RIPUC Use Only
Date Application Received: _____/_____/______
Date Review Completed: _____/_____/______
Date Commission Action: _____/_____/______
Date Commission Approved: _____/_____/______

GIS Certification #:
NON161724

RENEWABLE ENERGY RESOURCES ELIGIBILITY FORM

The Standard Application Form
Required of all Applicants for Certification of Eligibility of Renewable Energy Resource
(Version 9 – April 19, 2021)

STATE OF RHODE ISLAND PUBLIC UTILITIES COMMISSION
Pursuant to the Renewable Energy Act
Title 810, Chapter 40, Subchapter 05, Part 2 et. seq. of the General Laws of Rhode Island

NOTICE:

- When completing this Renewable Energy Resources Eligibility Form and any applicable Appendices, please refer to the State of Rhode Island Public Utilities Commission Rules and Regulations Governing the Implementation of a Renewable Energy Standard 810-RICR-40-05-2 (RES Rules) , and the associated RES Certification Filing Methodology Guide. All applicable regulations, procedures and guidelines are available on the Commission's web site: www.ripuc.ri.gov/utilityinfo/res.html.
- Please submit one original of the completed Application Form, applicable Appendices, and all supporting documentation to the Commission at the following address:
  Rhode Island Public Utilities Commission
  Attn: Luly E. Massaro, Commission Clerk
  89 Jefferson Blvd
  Warwick, RI 02888
- Electronic submittals are also required and should be sent to
  Res.filings@puc.ri.gov.
- In addition to filing with the Commission, Applicants are required to send an electronic copy of the application and supporting documents to the service list located at
  http://www.ripuc.ri.gov/utilityinfo/reslist.doc
- Keep a copy of the completed Application for your records.
- The Commission will notify the Authorized Representative if the Application is incomplete.
- Pursuant to RES Rules Section 2.6(A)(3), the Commission shall provide a thirty (30) day period for public comment following posting of any administratively complete Application. All information submitted with the Application is considered to be a public record unless the Commission deems some portion of the application confidential after consideration under Rules of Practice and Procedure 810-RICR-00-00-1, Section 1.3(H)(3). It is the applicant's responsibility to request confidential treatment and to provide redacted copies to the Commission and the service list.
- Questions related to this Renewable Energy Resources Eligibility Form can be submitted to
  Res.filings@puc.ri.gov

SECTION I: Identification Information

1.1 Name of Generation Unit (sufficient for full and unique identification, and consistent with the Generation Unit name listed on the NEPOOL GIS, if currently listed):

Greenwich Wind

1.2 Type of Certification being requested (note: if the Generation Unit has not yet achieved Commercial Operation, check Prospective Certification/Declaratory Judgement):

☒ Standard Certification

☐ Prospective Certification (Declaratory Judgment)

1.3 This Application includes: (Check *all and only* those that apply)

☐ Appendix A: Authorized Representative Certification for Individual Owner

☒ Appendix B: Authorized Representative Certification for Non-Corporate Entities Other Than Individuals, including Limited Liability Companies (LLC) *Note: Please refer to Section 6.1, Corporations, for required evidence certifying Authorized Representative.*

☐ Appendix C: Existing Renewable Energy Resources

☐ Appendix D: Special Provisions for Aggregators of Customer-sited, Off-grid Generation, or RI-sited Remote Net Metered Facilities

☐ Appendix E: Special Provisions for a Generation Unit Located in a Control Area Adjacent to NEPOOL

☐ Appendix F: Fuel Source Plan for Eligible (including Unlisted) Biomass Fuels

1.4 Primary Contact Person

Name and title: **Stephen Salzer, Member**

Address: **23 West Brother Dr Greenwich, CT 06830**

Phone: **203-550-6364**

Email: **agplat2@yahoo.com**

1.5 Backup Contact Person

Name and title: **Stephen Salzer, Member**

Address: **23 West Brother Dr Greenwich, CT 06830**

Phone: **203-550-6364**

Email: **agplat2@yahoo.com**

1.6 Authorized Representative (the individual responsible for certifying the accuracy of all information contained in this form and associated appendices, and whose signature will appear on the application):

Name and title: **Stephen Salzer, Member**

Company: **Greenwich Renewable Energy, LLC**

Address: **23 West Brother Dr Greenwich, CT 06830**

Phone: **203-550-6364**

Email: **agplat2@yahoo.com**

Appendix A or B, or Corporate Authorization (as appropriate) completed and attached?

☒ Yes ☐ No

1.7 Owner

Name and title: **Stephen Salzer, Member**

Company: **Greenwich Renewable Energy, LLC**

Address: **23 West Brother Dr Greenwich, CT 06830**

Phone: **203-550-6364**

Email: **agplat2@yahoo.com**

1.8 Owner business organization type (check one):

☐ Individual

☒ Partnership (including Limited Liability Company and other Non-Corporate Entities)

☐ Corporation

☐ Other:

1.9 Operator

Name and title: **Stephen Salzer, Member**

Company: **Greenwich Renewable Energy, LLC**

Address: **23 West Brother Dr Greenwich, CT 06830**

Phone: **203-550-6364**

Email: **agplat2@yahoo.com**

1.10 Operational business organization type (check one):

☐ Individual

☒ Partnership (including Limited Liability Company and other Non-Corporate Entities)

☐ Corporation

☐ Other:

SECTION II: Generation Unit Information, Fuels, Energy Resources and Technologies

2.1 NEPOOL GIS Identification Number (if assigned yet, along with appropriate MSS, NON or IMP designation): **NON161724**

For facilities enrolled in the RI Renewable Energy Growth Program: National Grid will provide the participant with an MSS ID.

2.2 Nameplate Capacity (list AC, and DC if applicable): **50.00** kW AC **N/A** kW DC

2.3 Maximum Demonstrated Capacity (list AC, and DC if applicable): **50.00** kW AC **N/A** kW DC

2.4 Please indicate which of the following Eligible Renewable Energy Resources are used by the Generation Unit: (Check ALL that apply) – *per RES Rules Section 2.5*

☐ Direct Solar Radiation
☒ The wind
☐ Movement of or the latent heat of the ocean
☐ The heat of the earth
☐ Small hydro facilities
☐ Biomass facilities using Eligible Biomass Fuels *(per RES Rules Section 2.3(A)(7)*
☐ Biomass facilities using unlisted biomass fuel *(per RES Rules Section 2.3(A)(7)(a)*
☐ Fuel cells using a renewable resource referenced in this section

2.5 For small hydro facilities, please certify that the facility's aggregate capacity does not exceed 30 MW. – *per RES Rules Section 2.3(A)(32)*

☐ <-- check this box to certify that the above statement is true
☒ N/A

2.6 For small hydro facilities, please certify that the facility does not involve any new impoundment or diversion of water with an average salinity of twenty (20) parts per thousand or less. – *per RES Rules Section 2.3(A)(32)*

☐ <-- check this box to certify that the above statement is true
☒ N/A

2.7 For biomass facilities: Appendix F completed and attached?

☐ Yes (Please specify fuel or fuels used or to be used in the unit:)
☒ N/A

2.8 Has the Generation Unit been certified as a Renewable Energy Resource for eligibility in another state's renewable portfolio standard?

☒ Yes
☐ No

If "Yes," a copy of each state's certifying order is attached?

☒ <-- check this box to certify that the above statement is true

SECTION III: Commercial Operation Date>

Please provide documentation to support all claims and responses to the following questions:

3.1 Date Generation Unit first entered Commercial Operation or, if not yet in operation, the anticipated Commercial Operation Date:

11/25/2021

If the Commercial Operation date is after December 31, 1997, please provide independent verification, such as the utility log or metering data, showing that the meter first spun after December 31, 1997. For facilities located in Rhode Island, a copy of National Grid’s Authorization to Interconnect letter would also be sufficient. This documentation is needed in order to verify that the facility qualifies as a New Renewable Energy Resource.

Documentation of Commercial Operation Date attached?

☒ Yes

☐ No

☐ N/A

3.2 Is there an Existing Renewable Energy Resource located at the site of Generation Unit?

☐ Yes

☒ No

3.3 If the date entered in response to question 3.1 is on or earlier than December 31, 1997 or if you checked “Yes” in response to question 3.2 above, please complete Appendix C. Appendix C completed and attached?

☐ Yes

☐ No

☒ N/A

3.4 Was all or any part of the Generation Unit used on or before December 31, 1997 to generate electricity at any other site?

☐ Yes

☒ No

3.5 If you checked “Yes” to question 3.4 above, please specify the power production equipment used and the address where such power production equipment produced electricity (attach more detail if the space provided is not sufficient):

SECTION IV: Metering

4.1 Please indicate how the Generation Unit's electrical energy output is verified:

☐ ISO-NE Market Settlement System

☒ Other, including Self-Reported to the NEPOOL GIS Administrator (please specify below and complete Appendix D):

OTHER, Generation will be reported by VEPP Inc. acting as Rhode Island approved independent verifier.

For "Other," Appendix D completed and attached?

☐ Yes

☒ No

☒ N/A

For facilities enrolled in the RI Renewable Energy Growth Program: National Grid will be reporting output to the ISO-NE Market Settlement System.

4.2 Please check one of the following that apply to the Generation Unit:

☒ Grid Connected Generation

- Connected directly to a utility transmission or distribution system with only station load at the unit site
- Units participating in the RI Renewable Energy Growth Program fall in this category.

☐ Off-Grid Generation

- Not connected to a utility transmission or distribution system

☐ Customer-Sited Generation

- Connected on the end-use customer side of a retail electricity meter in such a manner that it displaces all or part of the metered consumption of the end-use customer, other than station load
- Traditional behind-the-meter net metering falls in this category.
- Units located outside Rhode Island with this configuration will be deemed ineligible by PUC (see RES Rules Section 2.6(H)(1) (see also Order No. 23710, http://www.ripuc.ri.gov/eventsactions/docket/4858-4891-Kearsarge%20Ord23710%2011-12-2019.pdf

☐ Remote Customer-Sited Generation

- Connected directly to the local electric utility distribution grid with only station load
- All or some of the electrical energy from the unit is designated for use in displacing all or part of the retail electricity metered consumption of one or more end-use customers (including through a transfer of bill credits)
- "Virtual" and "remote" front-of-the-meter net metering falls in this category.
- Units located outside Rhode Island with this configuration have been found ineligible by the PUC (see Order 23710, http://www.ripuc.ri.gov/eventsactions/docket/4858-4891-Kearsarge%20Ord23710%2011-12-2019.pdf

SECTION V: Location

5.1 Generation Unit address:

6089 Rt 17 Addison, VT 05491

5.2 Please provide the Generation Unit’s geographic location information:

A. Universal Transverse Mercator Coordinates: **18 N 627753 4880015**

B. Longitude/Latitude: **44.062171/-73.404890**

5.3 The Generation Unit is located: (please check the appropriate box)

☒ In the NEPOOL control area

☐ In a control area adjacent to the NEPOOL control area

☐ In a control area other than NEPOOL which is not adjacent to the NEPOOL control area <-- *If you checked this box, then the generator is ineligible.*

5.4 If you checked “In a control area adjacent to the NEPOOL control area” in Section 5.4 above, please complete Appendix E.

Appendix E completed and attached?

☐ Yes

☐ No

☒ N/A

SECTION VI: Certification

6.1 Please attach documentation, using one of the applicable forms below, to demonstrate the authority of the Authorized Representative provided in Section 1.6.

Corporations

The Authorized Representative of the Corporation shall provide **either**:

(a) Evidence of a Board of Directors' vote granting authority to the Authorized Representative to execute the Renewable Energy Resources Eligibility Form, **or**

(b) A certification from the Corporate Clerk or Secretary of the Corporation that the Authorized Representative is authorized to execute the Renewable Energy Resources Eligibility Form or is otherwise authorized to legally bind the Corporation in like matters.[1]

Evidence of Board Vote provided?

