs whose renewable attributes had already been counted for RES compliance purposes.

Both the federal and the Colorado constitutions include takings clauses that prohibit the government from taking private property for public use without just compensation.[18] The Colorado takings clause provides, in relevant part, "private property shall not be taken or

[17] WREGIS Operating Rules, Page 25, Section 6.2 Retirement Subaccount, May 1, 2018. *Available at:* https://www.wecc.org/Corporate/WREGIS%20Operating%20Rules.pdf. ("A Retirement Subaccount is used as a repository for WREGIS Certificates that the Account Holder wants to designate as Retired to show compliance with a state, provincial, or voluntary renewable energy program or to otherwise show the Certificates have been used and **removed from circulation.**") Emphasis added.

[18] U.S. Const. amend. V. (This provision is applicable to the states through the Fourteenth Amendment.)

damaged, for public or private use, without just compensation."[19] For the most part, the Colorado Supreme has interpreted the Colorado takings clause as consistent with the federal clause.[20]

In the context of regulations, a regulation that effectively wipes out the value of a property is a taking. However, where a regulation places limitations on property that fall short of eliminating *all* economically beneficial use, a taking nonetheless may have occurred. Regulation that does not prevent all economic use may constitute a taking if it goes "too far."[21] The determination of whether a regulation goes "too far" for purposes of the Fifth Amendment is essentially an "ad hoc, factual" inquiry.[22] Both the US and Colorado Supreme Courts have identified several factors that should be taken into account when determining whether a governmental action has gone beyond "regulation" and effects a "taking." Among those factors are: "the character of the governmental action, its economic impact, and its interference with reasonable investment-backed expectations."[23]

If the proposed rules, which essentially de-value customer-owned RECs are adopted, customers who may have invested in Retail DG could have a viable regulatory takings claim against the state of Colorado. This is especially likely to the extent that customers, or third-party developers, can demonstrate that the value of the Retail DG systems and their ability to finance those systems was dependent on the RECs having a monetary value.

Regardless of whether or not the proposed rules discussed above are legally permissible or not, COSSA and SEIA are gravely concerned that the proposal to allow IOUs to utilize the

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[19] Colo. Const. art. II, § 15; Animas Valley Sand & Gravel v. Bd. of Cty. Comm'rs, 38 P.3d 59, 63 (Colo. 2001).

[20] See *Cent. Colo. Water Conservancy Dist. v. Simpson*, 877 P.2d 335, 346 (Colo. 1994).

[21] *Pennsylvania Coal Co. v. Mahon*, 260 U.S. 393, 415, 67 L. Ed. 322, 43 S. Ct. 158 (1922).

[22] *Golden Pacific Bancorp v. United States*, 15 F.3d 1066, 1072 (Fed. Cir. 1994) (citation omitted), *cert. denied*, 1994 WL 388213 (U.S. [**10] Oct. 31, 1994).

[23] *Dep't of Health v. Mill*, 887 P.2d 993, 999 (Colo. 1994).

non-energy attributes of Retail DG production will have significant anti-competitive impacts. Currently, the only ways by which a Colorado utility customer can acquire renewable energy that is bundled with the associated RECs is to (1) install retail DG without taking a utility incentive that requires the transfer of RECs (*i.e.*, NEM-only DG), or (2) for Public Service customers, purchase a subscription to Renewable*Connect. Customers that install DG through a utility incentive program must sell their RECs, CSGs are currently required to provide all RECs to the QRU, and Public Service's WindSource subscribers pay the utility to retire RECs on their behalf and receive no associated energy as part of that transaction.

Solar advocates have repeatedly raised concerns with the competitive disparity between Public Service's Renewable*Connect program and solar offerings available through retail DG providers. For example, Public Service's subscription-based facility is 50 MW and can be subscribed to by any of its customers who receive both the energy and the RECs from the utility-scale array. In contrast, CSG providers who offer a very similar subscription-based service are limited to 2 MW systems and are only allowed to sell subscriptions to customers in the same or an adjacent county and must forfeit their RECs to the utility, in some cases paying the utility for the privilege to do so. CSGs are seeing customers choose Renewable*Connect versus a non-utility product simply because the industry is currently prevented from offering customers what the utility can offer in their product, including RECs.

Market analysts agree that near to medium term growth potential in the on-site solar market will be largely driven by corporate sustainability goals and desires to be 100% renewable.[24] In Colorado such customers are currently limited to procuring onsite non-

[24] *See e.g.*, https://acore.org/looking-ahead-my-2019-renewable-energy-industry-outlook/; Business Renewables Center, Rocky Mountain Institute https://www.rmi.org/our-work/electricity/brc-business-renewables-center/ (Nearly two-thirds of Fortune 100 and nearly half of Fortune 500 companies have set ambitious renewable

incentivized behind-the-meter ("BTM") NEM-eligible generation or subscribing to Public Service's Renewable*Connect offering. The proposed rules would essentially eliminate the value of the RECs from a Retail DG system, leaving corporate buyers that seek bundled energy and RECs with only one provider – Public Service. Ironically, under this proposal the utility would not count its Renewable*Connect resource for RES compliance, even though it operates that program and did indeed cause that energy to be generated, while it would count customer financed and driven NEM-eligible Retail DG for compliance by simply interconnecting such customer-owned systems, as required by state and federal law.[25]

Furthermore, the proposed rules do not solve any current problem associated with customer-owned RECs because the Colorado QRUs do not currently need retail DG RECs for compliance proposes. Both Xcel and Black Hills report sufficient Retail DG RECs for compliance purposes.[26] If the Commission continues to approve programs to "encourage the development of cost-effective retail renewable distributed generation…" consistent with proposed Rule 3656(VI), it is likely that participation in such programs will require the transfer of Retail DG RECs to the utility, providing a future source of Retail DG RECs that QRUs can use for compliance.

Proposed Rule 3657(b), which largely tracks current Rule 3658(b) and C.R.S. section 40-2-124(e)(III), allows QRUs to purchase RECs from NEM-eligible systems through a standard REC purchase offer. If QRUs someday in the future find themselves short on Retail DG RECs

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energy targets); https://businessrenewables.org/corporate-transactions/ (In 2018, U.S. companies signed PPAs to purchase 8.5 GW of clean energy, which was nearly triple the amount signed in 2017).

[25] *See* 18 C.F.R. § 292.303(c) (general obligation to interconnect).

[26] Proceeding No. 16A-0139E, Public Service 2017 Renewable Energy Standard Compliance Report at p. 2 (June 1, 2018); Proceeding No. 16A-0436E, 2018-2021 Renewable Energy Standard Compliance Plan at p. 10 (June 3, 2016).

needed for compliance, they could exercise their right to issue standard REC purchase offers, thereby compensating customers for the use of their non-energy renewable attributes.

Finally, the proposed rules are unnecessary from a policy perspective because QRUs already get the benefit of Retail DG in their calculations related to RES compliance. The RES is calculated as a percentage of a QRU's total "retail electricity sales"[27] which is measured in megawatt-hours ("MWh"). However, to the extent that customers self-generate, the utilities total MWh sales are reduced, meaning that a smaller volume of eligible energy is needed to meet the RES.

<u>Examples:</u>

1) **Utility sells 100 MWh and utility has 40 RECs, the utility can claim 40% eligible energy to comply with the RES:**

   <u>40 RECs/100 MWh sold = 40% RE</u>

2) **DG reduces utility sales down to 96 MWh and utility has 40 RECs, the utility can claim 41.7% eligible energy to comply with the RES:**

   <u>40 RECs/96 MWh sold = 41.7% RE</u>

Allowing QRUs to count the energy from a NEM-only Retail DG system would essentially allow the utility to double count the Retail DG's contribution to the RES. First, the reduction in sales reduces the denominator (as demonstrated above) and the generation would then also increase the numerator.

For all for the reasons stated herein, COSSA and SEIA respectfully request that the Commission reject the proposed changes found in Rules 3654(a), 3655(a), 3655(d), which would allow utilities to count un-incentivized NEM-eligible generation systems towards its RES compliance.

[27] C.R.S. § 40-2-124(1)(c)(I), et. seq.

2.3 The NOPR Fails to Include Specific Guidance to Ensure that QRUs Do Not Mis-Apply the 120% Rule

The Joint Solar Party Comments in Proceeding No. 17M-0694E emphasized the need to include specific rules to guide QRUs in their administration of the 120% rule for sizing Retail DG. Retail DG is defined by Colorado Law, *inter alia*, as “retail distributed generation shall provide electric energy primarily to serve the customer's load and shall be sized to supply no more than one hundred twenty percent of the average annual consumption of electricity by the customer at that site.”[28] The 120 percent rule is intended to ensure customers do not oversize their systems relative to their average annual electric energy consumption but also ensures that customers are allowed to self supply at least 100% of their own energy needs.

Unfortunately, current utility practice assumes perfect siting conditions in calculating system sizes under the 120% rule resulting in systems that tend to be under sized.[29] Every site for solar is different, where there can be a full 360° range of possible orientations (available compass directions), different available angles (tilt of a roof), varying amounts of shading, or other factors that are less than perfect. Indeed, a perfect solar location is the exception, not the rule. By assuming perfect siting conditions even where perfection cannot be achieved, utilities are artificially limiting customers to solar systems that produce less, and in some cases far less, than 120% of a customer’s annual energy consumption.

While not explicitly spelled out in any tariffs, guidelines or rules, Public Service Company is notorious among solar developers for their inflexibility in taking any siting conditions into account. The below screenshots from Public Service’s online interconnection application portal

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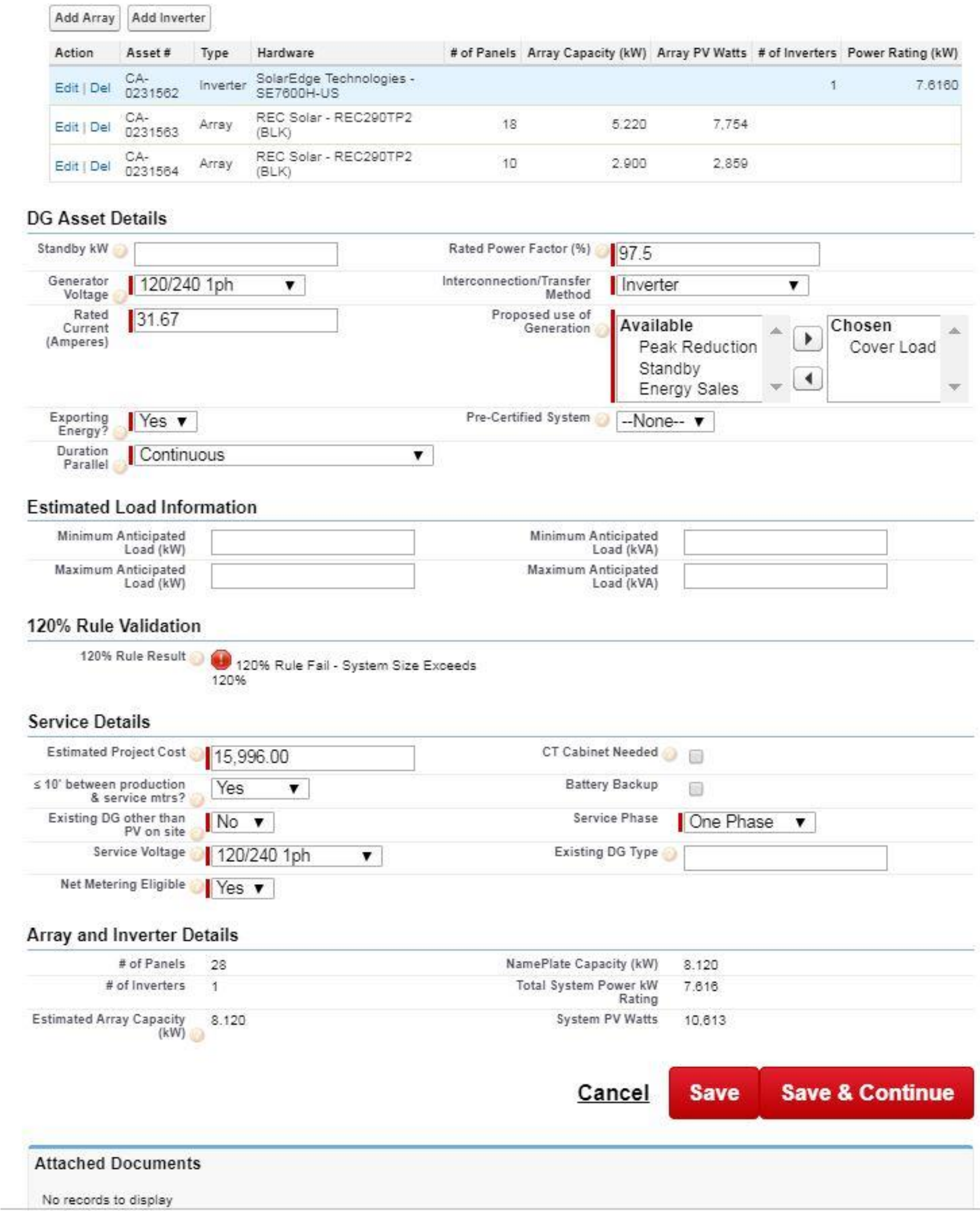
28 C.R.S. § 40-2-124(1)(a)(VIII).

29 Xcel Energy, Frequently Asked Questions – On-Site Solar Programs. *Available at:* https://www.xcelenergy.com/programs_and_rebates/residential_programs_and_rebates/renewable_energy_options_residential/solar/available_solar_options/on_your_home_or_in_your_yard/solar_rewards_for_residences/faq_on_site_solar_programs. (See question: “Can shading be considered in the 120% Rule calculation?”).

demonstrates that Xcel will not take input regarding a system's origination, tilt or any specific siting conditions in calculating compliance with the 120% rule.



Add Array | Add Inverter

Action	Asset #	Type	Hardware	# of Panels	Array Capacity (kW)	Array PV Watts	# of Inverters	Power Rating (kW)
Edit | Del	CA-0231562	Inverter	SolarEdge Technologies - SE7600H-US				1	7.6160
Edit | Del	CA-0231563	Array	REC Solar - REC290TP2 (BLK)	18	5.220	7,754		
Edit | Del	CA-0231564	Array	REC Solar - REC290TP2 (BLK)	10	2.900	2,859		

DG Asset Details

Standby kW:
Rated Power Factor (%): 97.5
Generator Voltage: 120/240 1ph
Interconnection/Transfer Method: Inverter
Rated Current (Amperes): 31.67
Proposed use of Generation: Available: Peak Reduction, Standby, Energy Sales; Chosen: Cover Load
Exporting Energy?: Yes
Pre-Certified System: --None--
Duration Parallel: Continuous

Estimated Load Information

Minimum Anticipated Load (kW):
Minimum Anticipated Load (kVA):
Maximum Anticipated Load (kW):
Maximum Anticipated Load (kVA):

120% Rule Validation

120% Rule Result: 120% Rule Fail - System Size Exceeds 120%

Service Details

Estimated Project Cost: 15,996.00
CT Cabinet Needed:
≤ 10' between production & service mtrs?: Yes
Battery Backup:
Existing DG other than PV on site: No
Service Phase: One Phase
Service Voltage: 120/240 1ph
Existing DG Type:
Net Metering Eligible: Yes

Array and Inverter Details

# of Panels: 28
NamePlate Capacity (kW): 8.120
# of Inverters: 1
Total System Power kW Rating: 7.616
Estimated Array Capacity (kW): 8.120
System PV Watts: 10,613

Cancel | Save | Save & Continue

Attached Documents

No records to display

Xcel also explains in its frequently asked questions section on its onsite solar website that shading cannot be considered in 120% Rule, claiming that "shade effects are not permanent — trees can be removed and shading varies over time — which jeopardizes the customer's consistency with the 120% Rule."[30] This explanation however fails to account for several important issues. First, shading can come from more permanent sources such as buildings or mountains that are unlikely to change. Second, trees that are big enough to shade a rooftop are also fairly long lived and are more likely to increase shading over time as growth happens. Third, consistency with the 120% rule is more likely to change over time due to customer load growth, such as the addition of electric vehicles ("EVs") or other appliances that would tend to decrease the relative system size. Public Service seems to have little concern with non-compliance of the 120% rule when it leads to smaller relative systems. Finally, the 120% rule is a snapshot in time and cannot reasonably take into account all future conditions.

Public Service's policy practically means that a customer with an imperfect site, who nevertheless chooses to invest their own money to self-generate, can be limited to a system that produces less than 120% (or even significantly less than 100% in some cases). This practice defeats the legislative intent of § 40-2-124(1)(a)(VIII), C.R.S. and limits some customers to a system that does not allow them to fully self-supply.

While little can be found on Black Hills' policies regarding accounting for site conditions, anecdotal reports from developers indicate that their process is much better. We understand that Black Hills takes orientation and tilt of a system into account up front and will also account for shading issues in some situations when follow-up is requested. If Black Hills can take real-world site conditions into account, Public Service should be able to do the same.

