BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE TARIFFS, AGREEMENTS, AND FORMS PROPOSED BY QUALIFYING UTILITIES FOR THE COMMUNITY SOLAR PROGRAM

Case No. 23-00071-UT

BRIEF-IN-CHIEF OF THE COALITION FOR COMMUNITY SOLAR ACCESS, THE RENEWABLE ENERGY INDUSTRIES ASSOCIATION OF NEW MEXICO, AND NEW ENERGY ECONOMY

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SUMMARY OF RECOMMENDATIONS

1. The Commission should find that it is in the public interest for non-subscribers to subsidize subscribers, up to three percent of non-subscribers’ aggregate retail rate on an annual basis.

2. The Commission should order the investor-owned utilities (“IOUs”) to utilize Net Utility Cost Method to calculate the subsidy amount in future rate cases. This methodology includes:
   ○ Defining the subsidy as utility costs in excess of avoided costs, or the “net utility costs.”
   ○ Adapting a calculation methodology derived from the ratepayer impact measure (“RIM”) test.
   ○ Defining initial avoided cost categories to input into this calculation as:
     ■ Avoided energy;
     ■ Avoided generation capacity;
     ■ Avoided transmission capacity;
     ■ Avoided line losses (adder to energy);
     ■ Avoided renewable portfolio standard (“RPS”) compliance; and
     ■ Avoided environmental compliance (if not included in other components).
   ○ Adapting CCSA’s proposed methodologies to quantify the initial avoided cost categories.
   ○ After the initial program is up and running, the Commission should reference the National Standard Practice Manual for Distributed Energy Resources (“NSPM”) to develop a broader evaluation of avoided costs, which include, but are not limited to:
     ■ Avoided uncollectible amounts and collection expenses;
     ■ Avoided distribution capacity;
     ■ Avoided greenhouse gas emissions reductions; and
     ■ Subscriber non-energy benefits, in particular, those that accrue to low-income subscribers.

3. The Commission should adopt a clear methodology to calculate the dollar value that constitutes the three percent subsidy limitation. This methodology should include:
   ○ Defining non-subscribers on a total system basis;
   ○ Defining aggregate retail rate (“ARR”) as synonymous with total aggregate retail rate (“TARR”). For this purpose, the TARR should be calculated as:

\[
TARR \, (\$/kWh) = \frac{(Total \, Base \, Revenue \, - \, Customer \, Charges) \, / \, Electricity \, Sales }{ + \, Fuel \, & \, Purchased \, Power \, Charge \, + \, RPS \, Charge }
\]

   ■ In the alternative, defining ARR in accordance with EPE’s recommendation, which is reflected as:

\[
\text{Total Billed Revenue/Total Energy Sales}
\]
○ Calculate the three percent cap as:

\[ 3\% \text{ Limit} = 3\% \times \text{System-Wide Nonsubscriber TARR ($/kWh)} \times \text{Non-Subscriber Sales ($/kWh)} \]

4 The Commission should order that the IOUs recover costs both below and above the three percent subsidy limitation, as follows:
   ○ For costs under the three percent cap, the Commission should issue a pure accounting order allowing all bill credit costs to be tracked in a regulatory asset. In future rate cases, the Commission may permit reasonable net utility costs to be recovered from the general body of ratepayers.
   ○ For costs above the three percent cap, the Commission should order the IOUs to recover these costs from post-cap project subscribers as a volumetric surcharge.

5 The Commission should order the IOUs to utilize a uniform methodology for administrative cost recovery. This methodology should:
   ○ Categorize administrative costs as one-time or recurring;
   ○ Order the IOUs to recover reasonable recurring costs through a three-year volumetric administrative rider rate; and
   ○ Order the IOUs to present one-time costs in future general rate cases for additional Commission review. Reasonable one-time costs approved by the Commission should be recovered from the general body of ratepayers.

6 In accordance with Recommendation 5, the Commission should adopt the following 2023-2026 administrative cost rates for the recovery of reasonable recurring costs:
   ○ PNM: $0.003007/kWh
   ○ SPS: $0.003125/kWh

7 In accordance with Recommendation 5, the Commission should order EPE to file an advice notice within 30 days of the conclusion of this proceeding that proposes a reasonable administrative cost rate for the recovery of recurring costs.
   ○ This filing should contain detailed estimates of the reasonable recurring costs EPE expects to incur from administering the program.

8 The Commission should order PNM and SPS to revise their bill credit rates to comply with the Community Solar Act. These revisions should include:
   ○ Ordering PNM to include minimum monthly demand charges in subscriber credit rates;
   ○ Clarifying that for the purposes of the bill credit calculation, the distribution cost component is based on the utilities’ cost of service studies; and

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1 If the Commission adopts EPE’s definition of the ARR, it can simply be substituted for the TARR figure in this calculation.
Ordering SPS to correct its calculation of the total aggregate retail rate based on the sum of annual revenues from customer or minimum charges. The corrected calculation should be reflected as:

**Number of Customers * Customer Charge * 12 Months**

9 The Commission should order PNM and EPE to remove restrictions to program participation and bill credit distribution from their program tariffs. Specifically:

- The Commission should reject PNM’s proposal to monitor carry over amount and subscription sizing;
- The Commission should reject PNM and EPE’s proposals to limit or withhold bill credits from customers in arrears;
- The Commission should reject PNM and EPE’s proposals to exclude customers with behind-the-meter solar; and
- The Commission should reject PNM and EPE’s proposals to limit the number of subscriptions per subscriber and per premise, respectively.

10 The Commission should adopt the combined Subscriber Disclosure and Consent form, subject to the following revisions:

- Remove the “Community Solar Project Name” field;
- Remove the “Subscription Size (kW AC)” field; and
- Remove the “Project Nameplate Capacity (in kW AC)” field.
COMES NOW and pursuant to Rule 1.2.2.36 of the New Mexico Administrative Code (“NMAC”) and the Hearing Examiner’s Order Stating Briefing Deadlines, the Coalition for Community Solar Access (“CCSA”), the Renewable Energy Industries Association of New Mexico (“REIA”), and New Energy Economy (“NEE”) (together, the “Joint Parties”) hereby submit this Brief-in-Chief regarding Phase Two of New Mexico Public Regulation Commission (“Commission”) Docket 23-00071-UT: In the Matter of the Tariffs, Agreements, and Forms Proposed by Qualifying Utilities for the Community Solar Program (“Phase Two”).

By enacting the Community Solar Act (“CSA”), the New Mexico Legislature opened the door to equitable and affordable access to distributed renewable resources for New Mexico residents across the state. Community solar (“CS”) provides customers with the unique ability to subscribe directly to solar resources to supply their energy needs. The CSA provides CS subscribers with a statutorily defined credit for each kWh of solar energy they cause to be generated, but also requires them to pay for all investor-owned utility (“IOU”) supplied generation at standard tariffed rates. Unlike rooftop solar, CS subscribers are able to access these benefits regardless of their renter-versus-homeowner status, their income, or the suitability of their rooftop for hosting solar. The program will also help to accelerate the state’s decarbonization goals, while providing long-term savings opportunities to all customers in the form of future avoided utility costs. With these public benefits in mind, the Legislature drafted the CSA to explicitly contemplate future expansion of the program beyond the initial statewide capacity cap.

In order to ensure a successful program launch and to allow Subscriber Organizations to begin subscribing customers, the Commission must quickly set many of the ground rules and

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3 N.M. STAT. § 62-16B.
4 N.M. STAT. § 62-16B-7(b)(1)-(2).
establish uniform accounting methodologies that will dictate how the program operates for the first approved tranche of 200MW. This proceeding became necessary because the IOUs put forth inconsistent proposals through advice letter filings, some of which flagrantly ignored the CSA and the Commission's CS Rules. It is critical for a successful statewide program that these ground rules and methodologies are applied consistently across all three IOUs.

After completing a five month rulemaking proceeding, the Commission directed the IOUs to file tariffs to implement the CS program. SPS refused to abide by the Rule deducting transmission costs from CS bill credits. Subsequently, the Commission ordered SPS to file an advice notice with the corrected bill credit calculation. SPS filed an advice letter with corrected bill credit rates under protest. In Advice Notice 594, PNM included a “minimum monthly charge” to subscribers in its bill credit tariff. The Commission suspended Advice Notice 594 and ordered PNM to file an advice notice with the correct calculation of the bill credit. In response, PNM filed Advice Notice 597, which removed the monthly minimum charge but included a “terms of payment” section limiting how much of the credit could be applied to a subscriber’s bill. Parties identified a number of issues that were in dispute and did not necessarily comply with the CSA or the CS rules. As a result, the Commission found it necessary to suspend the individual IOU Advice Notices and convene this implementation docket.

6 Order Opening New Docket for Two-Phase Proceeding, et al. at 5.
7 Id.
8 Id.
9 Id. at 7.
10 Id.
11 Id.
12 Id. at 8-9.
During the first phase of this proceeding, parties were able to reach consensus on a standard Subscriber Organization agreement.\(^\text{13}\) However, many of the more substantive issues that will impact the current and long-term viability of the CS program must be decided in this Phase Two.

In opening this proceeding, the Commission explained that,

The second phase will address all issues concerning proposed tariffs, agreements and forms that were not addressed in the first phase. These issues include but are not limited to the calculation of the three-percent subsidization limit for each of the Qualifying Utilities, proposed rate riders for various costs, proposed charges and fees, proposed terms of payment and the calculation of the community solar bill credits.\(^\text{14}\)

These issues must be decided here in order for the CS program to launch and in order to ensure that accepted bids are completed on time.\(^\text{15}\)

It is crucial that the Commission adopt implementation details in this proceeding that can accommodate future expansion, consistent with the Legislature’s apparent intent to grow the program after 2024.\(^\text{16}\) Therefore, in determining the methodologies and mechanics of program implementation, the Commission should enact policies that ensure the long-term success of the program. At a high level, this entails adopting program terms that are fair, create contract stability, financial predictability and allow for a high degree of customer satisfaction. In particular, the IOUs implementation of the program should be uniform in all material aspects, and the program should provide customers with clear expectations surrounding the long-term value of their subscriptions. Along these lines, IOU cost recovery should be structured so as not to degrade the value of

\(^{13}\) NM PRC Docket No. 23-00071-UT, Uncontested Phase I Stipulation, p. 3 (Aug. 10, 2023) (approved on Sept. 21, 2023, Order Approving Uncontested Phase I Stipulation).

\(^{14}\) Order Opening New Docket for Two-Phase Proceeding, et al. at 10-11.

\(^{15}\) At the time of hearing, evidence was presented that no CS facilities had completed the interconnection phase. No CS facilities have reached the construction stage. See Transcript (“Tr.”) Vol. 1, p. 132:7-11 (Jan. 17, 2023) (Hawkins); Tr. Vol. 2, p. 463:18-20 (Jan. 18, 2023) (Klemm); see e.g., PNM Exhibit 5: Direct Testimony of Michael Settlage, p. 19:19-22, 20:10-16 (Sept. 18, 2023) (explaining that while 29 CS facilities have been selected, PNM has not yet completed interconnection evaluation processes).

\(^{16}\) N.M. STAT. § 62-16B-7(B)(1)-(2).
community solar subscriptions over time. Finally, the Commission should ensure that subscriber organizations are not burdened with administrative and reporting requirements that increase costs, exceed statutory requirements, and are not necessary to achieve the objectives of the CSA.

In this proceeding, the Commission can ensure these outcomes by adopting program-wide methodologies for identifying and quantifying subsidization, and setting procedures to allow for any related cost recovery in ways that preserve the value of CS subscriptions over time. Similarly, the Commission should adopt cost recovery methodologies that provide reasonable predictability and stability of administrative costs. Finally, the Commission should implement reasonable program rules that do not arbitrarily impose limitations on subscriber eligibility. These recommendations are key components to the successful long-term community solar program envisioned by the Legislature and are detailed throughout this Brief. Attachment A directly responds to the Co-Hearing Examiner’s January 26, 2024 Order Stating Briefing Deadlines.

I. LEGAL AND EVIDENTIARY STANDARDS

In this case the Commission will be, among other things, setting rates for Southwestern Public Service Company (“SPS”), Public Service Company of New Mexico (“PNM”), and El Paso Electric Company (“EPE”) to recover administrative costs as well as defining credits that customers receive for their CS production. Section 62-8-1 N.M.S.A. requires that every rate made, demanded or received by any public utility shall be just and reasonable. The New Mexico Supreme Court has previously held that whether a rate is just and reasonable is determined based on the facts of each case and upon statutory guidelines. See Hobbs Gas Co. v. N.M. Pub. Serv. Comm’n, 1980-NMSC-005, 94 N.M. 731, 733 (Jan. 17, 1980). The Commission is afforded significant discretion in determining whether a requested rate is just and reasonable. Id. However, “the generally accepted rate-making principles for the development of a sound rate design include
continuity and stability.” In re PNM Gas Servs., 2000-NMSC-012, 129 N.M. 1, 34 (April 17, 2000) (citing United States v. Public Utils. Comm’n, 635 A.2d 1135, 1143 (R.I. 1993)). The concepts of continuity and stability are just as important in establishing CS bill credit rates, administrative cost riders, establishing any accounting orders, or calculating any subsidy amounts over time.

In proceedings before the Commission, the proponent of an order or the moving party generally has the burden of proof.\textsuperscript{17} In this case, each of the IOUs bears the burden of proof with regard to each of their own proposals related to CS program implementation. The burden of proof is two-pronged — it includes both the prima facie burden of producing sufficient evidence to move forward with a claim and the burden of ultimate persuasion.\textsuperscript{18} Unless otherwise provided by statute, the evidentiary standard in Commission proceedings is a preponderance of record evidence.\textsuperscript{19} A preponderance of the evidence is defined as the greater weight of evidence.\textsuperscript{20}

II. ARGUMENT

The implementation details the Commission must resolve in this proceeding can be grouped into four categories. First, the Commission must evaluate issues of subsidization, including how subsidization is identified, how the statutory three-percent limit is calculated, and associated cost recovery. Second, the Commission must evaluate the IOUs’ proposed administrative costs, and determine appropriate methodologies to recover certain types of costs. Third, the Commission must review the IOUs’ bill credit calculations, and order corrections to any

\textsuperscript{17} See NM PRC Docket No. 22-00270-UT, Recommended Decision, 16, (Dec. 8, 2023), Adopted in Final Order (Jan. 3, 2024) (citing NM PRC Docket No. 21-00267-UT, Certification of Stipulation at 24-25 (Nov. 10, 2022)); see also NM PRC Docket No. 22-00286-UT, Certification of Stipulation, 35 (Sept. 6, 2023).

\textsuperscript{18} Id.

\textsuperscript{19} Id. (citing Davis, Kenneth Culp, Administrative Law Treatise § 16.9 at 256 (2d ed. 1980); El Paso Electric Co. et al. v. N.M. Pub. Serv. Comm’n, 1985-NMSC-085, ¶ 12; and Re Southwestern Public Service Co., Case No. 2678, Recommended Decision of the Hearing Examiner (Nov. 15, 1996).

\textsuperscript{20} Id. at 16-17 (citing Campbell v. Campbell, 1957-NMSC-001, ¶ 24, 62 N.M. 330, 310 P.2d 266).
calculations that are unreasonable or illegal. Finally, the Commission must decide whether to permit the IOUs to impose additional restrictions on program participation, which are not present within the CSA or the CS Rules. The Sections below are organized in this order.

A. The Commission Should Find that Subsidization is in the Public Interest and Adopt the Joint Parties’ Recommendations for Related Calculations and Cost Recovery.

Some of the most important questions that the Commission must address in this proceeding include how to identify subscriber subsidization, the value of CS benefits to non-subscribers and the entire grid, and how any bill credit costs are to be recovered.21 These issues are deeply interrelated and have the potential to create reverberating impacts for future CS subscribers, subscriber organizations, and overall programmatic success. It is therefore imperative that these issues be decided quickly, at the outset of the program, to provide assurances for enrolling projects and for subscribers making long-term decisions regarding their source of energy and any associated costs.

Section 62-16B-7(B)(8) provides that the Commission must adopt rules to establish the CS program that:22

provide a community solar bill credit rate mechanism for subscribers derived from the qualifying utility's total aggregate retail rate on a per-customer-class basis, less the commission-approved distribution cost components, and identify all proposed rules, fees and charges; provided that non-subscribers shall not subsidize costs attributable to subscribers; and provided further that if the commission determines that it is in the public interest for non-subscribers to subsidize subscribers, non-subscribers shall not be charged more than three percent of the nonsubscribers' aggregate retail rate on an annual basis to subsidize subscribers;

From this language, it is clear that the Commission must make several key determinations, which are outlined step-by-step throughout this Section.

22 N.M. STAT. § 62-16B-7(B)(8) (emphasis added).
First, as a threshold matter, the Commission must decide that subsidization of CS subscribers, up to the permissible three percent limitation, is in the public interest. As discussed below, a Commission finding that subsidization is in the public interest, up to the three percent cap, is a crucial factor in creating a viable community solar program.

Second, the Commission must define a methodology for all three IOUs to calculate the total subsidy amount. In order to ensure that the IOUs consider both actual costs and quantifiable benefits of CS, the Commission should order the IOUs to use a “Net Utility Cost” methodology to calculate any subsidies. Once the Commission establishes a methodology in this proceeding, the IOUs can perform subsidy calculations and present them in future general rate cases (“GRCs”). As such, the Commission should adopt a clear and predictable methodology and, where feasible, identify how to value certain CS benefits based on publicly available and reliable data.

Third, the Commission should adopt a methodology for calculating the dollar value that constitutes the three percent limitation for each utility. The three percent subsidy limitation functions as a constraint on the future expansion and development of CS facilities. Once the subsidy cap is breached, the effective subscriber credit rate will no longer be sufficient to support the financeability of additional facilities. Consequently, calculation methodologies that produce a lower dollar value representing the three percent cap have the effect of limiting the amount of CS facilities that can proceed within this constraint, effectively creating a future CS program cliff. It is not necessary for the Commission to require these calculations be presented in this proceeding. However, the Commission should clearly define a reasonable methodology for this calculation and require the IOUs to perform this calculation in future GRCs or other cases related to subsequent phases of the CS program.

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23 CCSA Exhibit 1 at 14:21-23 (Barnes Dir.).
Finally, the Commission should adopt bill credit cost recovery mechanisms that preserve the value of CS subscriptions over time. As such, costs above the three percent limitation should be recovered from post-cap project subscribers. This approach ensures the value of initial subscriptions are preserved and that early adopters are not faced with unpredictable fees several years into their subscriptions.