☐ Yes

☐ No

☒ N/A

Corporate Certification provided?

☐ Yes

☐ No

☒ N/A

Individuals

If the Owner is an Individual, that Individual shall complete and attach Appendix A, or a similar form of certification from the Owner, duly notarized, that certifies that the Authorized Representative has authority to execute the Renewable Energy Resources Eligibility Form.

Appendix A completed and attached?

☐ Yes

☐ No

☒ N/A

Non-Corporate Entities

(Limited Liability Companies - LLCs, Proprietorships, Partnerships, Cooperatives, etc.) If the Owner is neither an Individual nor a Corporation, it shall complete and attach Appendix B or execute a resolution indicating that the Authorized Representative named in Section 1.6 has authority to execute the Renewable Energy Resources Eligibility Form or to otherwise legally bind the non-corporate entity in like matters.

Appendix B completed and attached?

☒ Yes ☐ No ☐ N/A

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[1] If the Corporation has only one sole Officer, it is acceptable for that Officer to provide signatory certification of same as Authorized Representative.

6.2 Authorized Representative Certification and Signature:

I hereby certify, under pains and penalties of perjury, that I have personally examined and am familiar with the information submitted herein and based upon my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate and complete. I am aware that there are significant penalties, both civil and criminal, for submitting false information, including possible fines and punishment. My signature below certifies all information submitted on this Renewable Energy Resources Eligibility Form. The Renewable Energy Resources Eligibility Form includes the Standard Application Form and all required Appendices and attachments. I acknowledge that the Generation Unit is obligated to and will notify the Commission promptly in the event of a change in a generator's eligibility status (including, without limitation, the status of the air permits) and that when and if, in the Commission's opinion, after due consideration, there is a material change in the characteristics of a Generation Unit or its fuel stream that could alter its eligibility, such Generation Unit must be re-certified in accordance with RES Rules Section 2.6(E). I further acknowledge that the Generation Unit is obligated to and will file such quarterly or other reports as required by the Rules and the Commission in its certification order. I understand that the Generation Unit will be immediately de-certified if it fails to file such reports.

SIGNATURE: **Signed Electronically** DATE: **2023-11-16 11:34:01**

Stephen Salzer

(Printed Name of Signatory)

Member

(Title)

Greenwich Renewable Energy, LLC

(Company)

GIS Certification #:
NON161724

APPENDIX B

(Revised 4/19/2021)
(Required When Owner is a Non-Corporate Entity Other Than An Individual)

RESOLUTION OF AUTHORIZATION

Resolved: that **Stephen Salzer, Member of Greenwich Renewable Energy, LLC**, named in Section 1.6 of the Renewable Energy Resources Eligibility Form as Authorized Representative, is authorized to execute the Application on the behalf of **Greenwich Renewable Energy, LLC**, the Owner named in Section 1.7 of the Generation Unit named in Section 1.1 of the Application.

SIGNATURE: ______________________ DATE: 11/16/2023

Stephen Salzer
(Printed Name of Signatory)

Member
(Title)

Greenwich Renewable Energy, LLC
(Company)

State: Connecticut

County: Fairfield

(TO BE COMPLETED BY NOTARY) I, CarolAnnPriore as a notary public, certify that I witnessed the signature of the above named **Stephen Salzer**, and said individual verified his/her identity to me on this date: 11/16/23.

SIGNATURE: ______________________

My commission expires on: 05/31/25 NOTARY SEAL:

CAROL ANN PRIORE
Notary Public
Connecticut
My Commission Expires May 31, 2025

STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket No. 7533

Investigation Re: Establishment of a Standard-Offer Program for Qualifying Sustainably Priced Energy Enterprise Development ("SPEED") Resources)

Order entered: 9/30/2009

ORDER ESTABLISHING A STANDARD-OFFER PROGRAM FOR QUALIFYING SPEED RESOURCES

I. Introduction

Pursuant to the Vermont Energy Act of 2009 ("Act" or "Act 45"),[1] the Public Service Board ("Board") is required to "put into effect, on behalf of all Vermont retail electricity providers, standard offers for qualifying SPEED [sustainably priced energy enterprise development] resources with a plant capacity of 2.2 MW or less." Standard offers[2] are a relatively new regulatory mechanism to encourage the development of renewable projects by requiring utilities to purchase the electricity generated from such projects at prices generally above current market price — in the case of the Vermont program, at prices calculated to cover the cost of developing a qualifying project.[3]

The majority of standard-offer programs have been structured so that one utility provides a standard price for one form of renewable energy (typically solar), under what is sometimes called a feed-in tariff. In contrast, only a handful of programs, including the standard-offer program created by Act 45, address several renewable technologies and impose requirements

1. Public Act No. 45 (2009 Vt., Bien. Sess.), codified in 30 V.S.A. § 8005.

2. In some deregulated states, the term "standard offer" means the service offer available to customers from their local utility if the customer has not purchased supply from another retail supplier. This is not the meaning used in Act 45 or this Order.

3. For a full description of the calculation of these prices in Vermont, see Docket 7523, Order of 9/15/09.

across multiple utilities.[4] There are a myriad of issues that need to be addressed to effectively implement Act 45's standard-offer program, in large part because the electricity, costs, and benefits must be allocated and transferred among multiple entities. These issues include: the process by which developers enter into the program; the exchange and reconciliation of generator output and related cash flows among developers, utilities, the SPEED Facilitator, and the regional grid operator; navigating federal and regional rules regarding transporting power produced from program participants to the utilities; and the interaction between utility-owned projects and the program. The determination of these issues involved an interplay of Vermont and federal law, as well as regional rules governing the New England grid. Pursuant to the Act, which went into effect on May 27, 2009, the Board was required to put the standard offer into effect, and thus resolve these issues, by September 30, 2009.

Act 45 provided detailed specifications regarding the program in some areas and left other issues to be resolved by the Board. In areas where the Act did not provide guidance, we have been required to utilize our statutory authority to "take such other measures as the board finds necessary or appropriate to implement SPEED."[5]

In this Order we establish the parameters of the standard-offer program; direct the SPEED Facilitator as to the general procedures for delivering the power produced by participating generators and assigning the associated costs and benefits to Vermont's electric distribution utilities; provide a standard contract that will be available to qualifying SPEED resources; and clarify the interaction between the program and qualifying projects owned and operated by utilities. Additionally, we identify certain issues that could not be resolved during the timeframe established by Act 45. We will act in a timely manner to take all necessary and appropriate steps to resolve such issues and ensure the effective and efficient operation of the standard-offer program.

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4. Karlynn Cory, Toby Couture, & Claire Kreycik, *Feed-in Tariff Policy: Design, Implementation, and RPS Policy Interactions;* National Renewable Energy Laboratories; Technical Report NREL/TP-6A2-45549, March 2009.

5. Section 8005(b)(9).

II. BACKGROUND

In 2003, the Vermont General Assembly enacted 30 V.S.A. § 8001, which sets forth the renewable energy goals for the State. In addition to encouraging the acquisition of the environmental benefits associated with renewable energy, the statute includes the following goals:

> (2) Supporting development of renewable energy and related planned energy industries in Vermont, in particular, while retaining and supporting existing renewable energy infrastructure.
>
> (3) Providing an incentive for the state's retail electricity providers to enter into affordable, long-term, stably priced renewable energy contracts that mitigate market price fluctuations for Vermonters.[6]

In 2005, the General Assembly established the SPEED program to encourage the development of renewable energy resources in Vermont, as well as the purchase of renewable power by the State's electric distribution utilities.[7] In response to that legislation, the Board promulgated Board Rule 4.300 to implement the SPEED program. Board Rule 4.300 also established a SPEED Facilitator to encourage the development of resources under the program. The SPEED Facilitator, in its role as envisioned under Board Rule 4.300, provides a clearinghouse function for information related to the SPEED program, assists with the development of contracts for qualifying SPEED facilities, and administers such contracts, if requested to do so.

On May 27, 2009, the Vermont Energy Act of 2009 took effect, substantially modifying the SPEED program. It establishes a standard-offer mechanism for potential project developers seeking a market for the energy produced from qualifying SPEED resources with a capacity of 2.2 MW or less. The Act establishes default prices for the standard offer for different technologies, calculated to allow developers of renewable power purchased through the SPEED program to recover their costs plus a return on their investment. Act 45 imposes a ceiling of 50 MW on the program, and allows qualifying projects owned and operated by utilities to count toward this ceiling. Additionally, pursuant to the Act, the SPEED Facilitator is required to

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6. Section 8001(a).
7. The SPEED program is codified in 30 V.S.A. §§ 8004 and 8005.

purchase, on behalf of the Vermont electric distribution utilities, energy from developers who accept the standard offer. The energy, and attendant costs and benefits, are assigned to the utilities based on their pro rata share of total Vermont retail kWh sales for the previous calendar year.[8]

III. Procedural History

On June 3, 2009, the Board issued an Order opening an investigation, in Docket 7523, into the development of standard-offer prices for SPEED resources. The June 3 Order stated that Docket 7523 would address:

> the review of the Act's standard-offer prices and, if the prices are not a reasonable approximation, set interim prices by September 15, 2009. In addition, the Board will consider non-price terms and conditions for standard-offer contracts in this Docket.

On June 22, 2009, Board staff issued a preliminary list of issues to be considered in these proceedings, and sent out a revised issues list on June 26, 2009. Participants filed comments on the issues on July 2, 2009, with reply comments on July 9, 2009.

On June 29, 2009, the Board issued an Order opening Docket 7533, "to build upon the record developed in Docket 7523, resolve all necessary implementation issues not addressed in that docket, and reevaluate the prices for SPEED projects set out in the statute."[9] The June 29 Order further stated:

> We open this investigation as a distinct proceeding primarily because the Act requires that the Board not only open the non-contested case docket that is Docket No. 7523, but also complete it by September 15, 2009. To meet this mandate, we intend to close that docket following completion of the tasks set out in Section 8005(b)(2)(B)(ii). To ensure that we can deal with any implementation issues that are not fully resolved and to avoid having to duplicate the gathering and evaluation of information that occurs in that docket, we intend to incorporate the

8. Section 8005(b)(7) allows an exception to the purchase power requirements of subdivision (5) if the retail electricity provider establishes that it receives at least 25 percent of its energy from qualifying SPEED resources that were in operation on or before September 30, 2009.

9. Docket 7533, Order of 6/29/09 at 2.

> record from that docket as it now exists plus any additional material subsequently generated therein.[10]

On July 10, 2009, Board staff conducted a workshop in these Dockets to, among other things, identify issues that require early determination, and to discuss the process for resolving these issues. At the workshop, it was decided that subgroups would be established to focus on the necessary issues. The subgroups consisted of: (1) a Cost Analysis Subgroup to determine whether the statutory default prices were a reasonable approximation of the prices that would be paid applying the statutory criteria and, for any prices that were determined not to be reasonable approximations, to determine appropriate prices using the statutory criteria; (2) a Settlement Subgroup to address the accounting of electricity and renewable energy credits from generators that accept the standard offer; (3) a Wheeling and Interconnection Subgroup to address the review process for connecting projects with the grid and transporting power produced from program participants to the utilities; and (4) a Contract Subgroup to develop a draft standard contract and attempt to resolve issues related to the establishment and management of a queue for developers seeking to participate in the standard offer.

The Cost Analysis Subgroup was required to complete its efforts on a different time frame than the other groups, as Act 45 required the Board to establish interim prices for qualifying SPEED resources by September 15, 2009. On September 15, 2009, the Board issued an Order in Docket 7523 setting these interim prices, which will be in effect until the price determinations due by January 15, 2010.

