PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ENERGY DIVISION

Agenda ID: 19688
RESOLUTION E-5038
August 19, 2021

R E S O L U T I O N

Resolution E -5038. Approval, with Modifications, of Rule 21 Telemetry Requirements Proposed in Compliance with Decision 19-03-013.

PROPOSED OUTCOME:

- Approves, with modifications, Pacific Gas and Electric Company (PG&E) Advice Letter (AL) 5595-E, Southern California Edison Company (SCE) AL 4044-E, and San Diego Gas & Electric Company (SDG&E) AL 3407-E to update telemetry requirements within Electric Rule 21, Generating Facility Interconnections, pursuant to Decision 19-03-013.

SAFETY CONSIDERATIONS:

- There are no safety considerations associated with this resolution.

ESTIMATED COST:

- There are no costs associated with this resolution.

By Advice Letters 5595-E, 4044-E, and 3407-E, Filed on July 26, 2019.

SUMMARY

This Resolution approves maintaining the threshold for requiring telemetry for projects sized one (1) megawatt (MW) or greater, requires the implementation of certain technical requirements for telemetry, and directs Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (jointly, the Utilities) to continue development of a telemetry solution using the IEEE 2030.5 communications standards.

In accordance with Decision (D.) 19-03-013[1] Ordering Paragraph 9, PG&E filed Advice Letter (AL) 5595-E, SCE filed AL 4044-E, and SDG&E filed AL 3407-E. In their filings, the Utilities compared telemetry options, indicated whether these options would result in utility costs less than $20,000, and provided conceptual outlines of benefits resulting from telemetry. However, they did not quantitatively or qualitatively estimate the benefits of telemetry as a means of collecting data on the distribution system. The CPUC hereby denies the Utilities' proposal to lower the threshold for requiring telemetry from 1 MW to 250 kilowatts (kW) and approves the implementation of certain technical specifications as laid out in the *Working Group One Final Report* filed on March 15, 2018 in Rulemaking (R.) 17-07-007. The CPUC also finds that continued development of a telemetry solution using the IEEE 2030.5 communication standards[2] is warranted and should be pursued.

BACKGROUND

A. Rulemaking 17-07-007 and Decision 19-03-013

The California Public Utilities Commission (CPUC) adopted the Order Instituting Rulemaking (R.) 17-07-007 to consider a variety of refinements to the interconnection of distributed energy resources under Electric Tariff Rule 21 of the Utilities and the equivalent tariff rules of the small and multi-jurisdictional electric utilities.[3]

The October 2, 2017 *Scoping Memo of Assigned Commissioner and Administrative Law Judge* (Scoping Memo) set forth the scope and schedule of the proceeding. The Scoping Memo also established a working group process in the proceeding

[1] Filed in Rulemaking 17-07-007 to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21.

[2] IEEE 2030.5 is the Institute of Electrical and Electronics Engineers (IEEE) Standard for Smart Energy Profile Application Protocol. More information can be found at: https://standards.ieee.org/content/ieee-standards/en/standard/2030_5-2018.html

[3] The Rule 21 tariff describes the interconnection, operating, and metering requirements for certain generating and storage facilities seeking to connect to the electric distribution system. Rule 21 provides customers access to the electric grid to install generating or storage facilities while protecting the safety and reliability of the distribution and transmission systems at the local and system levels.

whereby the scoped issues would be resolved. The first set of issues was assigned to Working Group One and the Smart Inverter Working Group:[4]

1. Screen Q modifications
2. Complex Metering clarification
3. Material modifications
4. Telemetry modifications
5. Retroactive Smart Inverter Activations
6. Smart Inverter Aggregator Forms and Agreements[5]
7. Income Tax Component of Contribution (ITCC) treatment

Working Group One and the Smart Inverter Working Group began meeting on October 16, 2017 and filed a *Working Group One Final Report* on March 15, 2018 (March Report).

Issue 4 posed the following question: "As the penetration levels of distributed energy resources increase, what changes to telemetry requirements should the Commission adopt to ensure adequate visibility while minimizing cost?" Telemetry, the near real-time transmittal of information from a generating resource to a utility or grid operator, provides distribution system operators with operational awareness of DERs, which can be used to inform decisions about grid operations. Currently, Section J of Rule 21 requires DERs larger than 1 MW to provide telemetry at the DER owner's expense, including both utility-related costs and additional customer costs, if no more cost-effective option for providing the necessary data is available.