To correct this problem, the Commission should adopt rule changes that require all utilities to take siting conditions into account when calculating the expected energy output of a solar facility. The PVWatts Calculator developed and hosted by the National Renewable Energy Laboratory provides the ability to input all site conditions and to determine a realistic expected

30 *Id.*

energy output.[31] The current Commission Rules direct utilities to utilize PVWatts to make the calculation of expected energy output, though that rule relates to standard rebate offers.[32] Instead, the Commission should include specific guidance on calculation of expected energy output within the NEM Rules for purposes of calculating the 120% rule.

Indeed, best practices from other states incorporate this concept. For example, New York has a 110% offset rule, but accounts for site conditions in making that calculation. The NY-SUN PV incentive program guidebook requires that developers "submit a report describing the percentage of the available solar resource that the solar electric array will receive, accounting for losses from shading, array azimuth, and tilt."[33] Further, the guidebook directs that "[t]he estimate of annual output will be calculated in the portal using NREL's PVWatts tool, based on information provided by the contractor or builder, including system size, location, and TSRF [total solar resource fraction]."[34] Developers also report that Nevada similarly uses full PVWatts functionality in estimating annual production, but we have been unable to locate this policy in writing.

COSSA and SEIA also recommend more specific rules surrounding calculation of annual average consumption. It is common for a customer to add load at the same time that they add solar, for example by purchasing an EV or new commercial equipment. Therefore, the rules should also specify that calculation of the "average annual consumption" also take into account expected load growth, such as the purchase of an EV or other major energy-consuming device.

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31 National Renewable Energy Laboratory, PVWatts Calculator. *Available at:* https://pvwatts.nrel.gov/.

32 Rule 3658 (f)(X)(D).

33 NY-Sun Residential and Small Commercial Program Manual at p. 14. *Available at:* https://www.nyserda.ny.gov/-/media/NYSun/files/Residental-SC-Program-Manual.pdf.

34 *Id.*

2.4 Production Metering Should only Be Required When Larger Customers Receive a Performance Based Incentive or Sell RECs

As detailed above, COSSA and SEIA oppose proposed rules that would allow utilities to count all BTM NEM production for RES compliance purposes. If the Commission agrees to forego adoption of those proposed rules, it would appear that the primary justification for proposed Rule 3680(a) would disappear.[35]

The current Rules only allow utilities to add a production meter for the purpose of counting RECs. *For purposes of the NEM rule*, the Commission's current Rules only require one meter to measure the flow of electricity in both directions. To the extent a utility wishes to install a second meter to track production of net-metered systems for their own system planning purposes, it should pay for such meters and should also be required to respect a customer's right to BTM privacy and should need to obtain the customer's approval to enter their property and install such meters. In the tri-proceeding settlement Public Service and all settling parties recognized that for NEM-only customers, production meters "are not necessary for the tracking of production based incentives," and therefore agreed that "the cost of those production meters will be assessed to the Company and funded through the RESA account."[36]

In a NEM-only situation where a customer does not sell their RECs, the only reason that a utility would want to measure all Retail DG production would be to know how much energy the customer is producing and consuming behind her own meter. Utilities often claim that this measurement is necessary for planning purposes even though most load fluctuations are based on forecasts and sampling techniques. Any requirements that reach behind a customer's meter to monitor certain behaviors or activities may violate a customer's constitutional right to privacy. At its core, the issue of additional metering is about the customer's right to privacy with regard

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35 NOPR at para. 204.

36 Proceeding 16AL-0048E, Tri-proceeding settlement at p. 36.

to BTM activities and therefore reducing purchase of electricity from a monopoly utility provider.

The Fourth Amendment to the U.S. Constitution provides a "right of the people to be secure in their persons, houses, papers, and effects, against unreasonable searches, shall not be violated ...." Section 7 of Colorado's Constitution provides a similar prohibition against unreasonable searches and seizures, but protects a greater range of privacy interests than does its federal counterpart.[37] These constitutional provisions protect individuals from unreasonable governmental intrusion provided that they have a reasonable expectation of privacy.[38] A private corporation, such as a utility may also be subject to constitutional privacy standards "if the government coerces, dominates or directs the actions of a private person conducting the search..."[39] For example, if the Commission were to require or encourage utilities to monitor BTM loads, the utility may be considered an agent of the state and subject to constitutional privacy norms. In one utility context, the Colorado Supreme Court has held that telephone subscribers have a legitimate privacy interest in the records of telephone calls made from their own homes.[40] The actual legitimate needs of the utility to manage a safe and reliable system must be balanced with customers' right to privacy in their decisions to self supply and reduce their purchases of utility service.

Imagine if we were talking about another product. What if a coffee distributer insisted on monitoring all the coffee that a customer was making in the home in order to forecast demand?

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[37] *People v. Oates*, 698 P.2d 811 (Colo. 1985); Colo. Const. Art. II, Section 7.

[38] *Casados v. City and Cty. of Denver*, 832 P.2d 1048 (Colo. App. 1992), *rev'd on other grounds*, 862 U.S. 908, *cert. denied*, 511 P.2d 1005 (Colo. 1993), 114 S. Ct. 1372 (1994).

[39] *Pleasant v. Lovell*, 876 F.2d 787, 796 (10th Cir. 1989); *United States v. Smythe*, 84 F.3d 1240, 1242 (10th Cir. 1996).

[40] *People v. Sporleder*, 666 P.2d 135, 138 (Colo. 1983).

While this may see far-fetched, the utility's demand to know what is happening BTM is out-of-step with privacy norms.

Even when a customer consents to the installation of a production meter and agrees to pay for it in order to measure the sale of RECs or to measure performance under a performance-based incentive, estimation is a commonly accepted methodology for smaller simple systems that is commonly employed in a number of jurisdictions. In its NOPR, the Commission posed the following question:

> *If net metering is deemed to "cause" eligible energy to be generated, could estimates of the electricity produced by certain systems suffice for RES compliance purposes such that no production meter is necessary? For example, would estimates be sufficient for retail renewable distributed generation not over ten 10 kW? If estimates are suitable, should the Commission adopt the same or similar provisions for estimating the production of retail renewable distributed generation as in Existing Rule 3658(f)(X) which was applied for the upfront standard offers to purchase RECs?*

As detailed above, COSSA and SEIA strongly oppose the notion that NEM is deemed to "cause" eligible energy to be generated. Aside from the legal and policy issues addressed above, it is simply not fair to consider the utility to be responsible for *causing* NEM-only generation to be generated. The decision to install and the funding provided for a NEM-only system is in no way attributable to a utility. The only thing that a utility does in a NEM-only situation is to interconnect the system and put the customer on a NEM rate rider, as required by law.

Regardless, estimation techniques, especially for smaller systems, are appropriate even when production must be known for compensating customers for REC sales or for providing a performance-based incentive. For example, Duke Energy Carolinas estimates the RECs generated by NEM facilities by using the PVWatts Solar Calculator developed by NREL per guidance from the North Carolina Utilities Commission.[41] Maryland similarly allows estimation of solar energy production for the calculation of RECs for systems under 10 kW-AC.[42] Estimation makes sense because requiring costly production meters for REC payments on smaller systems often negates the value of the REC payments.

As noted above, COSSA and SEIA support utilizing the framework (with some modifications) found in Rules 3658(f)(X) to be applied in the NEM Rules for purposes of implementing the 120% rule. COSSA and SEIA will provide specific redline rules in the near future. These same estimation techniques could also reasonably be used for calculating performance-based incentives and/or REC payments.

Best practices from other jurisdictions also support the notion that production metering should not be required on smaller systems. Research previously provided to the Commission demonstrated that only a small handful of other utilities require production metering on smaller NEM systems. Those that do require such production metering (also called "generation metering") often only do so for systems larger than 20 kW or 60 kW.

The table below provides an updated version of research previously provided on use of productions meters. This table provides similar data for the top 25 solar states, based on 2018 installation capacity additions.[43]

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41 *See* Duke Energy Progress North Carolina Integrated Resource Plan for 2018 at p. 233 *Available at:* https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=aa9862b5-5e31-4b3f-bb26-c8a12c85c658. (*citing*, NCUC's June 2018 Order Approving Rider and Granting Waiver Request, filed in Docket No. E-7, Sub 1113.)

42 *See* Code of Maryland Regulations Section 20.61.03.02 REC Creation from Renewable On-Site Generation. *Available at:* http://www.dsd.state.md.us/comar/comarhtml/20/20.61.03.02.htm.

43 U.S. Solar Market Insight 2018 Year in Review (Executive Summary), SEIA/Wood Mackenzie Power & Renewables, March 2019. *Available at:* https://www.seia.org/research-resources/solar-market-insight-report-2018-year-review.

State	Utilities	Generation Meter Required for NEM or On-Site Generation?	Generation Meter Required for Other Programs?
AR	Statewide	No	N/A
AZ	APS, TEP, UNS Electric	Yes	N/A
CA	Statewide	Only NEM paired storage systems above 10 kW	Production meter required for MASH program
CO	Xcel Energy	Yes	N/A
CT	Statewide	No	Required for ZREC program and RSIP
FL	Statewide	No	N/A
HI	Statewide	Depends on DG tariff: No for the (closed) NEM program; No for the Customer Grid Supply program; Yes for the Customer Grid-Supply Plus program	Not required for Customer Self-Supply option
ID	Statewide	No	Idaho Power requires production meter for facilities >25 kW
MA	Statewide	No	Required for SREC program participation; Required for facilities 60 kW or larger
MD	Statewide	No	Required for SREC program participation for facilities >10 kW
MN	Statewide	No	Required for Solar*Rewards participation; Required for any DER >40 kW
NC	Statewide	No	N/A
NM	Statewide	Varies by utility: Mandatory for PNM and EPE for all systems; Discretionary for Xcel but is explicitly not required for certain AC-coupled storage configurations	Required for DG REC program participation.
NV	Statewide	No	Required for Solar Incentives Program participation.
NY	Statewide	No	Required for NY-SUN program participation.
NJ	Statewide	No	Required for SREC program participation.
OR	Statewide	No	Required for Energy Trust incentives. Possibly required by Idaho Power for systems >25 kW.
RI	National Grid	No	Required for RE Growth program participation.

SC	Duke Energy Carolinas, Duke Energy Progress, SCE&G, Santee Cooper	Not required by Duke Energy Carolinas or Duke Energy Progress for facilities 20 kW or less; Required by SCE&G for all facilities; Discretionary for Santee Cooper.	N/A
TN	TVA, Kentucky Power	e.g., Required by Memphis Light Gas & Water; Not required by Kentucky Power	N/A
TX	Statewide	No	N/A
VA	Statewide	No	Required for customers electing to sell RECs to utility.
VT	Green Mountain Power	Yes, for all systems	N/A
WA	Statewide	No	Required for state PBI program.
WY	Statewide	No	N/A

2.5 The Commission Should Adopt Proposed Rules that Clarify that Rates for NEM Customers Must Be Non-Discriminatory

The proposed rules merely clarify existing PUC Rules that require non-discriminatory rate treatment for NEM customers. The PUC has recently had opportunity to revisit and re-affirm this requirement in Proceeding No. 17AL-0477E. Further, more recent NEM legislation applicable to cooperatives and municipalities specifically require non-discriminatory rates.[44] While this same language does not appear in the sections regarding IOUs, it would make little sense to allow discriminatory rate treatment for IOU NEM customers while it is not legal to do so for customer taking service from cooperatives or municipal utilities.

Below, COSSA and SEIA provide specific responses to some of the Commission's request for comments:

> *Do net metering customers share distinguishing characteristics that may justify the establishment of separate rate classes for net-metered customers?*

[44] C.R.S. § 40-2-124(7)(b)(III); C.R.S. § 40-9.5-118(2)(c).

In general, no. Average (low usage) NEM customers are no different from a system perspective than a customer with highly variable loads (in some cases) or a customer that uses energy efficiency to reduce overall consumption (in some cases). However, NEM customers are also no different from other customers in that they are not uniform and don't always conform to an "average." Some NEM customers have small systems and use lots of grid-supplied electricity while some have large systems paired with energy storage and use very little. Others may have an EV or a hot tub or some other energy consuming device that consumes most of their onsite generation before it is ever exported, while others may export most of their daytime generation and consume most of their electricity from the grid at night. Similarly, residential customers at large have significant variations in how and when they consume energy, such as multifamily versus single-family homes, large versus small homes, mountain versus urban locations, families that work at night versus those that work during the day and more- versus less-energy-efficient homes.

In the end, it is not practical to lump all NEM customers into one category with specific distinguishing characteristics, just as it is not possible to isolate all residential customers into specific sub-classes with distinguishing characteristics. Generally utility rate classes are based on larger more general characteristics such as the voltage upon which they take service or the maximum demand they impose on the system. When viewed from these larger perspectives NEM customers are more like other customers in their underlying rate class than they are like each other. A large industrial customer at a primary voltage with a NEM system will share many more common characteristics with other large industrial customers without a NEM, such as peak demands, total grid energy consumption and service voltages than they would with even a large commercial customer taking service at secondary voltages. Similarly, a small residential customer is likely to create the same magnitudes of fixed costs and impose the same levels of energy demand as other residential customers.

Do net-metered customers impose costs on the utility that are not imposed by non-net-metered customers?

No, similar to the answer provided above, NEM customers typically will impose similar fixed costs and similar demands on a utility systems as other customers in their rate class. To the extent exports from NEM customers cannot be accommodated by the utility's local distribution system without upgrades, such upgrades are directly assigned to interconnection customers ("IC").

Are there benefits to the system provided by net-metered retail renewable distributed generation in relation to the costs, if any, imposed by net metering customers?

Net-metered Retail DG from a renewable energy resource such as solar provides numerous system benefits as demonstrated in various utility and commission studies conducted across the country. Such benefits include avoided emissions, avoided fuel costs, avoided energy, avoided transmission and distribution line losses, avoided potential transmission and distribution capacity additions, reduced carbon costs (if monetized), avoided water consumption for cooling, market price effects and others. Onsite solar paired with energy storage and/or with advanced inverter functionality can also provide local distribution system benefits through the provision of ancillary services if and when such services are properly incented.

Nearly every independent expert benefit-cost study of net metering conducted over the last several years has concluded that the benefits of NEM outweigh the costs. For example, the Nevada Net Energy Metering Impacts Evaluation, updated in 2016, concluded that grid benefits of rooftop-distributed energy installed through 2016 exceed costs by approximately $36 million.[45]

Studies in Maine and Mississippi show similar results. Maine's value of solar study,[46] which was mandated by legislation passed in 2014, found that the value of solar power produced in Maine is $0.33/kWh, which is approximately $0.20/kWh more than the average net metering credit on solar customers' bills.[47] The net metering study in Mississippi was completed to help the Mississippi Public Service Commission in its investigation to establish and implement net metering and interconnection standards for that state, as Mississippi is one of the few states that does not currently have a net metering policy.[48] Overall, the analysis showed that the policy has the potential to provide net benefits to the state in nearly every scenario and sensitivity analyzed.[49] Additional studies completed in Vermont[50] and Missouri[51] also conclude that the benefits outweigh the costs.

> *Is there a point when the establishment of separate rates for net metered customers creates a potential violation of the requirements in § 40-2-124(1)(e)(III), C.R.S., that the Commission "encourage qualifying retail utilities to design solar programs that allow consumers of all income levels to obtain the benefits offered by solar electricity generation" and "allow programs that are designed to extend participation to customers in market segments that have not been responding to the standard offer program"?*

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45 *Nevada Net Energy Metering Impacts Evaluation 2016 Update*, Energy+Environment Economics, at pp. 7-8 (August 2018). *Available at:* http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-8/14264.pdf.

46 *Maine Distributed Solar Valuation Study*, Clean Power Research (March 1, 2015). *Available at:* https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2014-00171.

47 *Maine PUC's Solar Power Study Released Today Shows Enormous Benefits,* Natural Resources Council of Maine (March 3, 2015). *Available at:* http://www.nrcm.org/news/nrcm-news-releases/maine-puc-solar-power-study/

48 *Net Metering in Mississippi: Costs, Benefits and Policy Considerations*, Synapse Energy Economics, Inc. (September 2014). *Available at:* http://www.psc.state.ms.us/InsiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=337867.

49 *Id. at p.* 49.

50 *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012*, Public Service Department (January 2013). *Available at:* http://publicservice.vermont.gov/sites/psd/files/Topics/Renewable_Energy/Net_Metering/Act%20125%20Study%20130115%20Final.pdf.

51 *Net Metering in Missouri: The Benefits and The Costs*, Missouri Energy Initiative, Winter 2015. Available online: http://moenergy.org/images/Net%20Metering%20%20in%20Missouri%202015%201.pdf.