1. **The Commission should find that subsidization is in the public interest.**

   CS programs deliver a wide array of benefits to both participants and nonparticipants, including monthly bill savings, emissions reductions, grid resilience, and long-term value in the form of avoided utility costs. By enacting the CSA, the Legislature determined that a successful CS program would serve the public interest by bringing these benefits to New Mexico. To accomplish this, the Legislature granted the Commission the discretion to determine whether non-subscribers should subsidize subscribers, up to three percent of non-subscribers’ aggregate retail rate on an annual basis. The Commission has previously acknowledged that the “public interest” is a broad and “amorphous” phrase, and that statutes provide the needed context to help interpret this policy direction.

   The New Mexico Supreme Court has concluded that the Commission’s exercise of discretion on public policy matters may result in subsidies, and that “determining the level of subsidies, if any, is a Commission function.” *Mt. States Tel. & Tel. Co. v. N.M. State Corp. Comm’n*, 1977-NMSC-032, 90 N.M. 325, 333-339 (April 20, 1977) (stating “...traditionally and logically there is a great measure of public policy that enters into the apportionment of rates. It is

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24 N.M. STAT. § 62-16B-7(B)(8).
25 NM PRC Docket No. 22-00270-UT, *Recommended Decision*, at 12 (adopted in Jan. 3, 2024 *Final Order*) (stating “The Commission is expressly tasked with carrying out a broad policy mandate: it must serve and support the ‘public interest.’ A statute gives necessary content to better comprehend this amorphous phrase.”)
26 *Id.* at 170.
incumbent upon the Commission to make public policy decisions…”)). As SPS witness Trowbridge acknowledged at hearing, subsidization within utility ratemaking is not an uncommon occurrence. At hearing, Mr. Trowbridge was unable to opine as to whether he thought that CS programs in Colorado or Minnesota, also run by Xcel Energy, created subsidies despite their long history. However it is clear that Public Service Company of Colorado, Xcel’s Colorado affiliate where Mr. Trowbridge worked from 2014-2023, has argued that the Colorado CS Program creates subsidies since at least 2014. However, Xcel’s claims of subsidization did not stop the Colorado PUC from approving multiple capacity expansions during the last 10 years. Indeed, well designed subsidization can often be used to achieve valuable policy objectives. In the present case, modest subsidization is needed to carry out the overall public interest of implementing an accessible CS program for New Mexico ratepayers, largely focused on serving low-income customers.

The Legislature’s intent for the Commission to implement a viable CS program is partially evidenced by its mandate that the Commission adopt rules to reasonably allow for the creation,
financing and accessibility of CS facilities.\textsuperscript{32} As explained in the Direct Testimony of CCSA witness Barnes, allowing for the permissible level of subsidization is necessary to achieve a feasible program.\textsuperscript{33} Absent a small amount of subsidization, the utilities’ proposals would result in subscriber credit rates of $0.03$-$0.04$/kWh,\textsuperscript{34} which is unlikely to support a financeable value proposition for community solar subscriber organizations and therefore opportunities for customers to subscribe to CS facilities.\textsuperscript{35}

SPS mischaracterizes this conclusion, stating “[r]eading the statute to conclude that subsidization is allowed to benefit unregulated developer’s financing, and not for the overall public interest, is not an interpretation that the Commission should adopt…”\textsuperscript{36} This argument incorrectly assumes that adopting program implementation details to support CS development is an entirely separate issue from carrying out the public interest. Rather, the Legislature clearly recognized that to facilitate a viable, accessible program, the Commission must create a regulatory framework that allows projects to be created and financed in the first place.\textsuperscript{37} While SPS implies that this direction was limited to enacting rules,\textsuperscript{38} the Commission’s role in implementing these directives was not limited to the rulemaking. It is not only reasonable for the Commission to adopt implementation details that support the development of CS projects in order to achieve the greater public interest of a successful CS program — it is a logical extension of the CSA.

Without subsidization up to the three percent cap, the utilities’ bill credit cost recovery proposals would significantly, if not entirely, reduce the value of subscriber bill credits by charging

\textsuperscript{32} N.M. STAT. § 62-16B-7(B)(9).
\textsuperscript{33} CCSA Exhibit 1: Direct Testimony of Justin Barnes, pp. 40:15-23, 41:1-10 (Nov. 13, 2023).
\textsuperscript{34} Id.; see also SPS Exhibit 3 at Attachment AGT-R4 (Trowbridge Reb.).
\textsuperscript{35} Tr. Vol. 3, 533:2-3 (Jan. 19, 2023) (Barnes).
\textsuperscript{36} SPS Exhibit 2: Rebuttal Testimony of Zoe Lees, 34:3-6 (Dec. 8, 2023).
\textsuperscript{37} N.M. STAT. § 62-16B-7(B)(9).
\textsuperscript{38} SPS Exhibit 2 at 34:6-8 (Lees Reb.).
subscribers back for the bill credits they receive.\textsuperscript{39} For example, PNM proposes to record bill credit costs in a regulatory asset, then seek recovery of these costs back from subscribers in a future GRC.\textsuperscript{40} Subscriber bill savings are one of the most significant, immediate benefits that CS programs bring to program participants. For this reason, the CSA specifically directs that thirty percent of the electricity produced from each CS facility must be reserved for low-income customers and low-income service organizations.\textsuperscript{41} This requirement is a key equity component built into the CSA and guarantees that subscriber bill savings are available to customers who can benefit the most from these impactful bill reductions. The Commission reemphasized this priority in Rule 17.9.573.12(E)(5)(d), which sets forth the criteria by which projects may be awarded additional points through the RFP process by supplementing low-income bill credits up to certain levels.\textsuperscript{42} Allowing for subsidization within the permissible cap is necessary to preserve the value of bill credits and ensure that monthly savings are achievable for subscribers.

EPE and SPS oppose a Commission finding that subsidization is in the public interest. EPE argues that, “[s]ubsidizing the purchase of renewable energy from smaller, less efficient systems for a small group of customers is not in the public interest.”\textsuperscript{43} EPE provides no additional explanation to support its claim that CS facilities are “less efficient,” nor any justification as to why allowing subsidization is not in the public interest.\textsuperscript{44} SPS states that limiting subsidization during the initial phase may provide, “...a more accurate representation of on-going program costs...in anticipation of an expanded program.”\textsuperscript{45} However, whether the program will expand and

\textsuperscript{39} Id. at 41.
\textsuperscript{40} CCSA Exhibit 1 at 41:7-10 (Barnes Dir.).
\textsuperscript{41} N.M. STAT. § 62-16B-7(B)(3).
\textsuperscript{42} NMAC 17.9.573.12(E)(5)(d).
\textsuperscript{43} EPE Exhibit 2 at 11:5-7, 21:11-12 (Schichtl Reb.).
\textsuperscript{44} See In re PNM Gas Servs., 2000-NMSC-012, ¶ 66, 129 N.M. 1, 24, 1 P.3d 383 (explaining that conjecture is not a substitute for evidence).
\textsuperscript{45} SPS Exhibit 3 at 14:9-12 (Trowbridge Reb.).
to what degree is currently unknown. At hearing, SPS witness Trowbridge confirmed that without knowing what future capacity may be approved, it is impossible to actually send customers a precise signal of the ongoing costs of a future program. Given the unknown factors, disallowing subsidization in the initial phase will not have the effect of creating clearer expectations for the future program.

The impact of disallowing subsidization on bill credit rates is illustrated by SPS’s Bill Credit Cost Recovery proposal. Under SPS’s proposed approach, CS compensation would be less than what is provided to renewable resources that qualify as large qualifying facilities (“QFs”) under the Public Utility Regulatory Policy Act (“PURPA”). The specifics of SPS’s proposal are discussed in more depth in Section II.A.4.a. below, however, it is important to recognize that the result of this proposal would likely render project development unfinanceable for subscriber organizations. Under these circumstances, subscribers, including low-income customers and low-income service organizations, would be deprived from bill savings entirely. If projects could somehow be constructed, disallowing any subsidization would result in a credit rate so low that any savings opportunities intended by the Community Solar Act would be eliminated.

Accordingly, the Commission should find that subsidization up to the three percent limitation is in the public interest. This finding will ensure that the value of community solar subscriptions is preserved, allowing for the creation and financing of CS projects and creating access to bill savings for those that need them the most.

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46 Tr. Vol. 2 at 484:25, 485:1-6 (Trowbridge).
47 See SPS Exhibit 1: Direct Testimony of Ruth Sakya, pp. 10-16 (Sept. 18, 2023).
49 CCSA Exhibit 1 at 41:2-6 (Barnes Dir.).
50 Id.
2. The Commission should adopt a methodology to calculate the total subsidy amount.

Determining how to calculate the subsidy amount is a vital step to ensuring that the benefits of community solar to non-subscribers are properly accounted for. In this proceeding, the Commission should adopt a methodology for calculating the subsidy amount. At this juncture, it is not necessary or possible for the Commission to approve any specific numeric calculations of the subsidy amount because all costs and benefits are not yet known.\textsuperscript{51} Rather, the Commission should adopt a uniform methodology to perform this calculation, and order that the IOUs present the results in subsequent GRCs. This methodology should follow a cost-benefit analysis framework for calculating program costs and avoided cost benefits similar to the Ratepayer Impact Measure (“RIM”) test.\textsuperscript{52} This methodology is broken down into specific steps below.

a. The Commission should define “subsidy” as the net utility cost.

“Subsidy,” or any variation thereof, is not a defined term within the CSA. However, the CSA imposes an explicit limitation on the subsidization of subscribers by nonsubscribers.\textsuperscript{53} As a result, it is important in this proceeding that the Commission specifically identify what constitutes a subsidy.\textsuperscript{54}

As a foundational step, the Commission should adopt the most precise definition of subsidy for this context, which is “net utility cost.”\textsuperscript{55} This definition is informed by the consideration of both the quantifiable utility costs and benefits to non-subscribers in the form of avoided costs that

\textsuperscript{51} PNM Exhibit 2: Rebuttal Testimony of Alaric Babej, p. 5:14-17 (Dec. 8, 2023).
\textsuperscript{52} CCSA Exhibit 1 at 16:14-20 (Barnes Dir.).
\textsuperscript{53} N.M. STAT. § 62-16B-7(B)(8).
\textsuperscript{54} Tr. Vol. 1 at 28:22-25 (Schichtl).
\textsuperscript{55} CCSA Exhibit 1 at 15:21-23, 16:1-10 (Barnes Dir.).
can be attributed to community solar.\textsuperscript{56} Essentially, net utility cost means that the subsidy is utility costs in excess of CS benefits.

EPE argues that the subsidy should be defined as, “monetary assistance granted by a government to a person or group in support of an enterprise regarded as being in the public interest.”\textsuperscript{57} Alternatively, SPS asserts that the term “subsidy” should be given its ordinary meaning.\textsuperscript{58} However, these definitions are not precise and offer no assistance in explaining how to calculate the subsidy amount. Rather, the net utility cost definition is a necessary starting point to clearly define the components (the costs and the benefits) that should be used to perform the subsidy calculation.

b. The Commission should adopt a methodology for performing the net utility cost calculation in future rate cases.

In this proceeding, the Commission should adopt a uniform methodology to calculate the subsidy amount. The Commission should not approve the results ($ figures) of any subsidy calculation, but rather, should order the IOUs to perform this calculation in future GRCs, where the results can be reviewed and vetted to ensure accuracy.

To calculate the subsidy amount, the Commission should adopt a cost-benefit analysis similar to the RIM test.\textsuperscript{59} The RIM test is particularly useful in this context, as it provides a measure of whether non-participant rates will increase or decrease due to a certain program.\textsuperscript{60} To achieve the most accuracy in this analysis, program costs and avoided cost benefits should be evaluated over a timeframe consistent with the lifetime of a community solar facility.\textsuperscript{61} In practice, the

\textsuperscript{56} Id. \\
\textsuperscript{57} EPE Exhibit 2 at 20:5-7 (Schichtl Reb.). \\
\textsuperscript{58} SPS Exhibit 3 at 17:1-4 (Trowbridge Reb.). \\
\textsuperscript{59} CCSA Exhibit 1 at 16:14-20 (Barnes Dir.). \\
\textsuperscript{60} Id. \\
\textsuperscript{61} Id.
defined benefits adopted by the Commission should be netted against utility costs to arrive at the net utility cost amount.\textsuperscript{62} At hearing CCSA witness Barnes explained that all reasonable costs and all reasonable benefits should be considered in determining whether or not a subsidy exists.\textsuperscript{63}

Under this methodology, the first step in determining the subsidy amount is to calculate utility costs. Costs should be calculated by adding together any compensation for CS output (i.e., the value of subscriber bill credits) plus any actual compensation for unsubscribed energy.\textsuperscript{64} The result can be stated in volumetric terms ($/kWh) (the “cost rate”).\textsuperscript{65} Next, the defined benefits attributed to community solar should be quantified based on the methodologies discussed below in Section II.A.2(c).\textsuperscript{66} This result can also be stated in volumetric terms (the “benefits rate”).\textsuperscript{67} To arrive at the “net utility cost rate,” the benefits rate is subtracted from the cost rate.\textsuperscript{68} Finally, the subsidy amount is the net utility cost rate multiplied by the volume of CS generation (kWh).\textsuperscript{69} For example, if the Subscriber Credit Rate is $0.10/kWh and the Benefits Rate is $0.06/kWh, the net utility cost rate is $0.04/kWh. At a subscription volume of 100,000,000 kWh, the subsidy amount is $4,000,000.\textsuperscript{70} These illustrative figures were employed for simplicity, and do not reflect any analysis as to the subsidy amount.

SPS criticizes Mr. Barnes’ proposal, stating “the RIM test is more commonly associated with Demand Side Management programs and Energy Efficiency programs and is used to measure the cost-effectiveness of those programs, which are different from Community Solar.”\textsuperscript{71} SPS

\textsuperscript{62} Id. at 16:20-22, 17:1-2.
\textsuperscript{63} Tr. Vol. 3 at 588:8-14 (Barnes).
\textsuperscript{64} CCSA Exhibit 1 at 21:10-21 (Barnes Dir.).
\textsuperscript{65} Id.
\textsuperscript{66} Id.
\textsuperscript{67} Id.
\textsuperscript{68} Id.
\textsuperscript{69} Id.
\textsuperscript{70} Id.
\textsuperscript{71} SPS Exhibit 3 at 18:4-8 (Trowbridge Reb.).
argues that the RIM test does not account for utility lost revenues and that its use is not wholistic or appropriate in this context. However, at hearing, SPS witness Trowbridge explained that despite his stated opposition to the use of the RIM test, he did not actually have a complete understanding of the RIM test. After reviewing a description of the RIM test contained in Exhibit JRB-5 attached to CCSA Exhibit 1, Mr. Trowbridge acknowledged that the RIM test does, in fact, account for the costs of decreased revenues for any periods in which load has been decreased by a program. In this context, Mr. Barnes employs an equivalent assumption to utility lost revenue, as program costs reflect the dollar value of subscriber credits inclusive of lost base rates revenue. Furthermore, while Mr. Trowbridge asserts that the RIM test is more commonly used for energy efficiency programs, he fails to explain why there is a difference.

In testimony, PNM argued that Mr. Barnes’ proposed cost-benefit analysis is asymmetrical as to its treatment of costs versus benefits, and that the utilities may experience additional costs not raised by Mr. Barnes. More specifically, PNM witnesses Cindy Buck and Thomas Duane raised several transmission and distribution related costs as attributable to the CS program. However, several of the costs noted by Mr. Duane and Ms. Buck, in particular, wheeling fees and volt var management, are assigned to the CS developer during the interconnection process and therefore are not utility costs that are borne by non-subscribers. In addition, as described

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72 See Tr. Vol. 2 at 497:1-4, 498:18-21 (Trowbridge); SPS Exhibit 3 at 19:15-16 (Trowbridge Reb.).
73 SPS Exhibit 3 at 18:7-11 (Trowbridge Reb.).
74 Tr. Vol. 2, 486:7-12 (Trowbridge).
75 Id. at 498:18-25, 499:1-9.
76 CCSA Exhibit 1 at 17:8-10 (Barnes Dir.).
77 PNM Exhibit 2 at 14:3-5 (Babej Reb.).
79 PNM Exhibit 9 at 6:20-23, 7:1-4 (Duane Reb.).
80 PNM Exhibit 7 at 5:7-10 (Buck Reb.).
81 CCSA Exhibit 12: PNM Response to CCSA DR 7-15; CCSA Exhibit 13: PNM Response to CCSA DR 7-20.
below, avoided costs associated with CS should be calculated in future GRCs based on actual utility data. Along these lines, the IOUs may propose a value associated with a CS benefit category that reflects actual, identifiable costs and benefits attributable to CS.

Similarly, SPS argues that any evaluation of avoided costs should consider costs related to integration, interconnection, and administration. As mentioned above, Mr. Barnes’ methodology allows for the calculation of avoided costs based on actual incremental costs and quantifiable avoided costs. Moreover, many of the interconnection costs associated with community solar facilities will be assigned directly to CS developers. Finally, the CSA and Rule 573 allow utilities to recover reasonable administrative costs from subscribers. As these costs are assigned directly to subscribers, they are not a cost to non-subscribers that should be included in determining the subsidy.

c. The Commission should clearly define avoided cost categories attributable to community solar, which the IOUs must quantify.

The Commission should clearly define, in this proceeding, the avoided cost categories (aka benefits) attributable to CS and applicable for the subsidy calculation described above. The Commission need not establish specific figures of avoided costs that CS provides for non-subscribers, but should adopt categories of benefits that the IOUs must quantify and present when performing the subsidy calculation in future GRCs. Defining specific avoided cost categories and approved sources of information to quantify such benefits now, will provide the Commission,

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82 SPS Exhibit 3 at 24:7-9 (Trowbridge Reb.).
83 See AN 1: Appendices to 17.9.568 NMAC, Appendix 1C, Section IV “Responsibilities of the Parties,” Subsection D (“the cost of utility system modifications required pursuant to the Fast Track process or the full interconnection study process will be borne by the interconnection customer unless otherwise agreed to by the parties or following a determination by the commission that some or all of the costs constitute system benefits eligible for cost-sharing options as described in Rule 17.9.568.15.”).
84 N.M. STAT. § 62-16B-7(B)(6); NMAC 17.9.573.13(D).
85 PNM Exhibit 2 at 5:14-17 (Babej Reb.).
the utilities, and stakeholders with certainty and predictability in how to determine the subsidy amount.