On April 5, 2019, the CPUC issued D.19-03-013, *Decision Adopting Proposals from March 15, 2018 Working Group One Report*, addressing the five separate proposals to Issue 4. The first proposal was put forth by the Utilities ("the Utility Telemetry Proposal") and would allow the Utilities to require systems between 250 kW and

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[4] The Smart Inverter Working Group grew out of a collaboration between the CPUC and the California Energy Commission in early 2013. The collaboration identified the development of advanced inverter functionality as an important strategy to mitigate the impact of high penetrations of distributed energy resources.
[5] In response to a January 25, 2018 motion filed by the California Solar Energy Industries Association, the Administrative Law Judge issued a ruling on February 14, 2018 that reassigned Issue 6 from the Smart Inverter Working Group to Working Group Two.

9.9 MW to provide telemetry if the estimated utility-related costs are less than $20,000. The decision directed that if Proposal 1 was adopted, this resolution would cap utility-related costs at $20,000. Proposal 2 would instead maintain the 1 MW threshold for requiring telemetry. Proposal 3 would implement specific technical requirements[6] for systems larger than 1 MW, which are intended to avoid unnecessary costs. The Commission found Proposal 4 to be unnecessary given the adopted combination of Proposals 1 through 3, and Proposal 5 was adopted to allow customer ownership of behind-the-meter telemetry equipment where practicable.

D.19-03-013 addressed Issue 4, as well as the other scoped issues. In considering the Utility Telemetry Proposal, D.19-03-013 found that additional information was necessary for implementation and authorized a public workshop in which the Utilities would present, in detail, the telemetry requirements for systems between 250 kW and 9.9 MW, before filing ALs to resolve the issue.

On June 26, 2019, the CPUC's Energy Division hosted a public workshop during which the Utilities presented their proposed telemetry requirements.

Ordering Paragraph 9 of D.19-03-013 required the Utilities to file Tier 3 ALs: (1) proposing technical specifications for telemetry, (2) including a cost-benefit analysis of the telemetry as a means of collecting data on the distribution system, and (3) providing information to indicate that Supervisory Control and Data Acquisition System (SCADA)[7] and smart inverter data would not be able to provide sufficient data to satisfy the Utilities' needs. Ordering Paragraph 9 directed that the ensuing resolution should seek to implement the Utility Telemetry Proposal, and it required that the Utilities publish technical requirements rather that requiring specific equipment, if the telemetry is deemed necessary. However, if the Tier 3 ALs do not indicate that the Utilities' proposed

[6] The March Report's Issue 4, Proposal 3 puts forth the following technical specifications: 1) facilities can report measurements in 15-minute increments using customer-owned, nonrevenue-grade metering and a data aggregation device comparable to the serial device server that SCE has historically required, 2) customers can choose to connect the reporting device to the utility Energy Management System via cellular modem or dedicated internet connection, and 3) measurements do not have to be made from revenue grade equipment.
[7] SCADA is a combination of hardware and software for collecting real-time data and sending commands to control remote equipment from a centralized human-machine interface.

approach is cost-effective, the resolution should instead adopt Proposal 2, to maintain the current 1 MW threshold, and Proposal 3 to implement specific technical requirements for systems larger than 1 MW.

B. Advice Letters 5595-E, 4044-E, and 3407-E

Pursuant to D.19-03-013 Ordering Paragraph 9, PG&E filed AL 5595-E, SCE filed AL 4044-E, and SDG&E filed AL 3407-E on July 26, 2019.

PG&E AL 5595-E states that PG&E seeks to move towards a telemetry solution that utilizes the IEEE 2030.5 communication standards in conjunction with the California Smart Inverter Profile (CSIP)[8] to retrieve measurements from smart inverters. PG&E compares this IEEE 2030.5-based solution with the existing telemetry solutions, which utilize a SCADA telecommunications network with either a recloser[9] or Mini-Remote Terminal Unit[10] and cost in excess of $20,000 in utility-related costs per project. PG&E also compares the proposed IEEE 2030.5-based solution with data collection utilizing existing Advanced Metering Infrastructure (AMI) capabilities. PG&E indicates that an AMI-based solution cannot meet operational needs because, as currently configured, AMI provides low sampling and retrieval rates of data from customers. PG&E notes that both SCADA and AMI solutions also provide net loading data, "which does not help with the masked load issues presented by DERs."[11, 12] PG&E asserts that a telemetry solution using the IEEE 2030.5 communication protocol "will address the challenges with the existing solutions by identifying masked load effects, creating a near real-time system integrated with PG&E Operations, and reducing costs for customers."[13]

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[8] More information can be found in the CSIP Implementation Guide at: https://sunspec.org/wp-content/uploads/2018/04/CSIPImplementationGuidev2.103-15-2018.pdf

[9] A device that shuts off power when it detects a disturbance in the power quality and then automatically restores power if it detects that the disturbance was only temporary.

