STAFF REPORT

December 29, 2021

PROCEEDING NO. 21I-0321E

IN THE MATTER OF THE INVESTIGATION INTO THE INTERCONNECTION OF DISTRIBUTED ENERGY RESOURCES

COLORADO

Department of Regulatory Agencies

Public Utilities Commission

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List of Acronyms

BHE – Black Hills Energy
BTM – Behind the meter
CF – Capacity factor
CPUC – Colorado Public Utilities Commission
CSG – Community Solar Garden
CSU – Colorado Springs Utility
DER – Distributed Energy Resource
DMEA – Delta Montrose Electric Association
DSP – Distribution System Plan
ERP – Electric Resource Plan
HCA – Hosting Capacity Analysis
HCM – Hosting Capacity Maps
IREA – Intermountain Rural Electric Association, now CORE
IREC – Interstate Renewable Energy Council
IOU – Investor-owned utility
LCOE – Levelized cost of energy
MW – Megawatts
MWh – Megawatt-hours
MVEA – Mountain View Electric Association
PIM – Performance incentive mechanism
PBR – Performance-based regulation
PGE – Pacific Gas and Electric
PSCo – Public Service Company of Colorado
PADRs – Pre application data reports
PTO – Permission to operate
PUC – Public Utilities Commission
RES - Renewable Energy Standard
RFP – Request for proposal
SOPS – Standard operating procedures

Acknowledgments: The PUC Fixed Utility Staff would like to recognize and appreciate the following organizations that helped with the development of this report: Utilities in alphabetical order including Black Hills Colorado Electric, Delta Montrose Electric Association, Holy Cross Energy, Intermountain Rural Electric Association (now CORE), Public Service Company of Colorado and United Power; the Colorado Solar and Storage Association and the anonymous survey participants; and the California Public Utilities Staff.

Cover Photo: April 2013 Dedication of Clean Energy Collective's Community Solar Garden (CSG) on contaminated lands, the first in Boulder County. Photo by Joseph McCabe.

I. Executive Summary

The Colorado Public Utilities Commission ("Commission"), on June 2, 2021, adopted Decision No. C21-0399 opening a non-adjudicated proceeding (21I-0321E) for the purpose of directing the Staff of the Commission ("Staff") to complete an investigation into the interconnection practices of Colorado's regulated electric utilities as they affect distributed energy resources (DERs).

The origin of the investigation is found in Decision No. C21-0399, where the Commission discussed a number of interconnection practices which may provide helpful information to improving the interconnection process for DERs. On November 10th the deadline was extended to December 15th by minute entry. On December 15th the deadline was extended to December 29th by minute entry.

Interconnection of distributed energy resources (DERs) is a contentious issue across the country, including in Colorado. In this investigation the Staff performed the activities outlined in the Commission order, and determined that the state's statutes, rules and proceedings relating to interconnection, along with the Stakeholder process to this point, have enabled large quantities of DERs to be interconnected to the electric grid. In the dynamic electric utility sector things are constantly changing. This report provides an assessment for the specific point in time of 2021.

II. Findings

The investigation into the interconnection practices of Colorado's regulated electric utilities as they affect distributed energy resources resulted in the following observations:

1. The Stakeholder process at Public Service Company of Colorado ("PSCo") for interconnection can be improved.
2. The Interconnection process is inconsistent at electric utilities across the state.
3. Changing investor-owned utility ("IOU") interconnection staff and attrition causes interconnection disruptions; staffing back up plans are appropriate.
4. The new PSCo policy regarding CSG 75% capacity reserve could have been handled better.
5. Beginning in January 2022 for PSCo, Hosting Capacity Maps are to be updated per distribution system planning ("DSP") rules (Proceeding No. 20R-0516E). BHE data is due January 2023. The state and the industry DER needs greater assurances on accuracy.
6. Customers, developers, or industry associations having difficulty with a cooperative electric association utility ("Cooperative") can complain to the Board of Directors of

the utility, your local state representative or the PUC (https://puc.colorado.gov/utilityproviders)

7. A PIM/PBR is not recommended at this time because of other PIM/PBRs which could be broad/sufficient to further motivate interconnection efficacy.
8. Success rate of applications for PSCo can be much better.

III. Recommendations

The Staff provides the following recommendations for Commission consideration:

1. IOUs should be directed to include all applications quantities in RESA monthly reporting, including failed applications and excluding proprietary information. For PSCo the Proceeding Number No. is 06S-016E. For BHE the Proceeding Number is 16A-0436E.
2. A rulemaking Proceeding should be opened for 10 MW AC interconnections at the transmission level. The current PUC interconnection rules do not address interconnection at the transmission level. Currently, Small Power Producers and Cogeneration are addressed, at Rule 3900-3918 (over 10 MW).
3. In the SRC-CGS spreadsheet it shows 55,119 kW moving forward in 2019 & 2020, while 38,724 kW were withdrawn. Staff recommends increasing probability of CSG interconnection process success by performing:
    - Accurate pre-application data reports (PADR)
    - Accurate and timely HCA and HCMs
    - A critical review of CSG interconnection steps
    - Batch studies when appropriate
    - Accurate tracking of more details on reasons for CSG interconnection withdrawals
4. IOUs should be directed to plan for interconnection staff attrition because it has been observed to create difficulties in the interconnection process.
5. Interconnection is closely related to other rules and proceedings (RES Plan, CSG Rules, DSP Plans, Interconnection Rules, Net metering Rules, ERP, etc.) which all include the stakeholder processes, and Staff has identified several recommendations intended to address shortcomings identified for the stakeholder processes. The Distributed System Planning process was addressed in two recent proceedings: an initial miscellaneous proceeding in 2020, and a DSP rulemaking in 2021. The results of these activities resulted in a requirement that the investor-owned utilities submit distribution system plans to the PUC. Company DSPs will be reviewed by the PUC. We feel this is the appropriate venue to address the stakeholder process for interconnection which is very important for distributed energy resources on the utilities system. In the upcoming DSP proceeding, it is expected that stakeholders and IOUs will address the stakeholder process shortcomings identified in this report and summarized below with the following suggested agenda items:
    a. Timeliness of public disclosure for any IOUs interconnection process change
    b. Call center support

   c. Portal streamlining
   d. Solar only portal (so as to not confuse or complicate with storage if not applicable)
   e. Attention to customer preferred method of communication
   f. Minimize and develop attrition plans for interconnection staff
   g. Appropriateness of $250 and $320 Level 1 Application fees for less than 10 kW AC applications
   h. Hosting capacity analysis as described in 3531(II) is required to be updated quarterly pursuant to Rule 3541(d)(II)(F)
   i. Investigate Hosting Capacity Map ("HCM") and Hosting Capacity Analysis ("HCA") validation processes
   j. Coordination of HCA and HCM with DSP, RES Plans, and ERPs including opportunities for bidirectional substations.
   k. Submit this report in the interconnection manual proceeding 21M-0468E
   l. Support accurate pre-application data reports
   m. Support batch studies when appropriate
6. PSCo should track Company-owned interconnection costs.
7. Company should accurately track the reasons for withdrawal from an interconnection application.

IV. Commission Directive

1. The Commission, in Decision No. C21-0399, directed that the issues to be investigated shall include but not be limited to the following:

a) 24 months of both behind and in-front of the meter solar project interconnection data from IOUs, to develop a baseline of past interconnection performance successes and performance issues;

b) Total costs to ratepayers and the length of time for the interconnection process;

c) Ability of the interconnection process to address the large quantity of DERs expected to be proposed in ongoing and future ERPs, and its ability to handle the possible interconnection of 10 MW Community Solar Gardens after July 1, 2023, as contemplated by Rule 3877(a), 4 *Code of Colorado Regulations*, 723-3;

d) Smaller utilities and other jurisdictions' experiences with interconnection processes;

e) A comparison of the interconnection of utility owned projects and non-utility owned DER projects;

f) Opportunities to use PIMs/PBR to: (1) support obtaining planned capacity from DERs; and (2) minimize timely future "no capacity" notification;

g) How to coordinate hosting capacity analysis with distribution system planning, renewable energy standards and energy resource planning;

h) A comparison of how non-wires alternatives and distribution system equipment can increase hosting capacity of DERs; and

i) Topics that may best be investigated through the solicitation of anonymous comments from stakeholders, project owners, project developers and project installers, including but not limited to:

   i. For utility-scale or community solar projects, smaller distributed energy projects, energy storage projects: What specific problems are projects currently facing, and what opportunities exist to improve the policies and processes surrounding interconnections that the current interconnection rules do not sufficiently address?

   ii. What reporting requirements are needed for a more transparent interconnection process which can also support a potential PIM/PBR?

   iii. What are interconnection process costs to DER projects?

   iv. Ranking the relative importance to DER projects of (1) the interconnection processes meeting expected timelines (2) effective communications with the utility; (3) transparency of the utility's interconnection practices; and (4) customer service.

   v. What continuous improvements are needed to modernize the interconnection process?

The Commission further directed Staff to consider and investigate other related issues that may arise during the investigation.

Report Organization

It should be noted that information on interconnection is constantly changing, so this report content should be considered accurate for summer 2021. For reporting Staff's observations, findings and recommendations, the specific issues identified by the Commission were organized under the following primary topics:

- Data
- Survey(s)
- Items listed in Decision No. C21-0399
- Other items found during the investigation.