Although the RIM test typically limits the scope of benefits considered to utility system benefits,\textsuperscript{86} considering a broader range of benefits is a more accurate approach. It is particularly important that the Commission account for long-term benefits to accurately reflect the 25-year lifetime of CS facilities,\textsuperscript{87} which is incorporated into Mr. Barnes’ proposed methodology. If long-term benefits are not considered, the subsidy calculation will undercount CS benefits and overstate the true net utility cost.\textsuperscript{88} This would result in IOUs reaching the three percent subsidy cap too soon. Overall, failure to consider long-term benefits would reduce the number of CS facilities deployed within the three percent subsidy limitation.\textsuperscript{89}

In testimony, Mr. Barnes explained that the California Standard Practice Manual (“CA SPM”) and the National Standard Practice Manual for Distributed Energy Resources (“NSPM for DERs”) are suitable resources to help inform the Commission’s determination of community solar benefits categories.\textsuperscript{90} These resources outline a wide array of benefits and will be useful should the Commission evolve its benefits evaluation over time. The Joint Parties’ recommendations for future benefits calculations are set forth in Section II.A.2(d) below.

For the purposes of implementing the initial phase of the program, the Commission should adopt simplified benefits categories that are tailored to New Mexico and initially exclude

\textsuperscript{86} CCSA Exhibit 1 at 17:15-18 (Barnes Dir.).
\textsuperscript{87} Id. 23:1-19, N.M. STAT. § 62-16B-6(A)(3).
\textsuperscript{88} Id. at 23:12-14.
\textsuperscript{89} Id. at 23:16-19.
\textsuperscript{90} Id. at 24-25.
categories that are more difficult to quantify.\textsuperscript{91} The Commission should order that the following avoided cost categories initially be included in the subsidy calculation:\textsuperscript{92}

- Avoided Energy Production and Purchases;
- Avoided or Deferred Generation Capacity;
- Avoided or Deferred Transmission Capacity or Wheeling Costs;
- Line Losses (Adder to Energy);
- Avoided Renewable Portfolio Standard (“RPS”) Compliance Costs; and
- Avoided Environmental Compliance Costs (if not included in other components).

In testimony, Mr. Barnes provided detailed methodologies to calculate each of these avoided cost categories.\textsuperscript{93} Mr. Barnes’ recommendations for initial avoided cost categories and the related quantification methodologies are intended to achieve relative simplicity, stability, and accuracy, and to rely on existing methods of cost attribution.\textsuperscript{94} The determination of the specific values associated with these avoided cost categories should be based on actual program data in future GRCs.\textsuperscript{95}

In particular, the Commission should require the IOUs to submit a hosting or integration analysis in presenting data on avoided costs. An integration analysis is an engineering study that determines how much solar capacity can be interconnected at a given location.\textsuperscript{96} While EPE conducted a similar system impact study, it did not offer the results into the record.\textsuperscript{97} These engineering analyses have been relied upon in other states with CS programs to demonstrate where

\begin{itemize}
  \item \textsuperscript{91} Id. at 28:4-7.
  \item \textsuperscript{92} Id. at 28:9-14.
  \item \textsuperscript{93} Id. at pp. 28-36.
  \item \textsuperscript{94} Id. at 29:15-16.
  \item \textsuperscript{95} Tr. Vol. 3 at 589:1-10 (Barnes).
  \item \textsuperscript{96} Tr. Vol. 1 at 205:3-7 (Babej).
  \item \textsuperscript{97} Id. at 129:19-25, 130:1-3, 131:3-5 (Hawkins).
\end{itemize}
on the transmission and distribution system there is excess capacity.\textsuperscript{98} For example, NEE witness Farrell explained that a hosting capacity study performed by Xcel Energy in Minnesota illustrated that the cumulative capacity across dozens of distribution feeders could support an additional 400 to 800 MW with minimal grid reinforcement.\textsuperscript{99} This critical information is necessary to fully evaluate utility costs and avoided costs.

By contrast, the IOUs each propose methodologies that base avoidable costs solely on energy-related costs, excluding all avoided capacity costs.\textsuperscript{100} In effect, the IOUs’ evaluations of benefits are limited to short-term marginal energy costs, with PNM including a renewable energy attributes adder.\textsuperscript{101} While SPS acknowledged that CS facilities may have long-term benefits, such as avoided generation, transmission, and distribution investments,\textsuperscript{102} its methodology specifically does not account for future avoided capital investments.\textsuperscript{103} Similarly, EPE witness Schichtl explained that should future avoided capacity benefits occur, they would not be reflected in the subsidy calculation.\textsuperscript{104} In addition to creating a lower ceiling for program development, the outcome of these proposals would be that subscribers pay for a future benefit that accrues to all customers without compensation — effectively, subsidizing non-subscribers.

To avoid these outcomes, the Commission should adopt the Joint Parties’ proposed initial benefits categories, as well as the associated calculation methodologies. This approach strikes the appropriate balance between accounting for substantial CS benefits over the long-term horizon and

\begin{flushleft}
\textsuperscript{98} New Energy Economy Exhibit 1: Direct Testimony of John Farrell, p. 7 (Nov. 13, 2023).
\textsuperscript{99} \textit{Id}.
\textsuperscript{100} CCSA Exhibit 1 at 22:15-16.
\textsuperscript{101} \textit{Id}.
\textsuperscript{102} SPS Exhibit 3 at 21:8-10 (Trowbridge Reb.).
\textsuperscript{103} Tr. Vol. 2 at 499:11-21 (Trowbridge).
\textsuperscript{104} Tr. Vol. 1 at 34:2-12 (Schichtl).
\end{flushleft}
providing relative simplicity during the early program stages. Moreover, this approach will facilitate the establishment of rates that are just and reasonable.

d. In the future, the Commission should pivot to a broader evaluation of community solar benefits.

While the Commission should adopt a simplified benefits analysis for near-term implementation of the program, the evaluation should evolve over time, and as New Mexico gets more experience with front of the meter distributed generation projects such as CS facilities, to ensure that all benefits are quantified. The three percent limitation on subscriber subsidization will eventually require that the subscriber credit rate be equal to the CS benefits rate to allow for program continuity. Consequently, the Commission should eventually transition to a value of solar-based subscriber credit rate, in which the CS benefits rate is equivalent to the average subscriber bill credit rate. In effect, this type of subscriber credit rate will produce no subsidy and therefore allow for the program to remain operational over the long-term.

In the future, the Commission’s CS benefit calculation should encompass all sources of value produced by CS projects. In addition to those listed above, these benefits should include, but should not be limited to:

- Avoided Uncollectibles and Collection Expenses;
- Distribution Capacity;
- Greenhouse Gas Emissions Reductions; and
- Subscriber Non-Energy Benefits, in particular, those that accrue to low-income subscribers.

105 CCSA Exhibit 1 at 28:17-23 (Barnes Dir.).
106 Id.
107 Id.
108 Id. at 36:2-10.
109 Id.
In testimony, SPS witness Trowbridge argued that, “trying to quantify every potential avoided cost and externality in assigning a reasonable purchase price seems unnecessarily complex, if not impossible.”\(^\text{110}\) However, these broader avoided cost calculations are regularly employed in program cost-benefit analyses.\(^\text{111}\) The NSPM for DERs provides valuable guidance in how these benefits should be evaluated so that subsidization can be identified to the most accurate degree.\(^\text{112}\) Finally, PNM expressed specific support that both greenhouse gas emissions reductions and distribution capacity should be evaluated as avoided costs in the future.\(^\text{113}\)

3. **The Commission should adopt a methodology to calculate the dollar value that constitutes the three percent cap.**

The Community Solar Act provides that, should subsidization be permitted, “non-subscribers shall not be charged more than three percent of the non-subscribers' aggregate retail rate on an annual basis to subsidize subscribers.”\(^\text{114}\) As explained above, the “net utility cost” methodology allows the Commission to approve a total subsidy dollar amount once actual costs and benefits are better known in future GRCs. However, that dollar amount must then be compared to “non-subscribers' aggregate retail rate on an annual basis” to determine if the 3% cap has been reached.\(^\text{115}\) In order to determine if the 3% cap is reached, the Commission must clearly determine how to define both “non-subscribers” and “aggregate retail rate.” The Commission’s interpretation of these terms will directly impact the inputs into the calculation of the three percent limitation.

The terms “non-subscriber” and “aggregate retail rate” are not defined terms in the Community Solar Act. While parties to this proceeding generally agree as to the definition of “non-

\(^{110}\) SPS Exhibit 3 at 23:8-10 (Trowbridge Reb.).
\(^{111}\) See e.g., NMAC 17.7.2.9(B)(3).
\(^{112}\) CCSA Exhibit 1 at 29:8-10 (Barnes Dir.).
\(^{113}\) PNM Exhibit 7 at 8:2-7 (Buck Reb.).
\(^{114}\) N.M. STAT. § 62-16B-7(B)(8).
\(^{115}\) See N.M. STAT. § 62-16B-7(B)(8).
subscriber,” parties have proposed varying interpretations of “aggregate retail rate.” Therefore, the Commission must interpret this term and adopt a reasonable definition that ensures each IOU is measuring against the same metrics.

The New Mexico Supreme Court has previously explained that the canons of statutory construction guide the interpretation of administrative rules. *Albuquerque Bernalillo County Water Utility Authority (ABCWUA) v. NMPRC*, 2010-NMSC-013, ¶ 52, 148 N.M. 21, 39 (March 19, 2010). Further, the Commission has stated that, “[j]ust as the Supreme Court’s guiding principle in construing statutes is to ‘determine and give effect to legislative intent,’” the Commission must give effect to the legislature’s intent…”116 *Pub. Serv. Co. of New Mexico v. New Mexico Pub. Regulation Comm’n*, No. S-1-SC-39138, ¶ 18 (July 6, 2023) (citing ABCWUA at ¶ 52). This analysis is guided by the traditional canons of statutory construction. See ABCWUA at ¶¶ 50-52. There are two steps the Commission should employ to interpret a statute when the parties disagree as to its meaning. *State ex rel. Helman v. Gallegos*, 1994-NMSC-023, 117 N.M. 346, 347 (March 7, 1994).

First, the plain language of a statute should be given effect as written and, where it is free from ambiguity, there is no room for construction. *Id.* In this scenario, words should be given their ordinary meaning unless the Legislature indicates otherwise. See ABCWUA at ¶ 52. Statutory language that is clear must be given effect, while ambiguity allows for further analysis. *Id.*

Second, “where the language of the legislative act is doubtful or an adherence to the literal use of words would lead to injustice, absurdity or contradiction, the statute will be construed according to its obvious spirit or reason, even though this requires the rejection of words or the substitution of others.” *Id.* at 347-348. The Commission has explained that a statute is ambiguous

116 NM PRC Docket No. 16-00096-UT, *Certification of Stipulation*, 111 (Dec. 21, 2016) (citing ABCWUA at 39.)
if reasonably informed persons can understand the statute as having two or more meanings. In addition to analyzing the language of an ambiguous statutory provision, the Commission should also consider the statute’s history, as well as the practical implications and legislative purpose of the statute. Finally, when a statute is ambiguous, the Commission may consider the clear policy implications of the various constructions. Both of these principles should guide the Commission’s interpretation of the terms “non-subscribers” and “aggregate retail rate,” as described below.

a. The Commission should define non-subscribers on a total system level.

Section 62-16B-7(B)(8) provides that, “non-subscribers shall not be charged more than three percent of the non-subscribers' aggregate retail rate on an annual basis to subsidize subscribers…” As the three percent limitation is based on non-subscribers’ aggregate retail rate, it is important for the Commission to clearly define who non-subscribers are.

The CSA references two groups of customers: “subscribers” and “non-subscribers.” The CSA provides no distinction between non-subscribers based on the rate class in which they reside, nor the rate classes in which subscribers reside. Thus, the plain language of the statute indicates that non-subscribers are customers who do not enroll in the community solar program. In application, this definition evaluates non-subscribers on a total system-level basis, rather than by rate class.

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118 Id. at 25 (citing State v. Smith, 136, N.M. 372, 376 (Sept. 16, 2004); Bishop v. Evangelical Good Samaritan Soc’y, 146 N.M. 473, 477 (June 23, 2009)).

119 Id. at 26 (citing Smith at 376).

120 N.M. STAT. § 62-16B-7(B)(8).
Interpreting non-subscribers on a total system basis is consistent with EPE’s recommendation for calculating the three percent limitation.\textsuperscript{121} Further, while PNM initially recommended defining non-subscribers based on subscribing class level, PNM witness Settlage explained at hearing that PNM now supports defining non-subscribers at the system level.\textsuperscript{122}

Conversely, defining non-subscribers based on rate class would produce an impractical and illogical result.\textsuperscript{123} Any rate class could include certain types of subscribers, including schools, tribal nations, municipalities, among others.\textsuperscript{124} As a result, defining non-subscribers based on the rate classes in which subscribers reside would create a situation in which the three percent cap would fluctuate dramatically based on subscriber composition.\textsuperscript{125} In this scenario, the addition or attrition of a single subscriber could result in a large increase or decrease in the three percent value.\textsuperscript{126} Given the plain language of the statute, the consensus of parties, and the illogical outcome that would result otherwise, the Commission should order that for the purposes of the three percent cap calculation, non-subscribers should be defined on a total system basis.

\textbf{b. The Commission should define aggregate retail rate as synonymous to Total Aggregate Retail Rate.}

A key question before the Commission is how “aggregate retail rate” (“ARR”) as used in Section 62-16B-7(B)(8) should be interpreted. The ARR is the benchmark by which the three percent subsidy limitation is measured.\textsuperscript{127} To determine whether non-subscribers’ have been charged more than three percent of their ARR, the Commission must first clearly define what the ARR is.

\begin{itemize}
\item \textsuperscript{121} Tr. Vol. 1 at 37:14-18 (Schichtl).
\item \textsuperscript{122} Tr. Vol. 2 at 333:21-25, 334:1-10 (Settlage).
\item \textsuperscript{123} CCSA Exhibit 1 at 45:5-20 (Barnes Dir.).
\item \textsuperscript{124} N.M. STAT. § 62-16B-2(L).
\item \textsuperscript{125} CCSA Exhibit 1 at 45:5-20 (Barnes Dir.).
\item \textsuperscript{126} Id.
\item \textsuperscript{127} N.M. STAT. § 62-16B-7(B)(8).
\end{itemize}
As mentioned above, ARR is not a defined term within the Community Solar Act, and it only appears within the statute once. However, “total aggregate retail rate” (“TARR”) is a defined term in both the Community Solar Act and Rule 573. TARR is defined as:128

the total amount of a qualifying utility's demand, energy and other charges converted to a kilowatt-hour rate, including fuel and power cost adjustments, the value of renewable energy attributes and other charges of a qualifying utility's effective rate schedule applicable to a given customer rate class, but does not include charges described on a qualifying utility's rate schedule as minimum monthly charges, including customer or service availability charges, energy efficiency program riders or other charges not related to a qualifying utility's power production, transmission or distribution functions, as approved by the commission, franchise fees and tax charges on utility bills.

ARR and TARR both appear in Section 62-16B-7(B)(8). However, the statute provides no additional context to assist in defining ARR. The definition of TARR specifically includes and excludes various rate components, but it is unclear which of those rate components, if any, the Legislature intended to be considered in defining the ARR. In this proceeding, parties have put forth four separate proposals as to how ARR should be interpreted. The Joint Parties and Staff propose that the ARR be interpreted as synonymous with the TARR.129 By contrast, EPE, SPS, and PNM each propose a different definition of the ARR for use in the three percent cap calculation.130 Consequently, ARR is an ambiguous term that requires additional Commission interpretation.

It is doubtful that the Legislature intended for TARR and ARR to be defined as separate and distinct values within the Community Solar Act. In testimony, Staff witness Dunn explained that it is likely that the use of ARR was an unintentional oversight, and that the intention of SB 84

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128 N.M. STAT. § 62-16B-2(O); NMAC 17.9.573.20.B.
129 CCSA Exhibit 1 at 15:10-15 (Barnes Dir.); Staff Exhibit 1: Direct Testimony of Christopher Dunn, p. 25:5-9 (Nov. 13, 2023).
was, “to limit subsidization by non-subscribers such that non-subscribers will not be charged more than three percent of the non-subscribers’ total aggregate retail rate on an annual basis.” This is partially due to the fact that ARR, unlike TARR, is not a defined term in the statute, and also because the specific language surrounding subsidization was a late addition to SB 84.

Further, it is reasonable for the Commission to interpret TARR and ARR as synonymous based on the practical implications of the statute. While the definition of TARR is specific as to the included and excluded rate components, it would require a greater degree of speculation to assign a unique definition to ARR. It is unclear how this definition would differ from that of TARR, as “aggregate” and “total” both generally refer to the summation of several components. The Joint Parties recommend the following equation for calculating the TARR:

\[
TARR \text{ ($/kWh)} = \frac{(\text{Total Base Revenue} - \text{Customer Charges})}{\text{Electricity Sales}} + \text{Fuel & Purchased Power Charge} + \text{RPS Charge}
\]

EPE proposes to define ARR as the total annual billed revenue for all rates and charges divided by total energy sales. EPE witness Schichtl explained in testimony that this interpretation is based on a plain reading of the Community Solar Act. In the context of utility rates, “aggregate” could imply a customer’s whole retail rate, rather than the retail rate after subtracting certain components. In a practical application, using EPE’s definition, with all other data being equal, would produce a higher subsidy cap amount than the definition proposed by Mr.

131 Staff Exhibit 1 at 24:1-8 (Dunn Dir.).
132 Id. at 24:8-10, Exhibit CED-3.
133 Tr. Vol. 2 at 327:6-14 (Settlage).
134 CCSA Exhibit 1 at 42:3-4 (Barnes Dir.).
135 EPE Exhibit 2 at 27:19-20, 28:1-2 (Schichtl Reb.).
136 Id.
137 CCSA Exhibit 1 at 44:15-19 (Barnes Reb.).
As an alternative to the Joint Parties and Staff’s interpretation, it would be reasonable to adopt EPE’s definition of the ARR.

SPS recommends that the Commission adopt a definition of ARR derived from its Energy Efficiency Rider. The Energy Efficiency Rider is calculated based on, “...multiplying all of SPS’s utility charges (including the service availability charge, energy charge, the fuel and purchased power cost adjustment clause charge, and the demand charge and other authorized charges), except gross-receipt taxes and franchise fees.”

By contrast, PNM arbitrarily proposes to define ARR as the TARR, minus the Fuel and Purchased Power Adjustment Clause Credit and the Renewable Energy Attributes Credit. In testimony, PNM witness Settlage stated that the only basis for his proposed definition of ARR is his own professional judgment. PNM also confirmed that it does not use ARR in any other instances for any of its utility operations. By subtracting additional components from the TARR, PNM’s ARR value would have the effect of a lower three percent cap. More specifically, Mr. Settlage explained that using the TARR rather than the ARR to calculate the three percent limitation would increase PNM’s estimation of the subsidy cap by approximately $5.4 million.