[10] A power electronics device with computational capabilities that serves as the interface between physical devices in the field (e.g., relays) and the SCADA system.

[11] PG&E AL 5595-E at 13.

[12] "Load masking" describes a situation in which the lack of generation output visibility prevents system operators and engineers from determining the real system load conditions which can inhibit the ability to plan and operate the distribution system.

[13] PG&E AL 5595-E at 5.

AL 5595-E indicates that PG&E will carry out a pilot that will utilize the DER headend platform[14] in order to "(i) prove out the target of lowering utility-related telemetry costs below $20,000, and (ii) enable design around the future IEEE 2030.5 DER communications standards that will provide PG&E a way to monitor and control smart inverter based DERs."[15] The pilot was originally scheduled to run through the end of 2020; this effort is now ongoing, and field testing is set to be completed in 2021. After that, PG&E proposes to transition towards an in-production system[16] for widescale field deployment.[17] AL 5595-E indicates that PG&E will roll out the IEEE 2030.5-based solution to systems of or greater than 1 MW before considering whether to expand the requirements to systems between 250 kW and 1 MW. While AL 5595-E provides some preliminary functional and technical requirements, it notes that requirements will be further refined through the pilot.[18]

Like PG&E AL 5595-E, SCE AL 4044-E proposes to leverage IEEE 2030.5 and smart inverter data to enable low-cost telemetry. "SCE is currently developing and building a communication infrastructure that will allow SCE to communicate with DERs via the IEEE 2030.5 protocol" with completion projected for mid-2022.[19] SCE proposes to lower the threshold for telemetry requirements to 250 kW only after this communications infrastructure is in place.

SCE compares the proposed IEEE 2030.5-based solution with two alternatives. The first alternative would utilize a SCADA Distribution Automation Device. AL 4044-E indicates that this alternative solution would only allow visibility into net generation and hence would not resolve load masking issues. Moreover, it would result in utility-related costs in excess of $20,000, according to SCE's published Unit Cost Guide.[20] The second alternative would utilize existing AMI capabilities but would likewise fail to address concerns around load masking. AL 4044-E also

[14] The hardware and software system at the utility that serves as the collection point for all of the incoming telemetry data.
[15] *Ibid.*
[16] "In-production" refers to a system that has surpassed the concept or pilot stage and is ready for full-scale commercial deployment.
[17] Conversation on May 12, 2021 between CPUC staff and PG&E Pilot staff.
[18] PG&E AL 5595-E at 6.
[19] SCE AL 4044-E at 2.
[20] SCE AL 4044-E at 6.

raises concerns that AMI data is not retrieved frequently enough to inform grid operations decisions.

SCE provides proposed telemetry technical requirements in an attachment to AL 4044-E. In addition, AL 4044-E provides estimates of both utility-related and non-utility-related costs. However, SCE notes that the costs of ongoing communications services are not well understood at this time and might be reduced as the volume of projects using the services increases.

SDG&E AL 3407-E does not propose to reduce the telemetry threshold to 250 kW at this time, suggesting instead that all DERs, regardless of size, should be required to provide telemetry once IEEE 2030.5 has been fully implemented. AL 3407-E reports that SDG&E is moving to an internet-based solution in the interim period and provides technical requirements in an attachment. The proposed solution would transport the generator data over public Internet to a secure gateway at SDG&E's Data Center. It would then be "transported to SDG&E's Control Center for use by the system operators."[21]

AL 3407-E compares the proposed internet-based telemetry with SCADA data collection and notes that the cost of a SCADA device would be much higher than that of SDG&E's proposed telemetry solution. AL 3407-E concludes that smart inverters will provide a good solution for telemetry of smaller systems in the future.