The participants in the three remaining subgroups are identified herein as Attachments A, B, and C. The entire list of participants involved in these proceedings is provided as Attachment D.

On August 18, 2009, the Board issued an Order determining certain threshold legal issues relating to project eligibility, the potential use of an auction to establish standard-offer prices, and the appropriate process for this Docket.

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10. *Id*. (footnote omitted).

On September 4, 2009, the Settlement, Contract, and Wheeling and Interconnection Subgroups issued reports outlining the recommendations made by these subgroups.[11] Participants in Docket 7533 were provided the opportunity to file comments and reply comments on the subgroup reports.

IV. Standard-Offer Application Process

Pursuant to Act 45, the standard offer must be implemented through the SPEED Facilitator.[12] Certain aspects of the program are fairly well delineated in statute; for example, the standard offer is required to be available in the form of a contract that specifies the rights and obligations of project owners and the SPEED Facilitator. However, the legislature did not make specific provisions regarding other aspects of the program, most notably the means by which the Board would determine which projects qualify for the standard offer, given the 50 MW ceiling. As noted earlier, Board staff convened several subgroups to address issues related to the program. The Contract Subgroup addressed the development of a standard contract and the development of a queue for project developers that would provide clarity as to which individual projects would be eligible for the standard offer. In addition to providing a draft contract for the Board's consideration, the Contract Subgroup Report noted several areas where consensus was not reached, both in the draft contract and the structure of the queue. Where consensus was not reached, the Report outlined the issues involved to provide a framework for participants to file comments. Below we address the issues relevant to the queue and the standard contract.

A. Queue

One of the primary issues before the Board is the establishment of a mechanism to determine which projects would be entitled to the standard offer. The draft contract prepared by the Contract Subgroup assumes that a queue would be utilized for this purpose, and many of the

11. These reports are available at: http://psb.vermont.gov/docketsandprojects/electric/7523/settlement (Settlement Subgroup Report); http://psb.vermont.gov/docketsandprojects/electric/7523/standardcontract (Contract Subgroup Report); and http://psb.vermont.gov/docketsandprojects/electric/7523/wheeling (Wheeling and Interconnection Subgroup Report).

12. Section 8005(b)(1).

discussions of the Subgroup centered around the structure of a queue. The existence of a program ceiling, and the need for a queue to address that ceiling, were largely assumed in the Contract Subgroup Report and participants' comments. However, given the uncertain language of the Act regarding certain provisions related to project eligibility, we address below the statutory ceiling on projects eligible for the standard offer and the merits and details of a mechanism to determine which projects are eligible.

(1) Overview and Structure of the Queue

Pursuant to Act 45:

> These standard offers shall be available until the cumulative plant capacity of all such resources commissioned in the state that have accepted a standard offer under this subdivision (b)(2) equals or exceeds 50 MW; provided, however, that a plant owned or operated by a Vermont retail electricity provider shall count toward this 50-MW ceiling if the plant has a plant capacity of 2.2 MW or less and is commissioned on or after September 30, 2009.[13]

Due to the ceiling on program participation, some method that informs potential developers as to whether the standard offer — and the accompanying prices — is available at any given time, is necessary to provide a developer with information regarding expected revenue streams. This certainty allows a developer to obtain the necessary financing and raise capital to construct a project.

One approach to this issue is to establish a queue for qualifying SPEED resources. A developer would submit an application to the SPEED Facilitator, who would manage the queue. After processing the application, the SPEED Facilitator would inform the developer whether there is capacity remaining in the queue for that project, and therefore whether the project is eligible for the standard offer. If there is sufficient capacity for the project, the plant owner would sign the standard contract, thereby accepting the standard offer, with the prices, terms, benefits, and obligations that entails.

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13. Section 8005(b)(2).

In order to ensure that the queue does not simply become a placeholder for potential developers, the draft standard contract contains certain filing requirements to encourage rapid development of projects, as well as milestones that developers must meet to stay in the queue.[14] Any developer that applies to the queue after the 50 MW is full could be placed on a waiting list and could become eligible for the standard offer if a developer in the queue voluntarily withdraws or is removed from the queue for failure to meet the required milestones, or for other reasons set forth in the standard contract.

(2) Standard-Offer Ceiling

Act 45 states that "[t]hese standard offers shall be available until the cumulative plant capacity of all such resources commissioned in the state that have accepted a standard offer under this subdivision (b)(2) equals or exceeds 50 MW."[15] This provision creates two uncertainties with respect to the implementation of the standard-offer program, the first involving the term "commissioned," and the second regarding "equals or exceeds 50 MW."

The Act states that the standard offer is available until 50 MW are commissioned. Given that siting and constructing a generation plant can take time, issuing standard offers to all qualifying projects until such time that 50 MW are commissioned could result in significantly more than 50 MW of generation accepting the standard offer. Such a result would be inconsistent with the plain language of the Act that 50 MW is a ceiling, notwithstanding the language regarding "equals or exceeds 50 MW." In particular, the same sentence of Section 8005(b)(2) also refers to the 50 MW as a "ceiling." Similarly, Section 8005(g)(2), which discusses the allocation of both the electricity purchased under the program and the program costs, refers to 50 MW as a "ceiling." Accordingly, although the language could be interpreted to allow projects to obtain the standard offer until 50 MW had been constructed (thereby creating an indeterminate cap), in conjunction with the statutory references cited above, we conclude that the 50 MW is intended to be a cap on the amount of renewable energy entitled to the standard-offer

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14. The milestones included in the standard-offer contract are discussed further in Section IV.B.4, below.
15. Section 8005(b)(2).

prices. We understand that the purpose of the 50 MW ceiling is to contain the overall costs of the standard-offer program and address concerns that the program may adversely impact ratepayers.

We recognize that the statute requires that the standard offer be available until the 50 MW is equaled or exceeded. However, we interpret the "equals or exceeds" language as providing flexibility in filling the 50 MW ceiling. In other words, although there is a ceiling on program participation, once that ceiling is approached, the SPEED Facilitator does not have to reject a potential developer because its project would exceed the ceiling, and be able to accept a developer who applied later, but had a project with a smaller capacity that would fit within the 50 MW ceiling. For example, a 2.2 MW plant would be eligible for the standard offer even if there is 49 MW in the queue. Since 2.2 MW is the maximum project size eligible for the standard offer, there is a limit to the extent any single standard offer can exceed the 50 MW ceiling.

(3) Need for a Queue

Given the existence of a 50 MW ceiling on the standard-offer program, a method must be devised to determine which projects are eligible to receive the standard offer, because the existence of a ceiling on program subscription creates uncertainties for developers. The two primary options for addressing this uncertainty are basing eligibility on (a) which project applies first (assuming the project application is complete and meets relevant requirements) or (b) which project is commissioned first. The former option is generally referred to as a queue. Under this proposal, applicants would submit an application to the SPEED Facilitator, who would rank the applications on a "first-come, first-served" basis. Assuming that the project in the queue continues to meet any applicable requirements, such as continuing progress towards commissioning, the project would remain in the queue. This has the advantage of creating certainty for developers regarding the prices that they will receive for the electricity produced, prior to investing capital and obtaining the financing necessary to commence construction.

The alternative to the queue set forth in this Order, keeping in mind the 50 MW ceiling, is to only provide the standard offer to the first 50 MW of projects that have been commissioned.

Under this approach, the developer would not know whether it will receive the standard-offer prices until the project is complete. Without the certainty of the standard-offer price terms, deciding to invest capital and obtaining financing would be difficult, and only well-funded developers would be able to participate in the program.

Order is the best method for implementing the statutory directives and is consistent with the Act. The queue process will provide prospective developers with the certainty needed to obtain financing for, and consequently commissioning of, qualifying SPEED resources, as directed by the statute. Although the development of a queue is not expressly required by the Act, Section 8005(b)(9) authorizes the Board to "take such other measures as the board finds necessary or appropriate to implement SPEED." Given the developer's need for certainty and an orderly process to determine eligibility for the standard offer, we conclude that the establishment of a queue is both necessary and appropriate. Moreover, the alternative approach, issuing standard offers to developers only after the project is commissioned, is likely to slow the development of qualifying SPEED resources, as this approach would reduce the ability to obtain financing and discourage the investment of capital in a project. Such a result is contrary to the intent of the statute.

In establishing the queue for determining project eligibility, we are mindful that Section 8005(b)(2) refers to the commissioning of 50 MW. We interpret this language as ensuring that only projects that actually produce power receive a standard offer. This issue is addressed in the standard contract through the imposition of milestones that must be met to stay in the queue and financial incentives, beyond the standard-offer prices themselves, to rapidly commission projects. As we discussed above, any other interpretation of the term commissioning would either result in the standard offer being available to far more than 50 MW of resources, or the creation of significant barriers to obtaining financing and raising capital; both outcomes are clearly contrary to the statutory intent.

(4) Division of the Queue

One of the issues taken up by the Contract Subgroup was the potential division of the queue to ensure that the standard-offer program included a diversity of qualifying SPEED resources with respect to technology, and potentially project size. Under the statute, the standard offer is available to solar, wind, farm methane, landfill gas, hydropower, and biomass resources; in addition, projects may vary significantly in size up to 2.2 MW installations. The lead time required for planning, developing, and constructing a project may vary significantly by the type of resource and its size. The possibility therefore exists that projects that are easier to plan and site will enter the queue more quickly, potentially freezing out other types of renewable resources. For example, during discussions of the Contract Subgroup, there was some concern expressed that solar projects could fill the queue within a matter of days, leaving other technologies unable to compete. To address this potential, the Subgroup identified several potential methods of dividing the queue, but could not reach consensus on this issue, including whether a division of the queue was necessary at all. The Contract Subgroup Report set out four basic approaches to dividing the queue, recognizing that some of the options are not mutually exclusive:

> (A) Allow only a certain portion of the 50 MW to be filled before a set date. For example, only allow 25 MW into the queue until after January 15, 2010. This would allow the Board and participants to determine whether technology or size constraints should be established for the queue.
>
> (B) Open the entire 50 MW, but require a percentage cap on any single technology. For example, the Board could determine that no one technology could take up more than 25% of the available queue space.
>
> (C) Develop a comprehensive allocation by technology and/or project size for the queue. For example, the Board could determine that 20% of the queue is available for photovoltaic projects over 500 kW, another 10 % of the queue is available for photovoltaic projects less than 500 kW, 20% of the queue is available for wind, with 5% of that amount reserved for wind projects with a capacity of less than 15kW.
>
> (D) Make no provisions for dividing the queue.

Participants' Comments

The Group of Municipal Electric Utilities ("GMEU")[16] states that the Board has broad authority to implement Act 45 and, additionally, that there is no requirement in the statute that the entire 50 MW be included in the queue immediately. GMEU recommends that the Board allow only half the queue to be filled for a short time until there is further indication regarding the size, type and number of projects that accept the standard offer.

Central Vermont Public Service Corporation ("CVPS") states that the Board has broad authority to manage the queue and recommends that the Board make available only a portion of the 50 MW. CVPS contends that such a strategy would allow the Board to "rectify any mistakes and fine-tune implementation details in later rounds." In addition, CVPS states that the recommended approach would allow each utility to manage its own queue for interconnection agreements with standard-offer applicants pursuant to Board Rule 5.500 and would also provide the Board with a method of managing a potentially large number of petitions filed under 30 V.S.A. § 248.

Green Mountain Power Corporation ("GMP") recommends that the Board make the full 50 MW available with no specific cap on any given technology. GMP states that such a method is the simplest way to manage the queue and is consistent with legislative intent.

