Holly Anderson, Clerk
Vermont Public Utility Commission
112 State Street, 4th Floor
Montpelier, Vermont 05620-2701

Re: 21-2883-RULE Proposed creation of Vermont Public Utility Commission Rule Concerning Energy Storage

Dear Ms. Anderson,

This letter is a reply to the Public Utility Commission's (PUC) September 17 request for information from participants in docket number 21-3883-RULE. Responses are provided below.

Sincerely,

John R. Woodward
Goodenough LLC (Consulting)
in collaboration with Dynamic Organics, LLC

1.c. Codes and standards

Are there any codes and standards relevant to energy storage that the Commission should incorporate by reference into the rule? If so, which ones and why?

Energy storage systems that interconnect to the distribution grid are a specific type of distributed energy resource (DER). As such, the starting assumption for energy storage interconnection rulemaking should be that all future energy storage projects should meet the requirements of the most current version of the IEEE 1547 series of standards, regardless of size, grid location (namely, whether behind or in front of the customer meter), ability to export energy, device ownership or program participation.[1] Accordingly, the PUC should consider expanding the scope of Rule 5.500 to include distributed storage projects as well as distributed generation projects.

Theoretically, as inverter-based resources, energy storage systems can provide many, if not all, of the *autonomous* functions prescribed in IEEE 1547-2018 (for example, modulating the rate of charge or discharge in proportion to local grid frequency), as well as most, if not all, of the more forward-looking *advanced* IEEE 1547-2018 functions, each of which depends on active message exchanges between the energy storage system and the utility across a reliable telecommunication network.

That said, our understanding is that there are several interconnection issues specific to energy storage systems that are not explicitly addressed by IEEE 1547-2018, a situation that IEEE has acknowledged with its publication of a guide (currently in draft form) for applying IEEE 1547 specifically to energy storage interconnection.[2] This reality further underscores the need for informed guidance from a technical working group in Vermont ("working group"), along the lines we recommended in our June 22 filing in docket 19-0856-RULE ("June 22 filing", which is attached in full to these comments for convenience).

As to why IEEE 1547 should be a requirement, the reason is stated directly in the very title of the standard: *Interoperability*.[3] For a plain language explanation of the benefits and need for interoperability from a regulatory perspective, see the National Association of Regulatory Commissions' (NARUC) interoperability learning module website.[4] To get a sense of the the extent to which manufacturers and

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[1] Exceptions to this requirement may of course be warranted. For example, an energy storage system installed exclusively to support on-site loads as an uninterruptible power supply (UPS) should probably not be subjected to the exact same requirements as an energy storage system that will introduce bidirectional flows of real and reactive power onto the grid. In considering such distinctions it will be important to include electric vehicle charging equipment with grid export capabilities in the regulatory definition of energy storage.

[2] This and other relevant IEEE guidance can be found at the below links:

- IEEE P1547.9 - IEEE Draft Guide to Using IEEE Std 1547 for Interconnection of Energy Storage Distributed Energy Resources with Electric Power Systems (https://standards.ieee.org/project/1547_9.html).
- IEEE 2030.2-2015 - IEEE Guide for the Interoperability of Energy Storage Systems Integrated with the Electric Power Infrastructure (https://standards.ieee.org/standard/2030_2-2015.html)
- IEEE 2030.3-2016 - IEEE Standard Test Procedures for Electric Energy Storage Equipment and Systems for Electric Power Systems Applications (https://standards.ieee.org/standard/2030_3-2016.html)

[3] The full title of the standard is "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces"

[4] https://www.naruc.org/cpi-1/energy-infrastructure-modernization/smart-grid/interoperability-learning-modules/

vendors of inverters and controllers have already incorporated IEEE 1547 specifications into their product lines, see the Sunspec Alliance's product certification registry.[5]

2.a. Visibility to utilities.

Are there specific requirements related to two-way communications with distribution utilities that the Commission should impose on aggregators as a condition of receiving a §231 CPG?

Any energy storage project that complies with IEEE 1547-2018, whether it is an aggregation of multiple batteries or a single, independent plant, must be *capable* of communicating with the utility using at least one of three different protocols.[6] However, as explained in our June 22 filing, there are several critical "out-of-band communication and control issues" that IEEE 1547-2018 does not address. All of these out of band issues are equally applicable to the interconnection of energy storage projects as they are to distributed generation, and should be considered germane to both this proceeding and the ongoing Rule 5.500 and Rule 5.100 proceedings.