V. Cooperative Data

Staff was able to obtain informal data from a few of the State's Cooperatives, including DMEA, Holy Cross, United Power, and IREA. This data was not consistent because each utility has different interconnection methods and collects different data. The information is helpful to view electric cooperative interconnection experiences for the past couple of years. Two utilities declined to participate.[1] Data from utilities that did respond includes the following summaries:

- Holy Cross Energy ("HCE") was the first non-IOU utility to provide interconnection data to Staff. In 2019 and 2020 they had 7.8 MW of DG with 726 requests, and a 93.4% interconnection application success rate. The process averaged 139 days between the application and testing the system, and the application/study fee is $100 for over 12 kW and $250 for greater than 100 kW, with $16,400 in fees received in 2019 and 2020. HCE internal labor costs allocated to these projects during 2019 and 2020 was approximately $515k. HCEHCE stated that, *"[W]e ask our members to reach out to us early in the process. We do require members receive an approval letter from HCE prior to construction to qualify for the incentives. Additionally, many systems are installed on new construction which may extend their processing times. This report shows 649 systems, averaging 139 days. In 2019 and 2020, we entered 726 applications. 48 canceled, this leaves us with a 6.6% failed percentage. The abandoned capacity is 397 kW."* HCE attributes its good success rate to its timely application process, stating that, "*HCE Policy states that we acknowledge the receipt of the application within 3 business days, complete our initial review within 10 business days and test the array within 10 business days of a request."*

- Delta Montrose Electric Association (DMEA) had 528 net metered systems installed over the past three years for about 4 MW of capacity. This cost approximately $250k for the utility to evaluate with no cost for an application. The net metering policy is supportive of owner/members installing systems. DMEA notes: "*DMEA's Net Metering process does not require a pre-application or preapproval prior to system installation. A Net Meter is not installed until the Member has submitted a Net Meter application and indicates proof of having passed a final electrical inspection. The state electrical inspector also applies a blue tag to the meter base to confirm a system has passed a final electrical inspection. As a result, the time from DMEA receiving a Net Meter Application to having a net meter installed is fairly brief. Typical duration from application to net meter installation is within 5 days (97%-98% of all applications). The shortest duration from application received to net meter installed is the same day. The longest duration, thus far, has been 10 weeks."*

[1] Colorado Springs Utility and Mountain View Electric Association did not participate.

Thus, PUC Staff cannot compare the timelines for interconnection to other utilities because of the difference in process.

- United Power has 6.6% of its customers, more than 6,800, with net metered systems. Their peak is 577 MW with 42.2 MW of that being from rooftop solar. This is impressive considering their total number of meters is approximately 100,000. They allow net metering for 25 kW or less with a $200 application fee. In 2018 there were 2,900 rooftop solar systems or 3.3% of members, and 18 MW capacity. In the last few years, they have roughly doubled their installations.

- For CORE (formerly IREA) the total interconnected DG at of the end of September 2021 was 26,880 kW across 4,633 locations, a 25% increase since year end 2020. (At the end of 2020 CORE had more than 3,700 CORE members with rooftop solar interconnected to the system with a potential capacity of approximately 21 megawatts). CORE has processed 2,895 requests for distribution interconnection between July 1, 2019, and September 30, 2021, 2,731 have been approved for installation, and 2,136 received permission to operate. Of the 164 systems where an interconnection has not been approved for installation, 60 of those systems were submitted after September 1, 2021, and were likely awaiting approval at the end of the month or were subject to requests for correction or additional information. Of the 595 applications approved for installation but not yet completed, approximately 400 were received after June 1st, 2021, and are likely still in the construction or inspection phase of the project. In addition, approximately 350 applications were closed for various reasons or are undergoing longer than normal construction, inspection, or approval timeframes. Tariffed rates for interconnection fees are $100 for Level 1 applications, $500 for Level 2 or 3 applications. On average it takes 4 months from initial request to receive permission to operate ("PTO") to complete construction and inspection.

The data from the Cooperatives that participated show that a commitment to DERs is important to successfully connect many systems and demonstrate the strong interest in distributed systems.

VI. PSCo Data

From the data that PSCo provided to Staff for 2019, 2020 and 2021, Staff found 25,660 applications, of which 1,515 had expired, 2,778 designated as the customer does not want to proceed, 292 duplicates, 144 program terminations and 1,224 system closed. Some of these explanations overlap each other. In total it appears that 4,437 applications, or 19%, have not moved forward. For applications in 2021, it appears that there are fewer cancelled, at 16% thus far. PSCo indicates the average time from the application to Net Meter Install Date is 71 days from 2019 – 2021; improving to around 50 days in 2021. Average time for production meters is an average of 61 days from 2019 – 2021; around 40 days in just 2021. The interconnection process has resulted in large amounts of DG and CSG capacity and installations in the past two years.

In the SRC-CSG spreadsheet Staff received it shows 55,119 kW moving forward in 2019 & 2020, while 38,724 kW were withdrawn. See the Interconnection Process for Large Quantity of DERs, CSG subsection, in this report for more information and recommendations.

Comparing Company Owned Projects

There are three Company owned CSG projects that were completed in 2021 all of which took over 1 ¾ years to compete. There were no costs documented for the interconnection process for the Company owned projects. The PTO - The Activation Requirement Date of 550 days, is reflected in the days late below.

CSG Number	Days Late	Total days	Years
SRC075070	96	646	1.77
SRC075071	124	674	1.85
SRC075114	155	705	1.93

Staff recommends that the Commission direct PSCo to track Company owned interconnection costs.

VII. BHE Data

Black Hills Colorado Electric, Inc. ("BHE") estimates they are receiving about 20 interconnection applications per day, 90% of which are net energy metering. Some residential accounts and all commercial and industrial installations are performance-based projects. Approximately 6% of the total number of projects are performance based. The 2019, 2020 and 2021 on-site solar data BHE supplied to Staff indicated 3,428 interconnection applications were received. They included a breakdown of the reasons why interconnections requests did not result in successful projects. These included "application cancelled" (10.4%), and "application denied" (9%). The data showed that installed watts were 25 MW DC (approximately 19.4 MW AC). Application fees are $320 for Level 1 and $620 for level 2. BHE suggests that their internal costs are $500k more than the fees collected. There is an approximately 90-day average from application date to meter request for the 2019–2021 projects that completed the application process and 72 days for 2021 applications. BHE has not tracked the date of interconnect request withdrawals but is doing so going forward. Black Hills has performed no interconnection cluster studies.

VIII. IOU Portals

Both BHE and PSCo provided Staff with interconnection portal demonstrations Comparing/contrasting IOU portals.

By comparing the two IOU's interconnection portals it became clear to Staff that BHE's new portal had an easier, more customer-oriented, approach to making customer projects successful. PSCo's portal had a very lengthy PowerPoint to explain the portal, and when PSCo demonstrated the portal, it appeared to be very "if/then" oriented and difficult to understand. Storage is included in the portal, so solar-only interconnection requesters for PSCo must page through multiple storage-oriented inputs. PSCo's portal seemed to suffer from being older, with more content that might be outdated or unnecessary as compared with BHE's portal. In response to an inquiry on the complexity of their portal, Staff received this response from PSCo:

> We are building changes to the online application management system to enable us to report and track pre-application data requests. We anticipate launching this greatly enhanced system mid to late Q1 2022.

BHE demonstrated a communication culture; they reach out to developers quite frequently. The portal has automated communications and the BHE staff has a unique, collaborative approach while actively streamlining the process. Industry feedback on their portal has been positive.

It appeared to Staff that there are only two basic pieces of information needed for a quick capacity check on an interconnection request: location and AC capacity (with or without storage). If the location doesn't have the capacity, then putting a customer in a position to fill out the lengthy process is time wasted. There are further details which could still derail an interconnection request. Staff felt a pre-application with these two pieces of information would be helpful to any customer kicking the tires on interconnection.

Staff would like to remind the IOUs, regarding HCA updates, that the DSP rulemaking Proceeding 20R-0516E Web Portal Rule 3541(d)(II)(F) clearly contemplates <u>quarterly</u> updates for HCA.[2] There are more details on HCA as it relates to interconnection issues later in this report.

[2] Rule 3541(d)(II)(F): "a proposal for updating data provided through the web portal, specifically addressing the quarterly updating of the utility's hosting capacity analysis as described in subparagraph 3531(a)(II)."

IX. Anonymous Survey

Staff worked with the Colorado Solar and Storage Association (COSSA) and PSCo to both publicize the availability of the survey to targeted participants and to develop the anonymous survey which was administered through SurveyMonkey. There were a few people who had specific issues with DG that did not pertain to the Interconnection Investigation.

Process and Anonymity

Staff attended numerous Solardarity events (monthly gatherings in various locations) to target industry people who were developers, owners, or installers familiar with the interconnection process. Staff provided the SurveyMonkey survey location to those who qualified. During the discussions with the industry some feedback was obtained, including interest in more call center support, interest in portal streamlining, attention to customer preferred method of communication (because sometimes door hangers aren't received by contractors), and industry difficulties when utility interconnection staffing changes.

Average time spend on the anonymous survey by respondents was 21 minutes. Staff would like to thank those that participated. Thanks.

The anonymous survey consisted of the following 11 items.

1. This survey is for people who have experience with the DER interconnection process. Have you been directly involved with the interconnection process of a Colorado electric utility?

   Yes

   No

2. Are you a distributed energy resource (DER) project:

   Developer

   Owner

   Installer

Other (please specify)

3. Please provide at least one utility name for an interconnection process you have initiated in Colorado. [Comment Box]

4. For the project in the previous question, what type of project was it:

   Utility-scale

Community Solar Garden (CSG)

Smaller distributed energy

Energy Storage

Other (please specify)

5. What opportunities exist to improve the policies and processes surrounding interconnections that the current interconnection rules do not sufficiently address? (Note: current interconnection rules went into effect 7/30/21, 19R-0654E) [Comment Box}

6. What reporting requirements are needed by the utility for a more transparent interconnection process? Please provide up to three suggestions with timeframe of how often reporting would be optimal. [Comment Box]

7. What do you estimate the actual costs are for your interconnection process in $/kW (not including site specific studies or any equipment)? A whole number response please. [Comment Box]

8. Please rank the following in order of importance to your organization.

Meeting expected timelines, including overall length

Effective communications between applicant and the utility

Transparency of the utility's interconnection practices

Customer service

9. Do you have any suggestions on how non-wire alternatives (NWA) and distribution system equipment can increase hosting capacity of DERs? [Comment Box]

10. What continuous improvements are needed to modernize the interconnection process? [Comment Box]

11. What do you want to Public Utilities Commission to know about your experience with the interconnection process in Colorado? [Comment Box]

All respondents answered “Yes” to the first question. Second question had one third Developers, one third Installers, and the second third split between Owner and Other (Contractor). The third response included the utilities PSCo (Xcel), Loveland, United Power, Fort Collins, PVREA, Colorado Springs, Longmont, Mountain View Electric, IREA, Yampa Valley, San Luis Valley, Mountain Parks, and Holy Cross. The fourth question was 44% CSG, 33% Smaller Distributed energy, zero energy storage, one all the above and one Commercial Scale. The seventh question, when removing the low and high answer, averaged $64 for the respondents cost to administer each application. Responses to the eighth question were all very close, but Transparency scored 3.13, Meeting expected timelines scored 2.75, Effective communications scored 2.25 and Customer service scored 1.88 using the SurveyMonkey scoring methodology.