As is clear from PNM’s illustrative calculations, the definition of ARR has a significant impact on when the three percent cap is reached. Any definitions of the ARR that result in a value lower than the TARR will reduce the amount of headroom within the cap, thereby limiting future program expansion. Based on the history of the statute and practical implications of this ambiguity,

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139 SPS Exhibit 3 at 11:16-18, 12:1-4 (Trowbridge Reb.).
140 Id. at 11:17-18, 12:1-3.
141 See PNM Exhibit 5 at 7:5-9; PNM Exhibit 6 at 20:10-13 (Settlage Reb.).
142 PNM Exhibit 6 at 20:9-10 (Settlage Reb.); see also Tr. Vol. 2 at 327:22-24 (Settlage).
143 CCSA Exhibit 16: PNM Response to CCSA DR 7-8; Tr. Vol. 2 at 327:25, 328:1-4 (Settlage).
144 PNM Exhibit 6 at 8-10 (Settlage Reb.).
the Commission should interpret the ARR as synonymous with the TARR. Alternatively, it is reasonable for the Commission to adopt EPE’s definition of the ARR, which is consistent with the typical use of “aggregate” within utility rates. While the Joint Parties are not opposed to SPS’s definition of ARR, EPE’s definition provides for additional simplicity and less conjecture regarding Legislative intent.

c. **The Commission should adopt the Joint Parties’ methodology for performing the three percent cap calculation.**

Once the Commission has established its interpretation of “non-subscribers” and “aggregate retail rate,” it must establish a methodology by which the three percent cap can be calculated. Several parties to this proceeding proposed methodologies for performing this calculation. In addition, several parties provided illustrative calculations to demonstrate the mechanics of their approach. The Commission should not adopt subsidy cap figures in this proceeding because total costs and benefits (avoided costs) must be known to produce accurate results. Rather, the three percent cap should be calculated in a retrospective manner in the IOUs’ subsequent GRCs.

To calculate the cap in monetary terms, the Joint Parties recommend the following methodology:\textsuperscript{145}

\[
3\% \text{ Limit} = 3\% \times \text{System-Wide Average Non-Subscriber TARR} \ (\$/\text{kWh}) \times \text{Non-Subscriber Sales} \ (\text{kWh})
\]

This methodology reflects the Joint Parties’ recommendations to define ARR as synonymous as TARR, and to define non-subscribers on a system level. Using this methodology, Mr. Barnes provided illustrative calculations to allow the Commission to visualize this approach. Mr. Barnes estimated the three percent cap for each utility as approximately:\textsuperscript{146}

\textsuperscript{145} CCSA Exhibit 1 at 43:1-2 (Barnes Dir.).

\textsuperscript{146} Id. at 48, Table 2.
Mr. Barnes further explained that these figures likely understate the estimated cap figures, as they only reflect the rate classes included in the IOUs’ subscriber credit calculations, which omitted certain rate classes. Moreover, these estimations likely understate the cap figures due to a lack of access to total revenue requirement figures. These omitted rate classes should be included in actual determinations of the three percent cap amount in future GRCs.

In testimony, PNM witness Settlage proposed a methodology for calculating the three percent cap that shared structural similarity with Mr. Barnes’ approach. Mr. Settlage’s illustrative calculation differed only in that PNM employed a different definition of the ARR, and that the calculation only represented rate classes that have subscribers. These differences in approach are significant. PNM’s illustrative calculation based on its original approach produced a three percent cap figure of approximately $12.1 million, less than half of Mr. Barnes’ estimate. However, as discussed above, PNM has now agreed to include non-subscribers on a system level, which should increase its estimate.

EPE also proposes a calculation structurally the same as that proposed by Mr. Barnes, with the sole difference being EPE’s definition of the ARR. To illustrate this approach, EPE witness Schichtl provided an estimated three percent cap of $3.6 million. As mentioned above, EPE

<table>
<thead>
<tr>
<th>PNM</th>
<th>SPS</th>
<th>EPE</th>
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<tr>
<td>$25 million</td>
<td>$13.1 million</td>
<td>$4.3 million</td>
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148 Ibid. at 50:8-9.
149 See id. at 43:18-19, 44:1.
150 Ibid. at 44:3-8. As noted above, Mr. Settlage changed his position on the stand, stating that all rate classes should be included in the calculation.
151 PNM Exhibit 5 at 7, Table MJS-2 (Settlage Dir.).
153 CCSA Exhibit 5: EPE Response to CCSA DR 7-3.
154 EPE Exhibit 2 at 20:12-13 (Schichtl); see also CCSA Exhibit 5.
proposes a definition of the TARR that, all else being equal, should result in a higher subsidy cap amount than the approach proposed by the Joint Parties. However, Mr. Schichtl’s illustrative calculation produced a subsidy cap result approximately $700,000 less than the illustrative calculation supplied by Mr. Barnes.\textsuperscript{155} This discrepancy can be explained by a difference in time period over which total retail sales were calculated.\textsuperscript{156} Specifically, EIA data indicates that Mr. Schichtl’s illustrative calculation was based on nine months of sales and revenue data, as opposed to twelve months used by Mr. Barnes.\textsuperscript{157} With this correction, EPE’s approach appears to be a reasonable alternative to that of the Joint Parties.

SPS recommends that the three percent limitation be calculated in the same manner as the Energy Efficiency Rider via Rate No. 44.\textsuperscript{158} Specifically, SPS calculates the three percent limitation by multiplying SPS’s 2023 Total Revenue Forecast from its Energy Efficiency Triennial filing by 3%.\textsuperscript{159} Using SPS’s methodology, SPS witness Trowbridge provided an estimated annual cap of $19.9 million, which is over $5 million more than the Joint Parties’ estimate.\textsuperscript{160}

Given that the parties have provided calculation methodologies with structural similarity, the Commission should order the three percent cap to be calculated as:

\textit{3\% \times System-Wide Average Non-Subscriber TARR (\$/kWh) \times Non-Subscriber Sales (kWh)}

As discussed above, the inputs to this calculation should include the ARR as synonymous with the TARR, and non-subscribers based on a system-level.

\textsuperscript{155} Tr. Vol. 1 at 41:12-17 (Schichtl).
\textsuperscript{156} See Tr. Vol. 3 at 568:10-19 (Barnes); CCSA Exhibit 28: EPE’s Sales Data 12 Mo. Ending 9/23 Based on EIA Form EIA 861M.
\textsuperscript{157} CCSA Exhibit 28.
\textsuperscript{158} SPS Exhibit 3 at 11:10-12 (Trowbridge Reb.).
\textsuperscript{159} See id. at 11:10-18, 12:1-4.
\textsuperscript{160} Id. at 12:7-9.
4. The Commission should adopt cost recovery mechanisms that preserve the value of community solar subscriptions over time.

Finally, the Commission must determine the appropriate methodologies for cost recovery, both below and above the three percent cap. To facilitate a positive, equitable customer experience, the Commission should establish uniform methodologies for cost recovery that preserve the value of subscriptions over time. While it appears from initial estimations that the three percent cap will not be reached in the initial phase of the program,\textsuperscript{161} it is still important for the Commission to determine how costs above the three percent limit are recovered. In doing so, the Commission will ensure transparency and stability surrounding subscription value.

a. The Commission should issue a pure accounting order allowing the IOUs to track bill credit costs so that net utility costs within the three percent cap may be recovered from all customers.

To recover net utility costs below the three percent cap, the Commission should issue a pure accounting order authorizing the utilities to track all bill credit costs in a regulatory asset.\textsuperscript{162} Specifically, the Commission’s accounting order should not prejudge the ultimate ratemaking treatment of the accounting order.\textsuperscript{163} The Commission’s decision regarding specific recovery of amounts recorded in the pure accounting order should be deferred until the IOUs’ subsequent GRCs. At that time, the Commission should only authorize recovery of any net utility cost amount after consideration of offsetting CS benefits.\textsuperscript{164} The net utility cost amount should be determined in accordance with the recommendations set forth in Section II.A.2(b) above. Net utility cost

\textsuperscript{161} Id. at 14:6-7; CCSA Exhibit 1 at 50:4-15 (Barnes Dir.).
\textsuperscript{162} CCSA Exhibit 1 at 37:18-19, 38:1-2 (Barnes Dir.). While CCSA initially recommended that the IOUs be permitted to establish a regulatory asset to track bill credit costs, CCSA has since determined that requesting a pure accounting order is more accurate language to reflect Mr. Barnes’ recommendations.
\textsuperscript{163} See NM PRC Docket No. 18-00261-UT, Recommended Decision, p. 13, Adopted in March 27, 2019 Final Order (March 18, 2018).
\textsuperscript{164} CCSA Exhibit 1 at 37:18-19, 38:1-2 (Barnes Dir.).
amounts below the three percent limitation should be recovered from all customers, rather than just subscribers.¹⁶⁵

PNM and EPE also propose deferred recovery by establishing regulatory assets, however, there are several key distinctions between the IOUs’ approaches and CCSA’s recommendation. PNM proposes to establish a regulatory asset and record the full monetary amount of all bill credits distributed to customers.¹⁶⁶ The regulatory asset will accumulate carrying charges at a rate of 4%, and PNM will seek recovery of the costs recorded in that regulatory asset in its next GRC.¹⁶⁷

By contrast, EPE proposes to establish a regulatory asset and record the base bill credit rate (excluding fuel costs), minus avoidable operations and maintenance (“O&M”) costs.¹⁶⁸ The result of this calculation is a “net base rate” component.¹⁶⁹ EPE proposes that the recoverable amount attributable to CS is the net base rate component, multiplied by the electricity generated from CS facilities (in kWh) that is allocated to subscribers.¹⁷⁰ The amounts held in EPE’s regulatory asset would accumulate carrying charges at EPE’s weighted average cost of capital, and may be recovered in a future rate case.¹⁷¹

Unlike PNM and EPE, SPS proposes a Bill Credit Cost Recovery Rate Rider (“BCCR”).¹⁷² Under this approach, SPS proposes to conduct an “economic screening” based on the Southwest Power Pool’s (“SPP”) Day-Ahead Locational Marginal Price (“DALMP”). Compared against CS bill credits paid in a month to subscribers.¹⁷³ The result of this screening is intended to produce

¹⁶⁵ Id. at 54:16-20.
¹⁶⁶ PNM Exhibit 5 at 4:3-8 (Settlage Dir.).
¹⁶⁷ Id.; id. at 27:18-21.
¹⁶⁹ Id. at 13:9-12.
¹⁷⁰ Id. at 13:12-14.
¹⁷¹ EPE Exhibit 1 at 18:1-5, 6:1-4 (Schichtl Dir.).
¹⁷² See generally SPS Exhibit 1 at 10 (Sakya Dir.).
¹⁷³ Id. at 13:2-9; SPS Exhibit 3 at 8:6-9 (Trowbridge Reb.).
economic costs (avoided costs) and uneconomic costs. SPS proposes to recover economic costs through its fuel and purchased power adjustment clause. By contrast, SPS proposes to recover the uneconomic costs through the BBCR from subscribers. SPS argues that this approach is necessary to prevent subsidization. However, should the Commission determine that subsidization is in the public interest, SPS proposes that uneconomic costs should be recovered through its RPS rider.

Each of the IOUs’ bill credit cost recovery proposals unreasonably degrade the value of CS bill credits. Under PNM’s proposed approach, the IOUs essentially charge subscribers back for the bill credit they receive. This approach defeats the fundamental purpose of providing a bill credit in the first place, by assigning the costs of bill credits directly back to subscribers.

EPE proposes to offset subscriber bill credits with fuel and purchased power and avoidable O&M costs. However, this approach fails to account for any future avoided costs that would benefit non-subscribers.

Unlike PNM and EPE, SPS proposes to limit subscriber compensation to the DALMP. The DALMP is the compensation rate SPS offers to large QFs that elect to register in the SPP market. Under SPS’s tariff governing purchases from QFs, New Mexico CS facilities would qualify as large QFs. However, SPS’s tariff does not assign QFs any of the administrative costs.

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174 SPS Exhibit 3 at 8:9-13 (Trowbridge Reb.).
175 Id.
176 Id.
177 Id. at 7:16, 8:1-3.
178 Id. at 13:12-14.
179 CCSA Exhibit 1 at 41:7-10 (Barnes Dir.).
180 Id.
181 EPE Exhibit 6 at 13:9-12 (Carrasco Dir.); Tr. Vol. 1 at 31:18-20 (Schichtl).
182 Tr. Vol. 1 at 34:8-12 (Schichtl).
183 SPS Exhibit 3 at 21:18 (Trowbridge Reb.).
184 Tr. Vol. 2 at 480:5-12 (Trowbridge).
185 See Tr. Vol. 2 at 481:18-24 (Trowbridge); SPS Tariff No. 3018.33, p. 3.
associated with the operation of the QF program.\textsuperscript{186} As subscribers to the CS program are directly assigned administrative costs, SPS’s DALMP proposal results in a CS rate lower than that offered to large QFs.\textsuperscript{187} This result is both arbitrary and contrary to the intent of the Legislature, which specifically directed bill credit rate mechanisms to be derived from the IOUs’ TARR, minus Commission-approved distribution cost components.\textsuperscript{188} While SPS argues that its approach is necessary to resolve ambiguity surrounding cost recovery, Mr. Barnes provided specific proposals for recovery of these costs both below and above the three percent cap (for discussion of cost recovery above the cap, see Section II.A.4(b) below).

Moreover, the New Mexico Supreme Court has previously explained that, “a statute must be construed so that no part of the statute is rendered surplusage or superfluous.” \textit{Katz v. N.M. Dep’t of Human Servs., Income Support Div.}, 1981-NMSC-012, ¶ 18, 95 N.M. 530, 534 (Jan. 26, 1981) (citing \textit{Cromer v. J.W. Jones Construction Company}, 79 N.M. 179 (Ct. App. 1968). As QF rates are already available to CS facilities, it would be improper to conclude that the Legislature enacted the CSA with the intention of providing CS facilities access to these same rates.

To avoid these redundant outcomes, the Commission should adopt the Net Utility Cost methodology for cost recovery below the three percent cap. This includes issuing a pure accounting order directing each IOU to track all bill credit costs in an accounting order, then determining the net utility costs appropriate for recovery from all customers in future GRCs.

Finally, any carrying charges authorized for the pure accounting order should not be included in the subsidy calculation.\textsuperscript{189} This treatment is appropriate, as carrying charges are a cost

\begin{flushright}
\textsuperscript{186} Tr. Vol. 2 at 480:15-18 (Trowbridge).
\textsuperscript{187} Id. at 480:23-25, 481:1-2.
\textsuperscript{188} N.M. STAT. § 62-16B-7(B)(8).
\textsuperscript{189} CCSA Exhibit 1 at 38:11-16 (Barnes Dir.).
\end{flushright}
that arise from the cost recovery mechanism as a reflection of the time value of money.\textsuperscript{190} Consequently, carrying charges are not an incremental cost of the CS program itself.\textsuperscript{191} Consistent with PNM’s proposal, any carrying charges authorized should be set at 4\%.\textsuperscript{192} This rate is lower than the IOUs’ weighted average cost of capital, which is appropriate and reasonable for public policy-driven programs such as CS.\textsuperscript{193}

\begin{itemize}
\item \textbf{b. The Commission should order that net utility costs in excess of the three percent cap be recovered as a volumetric surcharge applied to post-cap project subscribers.}
\end{itemize}

To create a reasonable degree of certainty surrounding the future value of subscriptions, the Commission should, in this proceeding, define procedures for recovery of costs above the three percent cap. If and when the three percent cap is reached, subscribers will bear additional program costs.\textsuperscript{194} This reality sets up a scenario in which initial subscribers may see the value of their subscription degrade over time, with little insight into how large that degradation will be.\textsuperscript{195} Moreover, initial subscribers may experience a cost shift in which they are assigned costs that were caused by a later CS facility.\textsuperscript{196} This scenario would provide for a poor customer experience, and could be detrimental to program viability.\textsuperscript{197}

As a result, the Commission should order any subsidy costs above the three percent cap to be recovered from subscribers to CS facilities added after the cap has been reached.\textsuperscript{198} Any recoverable net utility cost in excess of the three percent cap should be assigned to new subscribers

\begin{itemize}
\item \textsuperscript{190} Id.
\item \textsuperscript{191} Id.; Id. at JRB-6: PNM Response to CCSA DR 5-16(A).
\item \textsuperscript{192} Id. at 38:3-8.
\item \textsuperscript{193} Id.
\item \textsuperscript{194} SPS Exhibit 3 at 14:8-9 (Trowbridge Reb.).
\item \textsuperscript{195} CCSA Exhibit 1 at 53:4-7 (Barnes Dir.).
\item \textsuperscript{196} Id.
\item \textsuperscript{197} Id. at 54:5-7.
\item \textsuperscript{198} Id. at 54:4-11.
\end{itemize}
as a volumetric surcharge to the volume of their subscription amount.\textsuperscript{199} For future tranches of the program, the Joint Parties recommend that subscribers that enter the program after the cap has been reached would receive a net credit based on all CS benefits, minus administrative charges.\textsuperscript{200} Assigning net utility costs above 3\% only to subscribers of projects that caused the subsidy limit to be breached, provides a reasonable degree of certainty and transparency into subscription value for both initial and future subscribers, and ensures that initial subscription value is not significantly degraded over time. Degrading CS subscription values over time will lead to customer frustration and loss of savings, including for low-income customers.

\section*{B. The Commission Should Adopt Uniform and Predictable Administrative Cost Recovery Mechanisms to Recover Reasonable and Demonstrable Incremental Administrative Costs of the Community Solar Program.}

Section 62-16B-7(B)(6) of the CSA and Commission Rule 17.9.573.13(D) provide that the IOUs may recover the reasonable costs associated with their roles in administering the CS program.\textsuperscript{201} In this proceeding, the IOUs have put forth a range of costs associated with administering the CS program, as well as varying methodologies to recover those costs. The Commission’s determination of which costs are attributable to CS, the reasonableness of those costs, and how recovery is effectuated are additional key factors that will impact the overall success of the program.

Potential CS subscribers will evaluate the value of a subscription based on the costs and benefits of participating in the program.\textsuperscript{202} One major, immediate benefit of participating in CS for subscribers is the bill credit they receive.\textsuperscript{203} On the other hand, the costs are the fees that

\textsuperscript{199} \textit{Id.} at 21:3-6.  
\textsuperscript{200} \textit{Id.} at 53:16-18.  
\textsuperscript{201} N.M. STAT. § 62-16B-7(B)(6); NMAC 17.9.573.13(D).  
\textsuperscript{202} Tr. Vol. 1 at 141:16-19 (Carrasco).  
\textsuperscript{203} \textit{Id.} at 141:20-23.
subscribers are charged for participating in the program. As a result, the monetary value of a CS subscription to a subscriber is the bill credit, minus the subscription fee for their participation in the program and any CS-specific utility costs recovered from subscribers.