With regard to the issue of communication protocol optionality (inherent to IEEE 1547-2018), the prospect of utilities needing to communicate with, and about, a multiplicity of DER types could be reason enough for Vermont to follow California's choice to elevate IEEE 2030.5 as the preferred IEEE 1547 compliance option for all DER interconnections. IEEE 2030.5 is unique among the IEEE 1547 communication protocol options in that it was designed not just to accommodate all different DER types but also to accommodate aggregations of DER that span multiple DER types (including demand responsive loads).[7] That said, whether designating IEEE 2030.5 as the default protocol is the best interconnection policy for the whole of Vermont should not be decided without more closely examining the implications for each individual Vermont utility. Ideally such study would take place within the structure of an official technical working group (as recommended in our June 22 filing).

There are many other more nuanced questions about aggregator obligations that would also benefit from the deliberations of a working group. In California, IEEE 2030.5 has been implemented in such a way that allows aggregators to play an intermediary role between DER devices and utility requests for grid services and telemetry reports. Specifically, aggregators are responsible for providing the utility with up-to-date and on-demand information about all the inverters under their supervision. They are also responsible for disseminating the details of any "events" or set point schedules created by the utility down to the individual inverters in the aggregation.[8] However, there are no requirements on

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[5] https://sunspec.org/certified-registry/

[6] The three communication protocols allowed by 1547-2018 are Distributed Network Protocol 3.0 (DNP3), Sunspec Modbus, and IEEE 2030.5. Note that the capability to communicate using one of these protocols in no way guarantees the capability will be used or that any communication link will even be established between the utility and the IEEE 1547 certified DER or aggregator.

[7] It is illustrative to point out that, in addition to generic telemetry data acquisition functions, IEEE 2030.5 specifies status reporting messages with semantics unique to energy storage systems (for communicating current state of charge for example).

[8] For clarity, it is possible, using IEEE 2030.5, for the utility to target specific commands to individual inverters within an aggregation.

aggregators to use any particular protocol for downstream communications with individual inverters, which are not expected to ever be in direct communication with the utility. That is, aggregators may use whatever downstream protocol they choose (proprietary or other) so long as upstream communications with the utility are structured using IEEE 2030.5.

This arrangement, while quite possibly necessary for bringing DER grid services to scale, nonetheless raises many questions about the reliability[9] and verifiability[10] of aggregator responsiveness to utility instructions, as well as questions about the long-term problems that a proliferation of proprietary downstream protocols might cause, e.g., vendor lock-in with customers, utility operational dependence on those same customers, stranded customer or utility investments in DER if an aggregation dissolves, etc. These types of questions are topics of active debate in California's Smart Inverter Working Group and would likewise be part of the focus of a Vermont based technical working group.

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2. b. Override.

Are there circumstances under which local distribution utilities may need to override operator control to charge or discharge aggregated systems to maintain system stability and reliability? If so, is that currently technically feasible?

Each of the IEEE 1547-2018 protocols allow for automatic alarms and fault codes to be sent to the utility (if voltage or frequency violations are detected by the inverter for example). They also allow for commands to connect or disconnect to the grid, and commands to cease to energize or return to service. However, as explained in our response to question 2.a. ("Visibility to utilities"), depending on how communications links with an aggregator are set up, the utility may not be able to directly control the devices that can execute these corrective actions. There are many ways that an aggregation could fail to show up as expected or scheduled by the utility. An aggregation could also show up in ways that exacerbate a contingency that the utility does not foresee.[11]

An established commissioning process that verifies aggregator-mediated devices are responsive in real time to emergency utility performance requests will be critical to long term goals of integrating aggregators and DER more fully into utility operating procedures (See "Commissioning and Data Acquisition" section of our June 22 filling). Partly because of the lack of DER communication protocol standardization, and partly because utilities have yet to invest in comprehensive software solutions for managing and sharing DER data, implementing such a commissioning process is not currently technically

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[9] Such as the one raised by the Commission in 2.b. ("Override").
[10] Such as the one raised by the Commission in 2.d. ("Dispute resolution").
[11] Some of the early experiences of California utilities are instructive. According to a 2018 account from Pacific Gas and Electric, "different vendors may interpret the same command differently. In [one pilot], when a DER was given a dispatch command beyond its capability, one vendor would dispatch as much as possible, while another vendor cancelled the command and did nothing. In [another pilot], the fixed power factor setting responses activated by the aggregator were the opposite of requested settings, e.g., producing VArs instead of absorbing VArs." (https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/Joint-IOU-SI-White-Paper.pdf)

feasible in Vermont. Nor is it yet possible (for the same reasons) for utilities to collect telemetry data from inverters spread across multiple aggregations through a single interface, which significantly complicates the challenge of monitoring DER status in real time.