Yes. If separate rate classes for NEM customers made it harder for customers to install and finance onsite solar and thus "obtain the benefits offered by solar electricity generation" § 40-2-124(1)(e)(III) could be violated. COSSA and SEIA also note that some classes of customers, most notably larger commercial and industrial ("C&I") customers, have not been responding to utility incentive programs and uptake in those sectors lags significantly behind residential installations.

3 Interconnection Rules (Proposed Rules 3850 – 3858) and Associated Storage Issues

In February 2017, over two years ago, several solar parties filed a joint petition to address interconnection issues as they relate to energy storage.[52] In its Order denying that petition, the Commission resolved to take up interconnection issues in this Proceeding.[53] While COSSA and SEIA appreciate the opportunity to now have this debate, we are disappointed that most of our specific recommendations provided through the stakeholder process were apparently not considered, as they were not discussed in the NOPR. We believe that many of our requests were not understood or fully discussed with other stakeholders and PUC Staff.

We see a revision of interconnection rules as a golden opportunity for the commission to lift barriers to self-generation to facilitate customer adoption and customer financed growth of renewable energy in Colorado. We wish to emphasize that many of our recommendations can provide positive movement towards the Governor's stated renewable energy goals, which necessarily require both utility and BTM solutions, while also supporting customers' rights to self-generate and maintaining economic prosperity and job growth. We propose to set aside specific hearing or workshop time to go into detail on our proposals and to explain why each one is necessary, reasonable and will effectuate a safe and reliable electric grid.

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52 Proceeding 17M-0131.

53 Decision No. C17-0388 at ¶¶ 2, 20 and 21.

Consistent interconnection standards that explicitly establish parameters and procedures for connecting to the grid are critical in enabling customer choice and ensuring that barriers to Retail DG are eliminated. Fortunately, Colorado established interconnection standards in 2005 by adopting, in large part, the Federal Energy Regulatory Commission's ("FERC") Small Generator Interconnection rules ("SGIP"). Prior to that, utilities had tremendous discretion in when and why they could deny an interconnection application and made interconnection a risky and costly deterrent for customers and developers.

Colorado's interconnection procedures have reduced the risk and cost of interconnection, but have not kept up with best practices, and the pace of change as utilities and regulators have learned more about integration of higher penetrations of DERs as technology has evolved. Further, the rules related to interconnection lack teeth and are often violated by utilities without consequence. One of the primary purposes of interconnection procedures is to provide concrete timelines that customers can rely on to ensure timely interconnection, but utilities in Colorado consistently miss their deadlines, creating confusion, delay and frustration. Some developers have even reported that they turn down customer requests for Retail DG in certain utility service territories because interconnection timelines and procedures are so onerous. Without some consequences for utilities that violate interconnection standards, or at least a process to resolve disputes, there is no incentive for utilities to comply.

Further, the proliferation of energy storage has changed the applicability and need of many existing interconnection rules and standards. Indeed, on March 22, 2018, Governor Hickenlooper signed SB 18-009 into law. SB 18-009, codified at C.R.S. 40-2-130 requires the Commission to "adopt rules allowing the installation, interconnection, and use of energy storage systems by customers of utilities."[54] In crafting such interconnection rules, the Commission must incorporate interconnection procedures that facilitate BTM energy storage, that reduce unnecessary burdens, that are simple, streamlined and affordable and that forbid requirements to install "customer-sited meters in addition to a single net energy meter for the purposes of monitoring energy storage systems."[55]

While the NOPR claims to implement SB 18-009's requirements, COSSA and SEIA respectfully disagree and provide specific recommendations to effectuate the legislative intent in the sections below. For example, specific rules are necessary to account for non-exporting storage systems, to require parameters around calculating the rated capacities of various types of storage facilities, and to forbid utility imposed requirements that customers with certain configurations of solar and energy storage pay for and install *two* production meters, in violation of the plain language of SB 18-009. These and other recommendations are detailed in the sections below.

3.1 Proposed Interconnection Rules Must Effectuate SB 18-009

SB 18-009, codified at CRS 40-2-130 declares,

(I) It is in the public interest to limit barriers to the installation, interconnection, and use of customer-sited energy storage facilities in Colorado; and

(II) Colorado's consumers of electricity have a right to install, interconnect, and use energy storage systems on their property without the burden of unnecessary restrictions or regulations and without unfair or discriminatory rates or fees.[56]

The law further requires the Commission to "adopt rules allowing the installation, interconnection, and use of energy storage systems by customers of utilities." In crafting such interconnection rules, the Commission must incorporate the following statutory principles:

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[54] C.R.S § 40-2-130(3).
[55] C.R.S § 40-2-130(3)(d).
[56] C.R.S. § 40-2-130(1)(b).

(a) It is in the public interest to limit barriers to the installation, interconnection, and use of customer-sited energy storage systems in Colorado;

(b) Colorado's consumers of electricity have a right to install, interconnect, and use energy storage systems on their property without the burden of unnecessary restrictions or regulations and without discriminatory rates or fees;

(c) Utility approval processes and any required interconnection reviews of energy storage systems shall be simple, streamlined, and affordable for customers; and

(d) Utilities shall not require the installation of customer-sited meters in addition to a single net energy meter for the purposes of monitoring energy storage systems; except that the commission may authorize the requirement of metering for certain large energy storage systems, as determined by the commission.[57]

These legislative requirements are clear, the Commission is required to incorporate interconnection procedures that facilitate BTM energy storage, that reduce unnecessary burdens, that are simple, streamlined and affordable and that forbid requirements to install "customer-sited meters in addition to a single net energy meter for the purposes of monitoring energy storage systems."

The NOPR states in the introductory section that "[t]his rulemaking satisfies the requirements of Senate Bill (SB) 18-009"[58] and then later states "[t]he proposed changes to the interconnection provisions entail: (1) introduction of provisions that address energy storage, pursuant to SB 18-009…." However, the term "energy storage" is not defined anywhere in the proposed rules and COSSA and SEIA could only identify a few additional references to energy storage anywhere in the rest of the interconnection section of the NOPR or the redlined rules. The additional sections that do reference energy storage fail to implement SB 18-009 because they fail to remove unnecessary burdens, unnecessary restrictions or regulations, fail to ensure that the utility approval processes and any required interconnection reviews of energy storage are

57 C.R.S § 40-2-130(3).
58 NOPR at para. 3

simple, streamlined, or affordable for customers and fail to forbid the installation of customer-sited meters in addition to a single net energy meter for the purposes of monitoring energy storage systems. Finally there is no definition of a "large energy storage system" or direction to utilities about when an exception to the statutory additional metering restrictions is permitted.

To effectuate SB 18-009, COSSA and SEIA recommend that the Commission incorporate the following concepts into the new interconnection rules.

3.1.1 Calculation of the Capacity of Energy Storage Plus Generation Should Be in Rules

One of the most important ways that the Commission can ensure that SB 18-009's requirements are satisfied, is to *ensure* that the capacity of an energy storage system is not treated the same as the capacity of other generating facilities. This is already the way many utilities, including Public Service, are treating storage. We encourage the Commission to establish certainty with regards to capacity treatment, like those that exist in other jurisdictions, as an opportunity to establish consistent statewide capacity calculation methods and simplify the interconnection process for both utilities and utility customers.

With interconnections that only encompass traditional generation technology, the calculation of the system's total capacity is straightforward. An interconnection application for a system comprised of 11 kW of solar behind a single inverter and 15 kW of small wind behind a single inverter would lead to an interconnection application of 26 kW and would not therefore qualify for a Level 1 process. However, when an 11 kW solar system is paired with a battery that has a peak capacity rating of 15 kW behind a single inverter, it is not appropriate to simply add these two systems together to 26 kW because the actual impact to the grid may still only be 11 kW. This situation can arise for various reasons.

In many smaller residential and small commercial solar plus storage systems, the solar system and the battery are likely to share one inverter (this is known as a DC-coupled system). This means that the solar system and the battery are limited in their impact to the grid by the size of the inverter, not the total capacity of the two systems. In other words, the maximum amount of power that this solar plus storage system could physically export to the grid is the maximum rating of the inverter. Simply adding the maximum capacity of each component could, in most cases, unfairly and unreasonably result in that system's disqualification for Level 1 interconnection procedures, creating unnecessary cost and complexity in violation of SB 18-009.

Many DG systems coupled with storage can also be limited by programming or other system configuration choices. For example, a solar plus storage system that has multiple inverters (an AC-coupled system) may be programmed such that the storage never exports energy to the grid and only serves onsite load. Under this scenario it would not be fair or just to measure the total size of the two components, or the two inverters, and potentially bump an interconnection process to a higher level of scrutiny. Taking these operating configurations into account effectuates the intent of SB 18-009 by removing unnecessary barriers to interconnection of certain non-exporting storage systems without compromising safety, reliability or power quality. When a storage system is configured not to export, that fact should be taken into consideration when reviewing a combined system.

This recommendation is also consistent with agreements that solar advocates and Public Service developed in early 2017. The storage interconnection guidance documents filed by Public Service in proceeding No. 16AL-0048E reflect the agreement that the operating characteristics (*i.e.*, whether a system exports or not) shall be taken into account when completing an interconnection review. Specifically, the following language appears in each of those guidance documents:

> Interconnections are reviewed based on the combined nameplate ratings of the sources that can actually be simultaneously supplied to the grid, such as two inverters. The ongoing operation capacity portion of the review is based on the actual simultaneous performance AC ratings. If the contribution of the energy storage to the total contribution is limited by programing or by some other on-site limiting element, the reduced ongoing capacity will be used.[59]

Because Public Service has already agreed to this methodology of calculating a solar + storage systems' total capacity for purposes of interconnection, and because SB 18-009 requires the Commission to streamline and simplify interconnection procedures for energy storage, this proposal is not controversial but is necessary to ensure that barriers to installation of energy storage systems are removed.

While the NOPR addresses this issue in proposed Rule 3853(b)(III), the proposed rules leave the utility with complete discretion to use "less than the maximum rated capacity of the DER if the utility determines that the DER is only capable of injecting less power into the utility's system." This proposed rule fails to provide assurance to an IC that their solar + storage system will be evaluated under the proper level of scrutiny if the utility, in its sole discretion, chooses to ignore export limiting factors.

Instead, COSSA and SEIA suggest incorporating the above-copied language contained in Public Service's storage interconnection guidance documents filed by Public Service in proceeding No. 16AL-0048E, as reflected in redlined rules provided during the stakeholder process.[60] At the very least, there should be low cost and expedited process by which an IC can challenge a utility's determination to use the maximum rated capacity of a solar + storage system in evaluating an interconnection request.

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[59] Proceeding No. 16AL-0048E, Report on Pub. Serv. Co. of Colo. Technical Specifications for Storage Systems Interconnected in Parallel with the Distribution System Attach. C at 2 nn.3 & 5, 10 n.3, & 18 n.2 (Jan. 31, 2017).

[60] Proceeding No. 17M-0694E, Closing Comments of the Colorado Solar Energy Industries Association, the Solar Energy Industries Association, Vote Solar and Sunrun Inc., Attachment B, proposed rule 3670(d) (Sept. 7, 2018).

This is also the approach that other jurisdictions have recently proposed to address this issue. For example, Arizona recently proposed the following definition in its updated interconnection rules:

> "Maximum Capacity" means the nameplate AC capacity of a Generating Facility. If the Operating Characteristics of the Generating Facility limit the power transferred across the Point of Interconnection to the Distribution System, only the power transferred across the Point of Interconnection to the Distribution System, not including Inadvertent Export, shall be declared as the Maximum Capacity of the Generating Facility.[61]

Nevada similarly defines Net Nameplate Rating as follows:

> Net Nameplate Rating: The gross generating capacity of a Generating Unit or the total of the gross generating capacity of the Generating Units comprising a Generating Facility as designated by the manufacturer(s) of the Generating Unit(s) minus the consumption of electrical power of the Generating Unit(s). Where the gross generating capacity of a Generating Unit or Units is limited (e.g., through the use of a control system, power relay(s), or other similar device settings or adjustments), the Net Nameplate Rating shall be the maximum specified by the Applicant in the Application. The Net Nameplate Rating will subsequently be contained in the net metering agreement or Interconnection and Operating Agreement.[62]

To effectuate SB 18-009, to encourage the beneficial use of customer sited energy storage and to align with other jurisdictions' best practices, Colorado should clearly define how utilities must calculate capacity for the purposes of interconnection.

3.1.2 Expedited Interconnection Review for Non-exporting Systems is Reasonable

COSSA and SEIA continue to propose that DERs, including energy storage systems, that are designed only to serve onsite load and will not intentionally export power to the grid should not be subject to detailed screens and should not be required to obtain specific utility permission

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[61] Arizona Corporation Commission, Docket No. RE-00000A-07-0609, Decision No. 77056 at p. 5. *Available at:* http://docket.images.azcc.gov/0000195373.pdf.

[62] NV Energy North, "Rule No. 15: Generating Facility Interconnections," Public Utilities Commission of Nevada Sheet No 48-B. Effective April 11, 2018. *Available at*: https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/electric-rules-north/Rule_15_Electric_North.pdf.

to operate. Alternatively, as has been recently proposed in Arizona, non-exporting systems should not bump interconnection review processes into a higher level of scrutiny.

Non-exporting (or inadvertent export only) systems are specifically designed to have little or no impact on a utility's system and have proliferated due the emergence of low cost home energy storage systems. The interconnection screens that apply to generators through the Commission's current interconnection rules are simply not applicable to non-exporting systems. Those screens are largely designed to ensure that the distribution system can handle exports from generators that regularly feed electricity back to the system. A non-exporting system by definition is minimal impact as all of the electricity from such systems is consumed onsite.

As recognized in Public Service's energy storage interconnection guidance documents, even systems designed to not export, will in some limited ways due to some normal events such as a drop in load, result in a momentary export of a small amount of power. The minimal impact of momentary, non-coincidental inadvertent export is far less than systems that export on a continuous basis. As such, states that have "no export" requirements typically include a specific definition of "inadvertent exports." So long as storage systems do not exceed the bounds of "inadvertent exports," such systems will be compliant. Public Service includes a definition of "inadvertent export" similar to that which COSSA and SEIA support in its energy storage interconnection guidance documents.[63] Any proposed definition of "inadvertent export" should make clear that minor inadvertent exports would not be compensated.

Exempting non-export systems from interconnection screening, or at least creating a special expedited interconnection process for non-exporting systems would effectuate SB 18-

[63] *See* Xcel Energy, Guidance No. 2 for Interconnection of Energy Storage Systems Operated in Front of a Production Meter and Paired with Onsite Renewable Generation Connected Under a Net Metering Tariff at pp. 4-5. (January 25, 2017). *Available at:* https://www.xcelenergy.com/staticfiles/xe-responsive/Programs%20and%20Rebates/Residential/CO-solar-residents-Storage-Guidance-2.pdf.

009's requirements that customers "have a right to install, interconnect, and use energy storage systems on their property without the burden of unnecessary restrictions or regulations" and that "interconnection reviews of energy storage systems shall be simple, streamlined, and affordable." Utilities have provided no rationale to require non-exporting systems enabled by energy storage to undergo interconnection screens that are designed to account for continuous exports back to the grid.

Other states are moving towards processed that recognize the uniqueness of non-exporting systems and creating special interconnection rules to encourage their adoption. For example, in California, non-export systems qualify for fast track, regardless of their size and certain screens are bypassed.[64] Similarly, Montana, Nevada and Oregon all have specific expedited review tracks for non-exporting projects.[65,66,67]

3.1.3 SB 18-009 Requires Rules Prohibiting Additional Production Meters for Energy Storage

As noted above, SB 18-009 requires the Commission to "adopt rules allowing the installation, interconnection, and use of energy storage systems …" and requires, *inter alia*, that such rules reflect the principle that "[u]tilities shall not require the installation of customer-sited meters in addition to a single net energy meter for the purposes of monitoring energy storage systems; except that the commission may authorize the requirement of metering for certain large

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64 Pacific Gas & Electric, "Electric Rule No. 21: Generating Facility Interconnections." Sheet 45. Effective June 8, 2017. *Available at:* https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf.

65 Administrative Rules of Montana, Small Generator Interconnection, §38.5.8411(3)(c), Level 3 Expedited Review. *Available at:* http://www.mtrules.org/gateway/RuleNo.asp?RN=38%2E5%2E8411.

66 NV Energy North,"Rule No. 15: Generating Facility Interconnections." Public Utilities Commission of Nevada Sheet No 48-P. Effective April 11, 2018. *Available at:* https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/electric-rules-north/Rule_15_Electric_North.pdf.