Questions 5, 6, 9, 10 and 11 specific to the investigation have insightful content. The responses received are shown below verbatim.[3]

Q5: What opportunities exist to improve the policies and processes surrounding interconnections that the current interconnection rules do not sufficiently address?

- Xcel should offer projects that are on hold for their feasibility/system impact review the option of beginning their review when the project ahead in queue has committed to their facilities study (at the cost risk to the developer on hold to restudy their project if the project ahead decides not to proceed beyond the facilities study). This would cut several weeks off the overall review in a multiple queue scenario at what may be considered an acceptable financial risk to developers. We understand that Xcel wants to avoid restudies entirely if possible, but this scenario with the current program structure should only incur a minimal amount of restudies.

- Keep working to reduce timelines for engineering review and delays in setting net meters. There have been issues when Solar Rewards indicates an IX plan is OK and then we find out later during engineering review that it's not. Opportunity to improve - Identify who can answer which questions. Commingling rules aren't clearly defined or publicized and answers depend on who's being asked. Background: the 19R-654E document includes language around the handling of connecting storage (ESS) Ask: related to inadvertent export, or non-export, clarification on what is the process to arrive at a “mutually agreeable, on-site limiting element”. Background: the 19R-654E document includes language concerning what happens if there are “material modifications”, dispute resolution provisions for determining material modifications determined vis a vis section 3853(d)(VI), and in anticipating of ever-changing procurement landscape. Ask: clarify if DC side changes are considered “material modification”. Can we go down in AC nameplate rating without triggering a “material modification”. Background: Certified inverters are UL listed, meeting the anti-islanding requirements from IEEE, effective grounding requirements can lead to a scenarios where Listed inverters are no longer able to meet anti-islanding requirements. Ask: can we remove all effective grounding requirements for Behind the Meter BTM projects.

- General 120% rule too limiting. Limit on 15% transformer capacity rule with MVEA is too strict. They have denied many customers the oppotunity [sic] to go solar and many they have limited so much that they were discouraged from going through.

- With Xcel Energy most specifically, the onerous requirements for interconnection of solar + storage are unacceptable. The requirements are especially skewed against DC-coupled backup systems, which are the most efficient and least costly for consumers.

[3] The order of the responses has been randomized.

- Concrete information that can significantly impact the project's economics do not come until very late in the process after a lot of significant investment have been made. More, site-specific, information (on potential upgrades, costs, timing) earlier in the process would help quite a bit. Likewise, consistent publicly-available resources on substation and feeder hosting capacity would benefit all stakeholders.

- CSU: -We've been experiencing communication disconnects. CSU has been slower to respond, and prefers only email communications. -Improvement suggestion: We would like a phone rep to be available. -We are unable to verify requirements easily (such as the meter height requirement). --XCEL: -We have experienced 120% Rule inconsistency from reviewers (prior to recent updated 200% rule), which leads to oversized corrections. -Improvement suggestion: Alignment across all teams -For the transformer upgrades, there have been irregular timeline updates and inconsistency on who owns the costs. -Improvement suggestion: Creating a set Transformer Upgrade process. -We have been noticing a PTO notice inconsistency, and have been receiving notices via either door hangers, or PTO letter emails. -Duplicate applications can be created in the portal, which may cause confusion. -Improvement suggestion: would like an existing application notice associated with account/address -But we like the flexibility of the portal! --IREA: -IREA does not send individual PTO letters, and send out mass PTO letters (causes a delayed timeline), which leads to not a great customer experience. -Improvement suggestion: Send out individual PTO's regularly. --United Power: -Also sends out multiple PTO's at once --Fort Collins: -Going well!

Q6: What reporting requirements are needed by the utility for a more transparent interconnection process? Please provide up to three suggestions with timeframe of how often reporting would be optimal.

- Portals have not been an issue since they provide live statuses of the projects, however for utilities with some email process, it would be appreciated if set timelines were given of when we can expect communication. -Weekly, or bi-weekly, updates for ongoing projects -For pending/escalated projects, weekly communication on project status would be appreciated.

- Feeder capacity: quarterly preferred (with a cold>hot map) Application to Approval timeframe: quarterly PTO Request to PTO issuance timeframe: quarterly

- 1) Quarterly hosting capacity updates for substations and feeders. CA utilities provide a great example of this. 2) Costs from previous substation upgrades as a reference point (annual). 3) Clear, understandable data on available capacity for substations and feeders (complements hosting capacity map)

- The utility should not be able to require unnecessary + costly disconnects and meter housings, much less the burdensome administrative process, for equipment wholly located on the customer side of the meter and owned by the customer. Installers should be allowed to install solar + storage per the National Electric Code and as reflected in code-compliant line diagrams, period.

- MVEA needs to be more transparent with their approval process and why the 15% rule is so important. They should make this information more easily accessible as we will be in contact with a customer for a few days before knowing whether or not they can install solar and how much they are allowed.

- one report that would be useful would be estimated customer load and connected DER perhaps as a ratio, for evaluating circuits for likelihood of effective grounding.

- We recognize you asked for three suggestions, however in an effort to be helpful to your investigation, we have a broader list to offer for consideration. We recommend these reports to be reported quarterly, except where such other frequency is identified. Many of these reports could be reported in standardized Excel spreadsheets to form a database, with each row representing a project: -Total costs for every CSG cost estimate, and a breakdown of component costs and actual costs for each CSG. All costs to be displayed on a per-watt basis. -Report a running average of CSG interconnection cost estimates for each annual year starting in 2014 through present, and going forward - and same for actual costs, on a per watt basis - to track interconnection cost estimates and actuals over time. -Report on every interconnection cost estimate over 5 cents per watt; for each of these, Public Service to identify and explain the significant factors that are driving the high cost, what cost-mitigation measures were considered by Public Service to address such high costs, whether new technology to mitigate upgrades was considered, and whether the work was competitively bid. -Report the time in days between initial interconnection application and Public Service's date of the delivery of a cost estimate, and aggregate on an annual basis to track performance over time. This information should be displayed both per project (developer name confidential), and on average for all projects in a calendar year. Furthermore, in each instance, where such cost estimate takes over 45 days, Public Service should explain the circumstances surrounding such delay. -Report the time between the developer signing an interconnection agreement and Public Service completing all interconnection work and having its side of the interconnection ready for connection. This should be reported per project and in aggregate on an annual basis. For each instance in which an interconnection upgrade takes longer than 90 days, Public Service should explain the circumstances surrounding such delay. -Any CSG system outages that a developer claims is caused by Public Service's power quality, and detail Public Service's investigation into such claims and if necessary, remediation actions taken. -The quarterly number of bill credit errors identified and reported by subscribers or subscriber organizations. -Any new or clarified program rules, policies, or business practices that Public Service intends to implement (or begin enforcing if not previously enforced) which are more constraining on business than past implementation practice, and document the reason for such change(s). -On an annual basis, submit to all CSG developers a confidential survey (to be returned by developers to COSSA and confidentially randomized) of all CSG program, program management, subscriber management, and area engineer staff as well as pertinent program characteristics such as interconnection timing, costs, customer service, etc. Ratings should be done on a 1-5 scale. -Report the number of projects and megawatts online and in the queue, and subscriber mix online in both number of subscribers and capacity.

- We'd like to see the current CSG interconnection queue amended to include the name and due date for the next action on each project. That is, if someone is required to make a System Impact Study payment by a certain date, we'd like to see that milestone and due date in the queue.

Q9: Do you have any suggestions on how non-wire alternatives (NWA) and distribution system equipment can increase hosting capacity of DERs?

- All new and replaced/upgraded distribution equipment should be required to allow bi-directional energy flow.

- Not my area of expertise, but I think more virtual (off-site) net metering.

- Our response to number 7 above: This is a false calculation because the same amount of time and expertise is required for 2 kW as 25 kW. However, solar + storage is easily twice as much work and time investment compared with solar only.

- There is no incentive to deploy battery storage with a community solar project. Without a mechanism or program for a solar developer to be compensated for time shifting the solar resource or participating in battery demand response, it will not happen.

- Require that Public Service recognize and incorporate modeling of energy storage when calculating a project's impact on the grid and Minimum Daytime Load at the point of interconnection and substations. For example, if storage is utilized to limit a PV facility's injection onto the grid during Minimum Daytime load, and shift that production to other times, grid upgrades should be avoided. This is not Public Service's current practice -Rather than utilizing minimum daytime load, require Public Service to use standard production modeling for renewables projects (for example, if minimum daytime load is recognized at 5pm, that should not be used to curtail a fixed-tilt PV project that is not at peak production at 5pm). -The cost for large upgrades that may make individual projects cost-ineffective, but if performed could enable many projects (ie: 3vo/VSR), should be spread across either the rate base (if more projects are deemed to be in the public interest), or spread amongst future developers utilizing such equipment (ie: PSCo amortizes the charge across multiple developers). This prevents the situation where current grid capacity is not utilized because no one company's DG project can afford such an upgrade.

- In the short term: Actively seek out a device or solution similar to a voltage regulator that would allow for projects slightly further away from the substation to exist without requiring massive reconductor upgrades. In the long term: Perform an internal assessment of where future DER may be likely to be located based on load expectation and land costs, and size a higher percentage of new poles to be suitable for a future upgrade to 336AL.