Thus, there may be a need, at least in the early stages of Vermont utilities' experience with aggregators, to implement additional protection schemes for storage projects that the utility can directly control through their SCADA or other existing systems. That said, the long-term goal should be for utilities to rely as much as possible on IEEE 1547 inverter functions (where applicable) as the first-resort in mitigation procedures.

Note also that the latency and quality of service provided by the telecommunication network that aggregators use to communicate with utilities will be a large determining factor in how quickly and reliably a utility request or command can be acted on by an aggregator. Even if aggregators can be trusted by utilities to respond accurately to incipient grid constraints, there are still telecommunication network limits to consider (see "Telecommunication Networking" section of June 22 filing).

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2. c. Notice of changes to an aggregation.

Aggregations are likely to change over time. For example, small resources may leave or join aggregations rather frequently. What requirements for notice should be included in § 231 CPGs when changes occur to aggregations?

It is instructive to point out that IEEE 2030.5 provides sophisticated functionality for registration and identification of DERs within an aggregation (including assigning or retiring unique identifiers to devices as they join or leave an aggregation), as well as dynamic DER grouping and group management functionalities, which can be based on grid location information collected through registration (see the section "Device Discovery and Registration" in our June 22 comments). Every piece of information that a regulator would likely need about the membership of an aggregation is natively available from an IEEE 2030.5 certified aggregator client. This points to one of the less obvious benefits of standards-based interoperability: reporting requirements could potentially be satisfied with simple automated workflows, lowering the transaction costs for both businesses and regulators.

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Re: 19-0856-RULE Proposed Revisions to Vermont Public Utility Commission Rule 5.500

Dear Ms. Anderson,

This letter is a reply to the Public Utility Commission's (PUC) June 22 request for information from participants in the April 19 workshop. Responses are provided below.

Sincerely,

John R. Woodward
Goodenough LLC (Consulting)
in collaboration with Dynamic Organics, LLC

1.a. Please describe how the Commission should weigh the two competing goals of issuing a rule to address urgent issues in a timely fashion and developing a comprehensive and forward-looking rule.

1.b. Which issues are most urgent for the Commission to address?

The draft of Rule 5.500 currently under consideration (as revised by the PUC on April 24, 2019), requires all "proposed Generation Resources…to be in compliance with the latest versions of the IEEE 1547 Series of Standards" (pp. 6, 40-42). Tying the technical requirements of Rule 5.500 to national standard IEEE 1547 in this way is a positive and appropriate modification that puts Vermont in a good starting position to reap the long-term benefits of successive generations of interoperable smart inverter product lines. However, it also raises many questions about how to ensure those future benefits will in fact accrue to ratepayers. These comments make the case for using this proceeding to establish a process dedicated to studying, clarifying and providing statewide guidance on the myriad implications of adopting IEEE 1547-2018 in Vermont.

The technical capabilities of inverters prescribed by IEEE 1547-2018 (and by extension UL 1741) can be categorized into two different types of grid-supporting function sets. *Autonomous* functions, which are triggered automatically (by inverter readings of local voltage, frequency, etc.), do not require either real-time telemetry from the DER (to the utility) or dispatch instructions from the utility (to the DER) in order to be utilized. There are a wide variety of *autonomous* function settings that can be enabled for a given DER project but few are enabled by default under IEEE 1547-2018. For Vermont to realize near-term benefits from the first generations of IEEE 1547-2018 certified inverters, it is important that utilities begin developing strategies for deciding which *autonomous* settings are appropriate to enable in which particular grid conditions.[12]

These comments focus more on the preparatory efforts that need to be taken in order to exploit the longer-term benefits and flexibility afforded by the *advanced* category of IEEE 1547 inverter functions. By design, *advanced* functions can only be utilized through an active exchange of messages between the DER and the utility.[13] As such, *advanced* functions anticipate widespread utility adoption of multiple nascent (and expensive) information and operational technologies (IT and OT) that utilities in Vermont and elsewhere have largely (and prudently) not yet procured—including software for monitoring and controlling DER (i.e., Distributed Energy Resource Management Systems or DERMS), software for optimizing DER dispatch schedules (i.e. Advanced Distribution Management Systems or ADMS), as well as new high transaction database management tools to support those software applications and high performance field area telecommunication networks to carry the data streams they consume (not to

[12] The PUC has provided a prompt for this line of investigation by asking (in question 3.e), whether, "curtailment [could] be used as a tool to either reduce interconnection costs or manage power quality on certain circuits?" There are autonomous inverter functions other than output curtailment that should also be examined for their impact on power quality, asset depreciation, etc.