The Department of Public Service ("Department") states that it does not oppose division of the queue to various technologies, but recommends that any such division expire after a specified period of time. In addition, the Department recommends that, if the queue is divided, a portion be allocated for utility projects.

Great Bay Hydro Corporation ("Great Bay") recommends that the entire 50 MW be available at the start of the program, and the queue be divided by technology as follows: solar - 10 MW; wind - 10 MW; landfill or farm methane - 10 MW; hydro -10 MW; other (including biomass) - 10 MW.

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16. Barton Village, Inc. Electric Department, Village of Enosburg Falls Water & Light Department, Town of Hardwick Electric Department, Village of Hyde Park Electric Department, Village of Jacksonville Electric Company, Village of Johnson Water & Light Department, Village of Ludlow Electric Light Department, Village of Lyndonville Electric Department, Village of Morrisville Water & Light Department, Village of Northfield Electric Department, Village of Orleans, Inc. Electric Department, Town of Readsboro Electric Light Department, Swanton Village, Inc. Electric Department.

Northern Power Systems ("Northern Power") recommends that the Board require that no single technology occupy more than 40% of the queue. Northern Power contends that such an approach would prevent a single high-cost technology from utilizing most of the 50 MW ceiling, would allow sufficient time for the Board and the Clean Energy Development Fund ("CEDF") to harmonize rules, would allow the Board time to establish non-interim prices, and would allow the Board to make future program adjustments.

The Agency of Agriculture, Food and Markets ("AAFM") recommends that the Board not allow more than five MW of any one technology to enter standard-offer contracts for the first six months (except for solar, which would be allotted 10 MW); if a specific allocation is not filled in the first six months, that allocation would be opened to any technology. AAFM states that such a process would allow a diversity of technologies to enter into standard offers, would spread out applications, would give the SPEED Facilitator and the Board time to deal with any issues that arise, and would give utilities time to deal with interconnection agreements.

Discussion and Conclusions

Although the Act does not specify that the standard-offer program should include resource diversity, the Act requires the Board to establish prices for six different specified technology types, and, in the case of wind projects, a separate price for projects with a capacity of 15 kW and less. This language at least implies that the legislature anticipated that the standard-offer program would be comprised of different resource technologies. In addition, different technologies provide different benefits to the electric system; for example, the output of solar projects is often coincident with peak demand, and landfill gas and farm methane projects provide baseload power. This leads us to conclude that some mechanism to ensure a diversity of resources are included in the standard-offer program is both necessary and appropriate, and therefore should be adopted pursuant to Section 8005(b)(9).

Some participants recommended that the Board allow only 25 MW in the queue for a certain period of time. This proposal appears to be inconsistent with the Act, which states that the "standard offers shall be available until the cumulative plant capacity of all such resources commissioned in the state that have accepted a standard offer under this subdivision (b)(2) equals or exceeds 50 MW . . . ."[17] In addition, the proposal presents logistical concerns. In particular, if the 25 MW is filled quickly, there is a question as to how the SPEED Facilitator would treat projects that are ready to sign onto the queue between the time that the first half of the queue is filled and the second half becomes available.[18]

With respect to a detailed division of the queue, such as that proposed by Great Bay, there is insufficient information to provide a rational division of the queue and still meet the Act's directive of rapid deployment of qualifying SPEED resources.[19]

We conclude that the most effective mechanism to address the resource-diversity issue is a cap on the amount of any one technology in the queue. Accordingly, we direct the SPEED Facilitator to implement a mechanism to ensure that no one technology fills more than 25% of the queue. This will retain substantial flexibility and encourage rapid deployment, while still ensuring that some diversity exists. We acknowledge that, as the Department suggests, it is possible that deployment of qualifying SPEED resources could be slower with this limitation than would occur if we had placed no limit. This would be particularly true if many projects were proposed for one category and an insufficient number in other categories so that the full 50 MW was not subscribed. To ensure that such an effect would be minimal, the 25% technology cap will apply for six months; the Board will revisit this mechanism no later than that time, unless the SPEED Facilitator informs the Board that earlier reevaluation is necessary.

In addition, we have discussed previously the ability of the last project in the queue to exceed the 50 MW ceiling. For purposes of administration, we direct the SPEED Facilitator to take a similar approach to implementing the technology-specific cap within the queue. For example, if 24.9% of the technology-specific cap is filled, the SPEED Facilitator may accept an additional project of that technology type, even if the addition results in that specific technology increasing the percentage beyond 25%. However, the overall 50 MW ceiling cannot be exceeded beyond the size of the last project that meets or exceeds 50 MW in the queue, as explained in Section IV.A.2, above.

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17. Section 8005(b)(2).

18. For example, should the applications be rejected or instead deferred? Would such applications take precedence over later-filed applications once limits are removed?

19. *See* Section 8005(b)(2)(B)(i)(II).

As discussed below, there are several issues related to the development of qualifying projects by utilities, including how utility-developed projects should be treated for purposes of the program. The intent of the technology-specific cap is to ensure that a diversity of projects are deployed. The cap will therefore apply to all projects, whether owned and operated by a utility, or by a non-utility plant owner. Allowing projects owned and operated by utilities to be counted outside the cap would negate the goal of encouraging resource diversity.

(5) Management of the Queue

One issue that was discussed in the Contract Subgroup was the application process to enter the queue and, in particular, how to establish a process that could handle a large number of applicants once the queue is opened, which some participants suggested could be a possibility. Some participants recommended specific practices, such as time stamping paper copies to know the place of the applicant in the queue.

Participants' Comments

AAFM recommends that the SPEED Facilitator accept applications for the first month of the program, but not sign any contracts. AAFM suggests that the Board require hard copies of all submissions that the SPEED Facilitator would date stamp, and if there were more applications at the end of the month than slots in the queue, a lottery would be held.

GMEU recommends that the SPEED Facilitator allow, at the opening of the queue, a short period of time, such as two to three days, to accept applications. If the queue is oversubscribed, a lottery could be used to determine which projects are accepted in the queue. GMEU states that this approach would address problems that could arise if there was an early rush to fill the queue.

Discussion and Conclusions

In this Order we provide the general outline of the queue process, but we do not specify the application process that will be used. It is likely that an online application process could resolve many of the issues surrounding the opening of the queue. The details of this process will be worked out between the Board and the SPEED Facilitator prior to implementation and will be available at www.vermontspeed.com.

In order to provide the SPEED Facilitator with sufficient time to develop the necessary processes with respect to the applications, settlement, wheeling, and other issues so that there may be an orderly start to the standard-offer program, we direct the SPEED Facilitator to begin accepting applications at 9 a.m., on October 19, 2009, unless the Board establishes a different starting date due to unforeseen implementation or other issues that require additional time for resolution.

B. Standard Contract

Act 45 makes several references to the existence of a contract available for plant owners. The Contract Subgroup developed a draft contract that the SPEED Facilitator would enter into with plant owners that accept the standard offer. We generally adopt the draft contract, with the exception of some non-substantive edits, and the determinations that we reach below. We are attaching to this Order the standard contract that the SPEED Facilitator will make available to qualifying SPEED resources in the queue.[20] The Contract Subgroup Report noted that the draft contract contained some provisions intended to serve as placeholders, as the subgroup could not reach consensus on all issues associated with the contract. The Contract Subgroup Report instead noted those areas where consensus was not reached and framed the issue for comments from participants.

(1) Other Products Related to Electric Generation

At the present time, a generator produces a number of separately marketable commodities, with the predominant attribute being the energy itself. Regional markets have evolved so that the capacity associated with the generator can have a separate value for which compensation is received. In a number of states, the renewable attributes, known as renewable

20. We are attaching the standard-offer contract to this Order for informational purposes only. Given the need for flexibility in administering the standard-offer program, changes to the standard-offer contract may be made without requiring a modification of this Order.

energy credits ("RECs"), have a separate value. In addition, the regional market also values certain ancillary attributes produced by some generators.[21]

The Act provides that, with the exception of farm methane projects, "tradeable renewable energy credits associated with a plant that accepts the standard offer are owned by the retail electric providers purchasing power from the plant . . . ."[22] In addition, Act 45 further requires that the SPEED Facilitator "transfer all capacity rights attributable to the plant capacity associated with the electricity purchased under standard-offer contracts to the Vermont retail electricity providers . . . ."[23] In an attempt to incorporate these provisions, the draft standard contract states:

> Facilitator shall retain all right, title, and interest in all Other Products Related to Electric Generation in trust for all Vermont Distribution Utilities that are subject to prorated allocations under the Act. Facilitator shall be entitled, unilaterally and without the consent of Producer, to deal with Other Products Related to Electric Generation in any manner it determines and consistent with the Act, regardless of whether any consideration is separately stated as being received or paid for by Facilitator.

The language in the draft contract specifically grants to utilities any other market products that may be developed in the future, in addition to the RECs and capacity credits.

Participants' Comments

GMEU contends that the intent of the Act is to convey all products associated with SPEED projects accepting the standard offer, except for RECs from farm methane projects, to the utilities for the benefit of ratepayers. GMEU further states that the Act sets standard-offer prices sufficient to cover the costs of projects, plus a reasonable rate of return, and therefore there is no rationale for providing developers with the benefits of other products with monetary value that may arise in the future.

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21. Other services include regulation service, capacity that is recognized in the forward capacity market, and dispatchable generation that contribute to forward reserves. For a detailed description of the various regional products and services relevant to settlements for generation services, see http://www.iso-ne.com/stlmnts/cost_comp/whlsle_load_cost_matrix.pdf

22. Section 8005(b)(6).

23. Section 8005(g)(4).

CVPS contends that any products related to electric generation developed in the future should be conveyed to the SPEED Facilitator for the benefit of ratepayers. CVPS states "[t]o the extent revenues from these products is not taken into account in the rate-setting process and the producer is permitted to keep the products and their attendant revenue streams, the rates set for these producers will provide them a much higher return than that contemplated under the Act."

The Department states that, given the fact that the standard contracts extend for 20 to 25 years, it is likely that electricity markets will evolve over time and the SPEED Facilitator should have flexibility to adapt to these markets. The Department contends that, to the extent that the value of any products was not included in the prices paid to plant owners, these products should be transferred to the SPEED Facilitator.

GMP states that it agrees with the Department's position on this issue and "[i]f a new product is identified in the renewable energy market, and has value, the subsequent price review (done by the Board every two years) should include the value for these new products."

Great Bay states that all products should be deemed sold to the SPEED Facilitator only if the Board orders technology-specific prices, rather than relying on the default prices established by Act 45. Great Bay contends that the default prices may not represent the full technology-specific revenue requirement for all technologies.

Northern Power states that the Act only contemplates the disposition of tradeable renewable energy credits and other credits, and should not be construed as conveying other products, especially since that term is not defined in the draft contract.

Ag Energy Consultants, LLC ("AEC") states that the Act supports the rationale that ancillary values associated with project generation be maximized for ratepayer benefit. However, AEC further states that the term "other products" "is simply too broad and too loosely defined to be used in the standard-offer contract."

AAFM recommends that the term "other products" be removed from the contract, and the contract only refer to RECs. If the Board does not accept this recommendation, AAFM recommends that the Board make clear that farms retain "other products" as well as RECs.