- Utilize SCADA systems for Inverter control to modify VARs and other grid support capabilities. Remotely controlled DER projects could also help to provide more grid stability and when coupled with storage introduces peak shaving potential to reduce the need to increase for distribution equipment.

Q10: What continuous improvements are needed to modernize the interconnection process?

- Reevaluate old limitations and rules for sizing residential solar. Public citizens deserve more autonomy in deciding how much solar they can install. Better communication methods between utility and contractor need to be opened. Current communication practices hinder the process by creating unneeded delay.

- Regularly updated grid information resources are essential to developers and utilities moving projects quickly from award to operation. It would be helpful for Xcel to provide regularly updated distribution system information related to queued capacity broken down by substation and further by feeder. Accurate resources, including but not limited to hosting capacity maps, minimum daytime load reports, and existing and queued generation should be made available to the public, and these should be updated regularly.

- Given the pace of changes in DER's, we'd suggest having a review such as this annually to ensure that issues are being addressed in a timely manner.

- Consistent, clear easy to find SOPS. Improving application portal will streamline overall process. More utility human resources who are dedicated to DER. This would allow Xcel to be more efficient and team members to succeed in their roles. Recommend having DER dedicated engineers for reviewing applications.

- Better hosting capacity maps to improve pre-development work and project siting. Complementary programs for battery demand response to increase the system value of community solar.

- Standard interconnection agreement across the state (wish list). At least that all contract templates be published or available. We've had to help utilities write (or re-write) their interconnection agreements at our own legal cost.

- Right now, a lot of a developer's success in going through Xcel's process is tied to who you know at Xcel, your ability to understand vague information and existing "insider knowledge." We need more transparency and more consistent, understandable information and data.

- Continuous alignment and communication would be greatly appreciated as we go through the Interconnection process to continue aligning with utility requirements, and ensuring a great experience for our mutual customers. The portal processes have been helpful in this area.

- Please note that the solar interconnection process can only be as good as its leadership. The Solar*Rewards staff works hard and we have seen many improvements to the process over the years, including a more collegial approach that we believe to be mutually beneficial for Xcel and the solar industry. The engineering team is less enthusiastic and helpful, and we recognize that is not within the control of the Solar*Rewards team.

Q11: What do you want to Public Utilities Commission to know about your experience with the interconnection process in Colorado?

- Xcel CO has been a good and reasonable facilitator of DER for at least the past few years. We have experienced an array of cooperation from different utilities ranging from actively being against DER to being indifferent toward DER to being supportive of DER. We frequently hold up Xcel CO as an example of being supportive of DER. We are concerned that Xcel CO will continue to adopt policies to more closely resemble Xcel MN, which would be a step in the wrong direction.

- Utility companies will always try to lever their control of the process. Some limitations on sizing have greatly discouraged business such is the case with MVEA. Some utility companies, like Colorado Springs Utility, are poor at communicating and have caused problems with our customer process by taking a long time and hindering communication with flawed rules regarding how they can respond to questions about specific projects. If you ask a question in an email chain for a specific project, it can delay them actually getting to your project by another 2 weeks as they strictly work with a 'first come first serve' mentaility [sic]. This strategy hinders the ability to communicate effectively.

- Public Service has repeatedly provided incorrect and misleading information in their pre-application data reports (PADRs), which is the first step in the interconnection process and how developers initially screen sites for viability. These are reports that Developers have to pay $300 for, and we should therefore be able to rely on them, especially since Public Service is relying on them in their evaluation of RFP bids. We have numerous examples of incorrect PADRs that were only identified as having bad information when we went to make a site move request, asked follow-up questions, or proceeded to a study. We also have multiple examples where Public Service denied us the ability to receive a PADR, but provided information to other Developers. Since PADRs were required to prove interconnection viability in the RFP, and therefore secure a project that can move through the interconnection process, this has had a material impact on us. - Public Service is constantly changing internal rules as a cat and mouse game with the Commission. For example, after a nearly two-year fight to overturn the No Capacity Notice protocol in the NOPR, which was plainly in violation of the Commission’s rules, Xcel found a workaround to block the Commission’s ruling that all projects must be entitled to a study. Removing the “No Capacity Notice” would have allowed us to move forward on project sites that had cost-effective upgrades, but Public Service stopped this from happening by implementing an Interconnection viability score in the 2020 RFP that was based on a formula that was irrelevant to a Developer’s ability to quickly and cost-effectively move projects forward, but instead prevented projects from being awarded at substations Public Service had previously declared were No Capacity prior to the Commision [sic] ruling in the NOPR. While creative on Public Service's end, it was clearly in violation of the Commissions NOPR ruling. Again, more detail can be provided upon request.

- Timing of engineering reviews and interconnection study can delay project financing, which in some cases can kill a project. Would like more regular communication from the utility, to streamline the process and save everyone time.

- Compared to other states, it is often less professional and more opaque. Information (hosting capacity, costs, timelines, etc.) is piecemeal or non-existent, and utility staff often refuse to share information that would be publicly available in other markets. There is a huge opportunity in CO, but without a clear, consistent process we will not be able to scale.

- The variability across electricity providers is incomprehensible. Standardization of process, forms, and contracts would increase velocity of solar and storage deal flow across the state.

- We appreciate the continued growth in aligning and communication over the years! Looking forward to continuing to grow and improve as we continue to help our mutual customers go solar.

- Please revise storage interconnection requirements before Colorado gets left too far behind by the onerous nature of this process

General Observations on the Anonymous Survey

The sample size of the responses isn't large, and this may indicate industry's general acceptance of the interconnection process. Nonetheless, the responses show room for improvement in the interconnection process.

PSCo Survey

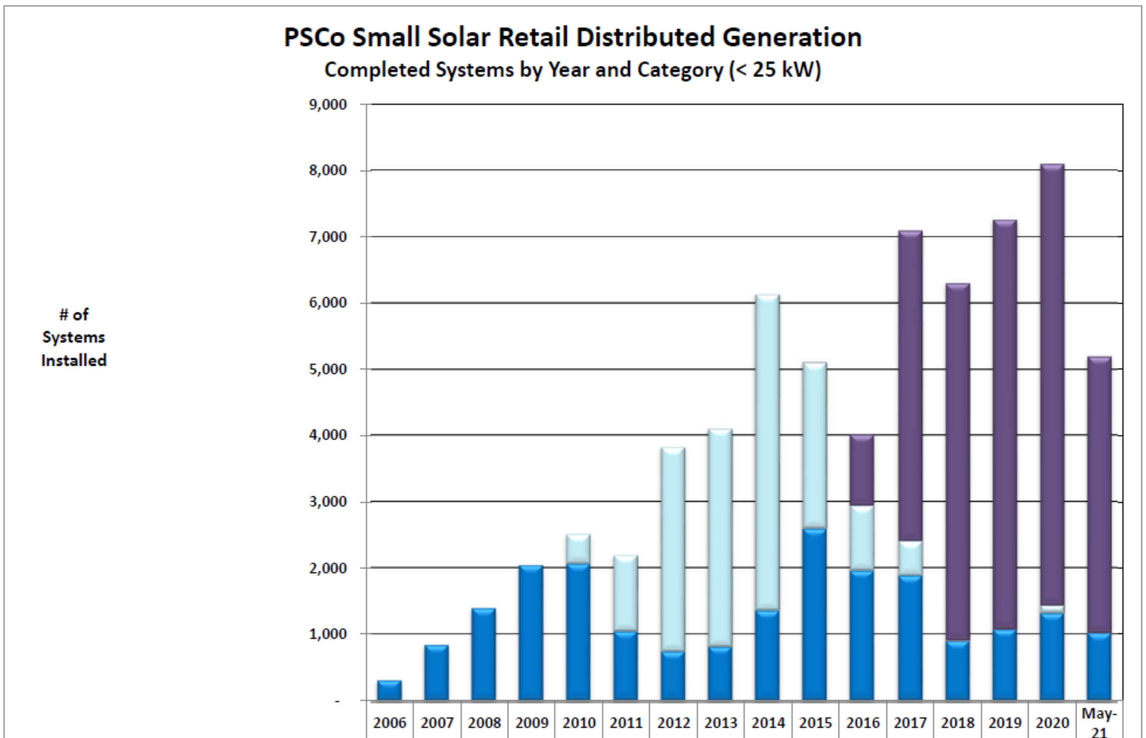
While PUC Staff was performing an anonymous survey, PSCo was conducting another similar survey that was not anonymous. It had a similar number of respondents and some similar questions. On the whole, in Staff's opinion, the PSCo survey had a more positive sentiment from the industry to interconnection issues. One statement from the PSCo survey about PSCo's interconnection process was notable: "Geared towards making projects successful." While the PUC-administered anonymous survey didn't include this particular feedback perspective, Staff feels this statement can be used as a mindset for future interconnection procedures and requests.

X. History of Interconnection

In this section Staff discusses the history of interconnection at the investor owned utilities. Before interconnection rules were established a subset of "guerrilla" solar people would attach inverters to utility systems without asking. That was before certified equipment built to industry standards like IEEE-1547 existed. Rules for interconnection were established. This helped the industry to grow and enabled utilities to safely increase DER capacity. In California, the first rules were called Rule-21. Colorado followed similar protocols, with changes specific to unique aspect to Colorado's grid and policies. The 2010 version of the interconnection rules were recently updated in proceeding 19R-0654E.