[13] For example, by temporarily changing inverter parameters for power output, power factor, or defining volt-var or volt-watt curves for specific time horizons.

mention the significant internal investment in professional development and business process redesign that will be required to make productive use of all of the above technologies).

In light of impending utility access to such expansive inverter functionalities and the extensive groundwork that needs to be laid in order to fully exploit those functionalities, this proceeding represents an important opportunity to begin charting an actionable path toward a more integrated, interoperable and automated grid in Vermont.

2.a. Please comment on whether the Commission should use an order or tariff to outline some interconnection requirements. Should the Commission use a model tariff or interconnection guidelines approach similar to Massachusetts?

2.b. Please identify which technical and procedural requirements should be implemented by order or tariff and which ones (if any) should remain in a formal rule.

7.c. At the end of an inverter's useful life, should the Commission require replacement with an inverter compliant with IEEE 1547? How would this be accomplished given that Project owners are not required to notify the Commission or local utility of the replacement of equipment with similar equipment?

8a. What technical requirements for communications protocols should interconnected DER systems be required to meet, and how should those requirements be reflected in this iteration of the Rule? (e.g., IEEE 2030).

8b. Is there anything else specific the Commission should include in the interconnection rule to facilitate greater communications and visibility into real-time DER behavior?

Incorporating IEEE 1547-2018 into Rule 5.500 leaves many important practical questions unanswered about how DERs and utility IT and OT systems will communicate and interoperate with each other in Vermont. A non-exhaustive description of these "out-of-band" issues is provided below (under the heading *Out-of-band communication and control issues*). Currently Vermont utility interconnection policies do not address these issues in great detail.[14]

Given the technical nuance of this subject matter and its relationship to larger grid modernization concerns, it is best at this juncture not to attempt to resolve the types of issues identified below within the direct language of Rule 5.500. The most productive and pragmatic way to take these issues up is by convening a technical working group ("working group") charged with developing a statewide guidance document ("guidance document") that utilities can electively reference as they update their individual interconnection policies on their own timelines—an approach that has proven useful in other states (including Massachusetts) whose experiences Vermont can draw on and learn from.[15]

The proposed working group would be comprised primarily, but not exclusively, of subject matter experts working for or on behalf of the utilities and the Public Service Department (PSD). The purpose of the guidance document would be twofold:

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[14] For ease of reference, the final section of this document (*Excerpts from utility interconnection policy documents*) provides selections of language from the published interconnection policies of Green Mountain Power, Vermont Electric Cooperative and Burlington Electric Department (the three largest Vermont utilities) that speaks specifically to communication requirements on "Interconnection Requestors."

[15] See for example, California's Smart Inverter Working Group (SIWG) and the Common Smart Inverter Profile (CSIP) Implementation Guide, Minnesota's Distributed Generation Work Group and the Technical Interconnection and Interoperability Requirements document (TIIR), and Massachusetts' Technical Standards Review Group (TSRG) and the Common Technical Standards Manual.

(1) to articulate a set of model requirements and processes addressing out-of-band communications and control issues that can feasibly be implemented by all Vermont utilities in the near and long terms, and
(2) for areas where statewide uniformity is undesirable or unworkable, to articulate the acceptable range of implementation possibilities across Vermont utilities.

The guidance document itself, once completed, could (but need not) be incorporated into Rule 5.500, or otherwise be ascribed status by the PUC as a binding policy or administrative code. The decision to do so should ultimately depend on the content of the guidance document, the timeliness of its completion, and the level of consensus behind its authorship, as well as the input of any non-working group stakeholders.

In any case, the guidance document would be subject to regular updates and revisions by the working group to ensure compatibility with evolving industry practices (by inverter manufacturers, software vendors, aggregators, etc.), and if justified, to articulate additional statewide model requirements and processes previously infeasible to implement across all Vermont utility service territories.