Discussion and Conclusions

Act 45 requires that the Board "[m]aximize the benefit to ratepayers from the sale of tradeable renewable energy credits or other credits that may be developed in the future, especially with regard to those plants that accept the standard offer issued under subdivision (2) of this subsection."[24] In addition, the Act states:

> It shall be a condition of a standard offer required to be issued under subdivision (2) of this subsection that tradeable renewable energy credits associated with a plant that accepts the standard offer are owned by the retail electric providers purchasing power from the plant, except that in the case of a plant using methane from agricultural operations, the plant owner shall retain such credits to be sold separately at the owner's discretion.[25]

Finally, with respect to RECs and other products, Act 45 states:

> The SPEED Facilitator shall transfer any tradeable renewable energy credits attributable to electricity purchased under standard-offer contracts to the Vermont retail electricity providers in accordance with their pro rata share of the costs for such electricity as determined under subdivision (2) of this subsection, except that in the case of a plant using methane from agricultural operations, the plant owner shall retain such credits to be sold separately at the owner's discretion.[26]

> The SPEED Facilitator shall transfer all capacity rights attributable to the plant capacity associated with the electricity purchased under standard-offer contracts to the Vermont retail electricity providers in accordance with their pro rata share of the costs for such electricity as determined under subdivision (2) of this subsection.[27]

The statute is explicit that, with the exception of farm methane projects, any RECs from projects that accept the standard offer shall be transferred to the electric distribution utilities for the benefit of ratepayers. In addition, the capacity rights for all qualifying SPEED resources under the standard-offer program, including those associated with farm methane projects, are transferred to the SPEED Facilitator, again to be transferred to the utilities. The remaining question is whether the other products, including those that may be developed over time, are retained by the qualifying SPEED project or transferred to the SPEED Facilitator. Our reading of

24. Section 8005(b)(3).
25. Section 8005(b)(6).
26. Section 8005(g)(3).
27. Section 8005(g)(4).

Act 45 persuades us that these attributes should be transferred to the SPEED Facilitator for the benefit of utility ratepayers.

First, the ancillary services and possible future attributes are directly associated with the generation of electricity. As noted, the statute is explicit that, with a limited exception, the RECs and capacity are transferred.[28] More significantly, the electricity is specifically transferred to the SPEED Facilitator. It is therefore logical to assume that those other attributes directly related to the electricity are similarly transferred.

Second, the prices available under the standard offer are cost based, and the statute specifically requires that the costs of the project be offset by any "reasonably available tax credits and other incentives provided by federal and state governments and other sources applicable to the category of generation technology."[29] While tradeable renewable energy credits are specifically excluded from the definition of "tax credits and other incentives," we conclude that this narrow exclusion is for the purposes of allowing farm methane projects to receive RECs.[30] The standard-offer prices do not include the benefits of RECs and capacity because they are not retained by the project. In the case of future products similar to RECs, there is no way to value them at the present time. However, such products may be developed, and could result in revenue to producers that would have resulted in a reduction of the price paid under the standard offer if they were known at the time the price was calculated. Accordingly, we conclude that the standard contract should transfer any and all future products that arise from the generation of projects accepting the standard offer. Furthermore, because the standard-offer prices reflect, on a generic basis, the full costs of developing the SPEED projects, all generation-related products, including future products, from the projects should be transferred to the utilities (other than RECs from farm methane projects), to avoid a windfall to developers that would be inconsistent with the intent of the Act.

Act 45 specifically states that the SPEED Facilitator shall transfer RECs from projects that accept the standard offer to the utilities, with the exception of those RECs derived from farm

28. Section 8005(g).
29. Section 8005(b)(2)(B)(i)(I)(aa).
30. *See* Section 8005(b)(6).

methane projects, which are to be retained "to be sold separately at the owner's discretion."[31] However, the next subdivision of the statute states that the SPEED Facilitator shall transfer all capacity rights attributed to standard-offer projects to the utilities, and provides no exception for farm methane projects. In addition, the calculation of standard-offer prices for farm projects did not include the value of generation-related products. Although farm methane projects were provided the value of RECs associated with the project generation in addition to the standard-offer price, we conclude that it is not appropriate to increase such a subsidy to farm methane projects, the costs of which are borne by ratepayers, absent a clear statutory directive. We conclude that the legislature provided a narrow exception that allows developers of farm methane projects to retain the RECs associated with the electricity generated by the project, but that exception does not extend to other products.

We agree with commenters that the lack of a definition in the contract for "other products related to electric generation" is problematic. Based upon the discussion above, we include the following definition in the standard contract:

> Other Products Related to Electric Generation means any transferable commodity, in addition to Electricity, that is directly attributable to the generation of electricity from the plant. For purposes of this definition, Other Products Related to Electric Generation does not include tradeable renewable energy credits, as defined in 30 V.S.A. § 8002(8), directly attributable to plants using methane from agricultural operations.

(2) Provision of Cost Data by Producers

The Department recommends that the standard contract include a requirement that developers provide information regarding project costs to the SPEED Facilitator. The Department states that other jurisdictions have collected such information and it has proven helpful to the Department in its work in the Cost Analysis Subgroup. The Department further states that such information would assist the Board in making future determinations regarding standard-offer prices. Finally, the Department contends that, as qualifying projects are receiving

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31. Section 8005(g)(3).

subsidized rates, "there should be sufficient transparency in the impacts of this program to allow ratepayers some insight into its costs and benefits."

Participants' Comments

GMEU recommends that the Board defer this issue at this time, given the significant amount of work involved in establishing the standard-offer program by the statutory deadline. GMEU states that the language contained in the draft contract, providing that "Producers shall comply with Board orders or rules governing the provision of cost data," adequately addresses potential Board resolution of this issue.

CVPS supports the Department's recommendation that developers be required to provide cost data and states that such information would help inform future program activities. CVPS further states that it does not object to the appropriate use of confidentiality terms and conditions to protect developers' interests.

Great Bay recommends that the Board not require cost data, but states that it "would abide by any Board order and rules governing disclosure of commercially sensitive information and that such information would be regarded as trade secrets."

AAFM contends that the Department's proposal to require cost data will not provide the necessary information. AAFM states that, with respect to farm methane systems, the cost of the system is not as significant as the maintenance costs, which will be determined over the next 20 years.

Discussion and Conclusions

The projects receiving standard offers are being provided long-term, guaranteed contracts with cost-based prices, subsidized by Vermont ratepayers. Consequently, the standard offer is similar to grant programs such as the Clean Energy Development Fund ("CEDF"), in that Vermonters are subsidizing the renewable energy projects. The CEDF requires developers applying for grants from the fund to provide information on the costs of the project requesting funding.

In addition, Act 45 requires that the Board re-examine the standard-offer prices at least every two years.[32] Accurate information on the costs associated with the actual deployment of generation facilities in Vermont would provide valuable input into this analysis. To date, the amount of solid cost data has been limited. For example, the Cost Analysis Subgroup relied, in part, upon a database of prices for renewable projects, produced by the Massachusetts Technology Collaborative under the Renewable Energy Trust, to develop solar costs.[33] The Board's analysis of the appropriate standard-offer price for landfill methane projects was informed by a single project that did not appear to be representative of recent experience.[34] To the extent that additional information on the cost of projects that accept the standard offer is available, such information will assist the Board in determining the appropriate prices under the program.

The Board therefore finds that requiring cost data from projects applying for the standard offer is appropriate and will assist in the biennial statutorily required reassessment of the standard-offer prices. Accordingly, we specifically include such a provision in the standard contract.

We include in the standard contract the following provisions to protect the confidentiality of project-specific information: "Facilitator shall seek to treat as exempt from disclosure information related to the development of the Project to the extent that such information constitutes trade secrets under 1 V.S.A. § 317(9), unless otherwise directed by the Board."[35] Project costs, with sufficient protections to shield identifying characteristics, will be made publicly available to assist in future price determinations.

(3) Amendment of the Standard Contract in the Public Interest

CVPS recommends that the standard contract include a clause allowing for amendment of the standard contract in the public interest. CVPS proposes that the following language be included in the standard contract:

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32. Section 8005(b)(2)(C).
33. *See* Cost Analysis Subgroup Report at 30.
34. *See* Cost Analysis Subgroup Report at 35-36.
35. *See* paragraph 9 of the attached standard contract.

> If the Board determines that any provision of this Agreement is contrary to the public interest, it may, after notice and opportunity for hearing, modify such provision accordingly, and the Parties shall be bound by such modification, provided that, notwithstanding the provisions of this Article, under no circumstances shall there be: (i) any reduction in the Rates for the Producer's Electricity and Other Products provided however that the Board retains the right to redesign said rates from time to time so as to achieve the same revenue requirements used in their development; (ii) modification of the opportunity for the Producer to operate the Project to the maximum extent reasonably possible provided however that the Board retains the right to implement dispatch provision so long as any such requirements still enable the Producer to recover its fixed costs and earn its return based on the costing information used to develop the Rates in effect under this Agreement; (iii) impairment of the right of the Interconnecting utility to inspect protective relaying and other interconnecting equipment; or (iv) impairment of any right of any First Lender. In any such hearing for modification, the Board shall consider the reliance of Producer and initial Project lenders on the Electricity and Other Product purchase obligations of this Agreement.

CVPS contends that the "intent of this clause is to assure that customers are not made to pay excessive rates, while the rights of producers are respected."

The Contract Subgroup Report states that such a clause would allow the Board to align the SPEED program with policies that serve the public interest, "[g]iven the very long-term nature of the contractual arrangements to be entered into by the SPEED facilitator and the expectation that the electricity market will be transformed or restructured over this term . . . ."[36]

<u>Participants' Comments</u>

GMEU recommends that the Board not include such language in the standard contracts. GMEU states that parties can voluntarily renegotiate the contracts and bring a proposal to the Board for consideration. GMEU cites to litigation regarding previous long-term contracts in its statement that such modification clauses "can produce vastly differing opinions as to what they mean, as well as questions regarding the obligations of utilities or others to invoke them."

AAFM recommends that the Board reject the proposal to include such a clause in the standard contract. AAFM states that, if such a clause is included, the clause also allow the price

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36. Contract Subgroup Report at 6.

to be raised for developers if average wholesale power costs over some term exceed the contract price. AAFM additionally states that any such clause would also need to guarantee the developer a reasonable return on its investment and take into account other reasons that a renewable project may be developed.

Great Bay recommends that the Board reject CVPS' proposal because it would make financing "nearly impossible to obtain." Great Bay also states that the proposed language is unclear.

GMP recommends that the standard contract include language that would allow the Board to amend the contract in the public interest, provided that the price set forth in the contract not be amended. GMP further states that such a provision would ensure "that the contract does not get out of sync with new policies that may be developed year to year."

The Department supports CVPS' argument that the Board include a provision to allow modification in the public interest, but recommends that any such condition be carefully worded to assure developers and financial institutions that modifications to the contract will not materially affect the financial performance of the project. The Department states that experience with projects developed under Board Rule 4.100[37] demonstrated the value of such a clause, and notes that the projects developed under that program were able to obtain financing, even with the inclusion of such a provision in the contracts.

Discussion and Conclusions

Act 45 states that a "plant owner who has executed a contract for a standard offer under this section prior to a determination by the board under subdivision (2)(B) or (C) of this subsection shall continue to receive the price agreed on in that contract."[38] Accordingly, the statute prevents us from requiring that parties modify a contract by altering the price terms.

37. Board Rule 4.100 — Small Power Production and Cogeneration, promulgated in 1983 in response to federal legislation, was designed to encourage the development of renewable power resources by requiring utilities to purchase renewable power from Independent Power Producers. The rule establishes a Purchasing Agent, contracted by the Board, to administer the program. Responsibilities include accounting, generating reports, and handling the settlements related to transactions between the qualifying producers and the Vermont retail distribution utilities.

38. Section 8005(b)(2)(E).

We recognize and agree with developers' concerns that an open-ended contract clause that allowed the contract to be amended without the contracting party's consent could significantly impact the ability to finance a project. However, the contract provides cost-based, long-term prices at ratepayer expense, and some limited ability to amend the contract to provide additional benefit to ratepayers is warranted, so long as it would not reduce or adversely affect the ability of the producer to meet the project's financial obligations. The terms for standard-offer contracts range from 15 years to 25 years. Over the course of this time period, it is likely that technologies and policies will change significantly; the ability to allow amendments to standard contracts to adapt to such changes has potential value to both ratepayers and producers. If additional value can be obtained without adverse consequences to the producer, it is reasonable that the ratepayers that subsidized the project should be able to benefit.