NOTICE

Notice of ALs 5595-E, 4044-E, and 3407-E was made by publication in the CPUC's Daily Calendar. Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric state that a copy of each Advice Letter was mailed and distributed in accordance with Section 4 of General Order 96-B. The ALs were served to the Service Lists for R.11-09-011 and R.17-07-007.

[21] SDG&E AL 3407-E at 3.

PROTESTS

On August 15, 2019, Advice Letters 5595-E, 4044-E, and 3407-E were timely protested by the Interstate Renewable Energy Council, Inc. (IREC), the Public Advocates Office (PAO), and The California Solar & Storage Association (CALSSA), (jointly, "the Parties").

PG&E, SCE, and SDG&E each replied to the protests of the Parties on August 22, 2019. These replies were filed timely.

We address the Parties' protests and the IOUs' replies in the Discussion Section below.

DISCUSSION

Issue 1: Demonstration of Cost-Effectiveness
We agree with IREC's Protest of ALs 5595-E, 4044-E, and 3407-E that the Utilities failed to fully explain how the benefits of telemetry (e.g., identifying load masking and improving accuracy and temporal granularity of electricity production data) justify its costs.[22] The Utilities did compare telemetry options,[23] indicate whether these options would result in utility costs less than $20,000,[24] and outline telemetry investment benefits in the form of work planning, minimizing customer impacts, and forecasting real-time response.[25] Nevertheless, they did not quantitatively or qualitatively estimate the benefits of telemetry as a means of collecting data on the distribution system, as required by Ordering Paragraph 9 in D.19-03-013. In their reply, PG&E argues that the need for telemetry has already been established in the March Report.[26] SDG&E replies that because their AL 3407-E does not propose to lower the threshold for requiring telemetry from 1 MW to 250 kW, they do not need to answer IREC's

[22] IREC's Protest to San Diego Gas & Electric's Advice Letter 3407-E, Pacific Gas and Electric Company's Advice Letter 5595-E, and Southern California Edison Company's Advice Letter 4044-E on Telemetry Technical Requirements at 2.
[23] PG&E AL 5595-E at 12.
[24] SCE AL 4044-E at 6.
[25] SDG&E AL 3407-E at 4.
[26] Pacific Gas and Electric Company's Protest Response to the Protests of IREC, CALSSA and Public Advocates Office to Advice 5595-E – "PG&E's Telemetering Proposals Pursuant to Decision 19-03-013, Ordering Paragraph 9" at 4.

questions.[27] SCE also responded that IREC's questions are irrelevant to this AL process.[28] We assert that it is not the need for telemetry at question here, but the need for an estimate of the benefits telemetry provides that can contribute to an assessment of the cost-effectiveness of the proposed solution. It is not enough to show that the proposed solution is the most cost-efficient option; the benefits must outweigh the costs.

Ordering Paragraph 9 of D.19-03-013 also requests the Utilities provide "information to indicate that Supervisory Control and Data Acquisition System (SCADA) and smart inverter data would not be able to provide sufficient data to satisfy the Utilities' needs." The Utilities assert that "SCADA devices only provide net loading[,] which does not help with the masked load issues"[29] because they are "located at the customer electric service entrance."[30] SCE provides both an example and a diagram to illustrate this.[31] PAO's protests assert that an itemized cost breakdown of existing SCADA systems is necessary to determine whether this solution is cost prohibitive.[32,33,34] The Commission agrees with the Utilities that a detailed cost analysis of SCADA systems does not add value because these systems do not meet the functional requirement of providing visibility into masked load.[35]

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27 Response of San Diego Gas & Electric to the Protests of Advice Letter 3407-E: San Diego Gas & Electric's Proposed Telemetry Requirements for Systems Between 250 Kilowatts and 9.9 Megawatts Pursuant to Decision 19-09-013 at 3.

28 Reply of Southern California Edison Company to the Protests of the Interstate Renewable Energy Council, Inc., the California Solar & Storage Association, and the Public Advocates Office of the California Public Utilities Commission to Advice 4044-E at 2.

29 PG&E AL 5595-E at 13.

30 SDG&E AL 3407-E at 4.

31 SCE AL 4044-E at 4-5.

32 Protest of the Public Advocates Office of San Diego Gas & Electric Company's (SDG&E) Advice Letter 3407-E – SDG&E's Proposed Telemetry Requirements for Systems Between 250 Kilowatts and 9.9 Megawatts Pursuant to Decision 19-03-013 at 2.