Out-of-band Communication and Control Issues

Communication protocol optionality

IEEE 1547-2018 requires interconnected DER to be *capable of* communicating with the utility using at least one of three different possible protocols.[16] Of these, Vermont utilities are likely most familiar with DNP3 (IEEE 1815), the protocol used by the majority of commercial Supervisory Control and Data Acquisition systems (SCADA) sold and used in North America (see section *Excerpts from utility interconnection policy documents* below). However, DNP3 is not necessarily the appropriate protocol to require for communication with all DER, especially those located behind the customer meter and those under the supervision of a third-party aggregator or utility partner. California has recognized the advantages of the more broadly applicable IEEE 2030.5 protocol, which it recently designated (through Rule 21) as the default communications option for smart inverters (in so doing sending a clear signal of future demand to inverter manufacturers and vendors).

One of the key advantages of IEEE 2030.5 is its reliance of the Common Information Model (CIM) for message semantics.[17] Also important is the fact that IEEE 2030.5 is intended for communication with, and control of, non-inverter based DER (in addition to smart inverters), such as demand responsive thermostats and HVAC systems, water heaters, pumps and other networked appliances. In addition, IEEE 2030.5 uniquely allows for messages that convey electricity pricing and customer billing information, which in the long run can be used to integrate new utility programs into legacy customer information and settlement systems.

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[16] The three communication protocols allowed by 1547-2018 are Distributed Network Protocol 3.0 (DNP3), Sunspec Modbus, and IEEE 2030.5.
[17] Formally the CIM is comprised of a set of International Electrotechnical Commission Standards (IEC 61968, IEC 61970 and the complementary IEC 61850). In plain language the CIM provides a standard way to design the various data models (i.e., interfaces) that different electric power industry software applications can use to share information.

There is a need in Vermont to carefully examine which of the 1547-2018 compliant communication protocols should be used in which contexts (considering for example the type, size and location of DERs, the quality of communication networks they have access to, and whether they are part of an aggregation), and to weigh the pros and cons of elevating IEEE 2030.5 as the protocol of choice in Vermont, as California has done.

Of particular importance to consider is the fact that there is nothing inherent to IEEE 1547-2018 that requires third party aggregators or utility partners to use any one of the three prescribed protocols to structure their communications with upstream utilities. All that is required within IEEE 1547-2018 is that the software or firmware used by the aggregator is capable of sending the correct messages (of at least one certified protocol) to the inverter model under their supervision. In other words, adopting 1547-2018 puts no requirement on aggregators to communicate with Vermont utilities using any particular protocol or any particular data model. For utilities to be able to interpret and organize (and ultimately act on) the data streams that smart inverters are capable of providing, they will have to take additional steps to specify the application layer requirements for interfacing with their enterprise systems.

Commissioning and data acquisition

The communications capabilities required by IEEE 1547-2018 apply only to the smart inverter system itself. This means that IEEE 1547-2018 in no way requires interconnected DER to maintain active communication with the utility. As such the conformance test procedures prescribed by the standard (specifically in IEEE 1547.1) do not involve any post-installation validation of message exchange performance or device functionality on the utility's actual physical systems (but rather in a computer-simulated environment in a laboratory).[18]

As a consequence, any process for testing whether a DER is able to send, receive and correctly act on messages using one of the IEEE 1547-2018 communication protocols must be specified by either the individual utility or a statewide interconnection rule. Realistically, utilities in Vermont and elsewhere are likely not currently prepared to integrate such commissioning procedures into their interconnection processes, since doing so would require (at the least) new software tools capable of ingesting and responding to low latency DER data streams (i.e., DERMS and/or ADMS software).

Nonetheless, it would be beneficial to begin articulating the possibilities for automating DER commissioning processes using IEEE 1547 communication protocols. A statewide guidance document could spell out the ideal elements of such commissioning procedures in a way that accounts for varying levels of utility readiness for DER data acquisition. The working group could also take up the more immediately pressing questions about which *autonomous* settings are best suited for different grid conditions in the absence of real-time communications links.

Device discovery and registration

It will be possible in the near future to utilize the communications capabilities prescribed by IEEE 1547-2018 to automate the exchange of basic nameplate and configuration information from any certified inverter, including those installed to replace devices that pre-date the current version of the standard.

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[18] IEEE 1547.1 is the companion standard to IEEE 1547 that specifies how to conduct the tests that certify IEEE 1547 compliance.