For example, it is possible that commercially viable storage technology could be developed within the next 20 years. If this were to occur, the Board could review whether standard-offer projects should be required to install these technologies, at utility expense, to align the dispatch of these units with peak load. Any Board approval would need to recognize that the economic value of the project to the producer could not be reduced by such action, and any costs associated with installation of the storage technology, such as parasitic load[39] or reduction in the life of the generation equipment, would be borne by the utility. An amendment to the standard contract that required such an action could provide a benefit to ratepayers with no harm to developers.

The following language, which we include in the standard contract, protects the financial interests of developers while also providing flexibility to adapt to changing circumstances over the term of the contract in a manner that benefits ratepayers:

> This contract may be amended, without the consent of the parties, by order of the Board, provided: (1) such amendment does not result in any reduction in the project's economic value to Producer; (2) such amendment will not adversely affect Producer's ability to meet the project's financial obligations; (3) such amendment will not impose additional operational or other economic costs on Producer without full compensation; and (4) the amendment results in a benefit to ratepayers.

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39. Parasitic load refers to additional demand for energy on the generation side of the meter.

(4) Milestones to Stay in the Queue

The draft contract submitted by the Contract Subgroup included two milestones that a developer would need to meet in order to maintain its place in the queue: filing an interconnection agreement within six months of entering the queue; and commissioning the project within three years of entering the queue. As the Contract Subgroup Report makes clear, these milestones were included as placeholders, as there was significant discussion in the Subgroup regarding whether these milestones were appropriate.

Participants' Comments

CVPS stated that the standard-offer prices should be sufficient incentive for projects to move quickly through the queue, and therefore limited milestones are necessary.

Great Bay stated that the proposed milestones are acceptable.

GMEU supports the milestones included in the Contract Subgroup Report. GMEU states that the use of a significant number of milestones could create an undue burden, with respect to monitoring, on the SPEED Facilitator. In addition, GMEU states that "setting milestones around regulatory filings — such as certificate of public good petitions — could well result in the Board receiving substandard filings if developers scramble to meet deadlines . . . ."

Discussion and Conclusions

The Board concludes that it is appropriate to include some limited milestones in the contract. The existence of the 50 MW ceiling creates a limit on the number of projects that can be developed. Assuming that the queue is filled, in order to ensure that we meet the statutory directive to encourage rapid deployment of qualifying SPEED resources, there must be a mechanism to prevent projects from holding a space in the queue indefinitely, thereby depriving other resources of the opportunity to take the standard offer. As CVPS notes, the prices paid to developers should provide a significant incentive to complete a project in a timely manner. However, it is possible that a developer could face logistical issues in completing a project, while other potential projects would be able to achieve commissioning more quickly. For this reason, it is appropriate to include milestones that require projects in the queue to move forward.

As to the specific milestones, there is insufficient information available regarding the speed with which projects will likely be developed, or meet potential milestones, to provide additional precision. No participant suggested that the milestones set out in the draft contract are not appropriate. Accordingly, we conclude that the milestones included in the draft contract are reasonable, and we include them in the standard contract.

(5) Administrative Fees and Deposits

The subgroup agreed that it was appropriate for the SPEED Facilitator to impose administrative fees to cover the costs of reviewing applications and managing the queue. In addition, there was considerable discussion regarding potentially requiring refundable deposits that would be returned once the project is commissioned or withdrawn from the queue. However, there was disagreement regarding the details of such provisions.

Participants' Comments

GMEU recommends that the Board adopt a fixed, non-refundable administrative fee and a size-based deposit that would be refundable if the project is commissioned or the developer voluntarily withdraws from the queue within one year. GMEU states that an administrative fee is an appropriate contribution to the SPEED Facilitator's administrative costs, and the refundable deposit will reduce the risk of projects occupying the queue without proceeding to development.

Northern Power recommends that the standard contract include an administrative fee and refundable deposit of $10 per kW, or $10,000 per MW, to be placed into an escrow account. Northern Power states that such a requirement, along with attainable milestones, would deter speculative projects from sitting in the queue, and due to the progressive nature of the deposit, would not adversely impact small projects.

CVPS supports the use of an administrative fee and a refundable deposit, and recommends that the deposit be large enough to deter strategic action with respect to the queue.

Great Bay recommends that the Board adopt an administrative fee and a refundable deposit, with the deposit, and associated interest, fully refundable if the project is commissioned. In addition, Great Bay supports the use of a sliding scale for calculating the amount of the deposit that is returned to the developer if the developer withdraws from the queue.

AAFM recommends that an administrative fee and a refundable deposit be required and recommends that both be based on a flat fee plus a certain dollar amount per kW of capacity. AAFM recommends that the administrative fee be refundable if the application is not accepted and supports the use of a sliding scale for returning the deposit, based on when a developer withdraws from the queue.

Discussion and Conclusions

We conclude that an administrative fee for project developers is appropriate. This fee will be used to help cover the costs of managing the queue and reviewing the applications, and will be non-refundable.[40] Given the uncertainty regarding the number of projects that will apply for the standard offer, it is difficult to devise a set dollar amount that accurately covers these costs. However, the SPEED Facilitator and participants that commented on this issue have indicated that an administrative fee of $200 would be appropriate. Consequently, we require an administrative fee of that amount in the standard contract.

One issue that we have addressed previously in this Order is the need to ensure rapid deployment of resources and, consequently, the need to develop mechanisms to encourage projects in the queue to proceed rapidly to commissioning. A refundable deposit, calculated on a per kW basis, will provide an incentive for developers to commission projects so that they may have the deposits returned to them. Some participants recommended that refund of the deposit be based upon the length of time in the queue: for example, if a developer voluntarily withdraws from the queue within the first year, the entire deposit is returned; if the developer withdraws after the first year, but before the end of the second year, 75% of the deposit is returned; and if the developer withdraws after the second year, but before the end of the third year, 50% of the

40. The SPEED Facilitator will not accept the administrative fee from an application that is not accepted into the queue.

deposit is returned. In addition, the deposit would not be returned if the developer did not meet the milestones contained in the contract. Several developers commented that $10/kW was an appropriate amount for such a deposit. We include in the standard contract a requirement to submit such a refundable deposit, and the associated timelines for receiving the deposit described above.

The Board received a comment late in the process from the Town of Norwich ("Norwich") recommending that the Board waive any fees and deposits for projects developed by municipalities. Norwich states that "the requirement for public approval of both the project and bond financing means that towns have no budget available for any significant pre-project costs. Payment of fees and/or deposits would be a significant burden, likely one that any municipal project could not overcome." An application fee is not unique to the standard-offer program, but is a widespread and generally accepted practice. A waiver of the administrative fee and refundable deposit would constitute special treatment for municipalities that is not contemplated by the Act and would pass on to other developers and utilities the costs of processing the municipality's application. In addition, waiving the refundable deposit would remove the incentive for rapid deployment that the deposits provide. For these reasons, we do not waive these requirements for municipalities.

The question of the interest earned on the refundable deposit was also discussed by the Contract Subgroup. We conclude that the effort involved in calculating the interest for each project does not justify such an action. Accordingly, the SPEED Facilitator shall retain the interest earned on the refundable deposit to defray its costs.

(6) Other Contract Provisions

The body of the standard contract does not specify the contract term. This was done deliberately to acknowledge that, pursuant to statute, there are different terms available for different technologies. The term of the contract will be included in Attachment C to the standard contract; for solar projects, the term shall be 25 years, for landfill gas projects, the term shall be 15 years, for all other projects, the term shall be 20 years. These are the terms that were used to calculate the standard-offer prices,[41] and any project accepting such prices must be bound by those terms.

The SPEED Facilitator shall not have the authority to alter the standard contract. The purpose of the standard-offer program is to have one price and one contract offered to any developer that meets the program qualifications, thereby providing a simplified and even-handed process for developers. Allowing alterations to individual contracts could significantly increase the administrative costs of the program, not just in the one-time alteration of a specific contract, but tracking the consequences of such alteration for the term of the contract. In addition, allowing alterations to individual contracts could put some developers at a competitive advantage over others. If there are issues with the contract that significantly impede the implementation of the program, the Board will alter the contracts as necessary and appropriate, on a forward-going basis.

Great Bay provided specific comments on certain portions of the draft standard contract: Paragraph 10 - Exclusivity; Paragraph 13 - Payment to Producer; and Paragraph 15 - Events of Default. We address these comments below.

Paragraph 10 of the draft contract states that, by accepting the standard offer, developers waive their ability to seek an alternate power sales arrangement. The last sentence, which Great Bay recommends that the Board delete, states: "Absent an order of the Board to the contrary, this waiver shall extend through the full term contemplated under this Agreement, even if this Agreement is terminated early for any reason by default, for cause, or otherwise." Great Bay contends that, if a developer defaulted on the contract, and was not able to correct this default during the cure period (see Paragraph 15 of the draft contract), it would be prevented from selling power through any other means.

We find no basis for making the change proposed by Great Bay. The intent of this provision is to prevent developers from withdrawing from the standard-offer program and pursuing more lucrative price terms that might develop over the term of the contract. Ratepayers are paying a significant premium to the renewable generators that take advantage of the standard offer. If more lucrative opportunities arise, it would be unfair to allow such a project owner to

41. Docket 7523, Order of 9/15/09 at footnote 9, page 7.

walk away from the contract after receiving substantial subsidies from ratepayers.[42] Given that a developer may request that the Board allow it to enter into other power purchase agreements, we conclude that the provision provides sufficient protection for developers while also preventing inappropriate strategic behavior if higher price terms become available over the term of the standard contract.

Paragraph 13 of the draft contract requires that the SPEED Facilitator pay the Producer[43] "within 45 days of the end of each billing period." Great Bay Hydro recommends that this time frame be reduced to 15 days, especially given that the process recommended by the Settlement Subgroup would result in settlement in less than two days.

The number of developers that will participate in this program is not known at this time, and therefore the workload required to provide payment to Producers is also not known. In addition, the SPEED Facilitator must obtain the funds to pay generators from utilities prior to paying Producers. For these reasons, we do not reduce the 45-day requirement contained in Paragraph 13 of the draft contract. The contract specifies that producers will be paid *within* 45 days; we will direct the SPEED Facilitator to pay Producers as soon as reasonably possible.

Paragraph 15 of the draft contract addresses potential defaults by the Producer. Great Bay recommends specific language changes to these provisions. Specifically, Great Bay recommends that the phrase "by Producer" be included in the first line of the paragraph, after the words "Any breach." In addition, Great Bay requests that subparagraph b include the words "after Commissioning" after the phrase "any Regulatory Approval." Finally, Great Bay recommends that this paragraph be made to apply to any contract breach by the Facilitator.

We accept these specific language changes recommended by Great Bay and also conclude that a default on the part of the SPEED Facilitator should also constitute a breach of the contract.

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42. If a developer wants the benefits of the standard-offer price, they must commit to the associated long-term contracts; if developers want flexibility in price or contract terms, they may choose to not apply for the standard offer.

43. "Producer" is the term used for plant owner in the standard contract.

V. Qualifying Projects Owned and Operated by Utilities

A. Relationship of Utility Projects to the Queue

Pursuant to Act 45, "a plant owned and operated by a Vermont retail electricity provider shall count toward this 50-MW ceiling if the plant has a plant capacity of 2.2 MW or less and is commissioned on or after September 30, 2009."[44] Accordingly, the standard-offer capacity available to qualifying SPEED projects is reduced in proportion to utilities' development of such projects. The Contract Subgroup discussed issues regarding the interaction of utility projects with the queue, such as whether such projects must be treated as any other project for purposes of queue management. The Contract Subgroup Report recognized that this was an area where agreement was not reached and instead framed the issue and invited comments.