67 Oregon Administrative Rules, Small Generator Interconnection Rules, Tier 3 Interconnection Review, §860-082-0055(1)(d). *Available at:* https://secure.sos.state.or.us/oard/viewSingleRule.action;JSESSIONID_OARD=A8PBBTMiB3FUfbci7YxyrdWAPyajSYkbENqIh_Q0RN6h2NJnGqE-!-1969788327?ruleVrsnRsn=223937.

energy storage systems, as determined by the commission.[68] This issue was also one of the main subjects of the joint petitions filed by several solar advocates in 2017, which the Commission committed to addressing in this NOPR in its order partially granting that petition.[69] Despite SB 18-009's legislative direction, Public Service continues to require a second meter to measure a customer's battery under certain configurations.[70] This lack of compliance by Public Service indicates that it is waiting for the Commission to act before changing its policy.

COSSA and SEIA proposed a rule in the stakeholder process to make clear that a utility shall not require additional metering for the sake of interconnecting a customer's generating facility, consistent with SB 18-009's requirements. SB 18-009 does state "the commission may authorize the requirement of metering for certain large energy storage systems, as determined by the commission." Therefore, the Joint Solar Parties proposed to allow such metering only on systems larger than 500 kW. 500 kW is the appropriate demarcation point to define a large solar system, consistent with Public Service's Large Solar*Rewards Program.[71]

This issue was fully briefed in Proceeding No. 16AL-0048E, in response to the "Report on Public Service Company of Colorado's Technical Specifications for Storage Systems Interconnected in Parallel with the Distribution System."[72] As explained in that reply, Public Service's additional "load meter" requirements inappropriately reach behind a customer's service meter to monitor the electricity that the customer consumes onsite. COSSA and SEIA are also concerned in this environment of rapid growth of technological innovation that allowing such

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68 *Id.* at (3).

69 Proceeding 17M-0131; Decision No. C17-0388 at ¶¶ 2, 20 and 21.

70 Xcel Energy, Guidance No. 3 for Interconnection of Energy Storage Systems Operated Behind a Production Meter and Paired with Onsite Renewable Generation Connected Under a Net Metering Tariff at p. 4 (January 25, 2017). *Available at:* https://www.xcelenergy.com/staticfiles/xe-responsive/Programs%20and%20Rebates/Residential/CO-solar-residence-Storage-Guidance-3.pdf.

71 *See,* Xcel Energy, Solar Rewards for Residences. *Available at:* https://www.xcelenergy.com/programs_and_rebates/residential_programs_and_rebates/renewable_energy_options_residential/solar/available_solar_options/on_your_home_or_in_your_yard/solar_rewards_for_residences.

metering will lead to proposals to meter all new DER technologies under the guise of "understanding the load behind the meter." Customers' rights regarding their own energy usage or generation BTM should not be compromised. This is a critical policy matter regarding a customer's right to privacy.

Additional policy reasons why such metering is inappropriate are included in Proceeding No. 16AL-0048E, in the Joint Solar Parties' response to the "Report on Public Service Company of Colorado's Technical Specifications for Storage Systems Interconnected in Parallel with the Distribution System," incorporated herein by reference, and in the Petition filed in Proceeding 17M-0131E. While the Joint Solar Parties stand by those policy arguments, they are somewhat mooted by the passage of SB 18-009, which requires that utilities abandon these metering requirements.

3.1.4 Rules Should Ensure NEM Eligibility In the Presence of Storage

Whether the Commission sees fit to include rules in the NEM section or the interconnection section, clear rules should be established to allow a customer with on-site energy storage that is paired with a NEM-eligible energy resource to qualify for net metering. This is consistent with the tri-proceeding settlement agreement with Public Service in 2016 and ensures that only NEM-eligible energy is exported to the grid.[73] Ensuring that this option is available to customers is critical to unlocking some of the benefits that energy storage can provide.

For example, energy storage can be used to help customers manage TOU rates, by charging the battery when electricity is cheaper or more abundant, and applying it to serve onsite need when electricity is in peak demand and more expensive.[74] If a customer with a solar plus

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[72] Proceeding No. 16AL-0048E, The Energy Freedom Coalition of America, the Colorado Solar Energy Industries Association, Sunrun Inc., and Vote Solar's Response to the Report on Public Service Company of Colorado's Technical Specifications for Storage Systems Interconnected in Parallel with the Distribution System (March 2, 2017).

[73] Proceeding No. 16AL-0048E, Non-Unanimous Comprehensive Settlement Agreement at pp. 20-21.

[74] Energy Storage Association, "End-User Billing Management." *Available at:* http://energystorage.org/energy-storage/technology-applications/end-user-bill-management.

storage system takes service under TOU rates, she can help manage her bill by charging the battery from the solar system in the early afternoon, when prices are lower, and then use the stored solar energy to meet a portion of her needs during a late afternoon or early evening peak, when prices are higher. Since she is charging her battery with solar-only she may also choose to export her energy in exchange for on-peak NEM credits when it is needed most by others nearby. By shifting load in this manner, the customer provides the benefit of reducing their contribution to system peak, helping to alleviate stress on the system, while also opening the door for NEM solar+storage consumers to assist with grid service needs and future programs.

The utilization of storage by C&I customers to manage their exposure to demand charges provides another example where parallel operation is critical. Storage systems deployed to manage large customer demand charges rely on an algorithm that monitors a customer's demand and then automatically discharges to meet a portion of their onsite demand during those times when their demand appears to be spiking. In doing this, the storage device reduces the amount of capacity that the C&I customer needs from the grid, avoiding demand charges they might otherwise incur. Similar to the scenario described above regarding TOU rates, a secondary benefit from the deployment of storage to address demand charges is that, to the degree a C&I customer's peak demand is coincident with the system or local peaks, the deployment of storage can help reduce the customers contribution to peak conditions and help reduce strain on the system.

While some utilities have claimed that additional metering is necessary to ensure compliance with these types of restrictions, a Certification Requirements Decision recently approved by UL[75] to support the 2020 National Electrical Code Section 705.13, renders these

[75] The March 14, 2019 Collaborative Standards Development System ("CSDS") Proposal regarding the addition of certification requirements covering Power Control Systems standard adopted on March 8, 2019, and is proposed for inclusion within the UL 1741 standard revision See March 14 CSDS Proposal information under "Summary of Topics" list in the "CSDS Proposals" tab, *accessible at:* https://www.shopulstandards.com/ProductDetail.aspx?UniqueKey=20941. A NRTL attestation that equipment meets the requirements of the UL 1741 Certification Requirement Decision on Power Control Systems shall be required until 18 months after publication of the test standard, whereupon certification to the standard will be required.

concerns moot. Additional metering is not required if there are processes in place to allow for applicants to submit proof that these certified inverters are programmed in the field to ensure no grid charging under a NEM profile or prevent export under a grid charging scenario.

In response to UL's development of this certification standard, the California PUC recently ordered methods to ensure device settings are configured correctly at installation and not subsequently changed by requiring that the NEM-compliant power control configuration appear in a device's configuration file as a non-editable value, such that installers would have to select an entirely different configuration file in order to modify the NEM-compliant configuration. Utilities in California are now required to accept UL certified "power control" settings/programming within the inverter in order to verify that NEM plus solar plus storage systems are eligible for NEM.[76] Previously, only storage systems with a capacity less than 10 kW were allowed to export under NEM. This decision opened NEM access to all storage systems (AC and DC-coupled) in California, regardless of capacity.

3.1.5 Rules Should Protect Against Unnecessary Recurring Interconnection Fees

Some modern storage systems allow customers to select various sub-operating modes within a non-export or export configuration. For example, a customer may modify the setting on a non-exporting system to focus on different tasks, such as using the storage primarily for peak shaving, or using it to maximize the amount of solar generation consumed onsite. Unless a customer modifies the setting of their onsite system in a way that impacts exports to the grid, they should not be subject to additional interconnection requirements and fees.

Similarly, some developers have reported that whenever they make a software or firmware upgrade to a customer's storage system, Public Service requires the customer to obtain a new

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[76] California Pub. Util. Comm., Rulemaking 14-07-002, D.19-01-030 at p. 17 January 31, 2019. ("To summarize, we approve power control-based options, for ensuring NEM credit accrues only to NEM-eligible generation in large solar plus storage systems, as long as the control configuration is certified to a national standard or a utility-approved interim testing procedure. Power control-based options include the use of equipment, whether firmware-based or software-based, to prevent the storage device from charging from the grid or to prevent the storage device from exporting to the grid.")

interconnection agreement and pay an additional interconnection fee even if the update does not impact the energy storage system's ability to export or impacts the system's capacity rating.

This concept is consistent with SB 18-009's requirements that customers be free of any unnecessary interconnection restrictions or regulations and that interconnection reviews of energy storage systems be simple, streamlined, and affordable for customers. Requiring multiple interconnection applications when a system remains within its agreed upon operating modes are unnecessary, burdensome and costly.

Because utilities have required multiple interconnection fees and applications in this situation, it is up to the Commission to create rules that dictate when and how this process should occur. Without clear guidance from the Commission, customers with energy storage will continue to face overly burdensome, costly and unnecessary restrictions, limiting their adoptions.

3.1.6 "Energy Storage" Should be Defined

The term "Energy Storage" should be clearly defined, consistent with the statutory definition as follows:

> "Energy storage system" means any commercially available, customer-sited system, including batteries and the batteries paired with on-site generation, that is capable of retaining, storing, and delivering energy by chemical, thermal, mechanical, or other means.

This definition should be placed in the general definitions section of the Electric Rules at Rule 3001, as the proposed RES Rules also reference energy storage.

Because energy storage is not an electricity *generation* source, but merely retains, stores, and delivers energy, it should be clearly delineated from the Commission's proposed definition of "Distributed energy resource" or "DER." The Commission proposed Rule 3852(b) replaces the current definition of "Small Generating Facility" with the more generic term as follows:

> “Distributed energy resource” or “DER” ~~“Small generating facility”~~ means the interconnection customer's source of electric power, including retail renewable distributed generation, other small generation facilities ~~device~~ for the production of electricity, and energy storage systems, as identified in the interconnection request, but shall not include the interconnection facilities not owned by the interconnection customer….

While COSSA and SEIA don’t necessarily oppose the inclusion of a DER definition, the proposal conflates a “source of electric power” such as a solar facility with other types of DERs such as energy storage, which as explained above is not a source of electric power in and of itself. Other types of DERs such as EVs or demand response are also widely considered to be DERs, but should certainly not be subject to blanket interconnection requirements, which are intended to ensure that exported energy to the grid does not create safety or reliability concerns.

3.2 The Commission Should Modify Other Interconnection Rules to Facilitate More Efficient Deployment of Renewables

In addition to changes to incorporate SB 18-009 and many of the changes proposed by the Commission to conform to the updated FERC SGIP, additional interconnection reforms are needed to keep up with technology and modern understanding of interconnection issues. The Commission should strive to make the process as standard and streamlined as possible to provide consistency and clarity to customers and developers while maintaining safety and reliability. A predictable process that includes sharing of relevant data and processes for resolving disputes is critical to reducing soft costs of renewable energy development and ensuring that all customer generators are treated fairly. Interconnection costs or grid upgrades should only be assessed when necessary for demonstrable and quantifiable safety and reliability concerns.

COSSA and SEIA are concerned that the NOPR’s proposed interconnection rule modifications do not go far enough in facilitating a smooth and speedy interconnection process for customers. Specific proposals to modernize the Interconnection rules are described below.

COSSA and SEIA will work expeditiously to provide detailed redline rule proposals in the near future.

3.2.1 The Commission Should Modify the Applicability Section

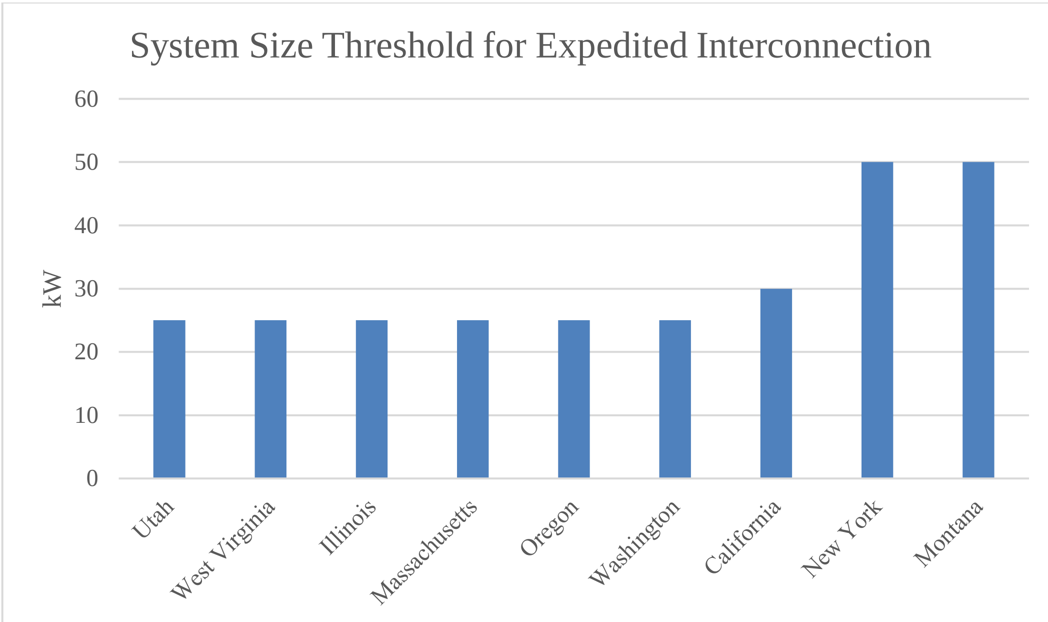
Rule 3850 concerning "Applicability" makes clear that the interconnection procedures apply when connecting Retail DG and "other" DERs. The rule also states, "Each utility shall also provide, on its web site, interconnection standards or other technical guidance not included in these procedures." This sentence leaves the door open for utilities to develop additional but unspecified "interconnection standards" and "technical guidance" that is free from any Commission oversight or guidance. These utility-specific standards and guidance documents are typically where utilities establish particular fees, metering requirements, and interpretations of the interconnections standards which can be unreasonably onerous and serve as a barrier to interconnection. While COSSA and SEIA recognize the need for individual utilities to create processes and rules that are specific to their technical capabilities and staffing concerns, such additional standards and technical guidance should require commission approval and an opportunity for interested parties to challenge unreasonable conditions or fees. Without such a process, developers and ICs are at the complete mercy of utility policies. COSSA and SEIA suggest that any additional rules and fees be filed with the Commission as Advice Letter ("AL") filings and be included in tariffs. While this is not always the procedure that utilities follow, it is precisely what Public Service did in Proceeding No. 17AL-0116E via AL No. 1736, which memorialized the Guidance Documents that were partially agreed to regarding interconnection of Energy Storage. The AL process ensures proper oversight of important utility specific interconnection procedures and fees.

Further, as noted above, "DER" is very general term that encompasses a wide range of technologies and practices including generation and storage technologies as well as energy efficiency, demand response and EVs. Also as noted above, the NOPR's proposed definition conflates a "source of electric power" such as a solar system or a wind turbine with an energy storage system that does not generate electricity at all. COSSA and SEIA do not object to including a definition of "DER" in the electric rules, but believe that "generation facility" (or even "small generation facility") is more appropriate for the applicability of interconnection rules. While we understand that some forms of exporting energy storage would also need to undergo interconnection reviews, those systems can be specifically mentioned. The generic term "DER" could lead to unintended disputes about the need to interconnect EVs, saver switches or other technologies that do not export energy to the electric grid.

3.2.2 Eligibility for Fast Track Interconnection Process Should Be Raised to 25 kW

Colorado utilities have gained a great deal of experience with small systems as the bulk of interconnection requests are for customers in the residential market segment. The interconnection standards incorporate a simplified interconnection process (*i.e.*, "Level 1 Process") to speed residential systems through the process. Indeed, no Level 1 system has ever been denied interconnection to COSSA or SEIA's knowledge. Building on the experience and knowledge base of more than a decade of interconnecting small systems, it is time for the boundaries of the Level 1 simplified interconnection process to follow the Solar*Rewards Small incentive program and grow to 25 kW. These systems remain subject to an appropriate subset of the interconnection screens applicable to the Level 1 Process.

Furthermore, many other states utilize an expedited interconnection process, similar to Level 1 for systems larger than 10 kW, some as large as 50 kW. The below graph provides examples:



References for each state in the above graph are in the footnotes.[77]

Increasing the threshold for Level 1 is especially critical if the Commission refuses to adopt the proposed method of calculating the capacity of solar plus storage described above.

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[77] *For Utah see* State Rule R746-312. *Available at:* https://rules.utah.gov/publicat/code/r746/r746-312.htm#T8.

For West Virginia see W. Va. Code § 24-2F-1 et seq. *Available at:* http://apps.sos.wv.gov/adlaw/csr/readfile.aspx?DocId=18382&Format=PDF.

For Illinois see state Rule 83 Ill. Adm. Code, Section 466.80. *Available at:* ftp://www.ilga.gov/JCAR/AdminCode/083/083004660000800R.html.