Many changes within the utility enterprise need to happen before the device discovery functionality provided for by IEEE 1547-2018 can be fully operationalized. Utilities should work toward a goal of replacing as much of their manual DER registration processes as possible with automated workflows using IEEE 1547-2018 communication protocols and standardized data models and interfaces.

Published guidance from a working group could provide clarity on which of the allowed communication protocols are best suited for automated DER registration purposes, as well as which parts of current registration processes can (and cannot) feasibly be automated. In the meantime, all replacement inverters should conform to the most current version of the IEEE 1547 standard, whether or not the new inverter is considered “similar equipment.”

Telecommunication networking

Real time telemetry and message exchange between utilities and DER (or DER aggregators) will require access by both entities to a secure, reliable, high bandwidth, low latency telecommunication network. There are many open questions about how such a network should be designed, owned, and operated.

Currently in the majority of Vermont service territories, distributed generators sized 150 kW and larger are required (by utilities) to establish a communications link to utility SCADA systems (see section *Excerpts from utility interconnection policy documents* below). Beyond that, there is not much detail or uniformity in utility interconnection policies as to which physical media are acceptable, which types of service providers are acceptable, what level of service quality is required, or what security and privacy measures are needed.

It is important to begin defining the network performance characteristics that *advanced* IEEE 1547-2018 inverter functions will require in order to be useful in future real time operations by utilities. It likely will not be sufficient to rely on data routed though the public internet by commercial internet service providers (ISPs) to dispatch grid support functions needed within minutes or seconds (or less) of an upstream request (to stabilize local frequency for example).

There are also large security and privacy issues not addressed within the scope of IEEE 1547-2018, which does not specify any authentication or certificate validation process, or any tests that ensure different security features and/or controls are enabled.

6b. Please identify all technical standards that small DERs should be required to demonstrate compliance with.

6g. Should small DERs be required to provide “as-built” information to the utility so that the utility has a record of what is installed on their system.

There is no reason to exempt small DER from any of the communication capability requirements of IEEE 1547-2018, or from any complementary “out-of-band” requirements that may be developed through this proceeding or any working group process initiated by this proceeding.

It is illustrative to note that “as-built” nameplate information is one of the core categories of information that IEEE 1547-2018 requires inverters to be capable of exchanging with a utility (or “Area EPS Operator,” in the language of the standard).

Excerpts from utility interconnection policy documents

Green Mountain Power Interconnection Guidelines (revised March 2021):[1]

From section 6.7 Monitoring and Control at DER Facility:

> Certified DER facilities [IEEE 1547] less than or equal to 150 kW AC may have monitoring required at the Company's discretion. Certified DER facilities greater than 150 kW AC shall require monitoring communication to the Company's supervisory control and data acquisition (SCADA) system. Certified DER facilities greater than 500 kW AC shall require monitoring and control to the Company's SCADA system…All monitoring information from the Customer DER to the Company RTU shall be provided over fiber using a DNP 3.0 protocol.

Vermont Electric Cooperative Interconnection Guide (revised March 2019:[2]

From section 4.15 Telemetry, Monitoring, and Control

> VEC will provide, at cost to the customer, a remote terminal unit (RTU) to provide the utility with visibility of the output of the generator. The implementation of supervisory control and data acquisition (SCADA) to the inverters, including remote power factor adjustment, active power curtailment, ramp rate, and scheduling, will depend upon the site and terms of the generation interconnection agreement. If necessary, the customer is responsible to provide a suitable environmentally controlled space for telemetry equipment inside a generator building. At locations without a generator building, the customer will be billed for a pole mounted, heated, rack mount cabinet for placement of the RTU and associated network service provider equipment.

Burlington Electric Department Interconnection Technical Requirements (revised May 2016):[3]

From section 12 SCADA Control/Indication

> For a Facility larger than 150 KW, a SCADA remote terminal unit shall be supplied by BED. However, the applicant shall bear the cost of the unit and the installation cost. The remote terminal unit shall monitor the output of the generator and status points which indicate the condition of the generator breaker. The unit shall also provide remote tripping control to BED's dispatcher.

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[1] https://greenmountainpower.com/wp-content/uploads/2017/01/Final-2021-DER-Guidelines-2-2021-03-19.pdf
[2] https://vermontelectric.coop/client_media/files/VEC_Interconnection_Guidelines_03142019.pdf
[3] https://www.burlingtonelectric.com/sites/default/files/inline-files/bed-interconnection-technical-requirement-2016-05-19.pdf