Participants' Comments

Green Mountain Power Corporation ("GMP") states that:

> the utilities should follow the same process as all other developers. While the legislation encourages utilities to construct renewable resources it does not single out or give any preferential treatment to the utilities, therefore, the electric utilities should follow the process set forth by the Board following September 30th.

AAFM recommends that utility projects be treated, as much as practical, like other projects. AAFM states that utility projects should not be allowed to "bump" projects already in the queue, but should be the first projects in line if projects withdraw from the queue. In addition, AAFM recommends that utility projects be required to provide the same information as any other applicant.

Great Bay recommends that utility projects be treated the same as non-utility projects in the program, including the provision of information and the payment of fees and deposits.

CPVS recommends that the Board instruct the SPEED Facilitator to "periodically survey the Vermont utilities and determine how many MW of qualifying resources are expected to come on line within the period when the initial projects entering the queue are expected to come on

44. Section 8005(b)(2).

line." The SPEED Facilitator would then reduce the queue allotments by the amount identified by the utilities and reopen the queue space if the utility projects do not come on line.

GMEU recommends that the Board defer this issue for several weeks as it "involves many factors, including consideration of the relationship between the utilities and the facilitator, the potential existence of confidentiality issues surrounding utility projects in the planning stages, and how the Board resolves other issues surrounding the queue."

Discussion and Conclusions

We conclude that to successfully manage the queue, the SPEED Facilitator must be aware of the status of projects owned and operated by utilities that could reduce the 50 MW available to potential developers. The most efficient means of providing this information to the SPEED Facilitator is to require utility projects to join the queue. Pursuant to Act 45, utility projects commissioned on or after September 30, 2009, automatically reduce the 50 MW ceiling.[45] However, utility projects would not displace any projects that have accepted the standard offer by signing the standard contract. Those developers who have accepted the standard offer have received a commitment with respect to a revenue stream; such commitment is necessary to obtain financing and raise capital for the project.

The application process contains certain provisions to ensure that projects cannot fill space in the queue indefinitely, thereby preventing the rapid deployment of qualifying SPEED resources; such provisions include proof of site control, a requirement that the project be commissioned within three years of entering the queue, and payment of a deposit. The purpose of these provisions, to provide disincentives for strategic behavior or gaming, apply equally to projects developed by utilities and independent developers and we conclude that such provisions shall apply to utility projects.

45. Projects owned and operated by utilities enter the queue, provided that there is sufficient space in the queue at that time, even if they applied for approval under Sections 248 or 219a prior to May 27, 2009. *See,* Section 8005(b)(2).

In summary, we conclude that only projects that are processed through the queue will count towards reducing the 50 MW ceiling, and we require utilities with qualifying facilities to enter the queue in order to be eligible to reduce the 50 MW ceiling.

B. Settlement of Utility Projects

An additional issue that was not raised in the subgroups is the treatment of utility projects for settlement purposes. Act 45 contains two provisions that address the development of projects owned and operated by utilities. Section 8005(b)(2) states that "a plant owned and operated by a Vermont retail electricity provider shall count toward this 50-MW ceiling if the plant has a capacity of 2.2 MW or less and is commissioned on or after September 30, 2009."

In addition, Act 45 requires that a utility that develops renewable projects with a capacity less than 2.2 MW should receive a credit for its pro rata share of the costs from standard-offer projects and specifies the calculation of this credit:

> The SPEED facilitator shall distribute the electricity purchased and any associated costs to the Vermont retail electricity providers based on their pro rata share of total Vermont retail kWh sales for the previous calendar year, and the Vermont retail electricity providers shall accept and pay the SPEED facilitator for those costs. For the purpose of this subdivision, a Vermont retail electricity provider shall receive a credit toward its share of those costs for any plant with a plant capacity of 2.2 MW or less that it owns or operates and that is commissioned on or after September 30, 2009. The amount of such credit shall be the amount that the plant owner otherwise would be eligible to receive, if the owner were not a retail electricity provider, under a standard offer in effect at the time of commissioning. The amount of any such credit shall be redistributed to the Vermont retail electricity providers on a basis such that all providers pay for a proportionate volume of plant capacity up to the 50 MW ceiling for standard-offer contracts stated in subdivision (b)(2) of this section.[46]

Pursuant to the Act, a utility project decreases the 50 MW ceiling and also alters the allocation of program costs among the utilities. A utility that develops a qualifying project receives a credit, calculated as if the project received the standard-offer prices for the project technology, towards its share of the program costs. Finally, it appears that the dollar amount that

46. Section 8005(g)(2).

would have been allocated to the developing utility, if not for the credit, is then reallocated to all the utilities, including the utility that owns and operates the project, on a pro rata basis.

Staff issued an email to participants requesting comments on the application of Section 8005(g)(2), and in particular, whether the RECs and other benefits associated with a utility project should be delivered to the SPEED Facilitator to benefit ratepayers of all utilities.

Given the complexity of this issue, we are outlining the issues involved, but holding any determinations until Board staff conduct further proceedings. We understand that our determination of these issues could well affect a utility's decision to develop qualifying projects. Given the concern that the queue could be filled quickly, we do not want our lack of resolution on this issue to discourage utilities from entering the queue with legitimate projects that meet the necessary criteria. We note that under the queue outlined in this Order, a developer may withdraw from the queue within one year and still receive 100% of the refundable deposit.

Participants' Comments

GMEU filed a letter stating that the intent of the Act is to allow a utility that develops a qualifying SPEED project to keep the power, RECs, attributes, and costs, and these attributes should not be allocated to all distribution utilities. GMEU represents that CVPS joins in its filing.

AAFM states that the benefits of a qualifying utility project should be transferred to all utilities since they receive a credit based upon standard-offer prices. AAFM further states that, if a utility developing a qualifying project wishes to retain the benefits associated with the project, it may choose not to include it in the standard-offer program.

The City of Burlington Electric Department ("BED") recommends that this issue be addressed by reallocating the developing utility's proportionate share of the standard-offer MW obligations to reflect the capacity of the utility owned and operated project. BED states that, if the Board does not accept this proposal, that utility projects should be treated as any other standard-offer project, with the project costs being shared on a pro rata basis by other utilities and all utilities sharing in the benefits produced by such a project.

Renewable Energy Vermont ("REV") states that, if the developing utility is allowed to keep the benefits associated with the project, it will raise the costs of the program incurred by other utilities. REV also expresses concern that, to the extent that utilities receive too much of an incentive to develop projects, it will reduce participation in the program by non-utility developers.

Vermont Electric Cooperative, Inc. ("VEC") recommends that utilities be allowed to retain the RECs and other benefits associated with utility projects. VEC contends that the price of RECs would "modestly reduce the costs of ownership, perhaps enough to tip the balance toward building renewable projects."

GMP states that it would support the allocation of benefits associated with a utility-developed project to all utilities, or allowing the developing utility to retain all benefits.

International Business Machines, Inc. ("IBM") states that utility-owned projects will reduce the costs of the standard-offer program, and the benefits associated with utility-owned projects should be retained by the utility developing the project, as this will encourage the development of qualifying projects by utilities.

Discussion and Conclusions

Act 45 requires that a utility that develops qualifying projects receive a credit towards its share of program costs, based upon the cost-based, standard-offer prices. The statute is unclear regarding the disposition of electricity, RECs and other benefits associated with the generation produced by utility-developed projects.

If these benefits are not allocated among all utilities on a pro rata basis, there is the potential for a disproportionate impact on those ratepayers whose utilities do not develop qualifying projects, or develop them at a proportionately smaller rate than do other utilities. Although the utility that develops a qualifying project effectively reduces the 50 MW ceiling, and therefore the overall costs of the program, unless the 50 MW are filled entirely with utility-developed projects, there are still costs associated with the program that will be borne by ratepayers. Utilities that develop projects receive a credit at a rate equal to the standard-offer prices. Ratepayers from other utilities will pay a proportionate share of the value of those credits, without receiving the benefits that would otherwise be transferred to ratepayers if those projects were not developed by utilities.

Conversely, the reallocation of the benefits associated with utility-developed projects among all utilities will significantly reduce the incentive for utilities to develop qualifying projects. In addition, such an allocation is a complex matter that would present significant accounting challenges and add administrative costs to the program.

As stated earlier, this is a sufficiently complex issue that cannot be resolved at this time. We direct Board staff to conduct additional proceedings to further explore this issue and allow participants a greater opportunity to provide comments. In these proceedings, we direct Board staff to assume as a starting point, the following principles: (1) there should be reasonable incentives adequate to encourage utility-developed projects; (2) both the costs and benefits of utility-developed projects should flow to the utilities, to the extent permitted by statute; and (3) there should be an equitable allocation of the costs and benefits of the standard-offer program to all utilities, including both those that do and do not develop qualifying projects.

VI. DELIVERY OF POWER AND ASSIGNMENT OF COSTS AND BENEFITS

The standard-offer program created by Act 45 is applicable to a diverse variety of project types and sizes, with the costs and benefits of the program assigned to the Vermont electric distribution utilities. Electricity is a commodity regulated at the state, regional, and national level. Although the Board has siting authority for generators and authority to implement the standard-offer program, the program must take into account and adhere to pertinent federal and regional regulations. For example, the Independent System Operator of New England ("ISO-NE") has requirements for registering generators to account for the resulting electricity and capacity in maintaining the New England Grid. In addition, there are federal requirements associated with transporting power from one utility to another, requirements that may distinguish between utilities that own and operate transmission, as defined in federal regulations. Below we address issues relevant to settlement, wheeling, and interconnecting projects with utilites' systems.

A. Settlement

The exchange and reconciliation of metering data and related cash flows between and among developers, the distribution utilities, the SPEED Facilitator, and other necessary entities is known as settlement. The discussion of settlement issues is necessary to provide affected parties (primarily the SPEED Facilitator, the project developers, and the utilities) with information regarding their respective rights and responsibilities regarding settlement. These include cooperation among parties, collection of data, and reporting of information needed to ensure a smooth settlement among all affected entities. We are reviewing these functions with the goal of minimizing the costs to ratepayers and developers, while still adhering to the relevant regulatory requirements.

The Settlement Subgroup was established to recommend to the Board "the best methods to administer the energy accounting and financial aspects of the 'Standard Offer' portion of the SPEED program."[47] On September 4, 2009, the Settlement Subgroup issued its report to the Board.

Act 45 includes the following provisions related to settlement requirements, as codified in Section 8005(g):

> (2) The SPEED facilitator shall distribute the electricity purchased and any associated costs to the Vermont retail electricity providers based on their pro rata share of total Vermont retail kWh sales for the previous calendar year, and the Vermont retail electricity providers shall accept and pay the SPEED facilitator for those costs.
>
> (3) The SPEED facilitator shall transfer any tradeable renewable energy credits attributable to electricity purchased under standard-offer contracts to the Vermont retail electricity providers in accordance with their pro rata share of the costs for such electricity as determined under subdivision (2) of this subsection, except that in the case of a plant using methane from agricultural operations, the plant owner shall retain such credits to be sold separately at the owner's discretion.
>
> (4) The SPEED facilitator shall transfer all capacity rights attributable to the plant capacity associated with the electricity purchased under standard-offer contracts to the Vermont retail electricity providers in accordance with their pro rata share of the costs for such electricity as determined under subdivision (2) of this subsection.