For Massachusetts see National Grid M.D.P.U. No. 1320 Sheet 12. *Available at:* https://www9.nationalgridus.com/non_html/Interconnect_stds_MA.pdf.

For Oregon see Oregon Administrative Rules, Small Generator Interconnection Rules, Tier 1 Interconnection Review, §860-082-0045. *Available at:* https://secure.sos.state.or.us/oard/displayChapterRules.action?selectedChapter=172.

For Washington see Washington Administrative Code §480-108-030. *Available at:* https://apps.leg.wa.gov/WAC/default.aspx?cite=480-108-030.

For California see Pacific Gas & Electric "Electric Rule No. 21: Generating Facility Interconnections." Effective June 8, 2017. Sheet 258. *Available at:* https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf.

For New York see New York State Standardized Interconnection Requirements and Application Process at p. 4. *Available at:* http://www.dps.ny.gov/distgen.

For Montana see Administrative Rules of Montana, §38.5.8411 Level 3 Expedited Review. *Available at:* http://www.mtrules.org/gateway/RuleNo.asp?RN=38%2E5%2E8411.

This is because the trend in the solar industry is to pair solar energy with battery storage, which creates many benefits to the utility system over standalone solar. However when doing so it will likely become common for smaller residential systems to include a battery system of between 5-10 kW. As explained above, the addition of the batteries' capacity should only be added to the solar facility when both systems are configured to export to the grid. However, if the Commission ultimately disagrees, utilities may simply add a 6 kW solar system to a 5 kW non-exporting battery system to come up with an 11 kW application. Without a modification to the Level 1 Process capacity threshold, many small residential systems will suddenly be kicked into a significantly more expensive, complicated and time-consuming Level 2 process.

The Commission should note that Arizona is currently proposing to both increase the capacity size threshold for Level 1 *and* modify its definition of "Maximum Capacity" to account for only energy that is capable of being exported to the grid. Arizona has significantly higher onsite solar penetrations than Colorado[78] and is still in a position to liberalize its interconnection policies on both of these points.

3.2.3 Interconnection and Pre-Application Report Fees Should Be Established By Rule

Both the current and proposed Interconnection Rules leave the utilities with absolute discretion to determine and fix the fees that an IC must pay either as an application fee[79] or for a pre-application report.[80] By leaving the determination of these fees entirely in the hands of the utility the Commission shirks its legal power, authority, and *duty* "to govern and regulate all rates, charges, and tariffs of every public utility," to "correct abuses" by public utilities, to "prevent unjust discriminations . . . in the rates, charges, and tariffs of such public utilities,"

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[78] As of Q4 2018, Arizona has an installed solar capacity of 3,738.58 MW, compared to Colorado's installed solar capacity of 1,184.41 MW. Data from SEIA/GTM Research U.S. Solar Market Insight. *See*, https://www.seia.org/state-solar-policy/arizona-solar and https://www.seia.org/state-solar-policy/colorado-solar.

[79] NOPR Proposed Rules 3853(c)(I); 3854(a)(IV); and 3854(b)(III).

[80] NOPR Proposed Rule 3853(A)(IV).

and to "generally supervise and regulate every public utility in this state," and "to do all things" that are "necessary or convenient in the exercise of such powers."[81]

Public Service's current practice for application fees is to charge $100 for interconnection applications up to 10 kW, $1,000 for systems that are 10 kW– 25 kW and $2,000 for systems that are 25 kW – 2 MW.[82] This means that sizing a system just one watt above 10 kW leads to a ten times higher charge for the application fee. It is hard to imagine that adding one additional watt creates ten times more costs on Public Service's interconnection staff. The Public Utilities Law provides that, except as expressly authorized by statute, no regulated public utility "shall make or grant any preference or advantage" or "establish or maintain any unreasonable difference as to rates [or] charges . . . ."[83] Like all other charges, utilities should have to show that the fees imposed for interconnection applications are cost based, just and reasonable and that there is no discrimination in fees charged for 10.1 kW systems as opposed to 10 kW systems. This could be done through an investigation of the fees in this rulemaking proceeding or through subsequent tariff filings. COSSA and SEIA suspect that the costs to interconnect a system are more gradual than the extreme increases in costs reflected in Public Service's current policy.

Setting interconnection application fees by rule is not uncommon. NREL released a report in which it reviewed the interconnection practices and costs in the Western US.[84] Specifically, the report compared interconnection application fees by state. New Mexico, for example, charges $50 for systems ≤ 10 kW, $100 for systems 10 kW - 100 kW, and $100 +

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81 C.R.S. § 40-3-102.

82 Xcel Energy, "Solar*Rewards Frequently Asked Questions" at p. 4 (2017). *Available at:* https://www.xcelenergy.com/staticfiles/xe-responsive/Programs%20and%20Rebates/Residential/CO-SR-Installer-FAQ.pdf.

83 C.R.S. § 40-3-106(1)(a).

84 *See*, Bird, Lori, Flores, Francisco, Volpi, Christina, Ardani, Kristen, Manning, David, and Richard McAllister. 2018. Review of Interconnection Practices and Costs in the Western States. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71232. *Available at:* https://www.nrel.gov/docs/fy18osti/71232.pdf.

$1/kW for systems > 100 kW.[85] This translates into paying $250 in New Mexico for a 250 kW system and paying $2,000 in Colorado for the same size system. Oregon's application fee may not exceed $100 for Tier 1 (systems ≤ 25 kW) review, $500 for Tier 2 (systems ≤ 2 MW) review, and $1,000 for review under Tiers 3 and 4.[86] There is no interconnection fee for NEM Tier 1 systems.[87] Washington charges $100 for facilities ≤ 25 kW, $500 for facilities 26 kW to 500 kW and $1,000 for facilities 500 kW to 20 MW.[88] Outside of the Western region, Maryland does not charge anything for Level 1 (inverter-based systems ≤ 20 kW), charges $50 + $1/kW for Level 2 (systems ≤ 2 MW) and $100 + $2/kW for Level 3 and 4 applications, which are generally systems up to 10 MW.[89]

Similarly, FERC's SGIP includes a specific $300 fee that may be charged for pre-application reports.[90] Both Black Hills and Public Service recommended adopting this same $300 fee in proposed redlined rules offered during the stakeholder process.[91] However, the NOPR proposes to leave the fee for pre-application reports ambiguous and merely states, "[t]he utility may charge a fee for the pre-application report."[92] While this fee should also be based on costs, COSSA and SEIA believe the $300 identified in the FERC's SGIP is likely reasonable.

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85 *See*, the New Mexico Interconnection Manual. *Available at:* http://nmprc.state.nm.us/utilities/docs/NMInterconnectionManual2008.pdf.

86 *See*, OAR § 860-082-0025. *Available at:* https://secure.sos.state.or.us/oard/displayDivisionRules.action?selectedDivision=4084.

87 *See*, OAR §860-039-0010 to 0080. *Available at:* https://secure.sos.state.or.us/oard/displayDivisionRules.action?selectedDivision=4053.

88 *See*, Washington Administrative Code §480-108-030. *Available at:* https://apps.leg.wa.gov/WAC/default.aspx?cite=480-108-030.

89 *See*, COMAR 20.50.09.05. *Available at:* http://mdrules.elaws.us/comar/20.50.09.05.

90 FERC Small Generator Interconnection Procedures Section 1.2.2. *Available at:* *https://www.ferc.gov/industries/electric/indus-act/gi/small-gen/sm-gen-procedures.pdf?csrt=14442720646318007348*.

91 Proceeding No. 17M-0694E Opening Comments of Public Service, Attachment A at PSCo proposed Rule 3667(b)(2)(B); Opening Comments of Black Hills, Attachment 4 at Black Hills proposed Rule 3667(b)(2)(B).

92 NOPR Proposed Rule 3853(A)(IV).

3.2.4 Capacity Measurements Should Be in AC, Not DC

The Commission should add a provision under proposed Rule 3853(b) to make clear that in evaluating the maximum rated capacity of a system, the utility shall utilize the AC rating and not the DC rating. DC ratings are not representative of the maximum output capacity of the system, which is based on the efficiency of the inverter. The AC rating is what determines how much electricity is capable of being exported at any one time. COSSA and SEIA are not aware of any Colorado law that restricts capacity for any program or incentive based on MW-DC, but both utilities commonly use the DC rating for their own evaluations. Doing so artificially shrinks the sizes of allowable systems in the case of CSGs, forces systems into higher levels of scrutiny under various interconnection levels and makes it harder for NEM customers to meet 120% requirements. Because it is only the amount of energy that can be fed back to the grid that is important for interconnection purposes, the Commission should instruct utilities to look at a system's AC output instead of its DC rating. Indeed, there are a number of states that have adopted AC ratings as the relevant metric for interconnections.[93]

3.2.5 Changes to Level 2 Timing Should Not be Adopted, Instead Shorter Timelines are Necessary

The NOPR proposes to increase timelines for certain interconnection study processes, which move interconnection rules in the wrong direction. For example proposed Rule 3855(d)(II) proposes to <u>triple</u> the time that utilities have to perform a supplemental review. Interconnection timelines and the uncertainty companies face when they are missed, is a source of significant added cost to developers. As pre-interconnection agreement projects have no

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[93] For example, on August 9, 2017, the IURC issued General Administrative Order (GAO) 2017-2 which clarifies a number of definitions and terminology, including specifying that nameplate capacity refers to the aggregate output rating of all inverters measured in kW AC (*available at*, https://www.in.gov/iurc/files/GAO%202017-2%20Order%208-9-17_201708091350.pdf); *see also* proposed Arizona interconnection rules; time did not allow a comprehensive survey, but others exist.

certainty of being successful, construction financing is not available, and developers must fund all pre-interconnection work with expensive equity capital which can have between a 20-30% (or higher) cost of capital. As such, the period of uncertainty between submitting an interconnection study and receiving an interconnection agreement is a very high cost period for developers, in the end driving up costs for consumers.

Utilities now have significant experience with interconnection rules and processes. Also because of a higher number of capacity screens, utilities have a far greater understanding of what's on their system. For these reasons, timelines for interconnection studies should not be increasing, but rather should be decreasing. Doing so will result in far more business certainty for developers that will translate into, lower costs of capital, less risk, and overall faster delivery at less cost for the end use customers.

As such, COSSA and SEIA proposes the below modifications to timelines. Note that all days are in business days, not calendar days. Importantly, as discussed in the following sections, these timelines are only as important as their enforcement

Proposed Rule 3853(a)(IV)(A) gives utilities 20 days to provide a pre-application report. COSSA and SEIA suggest this can reasonably be completed in 15 business days.

Proposed Rule 3855(b) provides an initial review timeline for Level 2 studies of 15 days. COSSA and SEIA suggest this can reasonably be completed in 10 business days.

Proposed Rule 3855(c)(II) provides utilities up to 5 business days to notify ICs that the interconnection request cannot be approved without minor modifications at minimal cost; without a supplemental study or other additional studies or actions; or without significant cost. There is no reason after this determination is made that utilities should need an entire week to notify the IC. COSSA and SEIA propose that utilities have only 1 business day so that ICs can begin working on remedies immediately. The utility should then be required to convene a meeting with the IC within 5 business days (not 10 business days as in the rule) to discuss the results. These types of notices may very well lead to significantly increased development costs, or even project cancellation, so it is very important for feedback to be communicated expeditiously.

As noted above, Proposed Rule 3855(d)(II) triples the amount of time that utilities have to conduct a supplemental review from 10 business days to 30 business days. This proposed change would be very harmful to the interconnection process by increasing timelines by a month (assuming no delays and accounting for weekends). COSSA and SEIA understand that additional screens were added, however utilities have far more experience with these types of tests than they did years ago because of the sheer quantity of tests performed. Keeping supplemental reviews at 10 days is very important for smooth, efficient and cost-effective interconnections.

3.2.6 Level 3 Timelines Should Be Modified to Facilitate More Efficient Processes

In addition to the modifications of Level 2 timelines, discussed above, COSSA and SEIA recommend the following modifications with regard to Level 3 timelines.

Proposed Rule 3856(a)(I) requires utilities to host scoping meetings within 10 days after the IC is deemed complete. COSSA and SEIA suggest modifying this to a 5-business day requirement, with the possibility of extending the timeframe when both parties agree to do so.

Proposed Rule 3856(a)(IV) requires utilities to provide an interconnection agreement within ten days if the utility and IC agree to waive feasibility studies, scoping studies, and facility studies. However, such interconnection agreements are typically off-the shelf *pro forma* documents, where only individual costs (which will have been determined already) are added. There is no rationale for utilities taking up to two full weeks to provide these agreements.

COSSA and SEIA therefore recommend that this requirement be shorted to five days. This suggestion is consistent with Proposed Rule 3856(b)(VI), which requires utilities to provide interconnection agreements within 5 days when no system impact study is required and no facilities study is required after the conclusion of a feasibility study.

Proposed Rule 3856(c)(II) requires utilities to provide ICs a system impact study agreement along with cost estimates within 15 business days of transmittal of the feasibility study report. COSSA and SEIA suggest that this timeframe be reduced to 7 days, as these agreements are also off the shelf *pro forma* documents and costs are generally known because study processes are typically only slightly customized.

Finally, COSSA and SEIA suggest that timelines for the various studies themselves should be included in rules. Currently utilities have no deadlines to turn these studies around, which can be a major choke point for getting renewable projects interconnected. System impact and facilities studies should be set at no longer than 20 business days (1 month). This makes sense considering that by the time these studies are run, the utility has already gone through numerous studies already and are not starting from zero.

3.2.7 The Commission Should Include Penalties for Utilities that Fail to Meet Interconnection Deadlines, or Provide an Expedited/Simplified Complaint Process

The proposed rules and the above suggested modification on timelines is of little import without some form of consequence for missing deadlines. Currently ICs are penalized for missing certain deadlines in that their application may be deemed withdrawn,[94] but there is no similar consequence for utilities.

As noted above, COSSA and SEIA have received multiple reports of utilities regularly missing interconnection deadlines. Unfortunately, short of hiring an attorney and bearing the

[94] *See*, Proposed Rule 3853(c)(IV); 3853(e)(III).

expense of filing a formal complaint, there is no remedy for ICs in this situation. In previous stakeholder comments, the Joint Solar Parties suggested that if a customer can prove that a utility has missed more than two deadlines required by a particular interconnection request, the Commission should assess a civil penalty of up to $2,000 per day. This is consistent with Colorado Statutes at section 40-7-105(1), which states "[a]ny public utility which … neglects to obey, observe, or comply with any order, decision, decree, rule, direction, demand, or requirement of the commission … is subject to a penalty of not more than two thousand dollars for each offense." This is also consistent with the approach taken in Massachusetts, where the Commission levies financial penalties on utilities that miss interconnection timeline requirements.[95] Massachusetts utilities must file an annual report detailing the number of average business days from when an application is received to when an interconnection agreement is executed.[96] Any penalties must be paid by shareholders - not customers - providing clear financial incentives to meet interconnection timelines.[97] While COSSA and SEIA continue to believe that the civil penalty process is the most effective and can be administratively workable, we are also open to other methods to incent utilities to meet interconnection timelines or to set up streamlined processes by which disputes can be resolved.

In addition to penalties, the Commission should formulate a performance-based incentive for utilities to minimize interconnection timelines, which would directly tie utility revenues to the acceleration of the installation of DG projects in the drive to 100% renewable energy. In

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[95] *See*, Bird, Lori, Flores, Francisco, Volpi, Christina, Ardani, Kristen, Manning, David, and Richard McAllister. 2018. Review of Interconnection Practices and Costs in the Western States. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71232 at p. 41. *Available at:* https://www.nrel.gov/docs/fy18osti/71232.pdf.

[96] Barnes, Chelsea, Justin Barnes, Blake Elder, and Benjamin Inskeep. 2016. Comparing Utility Interconnection Timelines for Small-Scale Solar PV: 2nd Edition. Cary, NC: EQ Research. *Available at:* http://eq-research.com/wp-content/uploads/2016/10/EQ-Interconnection-Timelines-2016.pdf.

[97] Massachusetts Department of Public Utilities, D.P.U. 11-75, "Order on a Timeline Enforcement Mechanism." (Issued July 31, 2014.) *Available at:* *https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9233725*.

other words, utilities could be required to track interconnection timelines and report on aggregated results over a specified time period. If the average interconnection time is below a reasonable threshold, they could be financially rewarded. COSSA and SEIA have not fully developed this approach but would be open to discussing how this might be implemented in Colorado, similar to how incentives for meeting demand-side management targets work today. The Commission could also look to approaches in Hawaii to implement recent legislation that requires the Hawaii commission to "establish performance incentives and penalty mechanisms on a variety of issues including quality and timing of interconnections for third parties."[98]

Another possibility would be to establish an interconnection ombudsman who could act as a neutral arbiter of interconnection disputes on an expedited basis. This approach is used in California, where each of the three major IOUs has a designated ombudsman to resolve disputes specifically related to missed timelines.[99] It might make sense to combine this role with that of a process to resolve technical disputes, such as an independent engineer arbitration process or a technical dispute resolution process in California, which is different from the ombudsman process related to timelines described above.