33 Protest of the Public Advocates Office of Southern California Edison Company Advice Letter 4044-E – Rule 21 Working Group 1 Telemetry Workshop Implementation Plan in Compliance with Decision 19-03-013 at 2.

34 Protest of the Public Advocates Office of Pacific Gas and Electric Company (PG&E) Advice Letter 5595-E – PG&E's Telemetering Proposals Pursuant to Decision (D.) 19-03-013, Ordering Paragraph 9 at 2.

35 SDG&E's Reply at 3; PG&E's Reply at 10; SCE's Reply at 6.

Each of the Utilities' proposed solutions use smart inverter data, but, noting that "for the Smart Inverter to provide telemetry information to the utility it must be connected to a communication network,"[36] they put forth differing solutions for the communications component. In addition, PG&E and SCE addressed the availability of data from AMI meters. These meters are used for billing purposes, providing net load data at 15-minute intervals with a 48-hour delay.[37] These limitations of AMI data establish that it does not meet the definition of telemetry from D.19-03-013: "the near real-time transmittal of information from a resource on the distribution system to the utilities…to inform decisions about grid operations."[38] Although IREC protests that AMI should still be considered,[39] each of the Utilities refutes this. SCE explains that the "AMI meter is physically located … where it can only measure the net output."[40] SDG&E recognizes that modifying the AMI system to provide real-time data "would require a complete overhaul that would impact non-DER customers."[41] PG&E entertains "that AMI could potentially be leveraged for more real-time data as IREC suggested,"[42] but cites cybersecurity challenges that prevent its consideration at this time.

Given it is impossible to assess the balance of costs and benefits without clearly articulated benefit information, the Commission declines to adopt the Utility Telemetry Proposal. Thus, the size threshold for systems requiring telemetry is not reduced to 250 kW, and a cap of $20,000 for utility-related costs is not created. To provide additional time for proposal development, we approve Proposal 2 maintaining the current threshold for requiring telemetry at 1 MW until more information is available. We also agree with CALSSA's protest of SDG&E's suggestion that IEEE 2030.5 be used to meter DERs of all sizes once implemented.[43] SDG&E's suggestion goes beyond the scope of the Decision.

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[36] SCE AL 4044-E at 5.
[37] PG&E AL 5595-E at 13.
[38] D.19-03-013 at 32.
[39] IREC's Protest at 3.
[40] SCE's Reply at 4.
[41] SDG&E's Reply at 3.
[42] PG&E's Reply at 5.
[43] CALSSA Protest of SDG&E AL 3407-E on Telemetry Specifications at 1.

Issue 2: Non-Utility-Related Costs

While D.19-03-013 would establish a cost cap of $20,000 for utility-related telemetry costs if the Utility Telemetry Proposal were adopted, the intention of the Commission is to meet operational needs for visibility while minimizing costs.[44] Hence, we find that it is essential to consider both utility-related telemetry costs and additional costs borne by the customer in order to meet utility-imposed telemetry technical requirements. Though this is not a protested issue, the Commission clarifies here that both utility-related and non-utility-related costs will need to be considered in assessing the cost effectiveness of proposed telemetry solutions. For example, SCE asserts that non-utility communications costs would be directly between the DER owner/operator and DER communications company, and that SCE is open to less expensive communications options as long as specifications are met.[45] Consistent with the Issue 1 discussion, SCE would have to justify these costs by demonstrating the benefits of these specifications in any cost-effectiveness calculation going forward.

Issue 3: Implementation of Proposal 3

Since the approach proposed by the Utilities has not been demonstrated to be cost-effective, D.19-03-013 requires the implementation of specific technical requirements for telemetering of systems larger than 1 MW. The technical specifications for systems larger than 1 MW referenced by D.19-03-013 come from the March Report and are as follows:

1) facilities can report measurements in 15-minute increments using customer-owned, nonrevenue-grade metering and a data aggregation device comparable to the serial device server that SCE has historically required,[46]

2) customers can choose to connect the reporting device to the utility Energy Management System via cellular modem or dedicated internet connection, and

3) measurements do not have to be made from revenue grade equipment.[47]

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[44] D.19-03-013 at 32.
[45] SCE AL 4044-E at 3.
[46] See (https://store.perle.com/iolansds1ta4d2) for the Serial Device Server SCE has historically required.
[47] Working Group One Final Report at 82.

