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

Re: 19-0855-RULE Proposed revisions to Vermont Public Utility Commission Rule 5.100

Dear Ms. Anderson,

On July 30, Goodenough LLC and Dynamic Organics LLC filed responses to the Public Utility Commission's (PUC) June 22 request for information from participants in docket 19-0856-RULE (Proposed Revisions to Vermont Public Utility Commission Rule 5.500). The present comments are intended to echo a point made in the June 22 filing that no future small Distributed Energy Resource (DER)—a category encompassing all new and amended Net Metering (NM) projects—should be exempted from any of the communication capability requirements prescribed by IEEE 1547-2018.

As currently drafted by the PUC (on April 24, 2019), Rule 5.500 appears to provide such coverage.[1] Nonetheless, it warrants emphasizing that simply adopting the most current version of IEEE 1547 into Rule 5.500, and doing nothing more to address out-of-band integration issues, provides an insufficient level of technical specification for Vermont to fully realize the long-term benefits of end-to-end interoperability between utility systems, third-parties and DER controllers.[2]

In our June 22 comments, we proposed that the PUC authorize a technical working group ("working group") charged with studying, clarifying and providing statewide guidance on the myriad implications of adopting IEEE 1547-2018.[3] A significant part of the research agenda of this working group would naturally focus on how information exchange and operational coordination should be allowed to differ across different plant scales and grid contexts, ranging from behind-the-meter or co-located NM projects to utility-scale and merchant plants. The extent to which NM DER may merit unique communications and control requirements (today and over future iterations of the NM program) would no doubt be a central concern. To put this in concrete terms, the list below provides some examples of the type of NM DER-specific questions the working group could take up:

[1] That said, section 5.512 of the draft rule 5.500 (Terms Applicable to All Interconnection Applications) is not unambiguous as to which specific requirements NM projects are exempted from.

[2] In a worst-case but not unthinkable scenario, neglecting to standardize out-of-band issues could result in a proliferation of unutilized and underutilized smart inverters.

[3] To cite back to our June 22 comments, the purpose of the working group would be two-fold:

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.

- Should there be a unique set of autonomous inverter settings assigned to all NM DER? Does it make sense to consider NM DER as a group unto itself for operational purposes?
- Which IEEE 1547-2018 protocols are acceptable for communicating with NM DER? Is there a need for gateway technology i.e., protocol translation? Is that technology commercially available?
- Will NM DER be required to provide low latency telemetry data streams to the utility? If so,
    - How will data transport be handled? Over what types of communication networks?
    - How will telemetry data reach the utility Energy Management System (EMS) and other utility software tools (some yet to be developed)? Will it travel through the SCADA system or independent channels? If the later,
        - Using what kind of application program interface? Using which data model?
- Will NM DER be required to execute changes to inverter settings requested remotely by utilities and third-parties? If so,
    - At what time scales? For which grid-support functions?

All of these questions and more will need to be settled to some degree along the way to any future where a multitude of small scale DER can be reliably and economically called on by distribution system operators for fast response ancillary services or emergency curtailment (a.k.a. grid-support functions). We raise them here to underscore the need for the systematic and comprehensive approach of a technically literate working group tasked with identifying and answering key questions about the obstacles to achieving the ideal of a “plug-and-play” distribution grid in Vermont.

Industry experience and competence with real-time DER dispatch is growing by the day and it is not unreasonable to expect that a mature and stable state of the art will emerge within the decade or sooner. When that day comes, if Vermont has not already established a functional interoperability ecosystem in which to enact this know-how, the benefits of optimized DER dispatch will simply be more costly and more difficult to secure—possibly even unobtainable.

Path-dependently,

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