3.2.8 Rules Should Include an Independent Engineer Review Process to Address Technical Disputes

In addition to addressing timing issues, the Commission should adopt an expedited, cost-effective, transparent, and fair process for managing technical disputes between interconnection consumers and utilities. The process should be developed to ensure that Colorado is using the most current industry standards for interconnection. Currently, dispute mechanisms in Colorado

98 Haw. Rev. Stat. Ann. § 269-16.1(b)(6)-(7) (Bill *available at*: https://www.capitol.hawaii.gov/session2018/bills/SB2939_SD2_.htm

99 Pacific Gas and Electric, "Electric Rule No. 21: Generating Facility Interconnections," Section K, Sheet 73. Effective June 8, 2017. https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf.

are not well tailored to addressing technical interconnection issues that often have a material impact on the timing and cost of interconnections and can often be contentious.

Indeed, over the past few years, many COSSA and SEIA members have experienced an increasing number of complex issues with utility interconnection processes, often involving utility-specific interconnection policies or practices not directly addressed to the level of specificity necessary in the Commission's Interconnection Rules, but increasingly relevant as more DG is added to the electric system, requiring the application of new industry standards on a faster basis. For example, several CSG developers have reported that they have projects that were built, financed, subscribed, and ready to energize, but instead sat idle for periods up to and including 7 months, delayed due to utility mismanagement of upgrades for varying reasons.

These utility-caused delays create significant costs for CSG developers that can run into the hundreds of thousands, and when combined across multiple projects, millions of dollars as well as creating customer inconvenience and reputational harm for the CSG developer, who is at the mercy of the utility. Each 2 MW solar garden kept waiting for interconnection by a utility costs developers approximately $50,000 a month in interest and lost revenues. When delays approach and exceed 6 months across multiple projects, these damages climb materially, and are sometimes insurmountable for small businesses.

Unfortunately, current dispute resolution practices have proven ineffective or impractical to resolve many of these issues. A litigated complaint process is costly, lengthy and of little value when utility delays cause costs to developers, as the Commission lacks authority to award damages. Litigated processes often cost far more in legal fees and time than the amount disputed when interconnection cost estimates are the cause of dispute. Less costly options, such as mediation before PUC staff, have proven to be less effective than desired because the process is not binding on utilities, and staff does not have the authority to issue penalties.

The lack of a technical process that can provide cost-effective binding resolutions results in higher-than-necessary interconnection costs in Colorado creates a barrier to new investment and diminishes access to DG resources. This leads to the material delay or even cancellation of projects, to the harm of customers, landowners, and developers. Over time without active oversight, interconnection barriers will have a dampening effect on Colorado's drive to 100% renewable energy, which must include customer driven DG as well as utility-scale renewables.

Other states can provide a helpful roadmap for Colorado because of their experience with other DG resources. COSSA and SEIA propose adopting a similar process in Colorado, as the state plans to dramatically increase adoption of DG projects to meet the administration's 100% renewable energy goals. Interconnections have and will continue to create areas of technical dispute between utilities and other parties, generally around timelines, costs, and methodologies of studies and the necessity and costs of interconnection upgrades themselves.

An independent engineer dispute-resolution mechanism provides developers and consumers with a process for having an expert third-party engineer review and issue rulings on interconnection-related disputes. Such a process in other states has prevented dozens of disputes from being brought to Commissioners, and when brought to the Commission on appeal (generally by the utility), the dispute comes with a detailed record and third-party engineer report to assist in the Commission's review. All of these aspects have brought tremendous value to other states, and could do likewise in Colorado.

3.2.9 Rules Should Define "Material Modifications" to Interconnection Applications

The NOPR's proposed Rule 3853(c)(6) deals with changes made to an interconnection application. The current rule deems any change to an interconnection request that is not agreed to in writing by the utility and the IC to be deemed an automatic withdrawal of an interconnection request requiring a new application and a new fee. The proposed rule improves upon the current rule by only deeming changes that have "a material impact on the cost or timing of the interconnection request" as those that would trigger an automatic withdrawal. COSSA and SEIA appreciate the Commission's recognition that some changes could actually be immaterial to the complexity of the interconnection request or could even lead to a simplification of the request, whereby an automatic withdrawal would make little sense.

However, the proposed rule as written is vague with respect to what constitutes "a material impact on the cost or timing of the interconnection request." Further, the proposed rule 3853(c)(6) states, "[a] new interconnection request shall not be required for minor modifications to DER data or equipment configuration or to the interconnection site of the DER." This sentence utilizes the term "minor modifications," to refer to changes to DER data and equipment configuration, but that term is a defined term in the NOPR's proposed rules that refers to modifications of the utility's distribution system.

In order to avoid confusion and ambiguity, the Commission should adopt a definition of "material modifications" that would trigger a withdrawal of an interconnection application and require a new request. In stakeholder comments, the Joint Solar Parties provided the following definition, which COSSA and SEIA continue to support:

> A "material modification" includes modification to equipment configuration or to the interconnection site of the generating facility at any time after receiving notification by the utility of a complete interconnection request that materially increases the cost, timing, or design complexity of any interconnection facilities

> or upgrades, or materially increases the cost, timing or design complexity of any interconnection request with a later queue priority date. A material modification shall include, but may not be limited to, a modification from the approved interconnection request that: (1) increases the size or output characteristics of the generating facility that is an exporting system by more than 10%; (2) changes or replaces generating equipment, such as generator(s), inverter(s), transformers, relaying, controls, etc., and substitutes equipment that is not like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment, where "like kind" is deemed to include replacements that do not change the capacity of the generating facility by more than 10%; (3) changes transformer connection(s) or grounding; and/or (4) changes to certified inverters with different specifications or different inverter control specifications or set-up. A material modification shall not include a modification from the approved interconnection request that: (1) changes the ownership of a generating facility; (2) changes the address of the generating facility, so long as the generating facility remains on the same parcel; (3) changes or replaces generating equipment such as generator(s), inverter(s), solar panel(s), transformers, relaying, controls, etc. and substitutes equipment that is a like-kind substitution in certification, size, ratings, impedances, efficiencies or capabilities of the equipment; (4) reduces the size or design complexity of the generating facility; and/or (5) increases the DC/AC ratio but does not increase the maximum AC output capability of the generating facility.

Without further guidance in the rules, COSSA and SEIA are concerned that utilities and ICs will not see eye to eye on what constitutes "a material impact on the cost or timing of the interconnection request" and will lead to costly and timely disputes.

3.2.10 Insurance Requirements are Unnecessary

Proposed Rules 3853(n) and 3854(c)(VII) continue to include insurance requirements on generating facilities that require ICs to procure insurance to protect both their own property as well as the utility's property for systems larger than 500 kW. As stated in previous stakeholder comments, the interconnecting customer is the appropriate party to determine the proper amount of insurance required for the generating assets. The existing rules are a relic of an era when little was known about the long-term operation of distributed energy systems. Today, we know the risk associated with these facilities is very small and nearly non-existent. Systems larger than these thresholds are most often installed on commercial and industrial sites, for which the companies and their financial backers are well aware of the relationship between risk and insurance requirements. In many cases the facility (including a residence) upon which a rooftop solar system is installed is already covered by insurance and rules requiring specified amounts of insurance are superfluous at best and costly at worst. Finally, FERC's SGIP does not contain any insurance requirements and such requirements do not exist in many other states. COSSA and SEIA recommend that the Commission remove all requirements on insurance and allow individual customers to determine their appetite for risk.

3.2.11 Point of Common Coupling or Point of Interconnection Should Specify Property Boundaries

The Commission's current rules define the term "point of interconnection" as "the point where the Interconnection facilities connect with the utility's system." In stakeholder comments, the Joint Solar Parties suggested also included a definition for the term "point of common coupling," which also appears in the Commission's current interconnection Rule 3667(i)(V), but is removed and replaced with "point of interconnection" in the proposed rules. Regardless of which term is used, language should be added to provide a clear point where the utility's system ends and the customer's private property begins. Doing so establishes the principle of BTM privacy discussed above. This is similar to the concept of a "demarcation point" used in the telecom industry.

Prior to the breakup of the Bell System, telephone utilities generally owned and operated all equipment that customers utilized on their premises. But when the telecommunications industry transitioned to a competitive market, a "demarcation point" between the customer premises and the network was defined. In the seminal 1956 case of *Hush-A-Phone Corp. v. United States*, the D.C. Circuit held that a telephone subscriber had a right to reasonably use his telephone in ways that are privately beneficial without being publicly detrimental.[100] This case was the first in a long line of jurisprudence that established a customer's right to self-supply equipment and to self-supply services that the telecom utilities had previously furnished, so long as such utilization caused no harm to the network.

Today, the Federal Communications Commission ("FCC") defines the "demarcation point" (also known as the point of interconnection) as "the point of demarcation and/or interconnection between the communications facilities of a provider of wireline telecommunications, and terminal equipment, protective apparatus or wiring at a subscriber's premises."[101] As electric utility service changes and more options become available for customers to satisfy their energy needs, the Commission should similarly find that a point of demarcation for electric service is warranted, just as the FCC has done. This could be accomplished either by adding a definition of "point of common coupling or by simply adding language to the definition of "point of interconnection" as follows:

> "Point of interconnection" means the point where the Interconnection facilities connect with the utility's system and represents the boundary between a customer's private property and the utility's system.

4 CSG Rules (Proposed Rules 3875-3883)

The NOPR leaves the CSG rules mostly unaltered except in two significant ways. First, the rules create a process by which customer can donate their excess CSG credits to low-income energy assistance organizations, such as EOC, which COSSA and SEIA generally support. However, is it important that such organizations communicate to low-income recipients that these donations come from solar generation. Nationally, Low-income Heating Assistance Programs ("LIHEAP") and the Department of Energy are working to move more of our

100 *Hush-A-Phone Corp. v. United States*, 238 F.2d 266, 269 (D.C. Cir. 1956).
101 47 C.F.R. § 68.3.

country's $3 billion annual LIHEAP investment from annual subsidy, towards opportunities for low-income customers to access long-term solar energy resources.[102] Commission decision making should support and encourage this evolution of energy assistance from annual subsidy toward investment in solar and distributed clean energy resources that provide long-term benefit for low-income customers.

Second, the proposed rules create an additional requirement that, "[n]ot less than 50 percent of the established purchases shall be reserved for residential, agricultural, and small commercial customers." While COSSA and SEIA fully support the Commission's intention to ensure that CSG subscriptions are available to residential, agricultural, and small commercial customers who have been traditionally underserved, we are gravely concerned that this requirement alone, without any corresponding market reforms will have the unintended effect of severely damaging the CSG market in Colorado, making CSGs more expensive, harder to finance, less competitive with similar utility offerings, and ultimately less available for all classes of customers. COSSA and SEIA present proposals below that other states have adopted, that can resolve the Commission's desire to serve these customers, while not hurting the program.

Smaller residential and commercial customers require significantly more resources to subscribe and maintain. For example, the cost is significantly higher to sign up, bill, manage transfer requests, etc. of 1,000 homeowners as opposed to 10 large debt rated municipal clients that never change a billing address. Furthermore, the cost of financing is higher, as the financial community ascribes more risk to homeowner credit and transferability, and thus charges higher interest rates. Lastly, many tax equity investors and debt providers will not even offer financing

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[102] U.S. Department of Health and Human Services, "LIHEAP and WAP Funding." *Available at:* https://liheapch.acf.hhs.gov/Funding/funding.htm.

to residential and low-income customer groups, which by reducing the size of the market for capital, also increases costs.

Instead of simply requiring a 50% carve-out for the most expensive customer classes to serve, the Commission should reform the CSG rules to provide opportunities for the CSG market to grow and cover the costs of addressing underserved market segments. The Commission posed the following question in the NOPR: *"[h]ow should the Commission best ensure that CSG subscriptions are available to residential, agricultural, and small commercial customers?"* In the sections below, COSSA and SEIA provide our response.

4.1 How should the Commission best ensure that CSG subscriptions are available to residential, agricultural, and small commercial customers?

The Commission posed the above question in the NOPR. In the sections below, COSSA and SEIA provide several specific suggestions intended to make CSG subscriptions more widely available to all classes of customers.

4.1.1 Utilities Should Be Required to Provide Standard Offer REC Prices Adders for Underserved Market Segments

In addition to the 50% requirement, Proposed Rule 3882 (a) states, "[t]he utility may propose a standard offer price for the purchase of RECs from residential, agricultural, and small commercial customers." Rather than creating a 50% mandate, COSSA and SEIA support the approach of instituting a standard-offer credit adder as a positive means to cover the costs of serving smaller customers, who are inherently more expensive to acquire, service, and finance. This policy should also include a standard offer REC price for low-income customers. This will allow the industry to serve these customers in more equal proportions. This approach has recently been implemented in Minnesota without any prescriptive capacity set-asides and has resulted in a market that is now shifting to a more balanced blend of customers. Similarly, the Illinois and New York markets also offer adders to cover the costs of smaller customer classes.

Over the past years of gaining experience in CSGs across multiple states, COSSA and SEIA members have reported there is a clear explanation for why the vast majority of capacity in the Colorado program is allocated to large, credit-rated organizations: most financiers will not accept what they view as "residential risk" at all. Most financiers will not finance community solar projects that have a large residential subscriber base because they perceive the risk to be significantly higher than it would be with a commercial-only portfolio. They are concerned about the potential for consumer complaints, customers moving, dropout, and how thousands of customers would react to changes in Public Service or PUC policy over the term of a contract, among other things.

All in, the result of this perception among the financial community is a significantly smaller pool of capital for projects with residential subscribers. This smaller pool of financiers, and perceived increased risk of serving these customers, directly results in higher borrowing costs for projects with residential subscribers. And just like on a home mortgage, a 2.5% increase in the cost of capital for a solar project leads to a massive increase in total lifecycle costs. As noted above, in addition to the increased cost of capital, the cost of subscribing and servicing thousands of customers is far more than subscribing and servicing a handful of commercial accounts.

However, the law encourages that community solar make solar accessible to all customers.[103] While the fixed bill credits do have a slightly higher rate for residential and small commercial customers, it is not sufficient, evidenced by the stark disparity between residential and commercial subscribers in the program. This is because developers either could not afford

103 C.R.S. § 40-2-127.

the higher cost of capital, or they could not cost-effectively acquire and manage the necessary volume of subscribers for the long-term at low rates. Simply put, in order for community solar to truly be accessible to all, the benefit of offering it to residential and other under served subscribers has to outweigh the risk – whether real or perceived – for both the developers and the financiers.

While COSSA an SEIA strongly oppose a 50% capacity mandate, if the Commission nevertheless adopts such a prescriptive rule, utilities should be required, not just permitted to propose a standard offer REC price which can be fully litigated through a RES compliance plan application.

4.1.2 CSGs Should Be Allowed to Interconnect Outside of a Utility's RES program

As advocated by multiple parties in the consensus RES Rule redlines provided during the stakeholder process, one of the best ways to create additional CSG capacity that can be utilized by smaller customers is to allow CSG interconnections outside of a utility's RES Plan. This would also have the effect of allowing customers of such CSGs to keep their RECs, which as described above, is available in Public Service's competing Renewable*Connect program.

For these "interconnection only" CSGs, there would be no annual program caps so long as there was sufficient customer demand for the product, in line with the statute's requirement that the product be available for customers who need an alternative to rooftop solar. This concept is consistent with the original intent of the statue, as recognized by the ALJ presiding over the original CSG rulemaking in Proceeding 10R-674E, and is particularly relevant now in the circumstances where customers wish to keep their RECs rather than be forced to sell them to the utility.

In Recommended Decision No. R11-0784, ALJ Adams provided a careful statutory analysis of § 40-2-127, noting the statute "specifies that QRU payment for output is via a net metering bill credit that does not value the REC, only energy."[104] The ALJ noted § 40-2-127(5)(IV)(E)(b)(I) requires a QRU to purchase CSG RECs only once the CSG is part of an approved RES Compliance Plan.[105] Ultimately, the ALJ held:

> [A] REC generated by a CSG may have life outside of a QRU acquisition plan. When unsubscribed, it is sold to the QRU with the energy, at the statutorily mandated price. Once subscribed, *the subscriber is not obliged to sell the REC to the QRU* unless and until it is incorporated into an acquisition plan approved by the Commission and relied upon for compliance by the QRU.[106]

As a result, the ALJ recommended adoption of the Rule language that is now reflected in the consensus RES Rule redlines at Rule 3665(c)(IV), which has been slightly modified to make clear that a customer can retire, sell, or trade their RECs. This policy would leave the door open for a customer to voluntarily sell their RECs to the utility under an open REC purchase offer or otherwise dispose of them as they wish.