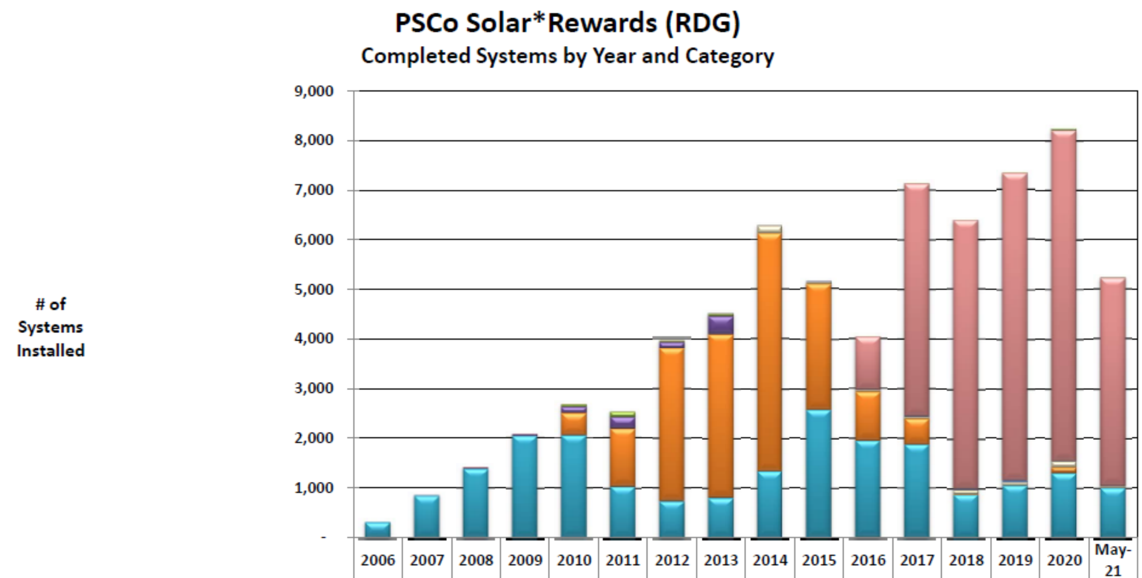
The history of the quantities of interconnection at PSCo can be seen in this year's Staff Review Report from proceeding 19A-0369E on PSCo's RES Report.

Exhibit CPUC - 6
2020 RES Report Review 19A-0396E



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	May-21
Net Metering Only - Small	-	-	-	-	-	-	-	1	4	10	1,071	4,685	5,389	6,178	6,661	4,170
S*R Small 3rd Party Developer (0.05 - 25 kW)	-	-	-	-	446	1,145	3,079	3,292	4,774	2,513	983	523	13	4	119	7
S*R Small Customer Owned (0.05 -25 kW)	298	833	1,385	2,035	2,056	1,041	734	808	1,351	2,586	1,954	1,880	892	1,068	1,313	1,013

Exhibit CPUC - 8
2020 RES Report Review 19A-0396E



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	May-21
Net Metering Only - Medium	-	-	-	-	-	-	-	-	1	-	4	8	3	10	34	11
Net Metering Only - Small	-	-	-	-	-	-	-	1	4	10	1,071	4,685	5,389	6,178	6,661	4,170
Community Solar Garden	-	-	-	-	-	-	-	7	7	10	1	9	19	28	10	5
Large (RFP)	-	2	17	7	2	2	1	1	2	-	-	1	3	4	1	1
Medium Tier (25 -500 kW)	-	-	-	-	-	-	-	-	146	36	30	36	74	52	109	31
Medium Tier 2 (100-500 kW)	-	-	-	-	43	102	29	45	-	-	-	-	-	-	-	-
Medium Tier 1 (10-100 kW)	-	4	11	30	128	236	121	348	-	-	-	-	-	-	-	-
S*R Small 3rd Party Developer (0.05 - 25 kW)	-	-	-	-	446	1,145	3,079	3,292	4,774	2,513	983	523	13	4	119	7
S*R Small Customer Owned (0.05 -25 kW)	298	833	1,385	2,035	2,056	1,041	734	808	1,351	2,586	1,954	1,880	892	1,068	1,313	1,013

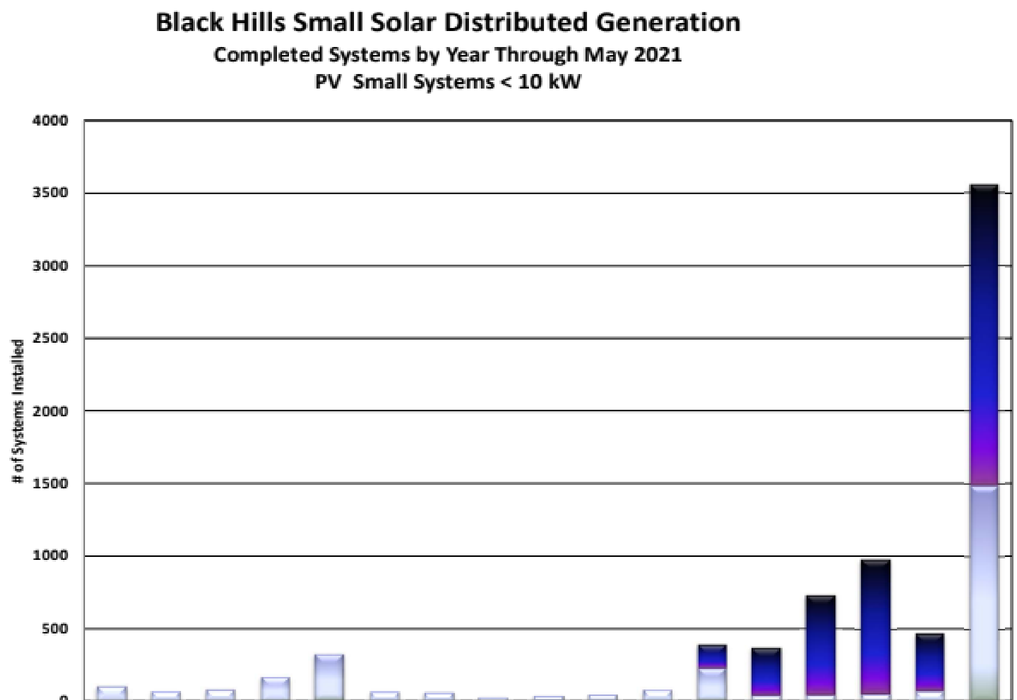
[4]

PSCo indicates that the cost was $1,358,116 in 2019 and $1,722,116 in 2020. These costs reflect both program administrative and engineering costs to administer and interconnect retail DG.

The history of the quantities of interconnection at Black Hills can be seen in this year's Staff Review Report from proceeding 16A-0436E on Black Hills RES Report.

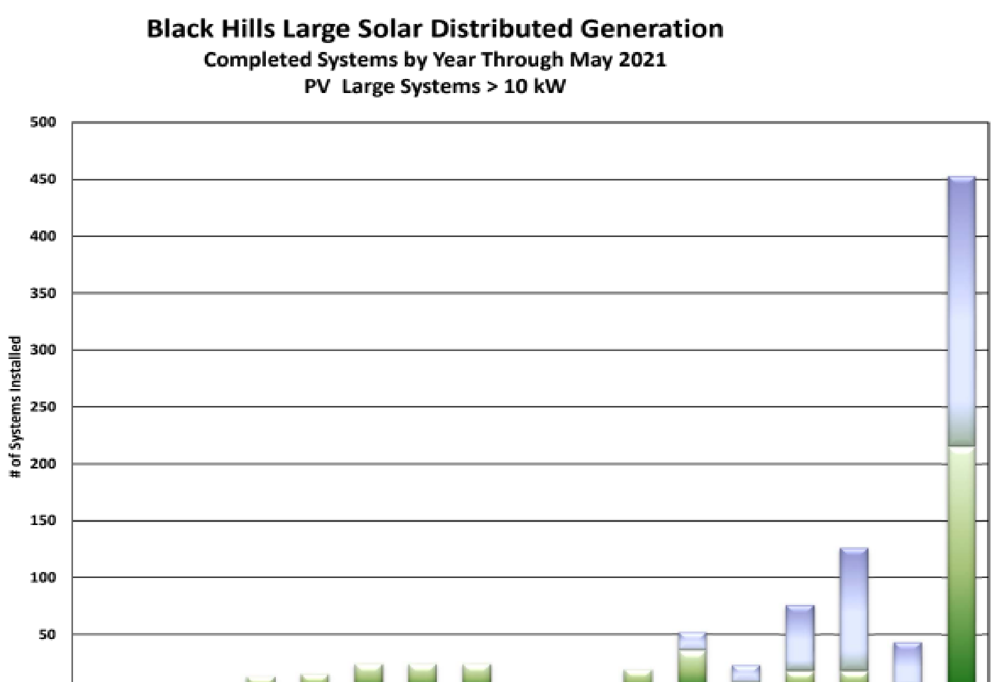
[4] 19A-0369E Staff Review of PSCo 2020 Res Report.

Exihibits CPUC 1
2020 RES Report Review 16A-0436E



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	May-21	Cumulative
Net Metering Only	-	-	-	-	-	-	-	-	-	-	-	157	315	678	920	389	2070
Completed Incentive Applications	101	67	76	168	319	63	61	28	36	42	77	228	44	48	55	75	1488

Exihibits CPUC 2
2020 RES Report Review 16A-0436E



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	May-21	Cumulative
Net Metering Only	-	-	-	-	-	-	-	-	-	-	-	16	15	58	108	41	238
Completed Incentive Applications	0	1	2	13	15	24	24	24	5	6	19	36	8	18	18	2	215

XI. Interconnection Process for Large Quantity of DERs

The major IOU in Colorado, PSCo, plans to increase interconnected solar capacity each year based on the Table B-15, shown below, from Attachment AKJ-3 in the Energy Resource Plan (ERP) Proceeding No. 21A-0141E.

Table B-15

Distributed Solar (Nameplate MW)			
Year	Behind the Meter	Community Gardens	Total
2021	496	118	614
2022	561	185	747
2023	629	252	882
2024	686	319	1,005
2025	726	385	1,111
2026	769	451	1,220
2027	815	516	1,331
2028	872	582	1,454
2029	950	646	1,596
2030	1,046	711	1,757

Approximately 65 MW additional BTM per year and an additional 67 MW CSG per year near-term. PSCo's interconnection process, and staff need to be streamlined to accomplish these annual increases.

As we saw from PSCo interconnection data, 19% of applications did not move forward. To address these ERP capacities, applications need a greater probability of success.