Given this reality, the scope of utility costs recoverable from subscribers is directly related to the value subscribers will reap from program participation. Along these lines, major, unforeseen fluctuations in the value of CS subscriptions will lead to a poor program experience for subscribers, and difficulty for subscriber organizations to deliver certain levels of savings committed to in the project selection process. Consequently, administrative cost recovery approved by the Commission should promote stability and predictability in order to protect subscribers and subscriber organizations from unreasonable volatility.

To accomplish these outcomes, the Commission should adopt the uniform methodology for administrative cost recovery proposed by the Joint Parties. This methodology includes:

- Categorizing costs as one-time or recurring;
- Recovering reasonable recurring costs through a uniform, volumetric administrative rider rate, separately from bill credit or subsidy costs; and
- Ordering that one-time costs be presented in the IOUs’ future GRCs for additional Commission scrutiny and recovery of reasonable costs from the general body of ratepayers.

In accordance with this methodology, the Commission should also adopt reasonable administrative cost rates based on PNM and SPS’s reasonable administrative costs. Approving administrative cost rates upfront will create additional transparency for potential subscribers as to

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204 Id. at 141:24-25, 142:1.
205 Id. at 142:7:10.
206 Id. at 142:11-14.
207 NMAC 17.9.573.12(E)(5)(d).
the value of a subscription.\textsuperscript{208} Moreover, upfront approval of these costs will provide subscriber organizations with the certainty needed to deliver certain guaranteed levels of bill savings. Because EPE has failed to produce an administrative cost proposal, the Commission should order it to develop a reasonable administrative cost rate proposal for evaluation via an advice letter. These recommendations are discussed in more depth below.

\textbf{1. The Commission should require administrative costs to be categorized as one-time or recurring.}

In this proceeding, PNM provided a detailed proposal in which specific administrative costs were delineated as one-time or recurring.\textsuperscript{209} In rebuttal, SPS also provided further clarification as to the categorization of its administrative costs.\textsuperscript{210} As explained by Mr. Barnes, one-time administrative costs should include essential upgrades in billing and customer information systems necessary for efficient subscriber enrollment, processing, and crediting.\textsuperscript{211} Recurring costs should encompass dedicated CS customer service and billing staffing.\textsuperscript{212}

Categorizing costs in this manner provides the Commission and stakeholders with predictability and clarity regarding the nature and timing of administrative costs. This distinction is key, as it allows for distinct approaches to cost recovery based on specific types of costs. For example, one-time costs associated with initial program setup are not appropriate for inclusion in an administrative cost rider. These specific recommendations are described in more detail below.

\textsuperscript{208} Tr. Vol. 2 at 365:1-11 (Settlage).
\textsuperscript{209} See PNM Exhibit 5 at 5:9-17, 6:6-10 (Settlage Dir.).
\textsuperscript{210} See SPS Exhibit 4: Rebuttal Testimony of Kerry Klemm, p. 8, Table 1 (Dec. 8, 2023).
\textsuperscript{211} CCSA Exhibit 1 at 66:14-16 (Barnes Dir.).
\textsuperscript{212} Id. at 66:16-17.
2. The Commission should order recurring costs to be recovered through an administrative cost rider.

Consistent with Commission Rule 17.9.573.13(D), the Commission should order reasonable recurring costs, incremental to the CS program, to be recovered through the utilities’ administrative cost riders.\(^{213}\) In this proceeding, PNM and SPS have offered specific estimates of their recurring CS program administrative costs.\(^{214}\) Based on these figures, the Commission should adopt specific administrative cost rider rates for 2023-2026. By setting these rates upfront, the Commission will ensure transparency and predictability for subscribers and subscriber organizations as to the value of CS subscriptions.

As a preliminary matter, administrative cost riders should be limited to the recovery of administrative costs. Any bill credit or subsidy costs should be recovered via a separate rider.\(^{215}\) To provide for subscriber equity and administrative efficiency, the structure for recovery of administrative costs should be uniform across all utilities.\(^{216}\) As proposed by PNM and SPS, the administrative cost charge should be a volumetric rate.\(^{217}\)

As discussed above, additional program costs reduce the monetary value of CS subscriptions. Given this reality, it is important to create predictability and stability for subscribers so that they have a reasonable degree of certainty as to the bill savings they can rely on. This is important not only for subscriber satisfaction, but also as a protection for low-income subscribers that will rely on monthly bill savings. This consideration is especially important at the outset of

\(^{213}\) *Id.* at 67:11-16.

\(^{214}\) See SPS Exhibit 3 at Attachment AGT-R7 (Trowbridge Reb.); PNM Exhibit 6 at 7:13-17, 8:1-3 (Settlage Reb.).

\(^{215}\) CCSA Exhibit 1 at 66:4-5 (Barnes Dir.).

\(^{216}\) *Id.* at 67:11-13.

\(^{217}\) *Id.*
the program, as both PNM and SPS expect recurring administrative costs to increase significantly after the initial program year.\textsuperscript{218}

To create stability and predictability for subscribers, the Commission should approve administrative cost rates for the recovery of reasonable recurring costs on a three-year basis. In this proceeding, the Commission should set administrative cost rates for PNM and SPS based on the total amounts of reasonable recurring costs the IOUs proposed for the 2023-2026 period. To calculate the appropriate administrative cost rate, the recurring costs (assuming full program subscription) should be divided by the full amount of estimated CS production over the 2023-2026 period. That figure should provide the basis to calculate the $/kWh administrative cost rate.

PNM identifies two types of recurring costs: (1) program administration costs, and (2) revenue support and customer assistance staffing costs.\textsuperscript{219} While PNM did not provide specific annual estimates covering expected costs through 2026, CCSA estimates PNM’s total 2024-2026 recurring program costs to be $2,819,486. This figure includes $219,662 per year in recurring program administration costs,\textsuperscript{220} which would sum to $658,986 from 2024-2026. Added to that is $447,000 in initial program staffing costs for six total supporting staff,\textsuperscript{221} which we have designated as 2024 costs for the purpose of the above estimate. For 2025 and 2026 the Joint Parties estimate PNM’s annual staffing costs at $856,750 based on its expectation of expanded staffing needs,\textsuperscript{222} totaling $1,713,500 over 2025-2026. Based on an assumption of full subscription at

\textsuperscript{218} See SPS Exhibit 4 at 8, Table 1 (Klemm Reb.); PNM Exhibit 6 at 7:13-17 (Settlage Reb.).

\textsuperscript{219} PNM Exhibit 6 at 7:13-17 (Settlage Reb.).

\textsuperscript{220} Id.

\textsuperscript{221} Id.

\textsuperscript{222} Id. (While PNM did not supply estimates of the costs associated with these additional employees, its initial staffing budget of $447,000 can be scaled to arrive at an estimated $856,750 based on the ratio of full expected staffing needs of 11.5 full-time equivalent staff to the initial staffing requirement of six employees).
937,500,000 kWh over three years (2024-2026),\textsuperscript{223} which equates to an implied capacity factor of 28.5%,\textsuperscript{224} PNM’s 2023-2026 administrative cost rider should be set at $0.003007/kWh ($2,819,486 / 937,500,000 kWh).

SPS estimates a total of $923,918 in recurring costs for program years 2023-2026.\textsuperscript{225} Based on full subscription over the same period at 295,650,000 kWh,\textsuperscript{226} which equates to an implied capacity factor of 25%,\textsuperscript{227} SPS’s administrative cost rider for 2023-2026 should be set at $0.003125/kWh.

In line with these recommendations, the Commission should allow the IOUs to propose changes to administrative cost rate riders no more frequently than once every three years (after 2026). The Commission should only approve changes if IOUs can support any proposed changes to administrative cost rates with evidence explaining the purpose of the costs and how they are incremental to the CS program.

3. The Commission should further scrutinize one-time costs in future rate cases for recovery from all customers.

The CSA and Rule 573 allow the IOUs to recover reasonable costs associated with their roles in operating the CS program.\textsuperscript{228} Therefore, costs assigned to subscribers through administrative cost riders must be both reasonable and incremental to the program. Costs that are not incremental are costs that the utility would have incurred regardless of the CS program, and therefore should be recovered from all customers. Both PNM and SPS have provided estimates of

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\textsuperscript{223} PNM Exhibit 5 at 5, Table MJS-1 (Settlage Dir.) (Calculated as the expected annual subscription volume of 312,500,000 kWh \times 3 years).
\textsuperscript{224} Capacity Factor = 312,500,000 MWh / (125 MW \times 8,760 annual hours) = 28.5%.
\textsuperscript{225} SPS Exhibit 3 at Attachment AGT-R7 (Trowbridge Reb.), Tab “Administrative Budget,” totaled for rows labeled “recurring.”
\textsuperscript{226} \textit{Id.} at Tab “WP Admin Cost,” Line 8.
\textsuperscript{227} Capacity Factor = 98,550,000 MWh / (45 MW \times 8,760 annual hours) = 25.0%.
\textsuperscript{228} N.M. STAT. § 62-16B-7(B)(6); NMAC 17.9.573.13(D).
\end{flushleft}
up-front costs related to the setup of the initial program that either provide a larger system benefit or are not incremental to the CS program. As such, the Commission should order these costs to be presented in future GRCs, and reasonable one-time costs should be recovered from all ratepayers.

Consistent with this approach, PNM proposes recovery of one-time technology system upgrades in base rates, rather than including these costs in its administrative cost rider.229 PNM witness Settlage explained that the expense to accurately identify and track CS-specific program costs within a larger IT investment is costly compared to the overall amount of the investment.230 Rather, PNM will seek recovery of one-time costs in its next general rate case.231

This approach is particularly reasonable, given the difficulty in ascertaining whether these costs are truly incremental to CS. The large-scale technology system upgrades proposed by the IOUs will likely provide system-wide benefits that extend beyond the confines of the CS program.232 It is difficult to predict how these upgrades may support other future programs and rate structures, resulting in future avoided costs to the utilities.233 Further, these investments are necessary to get the program up and running. This represents a larger system benefit, as it enables all eligible customers to equally participate in the program. Accordingly, excluding one-time administrative costs from the IOUs’ administrative cost riders is a more equitable approach to the allocation of these costs.

SPS has proposed several categories of costs that are either unreasonable or not incremental to the CS program. Specifically, the Commission should reject SPS’s proposal to include regulatory costs related to its decision to hire outside legal counsel, optional witness travel,

230 PNM Exhibit 5 at 6:6-10 (Settlage Dir.).
231 Id.
232 CCSA Exhibit 1 at 67:5-7 (Barnes Dir.).
233 Id. at 67:7-9.
and general notice costs for recovery through its administrative cost rider. These costs are associated with the general cost of doing business as a regulated utility and are not incremental to the CS program. Rather, SPS should present these costs in a future GRC, which will provide the Commission with more opportunity to scrutinize the reasonableness of these costs.

SPS seeks to recover $95,315 in outside legal costs as a one-time cost associated with the community solar program. In support of these costs, SPS argues that its in-house legal staff handles numerous regulatory matters and is therefore limited in its ability to act as the sole legal counsel litigating complex regulatory matters. This contention fails to acknowledge that costs associated with outside counsel are not unique to CS. Indeed, each IOU regularly uses outside counsel for cases before the Commission, as the work is highly specialized and often requires additional resources. As highlighted by SPS witness Lees, outside counsel would be necessary to supplement SPS’s in-house resources in any complex regulatory matter before the Commission, and is a regular part of SPS’s regulatory litigation. While Ms. Lees notes that each IOU has retained outside counsel for this proceeding, neither PNM nor EPE propose to assign outside counsel expenses directly to CS subscribers as an incremental administrative cost.

SPS also proposes recovery of $5,200 in witness travel expenses through its administrative cost rider. However, the Procedural Schedule in this proceeding allowed for virtual witness participation in all hearings via Zoom. While SPS witness Lees argues that it was “efficient and reasonable for witnesses to prepare and appear with their attorneys for the hearing in a manner as

\[\text{Id. at 62:14-17.}\]
\[\text{See SPS Exhibit 4 at p. 8 Table 1 (Klemm Reb.).}\]
\[\text{SPS Exhibit 2 at 22:10-13 (Lees Reb.).}\]
\[\text{Id. at 24:11-14.}\]
\[\text{See id. at 24:11-14, 25:6-11.}\]
\[\text{Id.}\]
\[\text{SPS Exhibit 4 at p. 8 Table 1 (Klemm Reb.).}\]
\[\text{CCSA Exhibit 1 at 62:9-10, Exhibit JRB-6 (Barnes Dir.).}\]
similar to an in-person hearing as possible,” this argument is unsubstantiated. In today’s digital age, virtual platforms offer an efficient and effective means for witness preparation, eliminating the need to incur costly travel expenses. Along these lines, conducting hearings virtually presents an opportunity for SPS to reduce unnecessary expenditures. If, however, unnecessary witness travel expenses are indeed part of SPS’s regular course of preparation for hearings before the Commission, then these costs cannot be considered incremental to the CS program. Similarly, SPS routinely incurs notice costs in its regulatory operations. While notices are an important consumer protection measure, they are a regulatory cost not incremental to the CS program. Consequently, notice costs are inappropriate for inclusion in the administrative cost rider.

Finally, SPS claims that it will incur $600,000 in upfront costs in upgrades to its online portal and its billing system. Specifically, SPS anticipates that online portal upgrades will cost $450,000, and the billing system upgrades will cost $150,000. These upfront technology costs represent the majority of SPS’s initial program budget. However, SPS has failed to meet its burden of demonstrating that these costs are reasonable. SPS is a jurisdictional utility of Xcel Energy, which operates similar community solar programs in Colorado and Minnesota. Both jurisdictions have online community solar portals, which are based on the same core system of salesforce.com. SPS has explained that the development of these technology systems is expected to require significantly less effort than other jurisdictions have required, due to the ability to reuse existing infrastructure and code.

242 SPS Exhibit 2 at 27:13-15 (Lees Reb.).
243 See e.g., NM PRC Docket No. 22-00286-UT, Certification of Stipulation, p. 105 (Sept. 6, 2023).
244 CCSA Exhibit 1 at 62:5-6 (Barnes Dir.).
245 See SPS Exhibit 4 at 8, Table 1 (Klemm. Dir.).
246 Id. at 10:2-4.
247 Id. at 453:14-17 (Klemm).
248 Id. at 454:25, 455:1-7 (Klemm).
249 See id. at 454:19-24 (Klemm).
SPS argues that the high cost estimate for building out the online portal is attributed to the unique requirements of the New Mexico program.250 However, many of the program requirements SPS cites to as unique to New Mexico are program components that Xcel has experience implementing in its other jurisdictions.251 Moreover, only two of the functions SPS lists as necessary to the buildout of the online portal are unique to New Mexico.252 While SPS claims that the ability to reuse existing infrastructure and code should result in some cost savings, it has provided no evidence that any cost savings will be achieved.253 In fact, its upfront cost estimate closely resembles the upfront administrative costs of its affiliate, Northern States Power in Minnesota.254 However, the Northern States Power CS program consists of 864 MW and 421 active systems.255 On a per-facility and per-MW basis, SPS’s administrative costs are significantly higher than that of Northern States Power.256

Finally, the disparity between SPS’s upfront administrative cost estimate and that of PNM, which does not have the benefit of affiliate experience with community solar and is allocated significantly more program capacity, underscores the need for scrutiny regarding the reasonableness of SPS’s cost projections.257 Specifically, SPS’s one-time administrative cost proposal is 5.9 times higher than that of PNM on a $/MW basis.258 By ordering the IOUs to present

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250 Id. at 444:17-25, 445:1-2 (Klemm).
252 Tr. Vol. 2 at 457:10-14 (Klemm).
253 CCSA Exhibit 25: SPS Response to CCSA DR 9-9; Tr. Vol. 2 at 458:10-22 (Klemm).
254 CCSA Exhibit 24: SPS Response to CCSA DR 4-8; Tr. Vol. 2 at 451:15-23, 452:1-4 (Klemm); Staff Exhibit 1 at 32:13-16, 33:1-3 (Dunn Dir.).
255 Staff Exhibit 1 at 32:13-16, 33:1-3 (Dunn Dir.).
256 See id. (referencing SPS’s original administrative cost proposal. However, this assertion remains true, even with SPS’s revised budget proposal).
257 See PNM Exhibit 3: Direct Testimony of Lisa Contreras, p. 11:5-18 (Sept. 18, 2023) (explaining that PNM’s cost of programming the CIS billing system for community solar is a capital cost of $338,842).
258 Calculated based on total one-time costs of $720,515 derived from SPS Exhibit 3, Exhibit AGT-R7 divided by 45 MW, producing an SPS one-time cost of $16,011/MW. PNM’s one-time costs of $339,000 were derived from PNM Exhibit 6 at 7:9-10, which are divided by 125 MW to produce a one-time cost of
these costs in a GRC for recovery from the general body of customers, the Commission will have a greater opportunity to determine if these costs are reasonable.

4. The Commission should order EPE to propose an administrative cost rate based on its expected reasonable costs for program administration.

Unlike PNM and SPS, EPE did not provide any estimate of the costs it expects to incur for program administration.259 Rather, EPE proposes to charge subscribers and subscriber organizations certain amounts for services in the interim, until actual costs for administering the program are known.260 EPE states that in a future filing or reconciliation, it intends to evaluate its administrative charges and rates based on actual activities and costs over the course of twelve months.261

Under EPE’s proposed approach, subscribers will have little insight into the value of their subscription once EPE evaluates its actual program administration costs.262 As EPE has not forecasted any administrative costs, its actual costs are likely to vary, possibly significantly, from the interim fees it proposes.263 While EPE suggests that customers should just expect unforeseen fluctuations in the value of their subscriptions,264 this is likely to create a poor customer experience and decrease the attractiveness of program participation for potential subscribers. Moreover, the program is designed to deliver monthly bill savings to low-income subscribers within EPE’s territory, and project selection criteria included consideration of certain levels of guaranteed savings to these customers. Without transparency surrounding administrative costs, volatility in

$2,712/MW. Therefore, the ratio of SPS’s one-time costs to PNM’s one-time costs on a $/MW basis equals $16,011/$2,712 = 5.90.

259 Tr. Vol. 1 at 139:5-11 (Carrasco).
260 Id. at 139:12-16.
261 Id. at 139:25, 140:1-5.
262 Id. at 143:1-5.
263 Id. at 140:20-25, 141:1-4.
264 Id. at 143:6-9.
the value of subscriptions could lead to a larger equity issue in which low-income subscribers are no longer able to depend on needed bill savings.