The changed market costs for solar over the past decade, as well as the market demand have proven to be far in excess of current supply and justifies a Commission review of the ALJ's reasoning above in order to fulfill the intent of statute. Many COSSA and SEIA members report that they have enough demand to fill years of capacity at the current constrained amounts, proving that customer demand is not being met under the current rules.

Allowing CSGs to interconnect outside of a utility's RES compliance plan is consistent with the CSG statute and is necessary to achieve its objectives. The General Assembly explicitly directed the Commission to "formulate and implement policies" that "encourage … ownership in community solar gardens by residential retail customers and agricultural producers, including

104 Decision No. R11-0784, at ¶ 184.

105 *Id.* at ¶ 187.

106 *Id.* at ¶ 188. Emphasis added.

low-income customers, to the extent the Commission finds there to be demand for such ownership."[107] The CSG statute also includes a legislative declaration that explicitly references residential customers, commercial entities, renters, low-income utility customers, and agricultural producers as groups that were intended to benefit from CSG deployment, participation and ownership.[108] The Commission has acknowledged this directive. For example, in Decision No. C16-0747, the Commission stated:

> The [CSG] statute was enacted in order to provide broader participation in CSG, which was to extend not only to commercial entities, but more importantly, to residential customers, including renters, low income utility customers, and agricultural producers. This is how the overall statutory scheme should be interpreted and the statutory goals determined.[109]

Currently, most CSG capacity is subscribed by larger commercial customers.[110] Indeed, part of the reason that the PUC adopted a settlement in Proceeding No. 13A-0836E in 2016 was because the bill credit methodology in place prior to the Settlement "created an incentive for CSG developers to seek out commercial customers for whom subscribing to a CSG is economic even at a negative REC price."[111] While the Commission properly addressed the bill credit issue that most egregiously benefitted large commercial customers, it left in place the ability for the utility to accept negative REC bids, which force a competitive drive to reduce subscription and financing costs. As a result, it is clear that commercial and municipal customers are still the focus of some CSG subscriber organizations.[112]

When CSGs are constrained to a utility program that forces subscribers to give up their RECs, especially at a negative price, CSG subscription availability is limited, making them out of reach for residential, agricultural, and low-income customers. When utility CSG programs

107 C.R.S. § 40-2-127(5)(a)(IV)(B).
108 C.R.S. § 40-2-17(1).
109 Decision No. C16-0747, at ¶ 44.
110 Proceeding No. 17D-0082E, Tr. 204:16-19.
111 Decision No. C16-0747 at ¶ 10.
112 Proceeding No. 17D-0082E, Tr. 204:12-19.

force developers to give up RECs, sometime at negative prices, it adds additional costs and forces CSG developers to cut costs in other areas. This, in turn, can limit a CSG developer's ability to cover the costs of subscribing, billing, financing, and maintaining transfers over 20 years for residential, low-income and agricultural subscribers. By allowing CSG interconnections outside an approved RES Plan more capacity will be available to serve the need of smaller customers. Similarly, by allowing CSG interconnections outside of an approved RES Plan and with a standard-offer adder to cover the costs of these customer classes, the program structure will be changed sufficiently to allow companies to serve these market segments.

Unlike the proposed rule to simply set aside 50% capacity, this approach would create more overall capacity in the market that would be available for subscription by smaller and larger customers alike, in line with the intent of all customers having access to a CSG product just in the way that they do for a rooftop solar option. This would allow CSG developers to meet the needs of all market demand instead of confining them to pick the customers that are least cost to serve. The notion continued in the CSG statute that it is intended to "[p]rovide Colorado residents and commercial entities with the opportunity to participate in solar generation in addition to the opportunities available for rooftop solar generation on homes and businesses" is fundamentally at odds with the current policy of a limited CSG market that is not able to meet the demands in the marketplace.[113]

4.1.3 Alternatively, Rules Should Require A Standard Offer Instead of an RFP for CSG Selection Within a Utility's Program

While COSSA and SEIA's primary recommendation is to allow CSGs outside of a utility's program, another approach could be to require utilities to offer standard rebates for CSG RECs instead of hosting RFPs. The current REC-driven RFP process has failed, with years of

[113] C.R.S. § 40-2-127(1)(b)(I).

data, to encourage CSG ownership by a diverse variety of customer types because CSGs compete for the right to build a project by offering the lowest possible price. This has led to the existence of negative REC prices being bid just to ensure CSG developers have a seat a the table. Similar trends are now reflected with the low-income CSG RFPs, with the average bid price awarded within the 2018 capacity at a negative price,[114] which is very concerning for the successful implementation of this program and impact for participating low-income customers. This RFP process is simply not working. However, there is nothing in the statutes or the Commission's rules that allows or requires an RFP process.

Indeed, the RFP-based process is a creation of utilities. Public Service first proposed to acquire CSGs through a competitive solicitation in its 2012 RES Compliance Plan.[115] At the time that Public Service filed its 2012 RES Compliance Plan, the Commission's rules implementing the new CSG statute were not yet final.[116] Public Service's proposal to acquire CSGs through an RFP process was not without controversy, and was opposed by the Solar Alliance.[117] In rendering a decision on Public Service's 2012 RES Compliance Plan, the Commission did not make any specific findings as to the propriety of the RFP proposal.[118] With this implicit approval, Public Service undertook its RFP solicitation for CSGs later in 2012.[119] This historical context demonstrates the RFP model for CSG acquisitions is not mandated by statute or rule. Rather, it is a creation of utilities, and thus can and should be abandoned.

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114 As governed by the Non-Unanimous Comprehensive Settlement Agreement in Proceeding 16AL-0048E, the REC incentive to be paid for standard offer participants will be the average annual awarded REC for the low-income CSG RFP plus $0.01/kWh. In the Q1 General Stakeholder Group meeting on March 12th, Xcel reported the 2018 incentive for low-income standard offer at a REC price of $0.0052/kWh (correcting a typo in the presentation distributed prior to the meeting), meaning that the average REC price for awarded low-income CSG bids in 2018 was negative.

115 Proceeding No. 11A-418E, RES Compliance Plan, Vol. 1 at pp. 48-52. *See also*, Proceeding No. 11A-418E, 2012 Renewable Energy Standard Compliance Report, at p. 13 (reporting the Public Service acquired 4.5 MW of CSG capacity through the RFP process in 2012).

116 Proceeding No. 11A-418E, RES Compliance Plan, Vol. 1, at p. 51.

117 Proceeding No. 11A-418E, Higgins Answer Testimony, at 14:23-15:3.

118 Proceeding No. 11A-418E, Decision Nos. R12-0261, C12-0606.

119 Proceeding No. 11A-418E, 2012 Renewable Energy Standard Compliance Report, at p. 13.

Given the Public Service's management and operation of Renewable*Connect, it is also inappropriate for it to manage an RFP process for CSGs, which are a directly competing product to its own. In addition to the advantages Public Service is given over CSGs with Renewable*Connect, an RFP for CSGs run by Public Service also allows the it to pick its competitors from the solar industry. This raises significant anti-competitive concerns, and is a reason in itself for ending the utility-managed RFP processes for Retail DG.

Creating standard offers for CSGs in a utility program with a positive rebate would eliminate the sunk costs preparing and submitting RFPs as well as the business uncertainty. The elimination of negative RECs by not holding an RFP would properly compensate CSG developers for the beneficial attributes of the renewable energy that they provide and would create more financial headroom to serve smaller, costlier to acquire and serve, customer segments, including low-income customers.

4.2 The Commission Should Consider Additional Modifications to Improve CSG Rules

In addition to the suggestions provided above to create more CSG capacity available to serve smaller customers, COSS and SEIA provide additional suggested modifications and recommendations below to improve the CSG Rules that have the effect of streamlining customer experience, reducing costs for subscribers by reducing project costs, and reducing financing costs by creating more certainty of rates.

4.2.1 Construction Timetables Should Not Be at the Sole Discretion of Utilities

Neither the current CSG Rules nor the proposed rules include specific timelines or construction requirements for project completion. Nevertheless, Public Service has taken it upon itself to require that all CSGs that win an RFP be completed within 18 months. COSSA and SEIA have anecdotal information that only one CSG on the Public Service system was ever completed within this 18-month timeframe. Public Service ***imposes penalties*** when its time period is not met, which has led to much confusion and consternation among CSG developers. As noted in the interconnection sections above, there are many reports of utilities delaying interconnections of CSGs, creating massive costs for CSG developers.

While there is certainly a good public policy reason to require that CSGs meet reasonable construction timelines, the time period should not be in the sole discretion of utilities, which are in direct competition with CSG providers. Further, 18 months is not a reasonable requirement given the cold winters in Colorado that can leave the ground frozen and stall construction for many months at a time and especially when utilities are also causing delays.

To provide clarity and consistency between the utilities the Commission should adopt a rule that makes clear that utilities cannot require CSG construction to be completed in less than 24 months. This is the amount of time that CSGs in Minnesota are afforded to compete construction and is a more realistic timeframe that reflects typical project development and construction time frames. Further, any penalties that are assessed for failing to meet this deadline should reflect the costs that are caused by the delay and should be properly vetted in a RES compliance plan instead of being left entirely within a utility's discretion.

4.2.2 The Term of a Producer Agreement Should Reflect the Life of a CSG

Neither the current CSG Rules nor the proposed rules include specific requirements regarding the proper term of a producer agreement. As a result utilities typically offer a 20-year term on CSG producer agreements. Colorado Statutes at section 40-2-124(1)(f)(V) requires that, "[a]ll contracts for acquisition of eligible energy resources shall have a minimum term of twenty years; except that the contract term may be shortened at the sole discretion of the seller." While 20-year contract terms meet the statutory floor, the Commission clearly has the authority to require longer contract terms when there is a sound reason to do so. A 20-year producer agreement makes little sense for a CSG where the actual useful life of the PV facility is expected to be in the 25-40 year timeframe.[120] Similarly, many CSG customers plan on using energy for longer than 20 years, and would like to secure their energy source and know that it will not suddenly disappear.

COSSA and SEIA recommend that the Commission include a new rule to require that utilities offer CSG producer agreements for a minimum term of 25 years, with the option for subscriber organizations to automatically extend those agreements in 5-year increments if they can demonstrate that customers wish to continue subscribing, and that the CSG facility is in good working order and still in compliance with the standards set forth in the interconnection agreement.

4.2.3 CSG Availability is Tied to Improved Interconnection Procedures

Without making any additional suggestions, COSSA and SEIA reiterate the importance of good interconnection policies that are enforceable and efficient while maintaining system safety and reliability. All of the suggestions provided in the Interconnection Rules section above will have a profound impact on the ability for CSGs to successfully and cost effectively come on line. CSG developers in particular have run into substantial delays from utilities in getting projects online and have little to no recourse while their projects sit idle.

4.3 CSG Programmatic Issues Belong in a RES Plan Application

The NOPR requests specific input on the following question:

> *Should the Commission continue to establish the acquisition targets for CSGs (i.e., the statutorily required minimum and maximum) as part of the utility's RES compliance plan proceeding? Specifically, should the Commission set the acquisition targets for the first four years of the utility's ERP pursuant to*

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120 National Renewable Energy Laboratory, "Useful Life. "*Available at:* https://www.nrel.gov/analysis/tech-footprint.html.

Proposed Rule 3656(b)? Or should the Commission instead set the minimum and maximum levels in other proceedings?

Consistent with prior stakeholder comments, COSSA and SEIA continue to support separation between RES Plan proceedings focused on DG resources (including CSGs) driven by customer choice, and Electric Resource Plans ("ERPs") that focus on larger scale acquisitions driven by system needs. As such COSSA and SEIA support proposed Rule 3656(b), which modifies the requirements for the filing of a utility RES Plan and removes the requirement that they be filed as part of QRU's ERP.

The proposed rule properly recognizes that the growth of DG resources is primarily customer-driven by individual choices to self-supply clean energy. A utility has significantly less control over the addition of DG resources on its system than it does for larger scale resources that it can self-build or procure by entering into bilateral contracts with independent power producers ("IPPs"). The RES Plan therefore does not focus on acquiring energy for the utility's system needs, but rather focuses on the acquisition of RECs from DG resources to achieve RES compliance. The RES Plan should also include decisions on significant DG and CSG policy issues such as the terms and conditions of producer agreements, the proper value of standard REC offers for various types of customers and the minimum and maximum capacity for a utility CSG program.

5 <u>RES Rules (Proposed Rules 3650-3665)</u>

The biggest proposed change to the RES rules are to move the rules related to NEM, CSGs and interconnection into their own rules section and move many of the rules related to large-scale renewable resources, typically acquired in an ERP to that rule section. COSSA and SEIA generally support these structural shifts. The other major shift in the RES rules, discussed above, is the proposal to allow utilities to count NEM systems that did not participate in the

Solar*Rewards program (and therefore did not receive an incentive and therefore those customers retain their RECs), as a means by which QRUs cause eligible energy to be generated and therefore towards compliance with the RES. COSSA and SEIA strongly oppose this change for the reasons discussed in the NEM section of these comments. Indeed, there is nothing required in the rest of the RES rules or that a QRU would need to file in a RES Compliance Plan that would *cause* NEM-eligible DG to be installed. Rather, the proposed RES rules properly focus on incentive programs to spur DG development where such incentives make sense. Incentives have become less important for promoting residential non-low-income onsite solar, but other DG market segments continue to struggle.

5.1 The Commission Should Adopt Proposed Rules Regarding Scope and Timing of RES Compliance Plans and Modify Requirements as to Their Content

The proposed RES Rule 3656(b) properly defines and maintains the scope of a RES compliance plan proceeding as "the venue for the Commission's consideration of: (1) programs intended to encourage the development of retail renewable distributed generation; (2) the statutory minimum and maximum purchases from CSGs pursuant to § 40-2-127(5)(a)(IV), C.R.S.; and (3) voluntary offerings related to renewable energy such as Public Service's Windsource program."[121] Further, the proposed rule strikes the requirement that RES Plans be filed within an ERP and instead moves many of the large-scale RES resource issues that properly belong in an ERP to that section of rules.

Proposed Rule 3656(c)(VI) requires that the utility's RES compliance plan include "[t]he programs the investor owned QRU intends to offer customers to comply with the RES or encourage the development of cost-effective retail renewable distributed generation during the first four years of the applicable resource acquisition period." This proposal is more or less

[121] NOPR at para. 138.

consistent with current practice and properly recognizes that standard rebate offers are not the only vehicle to encourage retail DG. COSSA and SEIA continue to recommend however that this rule be modified to require QRUs to focus their Retail DG programs on underserved market segments where DG uptake has lagged. Despite recent growth, the solar industry faces significant challenges in Colorado, particularly in the commercial and low-income market segments.[122] Similarly, advanced technologies such as energy storage, PV tracking systems, geothermal, and west facing solar are not always cost effective, even though such technologies can provide significant grid benefits.

COSSA and SEIA also generally support proposed Rule 3656(c)'s additional requirement that "[t]he QRU shall include the application forms, standard agreements, and general procedures for the QRU's programs and for the interconnection of renewable energy resources pursuant to the Interconnection Rules and Standards." The devil is often in the details when it comes to qualifying or applying for utility programs and securing a place in the queue. However, as stated in the interconnection rules section, COSSA and SEIA suggest that utility-specific interconnection standards and guidelines be contained in tariff filings. This reflects the fact that not all interconnections are for renewable energy resources and provides a forum to examine just and reasonable charges assessed as application or other interconnection-related fees. While COSSA and SEIA believe that AL filings are a superior mechanism to review utility-specific interconnection procedures, we nevertheless appreciate the Commission's inclusion of this requirement and support the overall concept.

In a similar vein, COSSA and SEIA are concerned about the elimination of current Rule 3657(b)(X), which currently requires utilities to include "[p]roposed request for proposals

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[122] Based on reports from COSSA and SEIA members and information provided by Public Service at its March 12, 2019 stakeholder meeting.

including any standard contracts the investor owned QRU plans to use as part of a competitive acquisition process." While COSSA and SEIA generally oppose RFPs for small-scale Retail DG resources, current utility practice does include RFPs for CSGs and for incentives in the large Solar*Rewards program. To the extent that utilities continue to propose RFPs for Retail DG programs, it is important that the RFPs be properly vetted. This is especially important where the monopoly utility, which is in direct competition with Retail DG providers, also acts as the gatekeeper for their ability to participate in the market. The structure of the RFP, its requirements and associated bid fees can often serve as a means by which utilities impose certain rules or restrictions on Retail DG providers and must be properly vetted.

5.2 Standard Offers for the Purchase of RECs is Good Policy for Retail DG

Proposed Rule 3657(b) allows a QRU to "establish one or more standard offers to purchase RECs from on-site solar systems that are eligible for net metering." This proposed rule contemplates the proper way for QRUs to be able to utilize onsite NEM-only generation for compliance with the RES. In other words, QRUs must compensate NEM customers for use of the renewable energy attributes associated with customer or third-party owned or financed systems. Without compensation, taking credit for customer investments is fundamentally unfair. While COSSA and SEIA support this rule in concept and believe it is consistent with statutory directives, we are concerned that it will never be utilized in light of the proposal to allow utilities to count NEM-only generation for RES compliance. In light of that proposed policy, utilities will have no incentive to purchase RECs.