A pre-application process may be an appropriate process step prior requiring an applicant to complete the more extensive full application. Capacity and location are two data points that should be supplied to the utility for an initial reality check on the probability of success. More concepts on increasing probability of success are in the next CSG section.

To be successful with interconnecting these large capacities in the 2021 ERP, PSCo can benefit from the comment from their own non-anonymous survey. The comment said that the Company should be, "Geared towards making projects successful."

CSGs

Public Service of Colorado (PSCo) is by far the utility with the most CSG applications that Staff studied. Looking at the years 2019 and 2020 there were 36 projects withdrawn thus far from those years. Out of a total 70 applications, more than half of the CSG projects withdrew. For capacity, approximately 55MW are still active while approximately 39MW had withdrawn, or 59% of the capacity still moving forward while 41% was withdrawn. There is a clear trend since 2017 to 2020 of an increasing percentage of CSG capacity not moving forward in the interconnection process. 2021 data isn't considered because it is too early in the project process. The goal should be to have applications apply when they have a high probability of success.

PSCo CSG Capacity in MW	**2017**	**2018**	**2019**	**2020**
Withdrawn	9	6	24	15
Grand Total	50	24	61	33
Percentage Withdrawn	19%	25%	39%	46%

So, what can be done to increase the likelihood that CSG projects applying for interconnection will be successful? There are some success examples from the investigation of the Cooperatives, and there are some comments from the industry anonymous survey which may help along these lines.

Accurate pre-application data reports (PADR) should be a good place to start if interested in increasing probabilities of success. Before an application is submitted, the PADR should accurately indicate if it has a realistic probability of success. Staff doesn't know if PADRs are accurate, but a good feedback mechanism should be the Company investing in analysis to determine if PADRs are accurate. This includes investigating both false positives as well as false negatives.

There exists an effective feedback loop where projects with low probability of success that don't apply help eliminate the time the utility spends evaluating these projects and frees up resources to address higher probability of success projects.

Similarly, accurate and timely HCA and HCMs are other tools that should be increasing the probability of success for CSP applications. Staff finds it concerning that the Q&As from current CSG RFP file named, "2021 RFP QA Tracker 11.2.21" reads as follows:

> Q: Does Xcel Energy have a hosting capacity map?

> A: Yes, it is available under the company's Interconnect Page. https://co.my.xcelenergy.com/s/renewable/developers/interconnection. As a reminder the tool is useful for geographic concerns but capacity is not guaranteed.

The red part above, "the tool is useful for geographic concerns but capacity is not guaranteed", is the concerning part. Please see the HCA/HCM section later in this report for more perspectives on this topic.

It is important to understand steps that competitively bid CSG projects are expected to perform if awarded a project in a CSG RFP. The Q&As from the most recent CSG RFP file named, "2021 RFP QA Tracker 11.2.21" the Developer Award Acceptance Process reads:

> Developers have up to 20 business days to notify the Company whether they are accepting an award. Email confirmation of award acceptance is an acceptable means of notifying the Company. Within 90 calendar days of notification of the award, the awardee must also meet post bid requirements for awarded bids as noted in Section 4.11 of the main RFP document.
>
> Engineering Review Process:
>
> After the bid acceptance notification is made and application documents are submitted, the Company will conduct the Completeness Review (including a non-refundable $2000 interconnection fee), which is the first step in the engineering process and can occur in as few as ten business days provided all documentation is complete and correct.
>
> Once the Completeness Review is completed, the developer can choose to move to the Feasibility Study, System Impact Study, and ultimately Facilities Study. This study process will occur between 60 and 90 days (60 days for Feasibility Study and System Impact Study, and 90 days for all three studies, if required). SIS are $12k.
>
> Queue position is determined by the Completeness Review process described in Commission Rule 3853(d)(IV).
>
> No, bids should include all relevant information. All developers have the same tools and processes available to them (e.g., PADRs, General Cost Outlines). A list of developer resources for Community Solar Gardens can be accessed at the following link:
>
> https://co.my.xcelenergy.com/s/renewable/developers/community-solar-gardens

> This statement reflects the site-specific nature of interconnection costs as well as the importance of position in the interconnection queue. Once the developer has successfully completed the "Completeness Review" step in the engineering review process (and correspondingly locked in an interconnection queue position), the Company is able to provide more detailed and site-specific interconnection costs via the study process.[5]

Each step in this process can be a cause for a project's withdrawal from an interconnection application. The Company's ability to reduce the number of low probability applications and help those that do apply to be a high probability of success will be reflected in future success ratios. Staff recommends a critical review of these steps with the mindset of increasing the probability for project success.

Batch Studies

Batch studies have the potential to target future CSGs where utility capacity will be the most appropriate and to target planned substation upgrades that can facilitate more DER. When asked about batch studies, PSCo stated:

> "[W]e believe that when the context allows for them, batch studies are justified. When multiple developers are involved, batch studies only tend to be a useful tool if all developers agree to move forward and have projects which are on similar timelines. Batch studies do tend to be easier to complete when it is a single developer with multiple projects. Cost savings can be realized with batch studies as long as all parties move forward based on the study results."

Staff understands that all parties may not be ready to move forward at the same time, but in the case where several developers are ready to proceed the batch study process is justified. Staff recommends the Commission encourage batch studies when appropriate.

No Capacity Notices

PSCo has indicated, "Since the inception of the CSG program, the Company has issued a total of six no capacity notices which applied to two substations – the Imboden and Quincy substations. These were issued as the Company sought to address significant CSG interconnection requests relative to total substation capacity. However, since these notices were issued, the Company recognized an opportunity for improving the communications under the program and has adopted a policy that it will avoid issuing no capacity notices and will work with developers to help them better understand the nature of constraints and allow for additional studies through processes like requesting a pre-application data report ("PADR")."[6] It is also very important to have capacity on feeders for distributed generation to make sure that future net metered customers do not receive no capacity notices.

[5] 2021 RFP QA Tracker 11.2.21

[6] Note that the anonymous survey has a comment that questions the accuracy of PADRs. Staff believes that an accurate PADR has the positive potential to help the interconnection process.

Utility tracking of reasons for withdrawal might help future applications for CSG. If the withdrawal was due to outside project transaction difficulties, such as land acquisition or local permitting, this would be helpful for a utility and the State to understand. Conversely, tracking of more detailed reasons for withdrawal that can actual be addressed by changes to the interconnection process will help the success ratio. Staff has found that the tracking of reasons for withdrawal from an application can be more detailed and more accurate. This lack of data is consistent with discussions with the California PUC regarding their interconnection investigation discussed in the next section. Staff recommends that utilities accurately track more details on reasons for CSG interconnection withdrawals.

XII. Other Jurisdictions

Colorado is not alone in its attempts to quickly, safely, and at low-cost, interconnect DERs. To get a feeling for other jurisdictions, we can review timelines from California's experience, specifically PGE.

California Assembly Bill 2861 (Ting, 2016) authorized the California PUC to evaluate adherence to Rule 21 interconnection timelines. Guidehouse (consultant) carried out the evaluation from May 2019 through July 2020. In March 2021 Guidehouse published a report titled, "Rule 21 Interconnection Program Evaluation" showing, among other things, the business days (BD) for interconnections in IOU territory PGE. The below tables reflect PGE interconnection project requests with permission to operate (PTO) dates for the three-year study between July 1, 2016 and June 30, 2019.

Table 40. PG&E NEM Time to Validate Application

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Size				
Less than 30 kW	185,331	7.2	18.8	87.6%
30-100 kW	1,711	32.1	48.9	39.6%
100 kW-1 MW	1,624	37.9	54.5	33.4%
1 MW or greater	71	22.0	23.6	26.8%

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 10 BD
By Project Technology Type				
Solar	185,904	7.5	19.8	87.3%
Storage	1,841	23.8	34.2	43.8%
Other	396	19.9	23.9	45.7%
Unknown	596	25.9	36.6	52.2%
Total	**188,737**	**7.7**	**20.2**	**86.7%**

Table 37. PG&E NEM 30-Day Provision Results

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 30 BD
By Project Size				
Less than 30 kW	183,589	5.5	16.6	96.9%
30-100 kW	1,288	60.8	90.2	54.0%
100 kW-1 MW	1,024	75.6	102.3	52.1%
1 MW or greater	7	30.4	47.8	71.4%

Category	Count	Mean (BD)	Std. Dev. (BD)	Percent ≤ 30 BD
By Project Technology Type				
Solar	183,006	5.8	19.6	96.8%
Storage	2,009	35.0	48.8	63.9%
Other	349	51.4	66.7	48.7%
Unknown	544	22.6	44.0	81.3%
Total	**185,908**	**6.3**	**20.8**	**96.3%**

The quantity of Pacific Gas and Electric interconnection requests, 188,737 DER projects in three years, averages to be 63,000/year. Those that received PTO is huge compared to Colorado's largest utility PSCo. This Colorado PUC interconnection study looked back for just two years, but if averaged, PSCo had closer to 8,800 PTOs/year.[7]

Staff discussed the Guidehouse reporting with the California PUC and in the second half of December Staff will be obtaining new California interconnection reports that can help guide Colorado's future interconnection reporting. These will be shared with the DSP proceeding stakeholders.

XIII. PIM or PBR

[7] Staff Review of PSCo 2020 Res Report, Proceeding No. 19A-0369E.

Staff is not recommending a specific performance incentive mechanism or a performance-based regulation (PIM/PBR) in this proceeding because these are best developed in litigated proceedings where the utility and interested parties have an opportunity to be heard before the Commission who authorizes implementation of such PIM/PBRs.

Recently, Xcel Energy was assessed a $1M fine in an interconnection PIM in Minnesota ("MN") because the MN PUC had received an excessive number of complaints.[8] The $1M fine in MN levied against Xcel was for lack of Quality of Service. An IREC report on the $1M MN fine include these highlights:

- 396 complaints about Xcel Energy were submitted to the MN PUC's Consumer Affairs Office; 129 of these were on behalf of residential/commercial solar customers.
- These complaints caused Xcel Energy to exceed in 2019 the threshold of 363 customer complaints that triggers the fine according to its Quality of Service Plan (QSP).
- The trigger for the fine is the number of complaints filed, not whether the company ultimately resolved the problems at issue.