To create a uniform, transparent, and predictable methodology for administrative cost recovery, the Commission should order EPE to propose a reasonable administrative cost rate via an advice letter within thirty days of the conclusion of this proceeding. The Commission should order that EPE follow the methodology described in the above sections to develop its administrative cost rate proposal. This process should provide stakeholders with the opportunity to review and provide suggestions on EPE’s proposed administrative cost rates. As EPE has entirely failed to carry its evidentiary burden of demonstrating a reasonable administrative cost proposal, CCSA recommends that the Commission consider the context of the 2023-2026 administrative cost rates for PNM and SPS in setting a reasonable rate for EPE.

C. The Commission Should Order PNM and SPS to Revise Their Proposed Bill Credit Rates to Comply with the Community Solar Act.

The CSA provides that the Commission shall, “provide a community solar bill credit rate mechanism for subscribers derived from the qualifying utility's total aggregate retail rate on a per-customer-class basis, less the commission-approved distribution cost components…” More specifically, Rule 573 directs the utilities to:

... calculate the total aggregate retail rate on a per-customer-class basis, less the commission-approved distribution cost components, and identify all proposed rules, fees and other charges converted to a kilowatt-hour rate, including fuel and power cost adjustments, the value of renewable energy attributes and other charges of a qualifying utility's effective rate schedule applicable to a given customer rate class, but does not include charges described on a qualifying utility's rate schedule as minimum monthly charges, including customer or service availability charges, energy efficiency program riders or other charges not related to a qualifying utility's power production, transmission or distribution functions, as approved by the commission, franchise fees and tax charges on utility bills.

265 N.M. STAT. § 62-16B-7(B)(8).
266 NMAC 17.9.573.20(A).
As explained above, TARR is a defined term within both the Community Solar Act and Rule 573.\textsuperscript{267} Subscriber credit rates are effectively calculated as the TARR, by rate class, minus the distribution cost component and the fixed monthly customer or service availability charges.\textsuperscript{268} To calculate the appropriate bill credit rate, the utilities must first calculate the TARR.\textsuperscript{269}

In this proceeding, PNM and SPS have proposed bill credit rates that fail to comply with this statutory and regulatory guidance. PNM improperly excludes “monthly minimum demand charges” and power factor adjustment charges from its calculation of the TARR in determining the bill credit rate for the General Power and Large Power rate schedules.\textsuperscript{270} This approach significantly lowers the bill credit rate for both rate classes.

Further, PNM proposed in its most recent GRC to apply a rate increase mitigation adjustment mechanism solely to the non-fuel energy cost of service rate component.\textsuperscript{271} This proposal is inconsistent with Rule 573 and ultimately lowers the residential subscriber bill credit rate.\textsuperscript{272} This proposal, if accepted, would set a precedent by which bill credit rates may fluctuate and be significantly reduced in value based on manipulations of the cost of service results.

SPS, on the other hand, inappropriately calculates the exclusion of all customer-related costs from the TARR, even those that are not recovered in a fixed monthly charge.\textsuperscript{273} Specifically, SPS improperly excludes customer-related costs identified in its cost-of-service study, even if those costs are recovered in a volumetric or demand-based rate. SPS’s approach is not consistent with the CSA or rules and would inappropriately lower subscriber credit rates; primarily for

\textsuperscript{267} N.M. STAT. § 62-16B-2(O); NMAC 17.9.573.20(B).
\textsuperscript{269} Tr. Vol. 2 at 317:9-12 (Settlage).
\textsuperscript{270} CCSA Exhibit 1 at 93:4-6 (Barnes Dir.); PNM Exhibit 5 at 10, Table MJS-3 and 11:9-12 (Settlage Dir.).
\textsuperscript{271} CCSA Exhibit 1 at 96:7-9 (Barnes Dir.).
\textsuperscript{272} \textit{Id.} at 95:11-15, 97:6-10.
\textsuperscript{273} \textit{Id.} at 90:34-35.
residential and residential heating customers. Consistent with Rule 573, and for the reasons detailed below, the Commission should order PNM and SPS to correct these improper bill credit rate calculations.

1. The Commission should direct PNM to include monthly demand charges incorporated within the General Power and Large Power rate schedules in the subscriber credit rate.

As the bill credit is based on the TARR, charges excluded from the TARR are also excluded from the bill credit. To this end, exclusion of charges from the TARR has the effect of reducing subscriber bill credit rates. Specifically, PNM’s exclusion of “minimum monthly demand charges” from the TARR reduces the credit for General Power customers by 2.46 cents/kWh. Similarly, this approach reduces the credit for Large Power customers by 2.35 cents/kWh.

The CSA and Rule 573 define the TARR to include the “total amount of a qualifying utility’s demand, energy and other charges converted into a kilowatt-hour rate…” The same definition requires the exclusion of, “charges described on a qualifying utility’s rate schedule as minimum monthly charges, including customer or service availability charges…” PNM’s proposal to exclude minimum monthly demand charges is based on the Rule’s reference to “minimum monthly charges.” To reconcile these two elements of the TARR, it is necessary to delineate what constitutes a demand charge and what constitutes a minimum monthly charge.

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274 Id. at 91:7-13.
275 PNM Exhibit 5 at 12:19-20 (Settlage Dir.).
276 CCSA Exhibit 1 at 94:9-12 (Barnes Dir.).
277 Id. at 94:12-13.
278 N.M. STAT. § 62-16B-2(O); NMAC 17.9.573.20(B).
279 Id.
280 CCSA Exhibit 1 at 93:16-18 (Barnes Dir.); PNM Exhibit 5 at 14:6-7 (Settlage Dir.).
281 CCSA Exhibit 1 at 93:18-21.
The most logical approach to distinguishing demand charges from minimum monthly charges is to evaluate whether the charge varies based on customer electricity use. In both the General Power and Large Power rate schedules, PNM includes a monthly minimum charge. The monthly minimum charge consists of two components: a fixed customer charge, as well as a variable minimum monthly demand charge. Variable demand charges should be included in the TARR calculation, while fixed monthly charges should be excluded.

Typically, large commercial customers pay demand charges based on their maximum kilowatt usage during a specified period in the month. For example, if the demand charge was $1, and a customer’s peak demand during the relevant period was 100 kW, the customer’s demand charge would be $100. However, if the customer had no demand in the following month, they would be subject to the minimum monthly demand charge. As such, the minimum demand charge is assessed based on the customer’s actual usage. Unlike the customer charge, it is not fixed.

Minimum demand charges are based on an assumed minimum usage, which is commonly 50 kW or 500 kW in PNM rate schedules. PNM’s minimum monthly demand charge is calculated as “Total Demand multiplied by the On-Peak Demand Charge rate.” Along these lines, if the customer described above was on a rate with a 50 kW minimum demand and a $1 minimum demand charge, and the customer used zero kW during the month, the customer would be subject to the $50 minimum demand charge.

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282 Id. at 94:1-2.
283 Tr. Vol. 2 at 323:14-21, 324:1-3 (Settlage).
284 Id. at 320:12-17.
285 CCSA Exhibit 1 at 94:4-6 (Barnes Dir.).
286 Tr. Vol. 2 at 318:13-17 (Settlage).
287 Id. at 318:18-25, 319:1.
288 Id. at 319:2-6.
289 Id. at 319:7-19.
290 CCSA Exhibit 1 at 94:2-4 (Barnes Dir.).
Depending on the customer’s usage, customers on demand-based rates sometimes pay minimum monthly demand charges, and sometimes pay their actual measured demand for the month. More specifically, customers are only subject to the minimum monthly demand charge when they use less than the minimum assumed demand (in the example above — 50 kW). In all other cases, these customers are charged based on their actual billable demand. As PNM’s minimum monthly demand charges vary based on a customer’s monthly demand, these charges are properly regarded as variable charges that should be included in the TARR.

Further, PNM’s minimum monthly demand charges are functionally in line with the charges explicitly included in the definition of the TARR. As mentioned above, the TARR includes the “total amount of a qualifying utility’s demand, energy and other charges converted into a kilowatt-hour rate…” At hearing, PNM witness Settlage explained that PNM’s minimum monthly demand charges are designed, at least in part, to recover demand-related costs. As a general rule, demand charges are designed to recover the demand-related costs of production, transmission, and distribution. PNM’s sample CS bill credit calculation confirms that this is also PNM’s practice. Consequently, it is reasonable to conclude that PNM’s minimum monthly demand charges should be included in the TARR in order to properly calculate subscriber bill credit rates.

292 Id. at 320:22-25, 321:1-3.
293 Id. at 321:4-8.
294 Id. at 321:9-11.
295 CCSA Exhibit 1 at 94:4-6 (Barnes Dir.); Tr. Vol. 3 at 563:14-23 (Barnes).
296 N.M. STAT. § 62-16B-2(O); NMAC 17.9.573.20(B).
297 Tr. Vol. 2 at 321:12-14 (Settlage).
298 Id. at 323:17-20; see also Staff Exhibit 2: Rebuttal Testimony of Christopher Dunn, p. 12:12-15 (Dec. 8, 2023) (explaining that Staff understands PNM’s minimum monthly demand charges to relate to its production function).
299 See PNM Exhibit 5 at MJS-4, p. 1, lines 104 (stating “PNM Community Solar Bill Credit Calculations Based on Case No. 16-00276-UT”).
Finally, as explained by Staff witness Dunn, the Commission has previously approved bill credit rates that include minimum monthly demand charges.\textsuperscript{300} Further, PNM previously proposed bill credit rates that included minimum monthly demand charges, which is consistent with the approach developed by Staff and the IOUs in a series of workshops.\textsuperscript{301} There have been no changes to the CSA, Rule 573, or additional collaborations between Staff and the IOUs that support PNM’s deviation from its previous proposal.\textsuperscript{302}

PNM also proposes to exclude monthly power factor adjustment charges from its calculation of the TARR.\textsuperscript{303} Similarly to the minimum monthly demand charges described above, PNM’s power factor adjustment charges vary based on a customer’s monthly maximum demand.\textsuperscript{304} Staff witness Dunn further explained that PNM has not “clearly demonstrated that these charges are not related to the utility’s power production, transmission, or distribution functions…”\textsuperscript{305} While PNM argues that it must collect these costs regardless of CS deployment,\textsuperscript{306} this issue is unrelated to whether the monthly power factor adjustment charges should be excluded from the TARR. As PNM’s power factor adjustment charges vary by customers’ monthly maximum demand, they are by definition demand charges that are properly included in the TARR.\textsuperscript{307}

To correct PNM’s calculation of the bill credit rates for the General Power and Large Power rate schedules, the Commission should order PNM to include minimum monthly demand charges

\textsuperscript{300} Staff Exhibit 2 at 9:10-15 (Dunn Reb.) (stating that EPE’s Commission-approved bill credit rates include minimum monthly demand charges).
\textsuperscript{301} Id. at 10:4-7.
\textsuperscript{302} Id. at 10:7-13.
\textsuperscript{303} PNM Exhibit 5 at 11:9-10 (Settlage Dir.).
\textsuperscript{304} CCSA Exhibit 3 at 21:20 (Barnes Reb.); REIA Exhibit 1 at 7:1-6 (DesJardins Dir.); Staff Exhibit 1 at 16:11-13 (Dunn Dir.).
\textsuperscript{305} Staff Exhibit 1 at 16:13-16 (Dunn Dir.).
\textsuperscript{306} PNM Exhibit 6 at 16:20-22 (Settlage Reb.).
\textsuperscript{307} CCSA Exhibit 3 at 21:20-21 (Barnes Reb.).
and power factor adjustment charges in its calculation of the TARR. The corrected inputs to the TARR are illustrated in Mr. Barnes’ Direct Testimony in Table 1, which provided applicable rates of:

**General Power:** $0.11419 (Total TARR); $0.07745 (Base Component)

**Large Power:** $0.09550 (Total TARR); $0.05924 (Base Component)

While these figures represent the appropriate application of the recommendations set forth above, they were calculated prior to the completion of PNM’s GRC and will therefore need to be updated.

2. **The Commission should clarify that for the purposes of the bill credit calculation, the distribution cost component is based on the IOUs’ cost of service studies.**

As explained above, the CS bill credit rate is calculated based on the TARR, less the Commission-approved distribution cost components. Rule 573 requires that, “The utility shall base its distribution cost calculation upon its most recently commission-approved cost-of-service study indexed to current value.”

“Indexing” refers to the practice of matching class revenue requirements from the cost of service study with adopted class revenue requirements on which retail rates, and subscriber bill credits, are based. In calculating bill credit rates, PNM has proposed distribution cost components that are not properly based on its cost of service study. PNM’s example residential community solar bill reflects a base bill credit that was calculated based on the rates proposed in its GRC, which was pending at the time of direct testimony. In its GRC, PNM proposed to apply a banding mechanism to its class revenue

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308 CCSA Exhibit 1 at 47, Table 1 (Barnes Dir.).
309 N.M. STAT. § 62-16B-7(B)(8); NMAC 17.9.573.20(A).
310 NMAC 17.9.573.20(C).
311 CCSA Exhibit 1 at 96:4-14 (Barnes Dir.).
312 Id. at 95:7-18.
313 Id.
requirements.\textsuperscript{314} In calculating estimated bill credit rates, PNM utilized a distribution cost component figure that reflected this proposed banding mechanism, rather than basing the distribution cost component figure on its cost of service study.\textsuperscript{315} This approach is inconsistent with Rule 573, and artificially lowers the residential bill credit rate.\textsuperscript{316} While it is unclear whether the Commission ultimately adopted PNM’s banding proposal,\textsuperscript{317} the Commission should clarify in this proceeding that for the purposes of the bill credit calculation, distribution cost components should be based on the actual cost of service. Further, the Commission should order PNM to calculate the subscriber bill credit by indexing the distribution cost component to the ratio of: (a) the cost of service calculated in the revenue requirement, to (b) the adopted class revenue requirement, for each customer class.\textsuperscript{318}

3. The Commission should require SPS to correct its calculation of the TARR to be based on the sum of annual revenue from customer or minimum charges.

As described above, the TARR excludes, “...charges described on a qualifying utility’s rate schedule as minimum monthly charges, including customer or service availability charges...”\textsuperscript{319} Unlike PNM and EPE, SPS proposes to exclude customer-related costs identified in its cost of service study rather than the actual charges described on its rate schedules as minimum monthly charges.\textsuperscript{320} This approach is in direct conflict with the CSA and the Commission's rules, which only allow for the exclusion of minimum monthly charges.\textsuperscript{321} The statute and rules do not allow for IOUs to exclude all customer-related costs identified in their cost of service studies. SPS’s non-

\begin{footnotesize}
\textsuperscript{314} Id.
\textsuperscript{315} Id.
\textsuperscript{316} Id. at 97:2-11.
\textsuperscript{317} See NM PRC Docket No. 22-00270-UT, Final Order, p. 70 (Jan. 3, 2024).
\textsuperscript{318} CCSA Exhibit 1 at 97:22-23, 98:1-3 (Barnes Dir.).
\textsuperscript{319} N.M. STAT. § 62-16B-2(O); NMAC 17.9.573.20(B).
\textsuperscript{320} CCSA Exhibit 1 at 91:7-13 (Barnes Dir.).
\textsuperscript{321} N.M. STAT. § 62-16B-2(O); NMAC 17.9.573.20(B).
\end{footnotesize}
compliance primarily impacts the residential and residential heating classes — reducing the residential and residential heating bill credit rates by 0.577 cents/kWh and 0.353 cents/kWh, respectively.\textsuperscript{322}

SPS calculates its customer and minimum charge exclusion by summing the customer-related revenue requirements from its most recent cost of service study and dividing that figure by total class retail sales.\textsuperscript{323} The result of this calculation is a volumetric rate that is ultimately subtracted from the TARR, along with distribution costs, to arrive at the bill credit rate.\textsuperscript{324} However, the definition of TARR bases the customer cost exclusion on “charges.”\textsuperscript{325} This distinction dictates that customer cost exclusions should be based on the sum of annual revenue from customer or minimum charges.\textsuperscript{326} In testimony, SPS witness Trowbridge explained that under a strict reading of Rule 573, SPS does not disagree with CCSA’s recommendation.\textsuperscript{327} SPS further states that it would be amenable to this change should the Commission require it.\textsuperscript{328}

To ensure that bill credit rates are properly calculated, the Commission should require SPS to calculate the customer cost exclusion from the TARR as the sum of annual revenue from customer or minimum charges. This calculation is properly reflected as:

\textbf{Number of Customers} \times \textbf{Customer Charge} \times 12 \text{ Months}.

Neither the CSA nor Rule 573 contemplate the exclusion of otherwise-eligible subscribers or withholding of bill credits, except in the case that a subscriber ceases to be a customer of a participating utility. In addition, neither the CSA nor Rule 573 impose requirements for subscriber organizations to report to the Commission regarding the details of subscriptions. However, PNM and EPE have proposed several arbitrary limitations on program participation and bill credit distribution, as well as a proposal to require subscriber organizations to report to the Commission when certain conditions are triggered. These proposals present significant challenges to the core objectives of the CS program and will create the potential for adverse impacts to subscribers. As explained below, the Commission should reject these proposed restrictions as arbitrary and inconsistent with statutory authority.

Further, in the first phase of this proceeding, the parties reached a settlement in which the IOUs agreed to propose a combined customer disclosure and consent form. Consequently, SPS included a proposed combined form as Attachment RMS-6 to the Direct Testimony of Ruth Sakya. The Commission should adopt the combined form, which represents a collaborative effort to streamline the customer enrollment process. However, the Commission should require that the combined form be revised in accordance with the suggestions proposed by the Joint Parties. These revisions will provide additional efficiency in the enrollment process and contribute to an overall positive program experience.

329 See N.M. STAT. § 62-16B-2(L).
331 NM PRC Docket No. 23-00071-UT, Uncontested Phase I Stipulation, p. 3 (Aug. 10, 2023) (approved in AN 12: Order Approving Uncontested Phase I Stipulation (Sept. 21, 2023)).
1. The Commission should reject PNM’s arbitrary and burdensome proposal for monitoring carryover amounts and subscription sizing.

The CSA requires that a subscription be sized to supply no more than one hundred percent of a subscriber’s average annual usage. In addition, Section 62-16B-6(A)(4) provides that the IOUs must, “carry over any amount of a community solar bill credit that exceeds the subscriber's monthly bill and apply it to the subscriber's next monthly bill unless and until the subscriber cancels service with the qualifying utility.” Neither the CSA nor Rule 573 delegate PNM any authority to withhold bill credits under any circumstance except a cancellation of a subscription.

PNM is the only IOU that has proposed a methodology for tracking and reporting carry over amounts. PNM defines “carry over amount” as bill credit amounts that exceed a subscriber’s monthly bill. It proposes to track carry over amounts and report annually to subscriber organizations and the Commission any subscribers who have a carry-over amount in more than six months out of a twelve month period. For those subscribers, PNM proposes to withhold application of the carry over amount to subsequent bills until the subscriber organization informs PNM and the Commission that the subscription sizing has been modified. Alternatively, subscriber organizations could provide an explanation to PNM and the Commission as to why the carry over amounts are not a violation of subscription sizing requirements.