The Utilities shall submit Tier 1 Advice Letters to implement these requirements 45 days from the adoption of this Resolution.

Issue 4: Continued Development of an IEEE 2030.5-based Telemetry Solution
Ordering Paragraph 9 of D.19-03-013 states, "The Utilities' published technical requirements shall be able to be met through alternative data sources, such as SCADA and smart inverter data, if those options are shown to more cost-effectively produce the data necessary to provide system visibility and address load masking." Following the discussion of Issue 1, the Commission finds that the only proposed solution that effectively addresses load masking is one that utilizes smart inverter data.

The Utilities support leveraging the IEEE 2030.5 communications standard to deliver smart inverter data as the default protocol[48] "for all smart inverters, including in multiple inverter-based generator aggregations and through a single aggregator or energy management system."[49] "SDG&E looks forward to deploying,"[50] "PG&E has decided to pursue deployment,"[51] and "SCE is currently developing"[52] telemetry solutions using IEEE 2030.5. SCE is building out infrastructure using the IEEE 2030.5 protocol that will allow them to communicate with DERs, and "projects completing this capability in 2022."[53] PG&E provides some preliminary functional and technical requirements but notes that requirements will be further refined through their pilot.[54] The pilot utilizes the IEEE 2030.5 protocol to create "a near real-time system integrated with PG&E Operations…and provide a foundation for more complex interactions between PG&E and DERs beyond telemetry."[55] SDG&E adds that the implementation of the IEEE 2030.5 communications standards will lead to a dramatic decline in the cost of obtaining generator output data and "enable the kind of large-scale deployment (potentially millions of systems) envisioned in

[48] IEEE 2030.5 is the approved default communications protocol for smart inverters in Rule 21 Section Hh.
[49] SDG&E AL 3407-E at 5.
[50] SDG&E AL 3407-E Appendix A at 7.
[51] PG&E AL 5595-E at 5.
[52] SCE AL 4044-E at 2.
[53] *Ibid.*
[54] PG&E AL 5595-E at 6.
[55] PG&E AL 5595-E at 5.

California."[56] There was no protest to moving forward with a telemetry solution based on the IEEE 2030.5 communications protocol. The Commission finds that continued development of an IEEE 2030.5-based telemetry solution is warranted and should be pursued.

In their advice letters, the Utilities have presented three different proposed paths forward. The Commission reminds the Utilities that it is CPUC policy that they "should maintain consistent tariffs in order to promote transparency and efficiency."[57] This means that the Utilities should put forth standardized technical requirements. For example, CALSSA's protest of SCE states that a fleet operator should be able to use their own cloud communications if it meets specifications.[58] While SDG&E's proposal does allow for the use of customer-owned internet with encrypted payload,[59] SCE's proposal does not. Any differences between Utility proposals that cannot be resolved will require justification.

There remains much to learn in the course of developing a telemetry solution utilizing the IEEE 2030.5 communications standard. Piloting telemetry solutions utilizing IEEE 2030.5 over the public internet for systems in excess of 1 MW will provide a valuable body of experience. The Utilities may use this experience, as well as any potential cost reductions or performance improvements that are identified, to request, via Tier 3 AL, to reduce the telemetry threshold from 1 MW to 250 kW at a future date. However, consistent with D.19-03-013, such a request must 1) report on the actual utility-related costs and non-utility-related costs incurred, over a period of at least 6 months, by systems providing IEEE 2030.5-based telemetry, 2) discuss the specific operational needs that would be met via a reduced telemetry threshold at a level of detail beyond that available in the March Report, 3) quantify the benefit provided by meeting those needs, and 4) provide detail on any implementation differences between communications directly to the inverter versus to an aggregator or gateway.

Additionally, as the Utilities gain experience through PG&E's pilot and others, the Commission finds that they should report on the capabilities and limitations of utilizing IEEE 2030.5 for telemetry. The Utilities shall present what they learn

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[56] SDG&E AL 3407-E, Appendix A at 7.
[57] Resolution E-5035 at 9.
[58] CALSSA Protest of SDG&E Advice Letter 3407-E on Telemetry Specifications at 1.
[59] SDG&E AL 3407-E Appendix A at 4.

at a meeting of the Smart Inverter Working Group at least 15 days in advance of any ALs proposing new requirements or options for telemetry.