There is an environmental PIM being discussed in the current ERP proceeding 21A-0141E which might be broad/sufficient to further motivate interconnection efficacy.

Staff believes the industry/utility stakeholder process provides an opportunity to continue to address interconnection issues, but Staff will be looking for ways to leave the door open to an interconnection PIM/PBR especially with regard to CSGs on PSCo's system. Application success ratios are a good indicator of the performance of the interconnection process. Consistently meeting ERP capacity objectives is another good indicator.

XIV. Other Issues That Arose During Investigation

Staff's 2021 interconnection investigation has received no public comments as of the date of this report. Out of the many companies given the opportunity to respond to the anonymous survey, nine (9) felt the need to express opinions. This indicated to Staff that interconnection had a relatively positive acceptance in the state. Albeit some of the comments in the anonymous survey obviously have merit and have already been discussed. This section brings to light other new issues since the anonymous survey was performed.

[8] https://irecusa.org/2021/01/minnesota-puc-fines-xcel-energy-1-million-for-interconnection-failures/

Issues of merit with Xcel in other jurisdictions

On August 25th, 2021, All Energy Solar submitted a letter to the Minnesota Public Utility Commission relating to their docket numbers E999/CI-16-521, E999/CI-01-1023 which addresses issues identified in this Colorado Interconnection Investigation proceeding.[9] The letter outlines, among other things, extraordinarily long interconnection queue times in Minnesota. Xcel Energy describes the Minnesota interconnection experience as drastically different from CSG projects in Colorado which they characterize as a wild west like activity. Staff is tracking interconnection times in Colorado to address any similar issues in Colorado.

Reservation of CSG Capacity

During the Investigation, PSCo made it known that CSGs would need to reserve capacity on distribution system, not to exceed 75% of the available DER capacity on any distribution line. This was publicly revealed late on a Friday afternoon in the October 22, 2021, Stakeholder meeting titled, "DSP and DG Manual Stakeholder Meeting." This stakeholder meeting should have been more clearly noticed as important to CSG Stakeholders.

Staff feels that this revelation was not presented correctly to the CSG community for both understanding, potential for comment and the appropriateness of the unilateral decision. It is true that Staff had hints of the possibility of such an action after the 2020 no capacity notices for CSG. In addition, during this investigation PSCo informed Staff that, "[a]s a general practice, the Company currently attempts to reserve 25% of feeder hosting capacity for non-CSG distributed photovoltaics. While this practice does not follow a formal Commission Rule or Decision, the Company believes it is in the public interest to maintain such a procedure." However, the practice of reserving no more than 75% capacity for CSGs was not clearly communicated to the CSG community. PSCo and COSSA subsequently filed their differing opinions on the reservation policy in 21M-0468E, the Interconnection Manuals repository proceeding.

During the period when the Interconnection Investigation was being completed, PSCo had opened a CSG Request for Proposal. In that that RFP PSCo was asked and answered the following question:

Q. Will the 75% feeder reservation described in the "RFP-Engineer-Resources" document, and updated in the DER Manual on 10/27, be used to evaluate a bid's proposed system size and in the awarding of points under the "preparedness" criteria?

---

[9] All Energy Solar 20218-177451-01

A. No, the planning limit will not impact the award of bids (i.e preparedness or other categories). The feeder reservation will be evaluated during the interconnection study process.[10]

Xcel Energy in Minnesota had similar negative experiences with restricting capacity for CSGs. Attached to this report *is Objection of Minnesota Solar Energy Industries Association, Fresh Energy & Interstate Renewable Energy Council To Implementation Of Xcel's DER Technical Planning Limit Before Commission Review* and Xcel's response to the objection filed on 10.12.21.

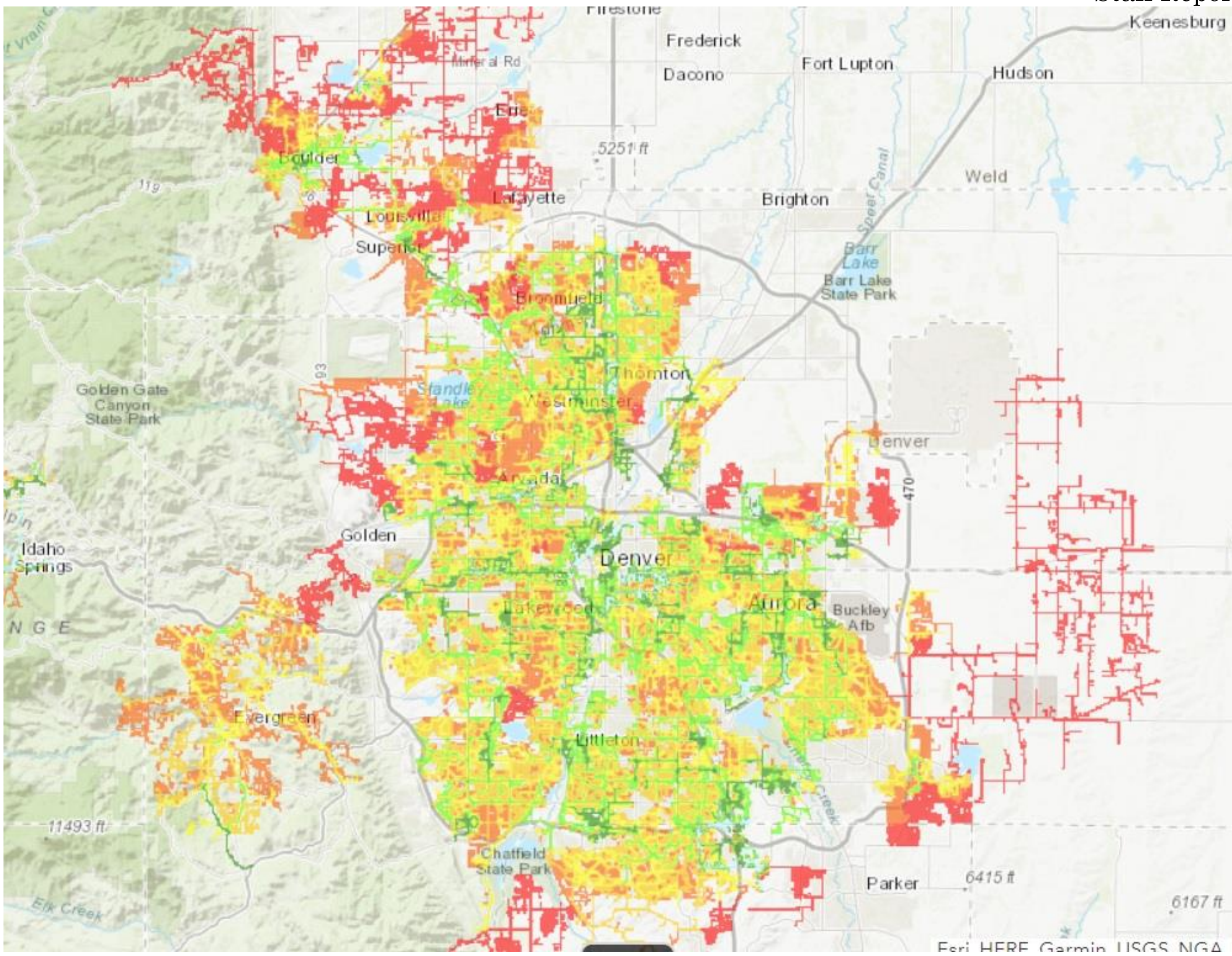
COSSA filed a response to the 75% capacity reservation change in the interconnection manual proceeding 21M-0468E. PSCo filed a response to COSSA's filing in the same proceeding.

Staff facilitated a resolution to this issue in which COSSA and PSCo have now agreed in principle to work out stakeholder engagement issues in the upcoming Distributed System Plan (DSP) proceeding. This will enable all stakeholders in the DSP proceeding to weigh in during the stakeholder process if interested. Staff suggests agenda items for the stakeholder process to include but not limited to: 1) communicating proposed interconnection process changes in reasonable amounts of time in advance of implementation; 2) how substations can be retrofitted or added to accommodate bidirectional flow of electricity. In this way, excess distributed generation can be backfed to the transmission system and create more available capacity for CSGs. Unfortunately, the scope of this interconnection investigation cannot address bidirectionality or new substation opportunities for CSGs.

Quarterly Updating Hosting Capacity Analysis

Hosting Capacity Maps (HCM) are used to help pinpoint capacity availability for DERs. The following graphic is an example of a PSCo HCM where the green areas are potentially good places to apply for interconnection and the red areas are not.

[10] 2021 RFP QA Tracker 11.2.21.xlsx



The DER industry has indicated to Staff that the HCM is "better than it was" and includes additional helpful information. That said, there is still room to improve as shown in Xcel's own HCM in Minnesota which demonstrates additional progress, but there remains room to improve in Colorado.

According to the new DSP rules, IOUs need to update the hosting capacity analysis (HCA). The Rule 3531(II) Hosting capacity analysis and Rule 3541(d)(II)(F) a proposal for updating data provided through the web portal, specifically addresses the quarterly updating of the utility's hosting capacity analysis as described in subparagraph 3531(a)(II).

As mentioned above, the most recent PSCo CSG RFP includes a disclaimer that HCA has no guarantees for approval of interconnection. However, Staff believes that PSCo validation of hosting capacity maps and hosting capacity analysis can help these tools to be more accurate. IREC is a leader in HCA validation, with its June 13, 2020, article titled "Validation Is Critical to Making Hosting Capacity Analysis a Clean Energy Game-Changer"[11] In that article IREC stated, and Staff agrees that "[t]he

[11] https://irecusa.org/blog/regulatory-engagement/validation-is-critical-to-making-hosting-capacity-analysis-a-clean-energy-game-changer/

usefulness of an HCA is highly contingent on having confidence that its results accurately reflect grid conditions at the site."