PNM argues that this process is simply a conservative check, designed to provide a means to identify potential over-subscriptions that are inconsistent with the Community Solar Act.

333 N.M. STAT. § 62-16B-6(A)(4).
334 See New Mexico People’s Energy Cooperative Exhibit 1: Direct Testimony of Brian Naughton, p. 11 (Nov. 13, 2023).
335 PNM Exhibit 5 at Exhibit MSJ-2 (Settlage Reb.).
336 PNM Exhibit 1 at 12:10-12 (Babej Dir.).
337 Id. at 12:13-15.
338 Id. at 12:15-18.
339 PNM Exhibit 2 at 22:15-17, 24:8-10 (Babej Reb.).
PNM argues that its proposal is necessary, as it is not involved in the subscriber enrollment process and there is no inherent check on over-subscription.\textsuperscript{340} Further, PNM witness Babej asserts that, “[w]hile CCSA witness Barnes argues that Xcel Colorado evaluates subscription sizing at the time of subscription, there has been no process built into New Mexico’s community solar rules for utilities to ensure that a community solar subscription is right sized.”\textsuperscript{341}

The Commission should reject PNM’s requests relating to monitoring, reporting, and withholding of bill credits based on carry over in their entirety. First, as noted above, PNM’s proposal is entirely devoid of statutory authority.\textsuperscript{342} No provision of the CSA provides PNM with the authority to withhold bill credits from subscribers who are current PNM customers. By contrast, the CSA specifically requires that carry over amount be applied to subsequent subscriber bills until the subscriber cancels PNM service.\textsuperscript{343} Additionally, no provision of the CSA authorizes PNM to create additional reporting requirements for subscriber organizations to ensure that bill credits are distributed to their subscribers.

Moreover, PNM’s proposal is not effectively tailored to the goal of identifying over-subscriptions and may produce “false positives” that deprive subscribers with correctly sized subscriptions of portions of their bill credit. In response to discovery, PNM acknowledged that it is possible that a carry-over amount could exist in six months out of the year while not exceeding annual subscription limits.\textsuperscript{344} As explained by Mr. Barnes and REIA witness DesJardins, annual variations in electricity usage are unavoidable and driven by a variety of factors, including:\textsuperscript{345}

\begin{itemize}
\item \textsuperscript{340} Id. at 23:6-8.
\item \textsuperscript{341} Id. at 23:9-12.
\item \textsuperscript{342} See NMPEC Exhibit 1 at 11 (Naughton Dir.); see also REIA Exhibit 1 at 8:17-23, 9:1-5 (DesJardins Dir.).
\item \textsuperscript{343} N.M. STAT. § 62-16B-6(A)(4).
\item \textsuperscript{344} CCSA Exhibit 1, Exhibit JRB-6: PNM Response to CCSA DR 4-9(C) (Barnes Dir.).
\item \textsuperscript{345} See REIA Exhibit 1 at 9:13-17 (DesJardins Dir.); CCSA Exhibit 1 at 81-82 (Barnes Dir.).
\end{itemize}
1) Weather in conjunction with the customer’s space conditioning configuration;

2) Electric heating, particularly electric resistance heating;

3) Changing home conditions;

4) Fluctuating business cycles;

5) Changing end uses; and/or

6) Underlying retail rate structures.

While PNM argues that even a subscription that is 140% over a subscriber’s average annual electricity consumption on a monthly basis would not be flagged under this method,\(^\text{346}\) this reality simply underscores the fact that PNM’s proposal is neither necessary nor effectively tailored to ensuring compliance with Section 62-16B-5(A)(1).

Further, Mr. Barnes and Mr. DesJardins both noted that subscriptions are sized in relation to a subscriber’s average annual electricity consumption.\(^\text{347}\) However, by definition, a single year cannot be viewed as an “average” of annual consumption.\(^\text{348}\) PNM’s reliance on a single calendar year of subscription volume and usage to determine whether subscription is inappropriately sized ignores the inherent variability of electricity consumption as described above.\(^\text{349}\)

In testimony, Staff witness Dunn argued that PNM’s approach is unnecessary and may strain the Commission’s limited resources.\(^\text{350}\) In addition to this point, PNM’s proposal is likely to create additional administrative costs that would ultimately be assigned to CS subscribers.\(^\text{351}\) As explained previously, additional administrative costs serve to reduce the monetary value of

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\(^{346}\) PNM Exhibit 2 at 24:10-14 (Babej Reb.).

\(^{347}\) CCSA Exhibit 1 at 81:1-2 (Barnes Dir.); REIA Exhibit 1 at 10:7-15 (DesJardins Dir.).

\(^{348}\) CCSA Exhibit 1 at 81:1-2 (Barnes Dir.).

\(^{349}\) Id. at 80:20-22.

\(^{350}\) Staff Exhibit 1 at 68:3-5 (Dunn Dir.).

\(^{351}\) See Tr. Vol. 1 at 182:18-25, 183:1-10 (Babej).
community solar subscriptions for subscribers. PNM has not developed an estimate of the administrative costs it expects to incur to carry out its proposal. Without upfront transparency of these costs, subscribers may experience unforeseen fluctuations in subscription value that undermine subscriber satisfaction and the level of monthly bill savings.

Finally, the subscription registration process can provide adequate checks to ensure that subscriptions are appropriately sized. For example, Xcel Colorado evaluates subscription sizing when the subscription is established. While PNM witness Babej argues that no process has been built into the New Mexico statute and rules for utilities to ensure that subscriptions are correctly sized, New Mexico’s statutory guidance on this issue is substantially similar to the Colorado community solar rules. Specifically, both Section 62-16B-5(A)(1) of the Community Solar Act and Colorado Rule 4 CCR 723-3-3878(b) provide a percentage limitation on subscription size, measured against a subscriber’s average annual electricity consumption. To this end, the Colorado CS rules do not delineate any additional role for the utilities in determining compliance with the subscription sizing provision.

The process of evaluating subscription sizing at the time of subscription registration is also consistent with PNM’s process for sizing onsite solar. For onsite solar owned by a third party, PNM performs an initial check at the time of the application that the system is correctly sized. PNM does not perform any ongoing monitoring for the sizing of onsite solar systems, even in

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352 Id.
353 Id.
354 CCSA Exhibit 1 at 79:15-18 (Barnes Dir.).
355 Id. at Exhibit JRB-11: Xcel Energy Colorado Solar*Rewards Community Subscriber FAQ.
357 Id.; see also 4 CCR 723-3-3878(b).
358 4 CCR 723-3-3878.
359 CCSA Exhibit 10: PNM Response to CCSA DR 7-12; Tr. Vol. 1 at 180:24-25, 181:1-4; see also REIA Exhibit 1 at 10:7-15 (DesJardins Dir.).
circumstances in which customers’ average annual consumption may fluctuate greatly.\(^{361}\) In this circumstance, PNM would not require any additional reporting and would not take any measures to require resizing of the customer’s solar array.\(^{362}\)

Accordingly, the Commission should reject PNM’s proposal to monitor and withhold carry over amounts and to require additional subscriber organization reporting requirements. Rather, PNM, and all IOUs, should check subscription size at the time of initial subscription registration or subsequent modification. This approach saves Commission resources, reduces administrative costs to subscribers, and is consistent with industry standards for both CS and PNM’s own distributed solar resource guidelines.

2. The Commission should reject PNM and EPE’s proposals to limit bill credits for customers in arrears.

The CSA provides that the IOUs “shall,” “apply community solar bill credits to subscriber bills within one billing cycle following the cycle during which the energy was generated by the community solar facility.”\(^{363}\) No provision within the statute or rules creates an exception to this mandate, and no provision of the statute or rules authorizes the utilities to withhold bill credits from certain subscribers.

In addition, Section 62-16B-7(B)(3) and NMAC 17.9.573.10(B) require that thirty percent of the electricity produced from each CS facility be reserved for low-income subscribers and low-income service organizations.\(^{364}\) Rule 573 also directs the third-party administrator to award additional points in the project selection process to bids that commit to supplement bill credits for low-income subscribers.\(^{365}\) Together, these program requirements comprise a key equity

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\(^{361}\) *Id.* at 181:5-20.

\(^{362}\) *Id.* at 181:22-25, 182:1-4.

\(^{363}\) N.M. STAT. § 62-16B-6(A)(2).

\(^{364}\) N.M. STAT. § 62-16B-7(B)(3); NMAC 17.9.573.10(B).

component of the CS program, and demonstrate the Legislature’s intent to deliver meaningful bill savings to low-income customers.

Both PNM and EPE propose program restrictions to withhold bill credits from customers in arrears. PNM proposes to suspend bill credit distribution for non-low-income and low-income customers with delinquencies of greater than 60 and 90 days, respectively.\(^{366}\) PNM witness Contreras explained that, “[o]nce the customer pays the…arrear in full the customer is once again eligible to receive the bill credit.”\(^{367}\) However, in rebuttal, PNM changed its position to require that customers pay or enter into and comply with a payment plan for a portion of their arrearage to remain eligible to receive bill credits.\(^{368}\) PNM argues that this approach will help customers manage their arrears, while taking full advantage of CS bill credits.\(^{369}\)

Similarly, EPE’s First Revised Rate No. 47 contains a provision stating that EPE retains the right to deny or terminate bill credits for customers in arrears.\(^{370}\) EPE defines “arrears” as past due amounts on customer’s current bills.\(^{371}\) In support of this approach, EPE stated that it “does not have authority to apply customer credits payable under the Community Solar program to EPE charges.”\(^{372}\)

The Commission should reject PNM and EPE’s proposals to limit bill credits from subscribers in arrears for several reasons. First, as mentioned above, neither the CSA nor Rule 573 provide the utilities with the authority to restrict the distribution of bill credits.\(^{373}\) Instead, the

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\(^{366}\) PNM Exhibit 3 at 8:11-19 (Contreras Dir.).
\(^{367}\) Id.
\(^{368}\) PNM Exhibit 4: Rebuttal Testimony of Lisa Contreras, p. 3:8-11 (Dec. 8, 2023).
\(^{369}\) Id. at 2:8-11.
\(^{370}\) EPE Exhibit 6 at Exhibit MC-3 (Carrasco Dir.).
\(^{371}\) See CCSA Exhibit 1 at Exhibit JRB-6: EPE Response to CCSA DR 6-2(c) (Barnes Dir.).
\(^{372}\) Id. at Exhibit JRB-6: EPE Response to CCSA DR 6-2(b)
\(^{373}\) See City of Las Cruces (“CLC”) Exhibit 1: Direct Testimony of Lisa LaRocque, p. 35:16-18 (Nov. 13, 2023).
statute explicitly mandates that the utilities apply bill credits within one billing cycle of the energy being generated.\textsuperscript{374} Consequently, PNM and EPE’s proposals expressly conflict with this clear statutory guidance.\textsuperscript{375}

In addition, any proposal to limit or withhold bill credits from customers in arrears will disproportionately impact low-income subscribers. Suspension of bill credits for customers in arrears will only serve to exacerbate delinquencies and increase the burdens on customers already struggling to pay their bills.\textsuperscript{376} Such a result is clearly contrary to the equity goals built into the CSA, which prioritize access to meaningful bill savings for vulnerable customers. By contrast, SPS’s proposed Rider No. 87 allows for bill credits to be applied towards a customer’s total bill, which may include past due bills and arrearages.\textsuperscript{377} This approach is more effectively tailored to achieve the equity goals embedded in the CSA, and is the only IOU proposal that does not violate the statutory requirement to apply the bill credit within one billing cycle following the cycle in which it is generated.

Finally, these proposals introduce unnecessary complexity into program operations. PNM’s approach entails a multi-step system that includes additional tracking and credit distribution processes for both PNM and subscriber organizations.\textsuperscript{378} Ultimately, PNM’s proposal would require subscriber organizations to perform multiple additional steps to ensure that subscribers are allocated their rightful credits.\textsuperscript{379} On the other hand, EPE’s proposal is overly vague and is unclear as to the processes for suspending bill credits.\textsuperscript{380}

\textsuperscript{374} N.M. STAT. § 62-16B-6(A)(2).
\textsuperscript{375} See Staff Exhibit 2 at 7:9-13 (Dunn Reb.).
\textsuperscript{376} CCSA Exhibit 1 at 71:1-3 (Barnes Dir.).
\textsuperscript{377} SPS Exhibit 1 at Attachment RMS-4, p.5 (Sakya Dir.).
\textsuperscript{378} CCSA Exhibit 1 at 72:14-19 (Barnes Reb.).
\textsuperscript{379} Id.
\textsuperscript{380} Id.
The Commission should reject PNM and EPE’s proposals to limit or withhold bill credits. Further, the Commission should order the utilities to apply any “net monthly credit,” or bill credit amounts in excess of new charges, to arrearage balances. These recommendations are consistent with the approach adopted by SPS and ensure that customers receive equitable access to CS bill savings.

3. The Commission should reject PNM and EPE’s proposals to exclude customers with behind-the-meter solar.

Neither the CSA nor Rule 573 delegate any authority to the utilities to exclude otherwise-eligible subscribers from program participation. However, both PNM and EPE propose to exclude customers with behind-the-meter ("BTM") solar from participation. By contrast, SPS has confirmed that customers with BTM solar may participate in the CS program, up to their net energy consumption amount.381

PNM argues that the bases for this exclusion include the limitations of its billing system and the overall intent of the Community Solar Act.382 In addition, PNM explains that this limitation is meant to recognize the administrative complexity of having customers on more than one voluntary rate or rider.383 PNM asserts that if customers take service in more than one voluntary program, it may not be able to recover its costs from CS subscribers.384 In rebuttal, PNM witnesses explained the processes needed to correctly apply CS bill credits to customers with BTM solar,385 and provided an estimate of $121,000 to upgrade the billing system to accommodate BTM solar customer participation.386

381 Id. at Exhibit JRB-6: SPS Response to CCSA DR 5-7(a).
382 PNM Exhibit 1 at 10:6-18 (Babej Dir.).
383 Id.
384 Id. at 10:23, 11:1-2.
385 PNM Exhibit 2 at 21:6-23, 22:1-8 (Babej Reb.).
386 PNM Exhibit 4 at 5:14-16 (Contreras Reb.).
In addition, EPE argues that its proposal to exclude customers with BTM solar is intended to maximize the availability of renewable energy from CS to customers who are unable to access customer-owned solar.\(^{387}\) EPE explains that while it may be amenable to allowing customers with BTM solar to participate, any customers that participate in net metering (“NEM”) should be excluded.\(^{388}\) EPE asserts that NEM already represents a considerable subsidy for distributed generation customers, and poses several questions surrounding the mechanics of applying CS bill credits to NEM customer bills.\(^{389}\)

The Commission should reject PNM and EPE’s proposals to restrict the participation of customers with BTM solar for several reasons. As a preliminary matter, subsidization of customers with BTM solar is a separate and distinct matter that has no practical bearing on the CS program.\(^{390}\)

Similarly to the other restrictions PNM and EPE have proposed, neither the CSA nor Rule 573 permit the utilities or the Commission from restricting the participation of certain customer groups.\(^{391}\) While PNM and EPE argue that CS should prioritize those without access to customer-owned solar, these policy arguments lack merit. A fundamental characteristic of CS is its ability to provide access to affordable renewable energy to all customers, including, but not limited to, customers who do not have access to onsite solar. Customers with BTM solar are often unable to achieve a 100% offset of their onsite energy needs for a variety of reasons, including financial limitations or rooftop siting constraints.\(^{392}\) However, these customers have a demonstrated interest in purchasing clean, affordable energy.\(^{393}\) From a fundamental customer fairness standpoint,

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\(^{387}\) CCSA Exhibit 1 at Exhibit JRB-6: EPE Response to CCSA DR 4-6(b) (Barnes Dir.).
\(^{388}\) EPE Exhibit 2 at 13:16-20 (Schichtl Reb.).
\(^{389}\) Id. at 14:18-19, 15:6-9.
\(^{390}\) CCSA Exhibit 1 at 76:19-20 (Barnes Dir.).
\(^{391}\) Tr. Vol. 3 at 579:17-19 (Barnes); see REIA Exhibit 1 at 11:18-20 (DesJardins Dir.); see also CLC Exhibit 1 at 39:1-3 (LaRocque Dir.); see also NMPEC Exhibit 1 at 6 (Naughton Dir.).
\(^{392}\) CCSA Exhibit 1 at 77:4-8 (Barnes Dir.); Tr. Vol. 3 at 579:20-25, 580:1-4 (Barnes).
\(^{393}\) Tr. Vol. 3 at 580:1-4 (Barnes).
customers with a 50% offset system could not have known at the time they invested in onsite solar that they would be later barred from supplying the remaining 50% of their energy needs from a program like CS. Along these lines, CS may be a particularly attractive option for customers who installed onsite solar, but have since acquired electric vehicles or further electrified their homes such that their onsite generation no longer meets 100% of their needs.

While PNM argues that billing system upgrades are necessary to properly bill CS subscribers with BTM generation, these issues are resolvable and should not be relied upon as justification for excluding a large number of prospective subscribers. Along these lines, PNM’s billing system should be able to accommodate customer participation in multiple programs, not just CS. The IOUs, as regulated utilities, are responsible for administering a variety of public policy programs directed by the Commission and the Legislature. They must stand ready to implement the programs they are required to run — even when customers choose to enroll in multiple programs. Thus, any cost to carry out this responsibility is more appropriately regarded as a cost of doing business, which PNM can seek recovery for in a GRC, and not an incremental cost associated with the CS program. Under PNM’s approach, an existing CS subscriber that subsequently added onsite solar should be assigned the incremental cost of any billing system upgrades necessary to accommodate this change. These complexities that could arise underscore the difficulty in properly assigning these costs, which should instead be assigned to all PNM customers.

To ensure reasonable uniformity and customer equity, the Commission should order PNM and EPE to allow customers with BTM solar to participate in the community solar program, up to

394 *Id.* at 580:5-11; see also CLC Exhibit 1 at 40:11-16 (LaRocque Dir.).
395 CLC Exhibit 1 at 40:16-19 (LaRocque Dir.).
396 CCSA Exhibit 1 at 77:15-17 (Barnes Dir.).
their average annual net energy usage amount. The Commission should order PNM and EPE to incorporate any additional billing system modifications necessary to achieve this. The costs associated with these billing system modifications should be presented in a future GRC for recovery from the general body of customers.

4. The Commission should reject PNM and EPE’s proposed limitations on the number of subscriptions per customer and per premise, respectively.

Similarly to the restrictions described above, neither the CSA nor Rule 573 impose restrictions on the number of subscriptions a subscriber may hold. However, PNM proposes that a subscriber may only have one single CS subscription during a given billing period. EPE proposes that only one CS subscription be allowed per premise. “Premise” is not a defined term within EPE’s First Revised Rate No. 47.