The Commission would also like to remind the Utilities that Ordering Paragraph 9 of D.19-03-013 mandates that they "shall propose technical specifications for telemetry rather than proposing specific equipment."[60] Similarly, it is the Commission's intent that the Utilities not mandate a single vendor as the basis of their proposed solution.

COMMENTS

Public Utilities Code section 311(g)(1) provides that this resolution must be served on all parties and subject to at least 30 days public review. Please note that comments are due 20 days of the date of its mailing and publication on the Commission's website and in accordance with any instructions accompanying the notice. Section 311(g)(2) provides that this 30-day review period and 20-day comment period may be reduced or waived upon the stipulation of all parties in the proceeding.

The 30-day review and 20-day comment period for the draft of this resolution was neither waived nor reduced. Accordingly, this draft resolution was mailed to parties for comments, and will be placed on the Commission's agenda no earlier than 30 days from today.

FINDINGS

1. Decision (D.) 19-03-013 directed Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (jointly, the Utilities) to file Tier 3 Advice Letters (AL) 1) proposing technical specifications for telemetry, 2) including a cost-benefit analysis of the telemetry as a means of collecting data on the distribution system, and 3) providing information to indicate that Supervisory Control and Data Acquisition System (SCADA) and smart inverter data would not be able to provide sufficient data to satisfy the Utilities' needs.

[60] D.19-03-013 at 36.

2. On July 26, 2019, PG&E filed AL 5595-E, SCE filed AL 4044-E, and SDG&E filed AL 3407-E, in which they compared telemetry options, indicated whether these options would result in utility costs less than $20,000, and outlined telemetry investment benefits.
3. The Utilities did not quantitatively or qualitatively estimate the benefits of telemetry as a means of collecting data on the distribution system in ALs 5595-E, 4044-E, and 3407-E, as required by Ordering Paragraph 9 in D.19-03-013.
4. More information on the associated benefits is needed to justify reducing the telemetry threshold from 1 MW to 250 kW.
5. The Commission should not adopt the Utility Proposal for Issue 4, reducing the size threshold for systems requiring telemetry to 250 kW.
6. The Commission should adopt Proposal 2 for Issue 4, maintaining the size threshold for systems requiring telemetry at 1 MW.
7. Since the advice letters do not demonstrate that the Utility Proposal for Issue 4 is cost effective, the Commission should adopt Proposal 3 for Issue 4 articulating the specific technical requirements for telemetering of systems larger than 1 MW.
8. The Utilities should continue development of an IEEE 2030.5-based telemetry solution.

THEREFORE IT IS ORDERED THAT:

1. Proposal 2 for Issue 4, to maintain the current threshold of 1 MW for requiring telemetry, is approved.
2. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall implement specific technical requirements for telemetering of systems larger than 1 MW. The adopted technical specifications for systems larger than 1 MW are as follows: 1) facilities can report measurements in 15-minute increments using customer-owned, nonrevenue-grade metering and a data aggregation device comparable to the serial device server that SCE has historically required, 2) customers can choose to connect the reporting device to the utility Energy Management System via cellular modem or dedicated internet connection, and 3) measurements do not have to be made from revenue grade equipment. The Utilities shall submit Tier 1 Advice Letters to implement these requirements no later than 45 days from the issuance of this Resolution.
3. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company may request, via Tier 3 Advice Letters,

to reduce the telemetry threshold from 1 MW to 250 kW at a future date. Such a request must 1) report on the actual utility-related costs and non-utility-related costs incurred, over a period of at least 6 months, by systems providing IEEE 2030.5-based telemetry, 2) discuss the specific operational needs that would be met via a reduced telemetry threshold at a level of detail beyond that available in the *Working Group One Final Report* filed on March 15, 2018, 3) quantify the benefit provided by meeting those needs, and 4) provide detail on any implementation differences between communications directly to the inverter versus an aggregator or gateway.

4. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall present their new understanding of the capabilities and limitations of utilizing IEEE 2030.5 for telemetry, gained through PG&E's pilot and other experience, at a meeting of the Smart Inverter Working Group at least 15 days in advance of any Advice Letters proposing new requirements or options for telemetry.

This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on August 19, 2021; the following Commissioners voting favorably thereon:

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Rachel Peterson
Executive Director