MVEA Issues

As previously discussed, MVEA was invited to participate in this interconnection investigation proceeding but did not respond. MVEA is the recipient of complaints during this Interconnection Proceeding from multiple solar installers and the Colorado Solar and Storage Association (COSSA). MVEA was not required to participate in this investigation. MVEA is, however, subject to the Commission's Interconnection Rules. Section 40-9.5-118(d), C.R.S., states:

> A cooperative electric association and a customer-generator shall comply with the interconnection standards and insurance requirements established in the rules promulgated by the public utilities commission pursuant to section 40-2-124; except that the cooperative electric association may reduce or waive any of the insurance requirements, and except that the public utilities commission shall initiate a rule-making proceeding no later than October 1, 2008, for the purpose of addressing cooperative electric association system issues in its small generator interconnection procedures. A cooperative electric association shall not prevent or unreasonably burden the installation of a net metering system if such system includes protective equipment that prevents any export of customer-generated electricity from the customer's side of the meter.

The current interconnection rules 3850-3859, for which Mountain View Electric Association (MVEA) "shall comply" went into effect 7/30/21, through the rulemaking proceeding 19R-0654E. Specifically, Rule 3855(b)(II) states: "[f]or interconnection of a proposed interconnection resources to a radial distribution circuit, the aggregated generation, including the proposed interconnection resources, on the line section(s) shall not exceed 15 percent of the line section's annual peak load as most recently measured at the substation or calculated for the line section(s)." This rule language is causing challenges between DG/solar installers and MVEA. PUC Staff is not receiving similar complaints for other utilities that are required to adhere to the Interconnection rules.

During this investigation there have been multiple comments, both anonymous and public, that MVEA is using the 15% capacity rule to stop DG projects. MVEA has been sending the following statement to those who are denied interconnection:

> MVEA' s Rules are consistent with Colorado Public Utility Commission 4 Code of Colorado Regulations (CCR) 723-3 Section 3665. Which states: Small Generation Interconnection Procedures for interconnection of a proposed small generating facility to a radial distribution circuit, the aggregated generation, including the proposed small generating facility, on the circuit will not exceed 15 percent of the line section's annual peak load as most recently measured at the substation or calculated for the line segment. A line section is that portion

of a utility's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. We stand by our calculations and compliance with the regulations.

Staff notes that the referenced section is outdated based on the rules that went into effect 7/30/21. In addition, Staff is unable to confirm if the MVEA distribution system is in fact not able to host additional DG due to the 15% factor.

A Google Maps by satellite exercise in the MVEA territory does not reveal many obvious rooftop solar installations.

Google Maps Satellite: Rare PV sightings in MVEA territory November 2021

During Exceptions in the Rulemaking proceeding, COSSA/SEIA was unsuccessful in attempting to change the language to, "For interconnection of a proposed Level 1 DER to a radial distribution circuit, the aggregated capacity, including the proposed small generating facility, on the line section shall not exceed 100% of minimum daytime loading." Exceptions also included this language: "In contrast, WRA disagrees with COSSA and SEIA's proposal in their part (b), which suggests changing the 15% screening threshold to the minimum load criteria that is used in Supplemental Screens. The 15% of maximum load screen is still in wide use, with 100% of minimum daytime load used as the supplemental screen. Maintaining this screen is especially important for smaller utilities, like Black Hills, that may not have minimum load data for all feeders. To the best of our knowledge, NREL has not modified their recommendation to go beyond the 15% threshold for initial screens." The reference to NREL may have come from the December 2012 NREL Technical Report NREL/TP-5500-56790 titled "Updating Small Generator Interconnection Procedures for New Market Conditions"[12] on page 9, where it states, "There is no technical consensus on the percentage of DG resources that defines high penetration on a given utility distribution feeder. Moreover, the impact of DG on the distribution system varies according to factors such as a) the type of resource, b) the expected performance of

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[12] NREL Updating Small Generator Interconnection Procedures for New Market Conditions

the resource, c) the usage patterns of customers on the distribution feeder, and d) the location of the DG on the feeder."

MVEA interconnection policy and Board meeting decisions include 2021 file named, "15.0-Interconnection-of-Consumer-Generators-FINAL-appr-11-17-2020-effective-1-15-2021.pdf." Staff observes that the current notifications for interconnection may not be using the most recent rules.

There is recourse available for MVEA Customers and Installers affected by MVEA interconnection denials which include but are not limited to:

1. Contacting the MVEA.
2. Contacting the MVEA Board of Directors, pursuant to § 40-9.5-109, C.R.S., or the specific member who represents the specific District (https://www.mvea.coop/about-us/board-of-directors/).
3. Attend MVEA meetings, including Board of Director meetings, as an owner/member to voice issues.
4. Requesting the assistance of DER industry representatives such as COSSA.

Staff recommends that Commission direct Staff to advise MVEA to review their policies to conform to the most recent Commission rules regarding interconnection, including updating polices based on the rules that went into effect 7/30/21.

Interconnection process is inconsistent across the state

While Statute § 40-9.5-118(d), C.R.S. requires that "[a] cooperative electric association and a customer-generator shall comply with the interconnection standards and insurance requirements established in the rules promulgated by the public utilities commission pursuant to section 40-2-124", each utility has its own procedures which differ across the state. Some of these may be minor, or major as seen in MVEA's example above. National developers of DER are interested in consistency across the state.

Equitable fees for applications smaller than 10 kW

In late October, PSCo indicated they were raising application fees from $100 for smaller than 10 kW to $250 for systems smaller than 25 kW. The interconnection rules did change from 10 kW to 25 kW for Level 1 review. Raising an interconnection fee to $250 for an interconnection application to connect small amounts of DER, for example below 7.5 kW AC, may create an economic barrier for some customers. Similarly, BHE's fees may pose an economic challenge for smaller systems. Recommend this be discussed in the DSP proceeding to ensure State policy goals for small DER and equity are being met.

XV. Conclusion

The interconnection process has generally been successful to this point as evidenced by the interconnection of 68,484 systems and over 710 MW DC at PSCo[13] and over 4,000 systems and approximately 32 MW DC at BHE.

Staff observes that utilities have found it difficult to adequately staff the interconnection activities because there has been and continues to be an increasing demand for interconnection services. This is primarily due to the state's policies to encourage large quantities of DER. Notwithstanding, the interconnection process must assure safe and orderly deployment of DER while addressing the needs of developers and installers whose livelihoods are at stake.

The process has had its ups and downs and could have been better or worse. Regardless, it is Staff's observation that it is improving, except for bumps in the road such as the capacity reservations.

Utilities like Holy Cross, DMEA and United Power, that are committed to their members DER needs, have been highly effective as demonstrated by their short interconnection approval timeline performance, and low-cost deployment of DER in their territories.

XVI. Recommendations

The Staff provides the following recommendations for Commission consideration:

1. IOUs should be directed to include all applications quantities in RESA monthly reporting, including failed applications and excluding proprietary information. For PSCo the Proceeding Number No.is 06S-016E. For BHE the Proceeding Number is 16A-0436E.
2. A rulemaking Proceeding should be opened for 10 MW AC interconnections at the transmission level. The current PUC interconnection rules do not address interconnection at the transmission level. Currently, Small Power Producers and Cogeneration are addressed, at Rule 3900-3918 (over 10 MW).
3. In the SRC-CGS spreadsheet it shows 55,119 kW moving forward in 2019 & 2020, while 38,724 kW were withdrawn. Staff recommends increasing probability of CSG interconnection process success by performing:
    - Accurate pre-application data reports (PADR)
    - Accurate and timely HCA and HCMs

[13] May, 2021 proceeding 19A-0369E PSCo and May 2021 proceeding 16A-0436E for BHE.

- A critical review of CSG interconnection steps
- Batch studies when appropriate
- Accurate tracking of more details on reasons for CSG interconnection withdrawals

4. IOUs should be directed to plan for interconnection staff attrition because it has been observed to create difficulties in the interconnection process.
5. Interconnection is closely related to other rules and proceedings (RES Plan, CSG Rules, DSP Plans, Interconnection Rules, Net metering Rules, ERP, etc.) which all include the stakeholder processes, and Staff has identified several recommendations intended to address shortcomings identified for the stakeholder processes. The Distributed System Planning process was addressed in two recent proceedings: an initial miscellaneous proceeding in 2020, and a DSP rulemaking in 2021. The results of these activities resulted in a requirement that the investor-owned utilities submit distribution system plans to the PUC. Company DSPs will be fully litigated at the PUC. We feel this is the appropriate venue to address the stakeholder process for interconnection which is very important for distributed energy resources on the utilities system. In the upcoming DSP proceeding, it is expected that stakeholders and IOUs will address the stakeholder process shortcomings identified in this report and summarized below with the following suggested agenda items:
    a. Timeliness of public disclosure for any IOUs interconnection process change
    b. Call center support
    c. Portal streamlining
    d. Solar only portal (so as to not confuse or complicate with storage if not applicable)
    e. Attention to customer preferred method of communication
    f. Minimize and develop attrition plans for interconnection staff
    g. Appropriateness of $250 and $320 Level 1 Application fees for less than 10 kW AC applications
    h. Hosting capacity analysis as described in 3531(II) is required to be updated quarterly pursuant to Rule 3541(d)(II)(F)
    i. Investigate Hosting Capacity Map ("HCM") and Hosting Capacity Analysis ("HCA") validation processes
    j. Coordination of HCA and HCM with DSP, RES Plans, and ERPs including opportunities for bidirectional substations.
    k. Submit this report in the interconnection manual proceeding 21M-0468E
    l. Support accurate pre-application data reports
    m. Support batch studies when appropriate
6. PSCo should track Company-owned interconnection costs.
7. Company should accurately track the reasons for withdrawal from an interconnection application.

The observations, findings and recommendations included in this report are those of the Staff of the Commission participating in this investigation and are not to be construed as being the observations, finding or recommendations of the Colorado Public Utilities Commission or of any individual Commissioners.

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Public Utilities Commission