As explained by City of Las Cruces (“CLC”) witness LaRocque, these conditions impose arbitrary limitations on participation for subscribers that may seek to serve additional needs through CS beyond their initial subscription size. This is particularly pertinent to subscribers that, after obtaining an initial subscription, choose to embrace electrification or add additional space conditioning measures — in particular, air conditioning. In these instances, if the subscriber’s original CS project has no available capacity, the subscriber would need to initiate an additional subscription.

Consequently, the Commission should reject PNM and EPE’s proposals to limit the number of subscriptions per subscriber and per premise, respectively. These restrictions are

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397 See CLC Exhibit 1 at 41:15-22, 42:1-4 (LaRocque Dir.); REIA Exhibit 1 at 11:1-20 (DesJardins Dir.).
398 PNM Exhibit 1 at 10:17-18 (Babej Dir.).
399 EPE Exhibit 6 at Exhibit MC-3, p. 4 (Carrasco Dir.).
400 CLC Exhibit 1 at 41:15-22, 42:1-4 (LaRocque Dir.).
401 See id.
unsupported by statute and impose limitations on customers that have a demonstrated interest in participating in the CS program.

5. The Commission should adopt the Joint Parties’ recommendations for streamlining the combined Subscriber Disclosure and Consent form.

Pursuant to the Uncontested Phase One Stipulation,\textsuperscript{402} SPS included a proposed combined Subscriber Disclosure and Consent Form as Attachment RMS-6 to the Direct Testimony of Ruth Sakya.\textsuperscript{403} The Commission should approve the parties’ proposal to combine the Consent and Disclosure Forms, which will create efficiencies and provide potential subscribers with “customer friendly” documentation.\textsuperscript{404} However, the Commission should order the combined Subscriber Disclosure and Consent form to be revised in accordance with the Joint Parties’ recommendations.

In testimony, Mr. Barnes recommended three changes to provide additional flexibility to the customer enrollment process. These changes include:\textsuperscript{405}

1) Removing the “Community Solar Project Name” field, or, in the alternative, allowing subscribers organizations to fill in this field with “To Be Determined;”

2) Removing the “Subscription Size (kW AC)” field, or, in the alternative, modifying this field to read “Estimated Subscription Size (kW AC);” and

3) Removing the “Project Nameplate Capacity (in kW AC)” field, or, in the alternative, modifying this field to read “Estimated Project Nameplate Capacity (in kW AC).”

These modifications are necessary to simplify and streamline the customer enrollment process. First, removal of the “Community Solar Project Name” field allows for additional flexibility to account for changes in development and interconnection timelines and ensure that

\textsuperscript{402} Uncontested Phase I Stipulation at 3.
\textsuperscript{403} See SPS Exhibit 1 at Attachment RMS-6 (Sakya Dir.).
\textsuperscript{404} Id. at 31:1-5.
\textsuperscript{405} CCSA Exhibit 1 at 86:3-12 (Barnes Dir.).
subscribers are enrolled in available projects as soon as possible to begin seeing bill savings.\textsuperscript{406} Subscriber organizations are required to place subscribers with projects that deliver the exact benefits described on their signed disclosure form, so elimination of this field introduces no risk to subscribers.\textsuperscript{407}

Next, elimination of the “Subscription Size (kW AC)” field is necessary to account for situations in which subscription size is not known at the time a subscriber signs the Disclosure and Consent Form.\textsuperscript{408} These situations are likely to occur with some frequency, as many customers do not know their average annual electricity consumption and may not have immediate access to that information as they initially enroll.\textsuperscript{409} However, average annual electricity consumption is a key metric in determining subscription size.\textsuperscript{410} To this end, this function is fulfilled by the “Information Sharing” clause of the Disclosure and Consent Form, which allows the subscription manager to access the subscriber’s energy usage data.\textsuperscript{411}

Finally, the “Project Nameplate Capacity (in kW AC)” field should be removed to account for variations in project nameplate capacity that might occur as projects progress through the development process, and in particular the interconnection study process.\textsuperscript{412} This modification creates no impacts on subscribers, as project nameplate capacity does not affect subscription size.\textsuperscript{413} However, final project capacity could change the number of subscribers that can participate in a given project, which could lead to subscriber organizations needing to assign subscribers to a

\textsuperscript{406} Id. at 86:18-20, 87:4-6.
\textsuperscript{407} Id. at 87:6-8.
\textsuperscript{408} Id. at 87:14-19.
\textsuperscript{409} Id. at 87:22-23, 88:1-3; Tr. Vol. 1 at 62:5-10 (Schichtl).
\textsuperscript{410} Id. at 88:1-3.
\textsuperscript{411} Id. at 88:3-6; Tr. Vol. 1 at 62:17-25, 63:1-2 (Schichtl).
\textsuperscript{412} Id. at 88:14-21.
\textsuperscript{413} Id. at 89:2-4.
different project. This scenario underscores the need for additional flexibility by eliminating both the “Project Name” and “Project Nameplate Capacity (in kW AC)” fields.

EPE opposes these recommendations, arguing that these fields are needed for transparency to subscribers as to subscriber organization details and subscription sizing. However, at hearing, Mr. Schichtl correctly acknowledged that the combined Subscriber Disclosure and Consent Form requires disclosure of the subscriber organization’s name, manager contact information, and phone number. Along these lines, Mr. Schichtl agreed that based on this Form, subscribers would know who to contact should a question arise with their subscription. The Subscriber Disclosure and Consent Form, with the Joint Parties’ revisions, effectively provides subscribers with fundamental information about the CS program, their subscriber organization, and the authorization necessary to share data between subscriber organizations and the IOUs.

The Joint Parties’ recommendations strike the appropriate balance between maintaining consumer protections and allowing for flexibility as subscribers initially enroll. The Commission should adopt the combined Subscriber Disclosure and Consent Form, subject to the modifications discussed herein.

III. CONCLUSION

WHEREFORE, the Joint Parties respectfully request that the Commission adopt the recommendations set forth in the Summary of Recommendations.

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414 EPE Exhibit 2 at 41:10-16, 42:1-12 (Schichtl Reb.).
415 Tr. Vol. 1 at 60:10-22 (Schichtl).
416 Id.
Respectfully submitted,

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Attachment A - Response to the Hearing Examiners’ Briefing Order

I. List of Issues that the Commission Should Rule Upon in the Proceeding:

1. Whether it is in the public interest for non-subscribers to subsidize subscribers, up to three percent of non-subscribers’ aggregate retail rate on an annual basis.
2. What method all three IOUs should use to calculate the subsidy amount in future rate cases. Within this decision the Commission must decide, the following:
   ○ Whether avoided costs should be considered in calculating the subsidy.
   ○ Whether a specific cost benefit test should be adopted.
   ○ Which avoided cost categories must be considered in future calculation of the subsidy.
   ○ How to quantify avoided costs for the first tranche of the program.
   ○ Whether additional avoided costs should be considered in future expansions of the program.
3. The appropriate methodology IOUs should use to calculate the dollar value that constitutes the three percent subsidy limitation. To provide clear guidance the Commission should decide specifically.
   ○ The definition of “non-subscribers”
   ○ The definition of aggregate retail rate (“ARR”)
4. How IOUs should recover CS subsidy costs both below and above the three percent subsidy limit
5. What methodology should IOUS use to recover administrative costs?
   ○ Should one-time administrative costs be recovered differently than recurring administrative costs?
   ○ Should the Commission limit the frequency that IOUS can seek to modify administrative cost recovery.
   ○ How can the Commission best ensure that all administrative costs are reasonable and prudent?
6. What specific dollar amount should PNM and SPS be authorized to charge subscribers at the outset of the program and should this be recovered through a separate rider?
7. Given that EPE put forth no administrative costs, how should the Commission ensure that it is able to approve administrative cost recovery for EPE as quickly as possible to enable its program to launch.
8. What bill credit rate should each IOU be required to provide to CS subscribers to comply with the Community Solar Act. Specifically, the Commission should decide the following:
   ○ Whether PNM’s proposal to rescue bill credits by subtracting out minimum monthly demand charges for certain customers is reasonable and consistent with the law.
○ Whether PNM’s banding proposal from its most recent GRC should allow it to depart from using its cost-of-service study to derive distribution costs.
○ Whether SPS’s proposal to remove all customer related costs from its proposed bill credit complies with the law or whether it is only allowed to remove customer related costs recovered through fixed monthly charges.

9. Whether various IOU proposals to restrict program participation and bill credit distributions are reasonable and comply with the law. Specifically, the Commission should decide:
○ Whether PNM’s proposal to monitor carry over amount and subscription sizing is reasonable and complies with the law;
○ Whether PNM and EPE’s proposals to limit or withhold bill credits from customers in arrears is reasonable and complies with the law;
○ Whether PNM and EPE’s proposals to exclude customers with behind-the-meter solar is reasonable and complies with the law;
○ Whether PNM’s proposal to limit the number of subscriptions per subscriber is reasonable and complies with the law; and
○ Whether EPE’s proposal to limit the number of subscriptions per premise, is reasonable and complies with the law.

10. Whether the Commission should order any modifications to the proposed combined Subscriber Disclosure and Consent form.

II. **Responses to Specific Questions from the Hearing Examiners:**

1. *Describe how the Commission should monitor compliance of Utilities with the Community Solar (CS) Act. Please include administrative costs to the utilities for reporting, time or regularity, logistics, and substantive requirements.*

For calculating any subsidy amounts and recovery of those amounts, the Commission should order the IOUs to utilize a standard methodology. The Commission should require that individual IOUs calculations be presented in future GRCs, where the Commission and parties can scrutinize the inputs, results and compliance with the CSA, CS Rules, and the Commission’s directives. See Brief at Sections II.A at pages 6-37.

The Commission should order each IOUS to implement specific bill credits, rates, and fees to be utilized for program launch proposed in this proceeding based on the record. If the Commission requires additional information to establish any rates, fees or credits, require relevant IOUs to file advice letters within 30 days of the final decision in this case. For any future changes to rates, fees or bill credits, require IOUs to file an advice letter, which will be subject to protest and suspension. See Brief at Sections II.B, II.C at pages 37-56.
2. *If there is an excess of generation, will your utility carry over any excess kWh credits earned by a subscriber which are not used in the current billing period to offset the subscriber’s consumption in subsequent billing periods until all credits are used?*

The Joint Parties are not a utility, but notes that the CSA requires IOUs to “carry over any amount of a community solar bill credit that exceeds the subscriber’s monthly bill and apply it to the subscriber’s next monthly bill unless and until the subscriber cancels service with the qualifying utility.” 62-16B-6(A)(4). See Brief at Section II.D.2 at pages 62-65.

3. *Should the excess KWh credits reduce the minimum monthly charges imposed by the utility? Please explain.*

Although the Joint Parties did not take a position on this topic in testimony, a review of the CSA indicates that the statute does not preclude credits from being applied to minimum monthly charges. Rather, minimum monthly charges are excluded from the calculation of bill credit rates. It appears that this approach is consistent with the position of SPS, which states that “SPS may apply the CSP Credit to the customer’s total bill and may include past due bills and arrearages.” (SPS Exhibit 1 at Exhibit RMS-4, p. 5 (Sakya Dir.)).

4. *What are your company’s net-metering provisions pursuant to 17.9.573.19 NMAC? Should the recommendation include limitations on cumulative, aggregate generating capacity? If so, please explain.*

The Joint Parties are not a utility, but addressed this issue at Section II.D.3 at pages 65-68. Nothing in the CSA or the CS Rules permits excluding net-metered customers from CS as long as their subscription meets the other sizing limitations.

5. *Provide your recommendation to the Commission regarding the definition of AGGREGATE RETAIL RATE (ARR).*

See Section II.A.3.b at pages 25-29.

6. *[For PNM only] Please elaborate on the basis of your request for the Commission to decide to record the total bill credits and other costs in the regulatory asset (referred to in case 22-00027-UT) and the offsetting of avoidable costs in that regulatory asset.*

The Joint Parties discussed its position on this issue in its Brief at Section at II.A.4.A at pages 32-26.
7. For EPE only] Does EPE agree that Aggregate Retail Rate is defined by a total system basis or a class basis for the purposes of CS. Please explain.

The Joint Parties discussed its position on this issue in its Brief at section II.A.3.b at pages 25-29.

8. Please provide your recommendation to the Commission regarding the definitions of SUBSIDY and AVOIDED COSTS. Please indicate your term time horizon when determining what costs are avoided by CS.

As discussed at length in Section II.A.2.a at pages 13-14, subsidy should be defined as “net utility cost.” Avoided costs are synonymous with benefits provided to CS. Because CS facilities have a lifetime of at least 25 years, all avoided costs should also be considered on a 25-year time horizon. At a minimum, the Commission should require IOUs to consider the following avoided cost in calculating the net utility cost:

1. Avoided energy;
2. Avoided generation capacity;
3. Avoided transmission capacity;
4. Avoided line losses (adder to energy);
5. Avoided renewable portfolio standard (“RPS”) compliance; and
6. Avoided environmental compliance (if not included in other components).

9. State your position and methodology for the baseline for determining 3% subsidy. Are all customer classes included in the 3% subsidy or just customer classes that are eligible to subscribe to CS? Explain why.

See brief at Section II.A.3 at pages 22-31. The Commission should adopt a clear methodology to calculate the dollar value that constitutes the three percent subsidy limitation. This methodology should include:

- Defining non-subscribers on a total system basis;
- Defining aggregate retail rate (“ARR”) as synonymous with total aggregate retail rate (“TARR”). For this purpose, the TARR should be calculated as:

\[
TARR \ (\$/\text{kWh}) = \frac{(\text{Total Base Revenue} - \text{Customer Charges})}{\text{Electricity Sales}} + \text{Fuel & Purchased Power Charge} + \text{RPS Charge}
\]

In the alternative, the Commission should define ARR in accordance with EPE’s recommendation, which is reflected as:

\[
\text{Total Billed Revenue}/\text{Total Energy Sales}
\]
To calculate the three percent cap, the Commission should direct each IOU to perform the following calculation:

\[
3\% \text{ Limit} = 3\% \times \text{System-Wide Nonsubscriber TARR (}\$/\text{kWh}) \times \text{Non-Subscriber Sales (}\$/\text{kWh})
\]

10. The Community Solar Act allows for a 3% limitation on any cross subsidization of CS by other ratepayers. State the estimated amount which would result for each utility if 3% were allowed by the Commission.

It is not possible to calculate a correct 3% limit for each IOU at this time because precise costs and avoided costs are not yet known. Instead, the Commission should adopt the methodologies described above to calculate the 3% limit and direct IOUs to do so in future GRCs. See brief at Section II.A.3 at pages 22-31.

11. Is it in the public interest to assess utility administrative costs to all ratepayers or to recover these costs solely from CS subscribers? What are the minimum administrative costs pursuant to 17.9.573.13(D) NMAC, specific to the CS program?

Ongoing administrative costs should only be collected from CS subscribers when utilities can prove that they are reasonably incurred and are incremental costs of running the CS program. These costs should be recovered from Subscribers on a per kWh production (credit) basis.

As proposed by PNM, one-time administrative costs should be considered general costs recoverable from all customers. This is because the one-time costs identified by PNM and SPS facilitate an IOU’s ability to offer its program, which provides all customers the option to participate in CS. See brief at Section II.B.1 at pages 39-42.

12. [For SPS only] If Xcel’s Ruth Sakya in her direct testimony (attachment RMS-7) indicated $847,369.00 in admin costs in 2022 for 421 active systems 864MW in Minnesota why is SPS including $1,170,909 in admin costs for the New Mexico CS program which is for 10 facilities only for 45 MW. Please explain and provide a consistent estimate.

N/A.

13. What are the issues involved in utilities and CS facilities interconnection agreements with respect to interconnection to the electric distribution system according to NMSA 1978 section 62-16B-3(A)(2) and 573.9.10.A.2 NMAC?
Compliance with this section of the CSA and Rule 573 should be based on the project’s point of interconnection being located in the respective utility’s service territory rather than considering the entire footprint of the facility.

**14. For each utility, what is the percentage of selected projects located in rural areas far from the load and the projects located close to the load with no utilization of the transmission system.**

While this question is directed to the IOUs, the Joint Parties wish to note that this is only relevant to the extent a CS project actually causes backfeed on the transmission system, thereby causing use of the transmission system. For example, a rural substation may only have an MDL of 4 MW, but if there are only 3 MW of CS projects proposed on that substation, then there are no transmission impacts.

**15. [For EPE only] Please confirm regarding the question as to “issues in the implementation of CS to be addressed in Phase 2” in Mr. Schichtl’s direct testimony at page 16 at L2, that the answer is corrected to reflect: facilitating interconnection of the selected CS facilities to the utilities’ distribution system” [emphasis added], pursuant to rule 573.10A.2 NMAC. [the word “transmission” is now replaced by distribution]. How does it change your analysis as to who should bear the interconnection costs to the point of delivery.**

N/A.

**16. For each utility in reference to transmission costs for the rural projects in your service territory, please provide hosting capacity analysis to determine how much solar cumulative capacity the Utilities feeders could support.**

N/A.

**17. Who should bear the costs of upgrading transmission system for rural CS facilities, please explain the financial implications for the CS facilities.**

Interconnection agreements, which developers must sign, will assign costs of system upgrades directly to the interconnecting entity, in this case the owner or developer of the CS facility. See brief, Section II.A.2.b. at page 17.

**18. As applicable, please provide a recalculation of your solar bill credit based on the changes of the general rate case or any changes applicable after the initial filing and calculation.**
The Joint Parties respectfully request that the IOUs include any workpapers created in developing their responses to this question.

19. Provide your recommendation to establish a methodology that includes all concerns and common approaches by all the parties.

The Joint Parties have done their best to present a comprehensive set of methodologies to address all unresolved issues in its brief. The Joint Parties respectfully remind the Commission that until critical issues in this proceeding are resolved, CS Subscriber Organizations are unable to enroll customers in the CS program. Customers need to know whether they will be faced with future subsidy costs, what their administrative costs will be in the next few years, and how much those costs are likely to change over time in order to understand the costs of enrolling in CS. Similarly, subscribers and developers need to understand specific bill credits so that subscribers can assess benefits and developers can determine long term program viability.
BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE TARIFFS, AGREEMENTS, AND FORMS PROPOSED BY QUALIFYING UTILITIES FOR THE COMMUNITY SOLAR PROGRAM

Case No. 23-00071-UT

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the Brief-in-Chief of The Coalition for Community Solar Access, The Renewable Energy Industries Association of New Mexico, and New Energy Economy was emailed on this date to the parties listed below.

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Dated March 1, 2024,

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