5.3 Standard Rebate Offers Are Appropriate in Some Contexts

The Commission posed the following question:

> *Given that § 40-2-124(1)(e)(I.5), C.R.S., states that the Commission may set the SRO at a lower amount than $2.00 per watt "if the Commission determines, based*

upon a qualifying utility's renewable resource plan or application, that market changes support the change," should the Commission adopt this proposed rule given the applications and RES compliance plans filed by Public Service in Proceeding Nos. 11A-135E, 11A-418E, 13A-0836E, 14A-0414E, and 16A-0139E and by Black Hills in Proceeding Nos. 12A-1207E, 13A-0445E, 14A-0535E, and 16A-0436E?

The statute appears to require that the decision to set the standard rebate offer below $2.00/watt must be made in each IOUs' RES plan filing, not by rule. While a $2.00/watt upfront rebate is clearly not needed anymore for residential onsite solar, there are still market segments or technologies where upfront rebates do make some policy sense. For example, the SRO price is currently being used to structure the up-front incentive leveraged by the Colorado Energy Office Low-income Solar Rooftop Pilot, an innovative program reducing low-income energy burden through solar in tandem with weatherization measures.[123] The amount of any standard rebate offers, if any, however should be determined on a case-by-case basis.

5.4 Responses to Additional High Level Policy Questions

COSSA and SEIA provide responses below to some of the Commission's high-level policy inquiries.

What is the appropriate and discrete role for the Commission in setting acquisition targets or capacity size limits to support the growth of retail renewable distributed generation and the growth of CSGs?

Where the utilities or other interested stakeholder propose to utilize customer dollars to incent the growth of Retail DG (which includes CSGs), it is entirely appropriate for the Commission to set acquisition targets and capacity size limits. However, where customers choose to forego incentives and to access Retail DG through NEM-only arrangements (or CSGs outside of a utility incentive program), the Commission should not impose limits. To do so would have the practical effect of limiting customer choice and restricting a customer's right to self-generate.

[123] *See*, Colorado Energy Office, "Rooftop Solar PV." *Available at:* https://www.colorado.gov/pacific/energyoffice/rooftop-solar-pv.

Indeed, the ultimate goal should be to provide Coloradans with access to DG with little to any intervention.

> *Should it be necessary for the utility to specify in each RES compliance plan its plan to acquire specifically: retail renewable distributed generation from residential retail customers; retail renewable distributed generation from nonresidential retail customers; wholesale renewable distributed generation; and eligible energy resources to be acquired pursuant to the ERP Rules?*

As discussed above, QRUs should be required to submit RES compliance plans that include plans to spur DG in low-income and other underserved market segments. As such is it important to identify which market segments are underserved and then to the extent that they are, design plans to encourage cost-effective Retail DG. "Acquisitions" should refer only to acquiring RECs from these resources so that they can be utilized for compliance with the RES. Without a mechanism to provide an incentive or purchase a REC it makes little sense for a utility plan to set target on how many customers will choose to self-generate because (absent erecting barriers) QRUs have little to no control over thee individual choices.

6 ERP Rules (Proposed Rules 3600 – 3617)

As noted in the introductory section, COSSA and SEIA largely support the Commission's changes to the ERP Rules and especially proposed Rule 3604(k), requiring, "[a]n assessment of potential cost-effective early retirements of utility-owned resources …." In addition COSSA and SEIA support creating additional processes and opportunities to review and critique various studies that are often significant inputs in modeling of solar and storage resources, with huge impacts on the competiveness of those resources. Similarly, COSSA and SEIA support more transparency around the modeling outputs and suggests that the Commission take this up in a separate proceeding prior to the ERP. Finally, COSSA and SEIA suggest that

Commission Rules require that all of the costs of carbon be calculated and included in analysis regarding the need for and selection of additional system resources.

6.1 The Commission Should Adopt Rules to Require Evaluation of Existing Resources

In the NOPR, the Commission posed the following question:

> *Would the inclusion of contracted resources in the utility's assessment of existing utility resources pursuant to Rule 3607 create uncertainty or risk for developers and dampen the competitive market in Colorado?*

Yes, there is certainly a significant risk that if IPPs fear their contracts will be terminated early, without proper compensation, that it would have a chilling effect on the ability for Colorado to attract competitive low-cost power. It is important that the Commission consider the impact such proposals could have on the competiveness of the IPP market in Colorado within the context of broader state objectives with respect to emissions and renewable energy. Therefore it is appropriate the Commission gives preference to early retirement of aging polluting resources whose retirement aids these goals.

While it is prudent to explore the costs and benefits of early retirements of all existing resources, regardless of ownership, the Commission does not have the authority to interfere with executed contracts or to force an unregulated IPP to retire its facility. To preserve and avoid harm to the substantial investment – current and future – in Colorado's IPP market, the Commission must uphold all contracted utility obligations to the IPP regardless of any Commission or utility review of the competitiveness of the resource, through the full term of the contract.

Nevertheless, it may make economic sense in some cases for a utility to cease taking power from an IPP even if it continues to fulfill its contract obligations. One example is where an IPP provides capacity and receives capacity payments but where customers bear all fuel costs.

If a new low cost resource can bid below the variable fuel costs of running that IPP facility, it may make economic sense to order a utility to cease taking power under a power purchase agreement, even though the capacity payments under the contract would be honored.

6.2 The Commission Should Require a Separate Proceeding to Examine of Input Studies

The Commission posed the following question:

> *Should the Commission open a proceeding for each utility in which the Commission may receive certain studies associated with the utility's next electric resource plan filing prior to the initial ERP filing?*

In short, yes. The lack of scrutiny over these important studies has led to confusion and frustration in previous ERPs. The utilities develop complicated studies regarding he appropriate effective load carrying capabilities of various resources, the cost of integrating wind and solar and the value that should be placed on large-scale energy storage systems. These are critical inputs that can have a big impact on the cost effectiveness of resources bid into the ERP and it is important that they be subject to scrutiny, review and approval prior to the start of an ERP, where many other complicated issues often obfuscate the analysis of these studies, if they are filed and presented by utilities at all.

In comments to the Independent Evaluator's ("IE") report in Public Service's most recent ERP COSSA (then COSEIA) raised several concerns with assumptions about solar and wind integration assumptions that Public Service used in evaluating bids.[124] For example, the IE explained in his Report,

> [t]he Company developed detailed storage modeling parameters to estimate [1] wind integration cost savings, [2] quick start capability credits, and [3] coal cycling credits that stand alone storage, CTs with storage, solar with storage, and wind with storage should receive as well as the firm capacity credit of each of the

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[124] Proceeding No. 16A-0396E, The Colorado Solar Energy Industries Association's Comments on the Report of the Independent Evaluator at pp. 4-6 (August 2, 2018).

configurations."

While COSSA and SEIA appreciate that Public Service recognized certain benefits of energy storage bids and that it provided corresponding credits, the details of how those credits were calculated and assigned to specific bids was not properly vetted and therefore not disclosed to bidders prior to the RFP. Wind integration cost studies were provided in Phase 1 of the ERP, but COSSA and SEIA believe that they were not given the proper scrutiny due to the many other litigated issues.

In his report, the IE recommended that Public Service be ordered to revise its renewable integration studies for the next ERP and that such studies should more carefully evaluate the specific value of varying configurations of battery storage.[125] Similarly, the IE report explained that Public Service's modeling included a 1,000 MW solar limit, that was never properly evaluated or explicitly approved by the Commission. As a result, COSSA recommended that in the future, Public Service should not be allowed discretion to impose artificial limits on any generation technology absent an approved empirical study that is open to public scrutiny.

For these reasons, COSSA and SEIA strongly support the Commission adding a rule to require utilities to file studies several months prior to submission of the initial ERP filing in the form of an application for approval.

6.3 Modeling Must be More Transparent

Many stakeholders and the Commission have expressed repeated concern regarding a lack of access and transparency issues surrounding utility modeling in a variety of forums and proceedings. Utility modeling guides Commission decisions in approving solar and wind integration cost studies, in establishing demand-side management funding and programs, in setting various rates including those for small qualifying facilities ("QFs") below 100 kW, in

[125] Proceeding No. 16A-0396E, Report of the Independent Evaluator (Conf.) at pp. 44-45 (July 13, 2018).

establishing cost effective resource plans in the context of an ERP and in other critical decisions implicating multiple critical consumer interests. Yet as far as COSSA and SEIA are aware, neither the Commission nor intervenors generally evaluate all of PSCO's modeling inputs, and certainly do not run parallel models to independently verify utility results. This is despite the fact that the Commission has previously required Public Service to provide the inputs used in the base case PLEXOS model.[126] Solar advocates have repeatedly expressed concern that utility modeling does not accurately model the operation of the Public Service system in ways that could undervalue solar resources.[127]

Due to the rise of energy storage technologies and the more granular impacts such facilities can have on utility systems, more complicated modeling will be needed to account for hourly marginal system costs in the future. As such, the Commission and interested parties need to take the time to more closely examine the model and its inputs to gain experience with the complex iterative process.

In the NOPR, the Commission posed the following questions:

> *What steps should the Commission take to improve the accessibility of the results of the bid evaluation and modeling in Phase II? Should these steps be codified in the ERP Rules*?

In general, COSSA and SEIA believe it is necessary for the Commission to explicitly require that IOUs purchase modeling software licenses that allow them to share results and provide for the ability of intervenors to run parallel models for verification.

> *Should this rulemaking proceeding be the venue for examining the specific software models that the utilities will use in their future ERP proceedings, or should the Commission initiate separate proceedings to examine these models?*

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126 Proceeding No. 13AL-0958E, Decision No. R15-1177 at p. 36, ¶ 111.
127 Proceeding No. 18AL-0808E, Vote Solar Protest at p. 6.

No. These issues are far too complex and technical to be effectively addressed in this already complex and massive rulemaking proceeding. Instead, the Commission should open a separate proceeding to examine modeling requirements and access issues prior to the start of the next ERP cycle. For example, details need to be worked out regarding how models can take into account ancillary benefits provided by energy storage and other resources to properly evaluate their cost effectiveness.

6.4 Rules Should Incorporate a Cost of Carbon

COSSA and SEIA appreciate Commissioner Koncilja raising the question in her concurring opinion on how to best capture the cost of carbon in modeling. In short, COSSA and SEIA continue to support the proposed rule changes advocated by the Institute for Policy Integrity at New York University School of Law that require utilities to evaluate the full impacts of greenhouse gas emissions.[128] The Commission's broad authority to protect the public interest and to effectuate the carbon reduction goals of the State of Colorado necessitates that it holistically consider impacts from all generation resources.

The Commission has previously held that it "has the authority to consider externalities in resource planning proceedings, regardless of whether the associated costs flow directly to customers as utility revenue requirements recovered through rates."[129] The cost of carbon and its impacts on society are real costs. The Commission's duty to protect the public interest goes beyond just examining utility rate impacts. We are well past the time for drastic action on climate change. As such, COSSA and SEIA fully support including all costs of carbon in the analysis of resource acquisition decisions.

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[128] Proceeding No. 17M-0694E, Comments from the Institute for Policy Integrity at New York University School of Law: Proposed Changes to ERP Rules 3604 & 3611 at p. 1, 5 (January 31, 2018).

[129] *Id.* at 29, ¶ 86.

7 QF/PURPA Rules (Proposed Rules 3900 – 3905)

COSSA and SEIA continue to believe that the proposed rules fail to comply with PURPA's "must-buy" requirement for the reasons presented in earlier stakeholder comments and argued by other parties in various forums. The new rules still require that a QF win a competitive solicitation in order to establish a legally enforceable obligation under PURPA. Indeed, much of the media coverage regarding this issue implicitly recognizes that PURPA requires utilities to buy energy and capacity from QFs. In one recent article two former state utility commissioners argue for competitive bidding in place of "must-buy." The Op-Ed states, "[c]ongress has given the FERC the tools it needs to address this problem. The time has come for the FERC to use them and to adopt federal regulations that promote the use of competitive pricing processes to fulfill PURPA's legal requirements."[130] While this article takes issue with PURPA's statutory requirements, it does not argue that FERC or the Courts have recognized competitive bidding as a legally compliant method of implementation.

The NOPR proposed QF Rules create additional legal problems with Colorado's PURPA implementation by misapplying Federal Law and the FERC's implementing regulations regarding *potential* exemptions to "must-buy" requirements for QFs between 20-80 MW. The NOPR states,

> Proposed Rule 3903(a) maintains the Commission's current practice of tying the establishment of a legally enforceable obligation to a contract awarded to the QF based on a winning bid in a Phase II ERP competitive solicitation. We propose that this rule apply to all QFs with nameplate capacity greater than 20 MW. The 20 MW level is based, in part, on FERC's determinations for legally enforceable obligations in organized markets.[131]

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130 Kavulla, T. and Marsha Smith, "Renewable Energy Prices Should be Based on Competition" (March 19, 2019). *Available at:* https://www.nationalreview.com/2019/03/renewable-energy-pricing-public-utilities-competitition/.

131 NOPR at para 268, *citing* FERC Order No. 688 at p. 9; codified at 18 C.F.R. § 292.309(d)(1).

In support of the contention that the 20 MW cut-off is appropriate, the Commission cites to FERC Order No. 688 and the related implementing regulations at 18 Code of Federal Regulations ("CFR") § 292.309(d)(1). However the plain language of the FERC order, the implementing regulations and the underlying section of the Federal Power Act are clear. First, *a utility* must apply for any exemptions to the "must-buy" requirement for QFs above 20 MW and receive FERC approval before being relieved of its PURPA obligations.[132] Second, the types of markets for which FERC grants exemptions are day ahead RTO/ISO type [regional transmission organization/independent system operator] markets – not vertically integrated markets like that in Colorado where competitive solicitation for long-term capacity are conducted every four years.[133] Third, the rebuttable presumption that the NOPR cites to, which says "that a qualifying facility with a capacity at or below 20 megawatts does not have nondiscriminatory access to the market" is preceded by a clause that makes clear that the rebuttable presumption is only to be used for the purposes of FERC-granted exemptions to must-buy requirements for facilities above 20 MW. In the absence of such a waiver, all QFs are assumed to not have nondiscriminatory access to markets. That is indeed the reason that PURPA exists in the first place. The PUC cannot unilaterally grant Colorado utilities and exception under 18 CFR § 292.309 and even if it could, it would not be able to do so without significant market reform.

COSSA and SEIA continue to recommend that the Commission adopt its proposed QF rules provided in earlier stakeholder comments. These rules effectuate the "must-buy" requirement and ensure no harm to customers by implementing the differential revenue requirements methodology that would be applied to each individual QF facility based on when it

[132] 16 C.F.R. § 824a-3(m)(1); 18 C.F.R. § 292.309(a) ("an electric utility shall not be required, under this part, to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility ***if the Commission finds that the qualifying cogeneration facility or qualifying small power facility production has nondiscriminatory access to***…"). Emphasis added.

[133] 1 6 C.F.R. § 824a-3(m)(1)(A)-(C); 18 C.F.R. § 292.309(a)(1)-(3).

enters the queue. The differential revenue requirement methodology produces a fair and accurate rate based on computer modeling of the actual value that a particular QF provides to the utility's system. Assuming that modeling is properly performed, this method ensures that customers are not negatively impacted by a QF contract and that QFs receive non-discriminatory treatment vis-à-vis utility-owned resources and non-QFs, as required by PURPA.[134] Finally, by requiring a utility to calculate an avoided cost purchase rate for each unique QF, the proposed rule avoids the possibility of avoided cost rates becoming stale, as they would if a competitive bidding process were used to set the rate.

In the NOPR, the Commission posed the following question:

> *Could tariff-based avoided cost determinations allow for "negative avoided costs" when QF-provided capacity or energy results in negative impacts to the utility's system and its customers?*

The answer to this question is yes. Indeed, this would be the result under the differential revenue requirement process described above. If the modeling reflected that the addition of a particular QF facility resulted in increased costs to the system, then the modeled avoided cost would be negative and would almost certainly result in the project not being submitted. However, to the extent the addition of the QF project resulted in a cost decrease to customers though the ability to avoid fuel, variable O&M or forecasted capital additions to reduce pollution, than the cost avoidance would result in the avoided cost available to the QF. Under this model customers never over-pay for QF energy and would be held harmless as Colorado moves towards a carbon-free economy.

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[134] *See* 18 C.F.R. § 292.304(a)(1).

8 Conclusion

COSSA and SEIA appreciate the opportunity to provide these comments and will provide more detailed proposed redline rule changes in the coming weeks. We look forward to further discussion on these topics.

Respectfully submitted this 29th day of March, 2019,

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