47. Settlement Subgroup Report at 1.

ISO-NE rules permit generators to either settle through the ISO-NE system, with the costs and revenue opportunities associated with participating through the ISO-NE settlement process, or by serving as a "load reducer" consistent with ISO-NE rules for small generators. Pursuant to ISO-NE Operating Procedure No. 14, generators that are smaller than 1 MW, or generators less than 5 MW that do not meet the ISO-NE requirements for telemetering,[48] have the option of:

- "Registering as a 'Settlement Only Generator,' which is eligible to participate in the ICAP Market, and in the Energy Market according to MWh generated;" or

- "Treating the unit as a load reducer, in which case the unit is not registered with ISO and has no direct ICAP or other market settlement implications."[49]

Settlement Subgroup Recommendation

For purposes of settling producer payments, the Settlement Subgroup recommended that the billing model used for Rule 4.100 projects also be used for settlement of standard-offer projects by the SPEED Facilitator. The procedure is as follows:

> the Purchasing Agent interrogates the output meter and acquires the hourly output data for each project. The hourly output data for each project is then evaluated against the applicable power purchase rate for that time frame. Monthly invoices of the amounts owed each producer are generated. The total monthly amount owed to the producers is then distributed pro rata to each of the Vermont utilities along with the pro rata share of the administrative fees of the Purchasing Agent owed by the utilities. The utilities pay Purchasing Agent their pro rata share of total producer monthly bills and administrative fees. The Purchasing Agent then remits those revenues to the producers less the producers' share of the Purchasing Agent administrative fees. [50]

Under the ISO-NE process, utilities report load to Vermont Electric Power Company, Inc. ("VELCO"), which then submits Vermont's load data to ISO-NE. Generators are treated for settlement purposes as either generation, or, as noted above, as load reducers. Generators

48. Pursuant to ISO-NE Operating Procedure 18, Section V.A., "Instantaneous metering is required for all Generators and Loads which are modeled and defined in the ISO Energy Management System (EMS) and are eligible to participate in the hourly markets." For smaller generators, participation through the EMS and instantaneous metering, and the associated requirements for telemetry, is generally not required.

49. ISO-NE Operating Procedure 14, Section II.A.3.

50. Settlement Subgroup Report at 2.

registered as load reducers are considered negative load for reporting purposes. Since Vermont utilities are assessed charges based upon load, categorizing generators as load reducers also reduces the charges assessed by ISO-NE.[51] After VELCO reports total Vermont load to ISO-NE, VELCO then assigns an ownership percentage of the generation to each Vermont utility and reduces each utility's load by its allocated ownership percentage.

In order to report the amount of load reduced by the generators, the SPEED Facilitator must transmit accurate data regarding the amount of electricity produced by each generator. The Settlement Subgroup Report describes this proposed process as follows:

> The SPEED facilitator would interrogate producer meters daily and transmit the hourly information to VELCO. VELCO would then "disaggregate" the producer's output and distribute it pro rata to each of the Vermont utilities so that each Vermont utility's hourly load would be reduced by their pro rata allocation of generation. VELCO would then transmit the adjusted load data to ISO-NE . . . . ISO-NE would see Vermont loads which are net of the generation of the standard-offer projects. Therefore market settlements calculated for each Vermont utility would be based on that reduced load in all markets and for all charges that use load as the basis for allocation, including ISO-NE administrative fees.[52]

The Settlement Subgroup Report concluded that standard-offer generators should be treated as "load reducers" because that model would likely provide the most value to utility customers.[53]

The Settlement Subgroup reached consensus that projects above 15 kW[54] should be subject to metering and reporting requirements that allow the SPEED Facilitator to access hourly

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51. This includes capacity charges, transmission charges, and charges for ancillary service markets. *See*, Settlement Subgroup Report, Appendix A, for a list of the various categories and estimates of monthly impacts and savings to Vermont utilities and their ratepayers.

52. Settlement Subgroup Report at 3.

53. Settlement Subgroup Report at 4. The Settlement Subgroup Report states that ratepayers would receive greater value from having developers that accept the standard offer treated as load reducers rather than as generators, the capacity of which could be bid into relevant ISO-NE capacity markets. The Report notes that generators below a certain size may be restricted from participating in such markets. For example, the ISO-NE Forward Capacity Market ("FCM") will not accept projects less than 100 kW, and it is possible that many of the standard-offer projects would be less than 100 kW. In addition, even projects larger than 100 kW would be unlikely to realize the majority of the capacity value in the FCM for several years.

54. The Subgroup divided the settlement methodologies into "larger" generators, those above 15 kW, and "smaller" generators. The Subgroup acknowledged that the precise cut-off is somewhat arbitrary. Settlement Subgroup Report at 6.

information that it would report to VELCO on a daily basis. Under this framework, when utility loads are reduced, charges to serve that load are reduced, including all other charges that are allocated based on load.

The Settlement Subgroup noted that the settlement model recommended for projects over 15 kW in size is the preferable model for projects under 15 kW, because of the increased accuracy and lower administration costs compared to alternative models. However, the Subgroup recognized that this method would be "economically challenging" for projects under 15 kW because of the cost of the daily meter interrogation necessary under this model. The Settlement Subgroup Report states that, over time, "Smart Grid implementation may substantially reduce the costs of such telemetry in the future and make this settlement method more feasible for small projects."[55] The Subgroup recommends that the "financial settlement" approach for smaller projects not require daily interrogation through remote access until such time as the cost of the daily meter interrogation can be significantly reduced via smart grid implementation.

Specifically, the alternative settlement model for projects under 15 kW considered by the Settlement Subgroup would still consider generators to be load reducers, but rather than requiring interrogation of the meter, would involve after-the-fact "financial settlement." Under this approach:

> The generation from the standard-offer projects would be treated as a load reduction for each host utility inside ISO-NE wholesale market settlements. After the end of the month, ISO-NE publishes values for various settlement components for the previous month. Using this information, the SPEED facilitator would perform an after-the-fact financial settlement of each host utility to remove all the settlement effects of the generation from the host utility's market settlements. The SPEED facilitator would then disaggregate and distribute pro rata the ISO-NE revenues and charges to each of the purchasing utilities. The calculations would also have to take into account each Vermont utility's monthly peak load as well as the yearly Vermont peak load coincident with the ISO-NE peak load.[56]

The Subgroup recommended this settlement model even though it is more complex to implement and more subject to error.

55. Settlement Subgroup Report at 5.

56. Settlement Subgroup Report at 3.

Further, the Subgroup recommends that all projects, regardless of size, "be subject to the same metering requirement; electronic, time-of-use meter with at least two channels of interval data storage and an interval modem."[57]

In addition to the settlement of electricity, and corresponding capacity benefits, the Settlement Subgroup addressed the issue of tradeable renewable energy credits. The Subgroup recommends that the SPEED Facilitator register each project with the NEPOOL-GIS system that tracks the RECs, and apply to the New England states with Renewable Portfolio Standards to qualify the projects as eligible under these states' regulatory regimes. The SPEED Facilitator would then submit total monthly generation for each project to the NEPOOL-GIS system and transfer title to the RECs on a pro rata basis to each utility's GIS account.

Participants' Comments

CVPS filed a letter generally supporting the Settlement Subgroup Report but providing additional detail in certain areas. CVPS recommends that the settlement procedures adopted by the Board not make any distinction between small and large producers, but instead require all producers to utilize the settlement process recommended for larger producers. CVPS contends that the after-the-fact financial settlement process "is easily understated in its complexity, can be error prone and administratively laborious." In addition, CVPS recommends that the SPEED Facilitator be encouraged to seek out markets for new products that emerge from renewable projects. With respect to metering, CVPS recommends that all projects, regardless of size, be subject to the same metering requirements, and be responsible for providing a means for VELCO to remotely gather the data. Further, CVPS recommends that the SPEED Facilitator coordinate with the distribution utilities to finalize the metering requirements as part of the interconnection process.

CVPS also notes that the Wheeling and Interconnection Subgroup Report describes the recommendations for SPEED standard-offer wheeling arrangements, and recommends that the SPEED Facilitator coordinate with the utilities to finalize any settlement strategies to assure compliance with applicable regulatory and other requirements involving the utilities.

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57. Settlement Subgroup Report at 5.

Great Bay states that the settlement model used under Rule 4.100 is inconsistent with Act 45, in that the revenues to the developers are reduced by the developer's share of the Purchasing Agent's administrative fees. Great Bay cites to Section 8005(g)(2), which states that the "SPEED Facilitator shall distribute the electricity purchased and any associated costs" to the utility. In addition, Great Bay indicates that it supports the Settlement Subgroup's recommendation to treat projects as load reducers.

Discussion and Conclusions

We generally agree with and accept the recommendation of the Settlement Subgroup with respect to the "Settlement of Producer Payments" for projects over 15 kW. The SPEED facilitator shall function in a manner that is substantially similar to the Purchasing Agent for existing Rule 4.100 projects as described above. However, in the case of standard-offer projects, the SPEED Facilitator may need to rely on the distribution utilities and/or third parties, as necessary, to conduct the meter interrogations necessary to determine hourly output data for each project. This process has been demonstrated to be effective in the context of Rule 4.100 projects. No parties have objected to the proposal. We find no reason to question its application here and therefore accept the proposal.

We generally agree with and adopt the recommendations of the Settlement Subgroup with respect to load reduction as the preferred path to settlement. The SPEED Facilitator shall work with VELCO and the distribution utilities to implement this framework in a manner consistent with statutory requirements and the requirements of this Order to allocate the products fairly among the distribution utilities. Based on the representations in the Settlement Subgroup Report, we conclude that the value to ratepayers of treating standard-offer projects as load reducers for settlement purposes should exceed the benefits that would be realized by registering the standard-offer projects as generation assets that could receive capacity payments in the ISO-NE Forward Capacity Market.

With respect to generators under 15 kW, we conclude that some accommodation is necessary to address the economic challenges presented by a requirement that the meter be interrogated on a daily basis.[58] For a project of such size, which would receive relatively modest monthly revenues, we conclude it would be inappropriate to burden the projects with expensive telemetry requirements. The settlement model for projects under 15 kW recommended by the Settlement Subgroup Report avoids the need for daily meter interrogation and a dedicated phone line, and appears to provide a cost-effective alternative. Over time, implementation of smart grid technologies may substantially reduce the costs of telemetry and permit cost-effective remote meter interrogation on a daily or even hourly basis.

The Settlement Subgroup recommended that a project size of 15 kW be the cutoff for determining which projects are eligible for this simpler metering requirement. No objections were raised to this threshold in the comments we received. We conclude that the recommended threshold is reasonable; although we may revisit this determination in the future as new information is presented.

As with the model for larger generators, the settlement model for generators less than 15 kW in size requires producers to utilize appropriate meters capable of interval data storage, as well as an internal modem. We recognize the need for interval data storage to ensure that loads can be read hourly or in appropriate time intervals to ensure a fair and accurate monthly settlement. However, it does not appear that the meter specifications identified in the Settlement Subgroup Report are necessary or appropriate to adopt at this time. At this juncture, we will only require that the metering technology be equipped with interval data storage and conform to such other specifications as are necessary to comply with the settlement requirements established in this Order, as determined by the SPEED Facilitator. To provide guidance to generators under 15 kW in size, we require the SPEED Facilitator to provide information regarding these meter obligations prior to the opening of the queue. As noted further below, we encourage the SPEED facilitator to work cooperatively with the utilities and VELCO to establish metering requirements that are consistent with current and future needs for financial settlements, mindful of utility plans for deployment of more advanced forms of metering equipment and communications capabilities that support remote meter reading and monitoring of the system under smart grid initiatives.

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58. As noted in the Settlement Subgroup Report, the additional phone line and interrogation costs are estimated to be up to $160/month on revenues of potentially less than $200 per month.

As noted above, the Subgroup made recommendations for project registration through the NEPOOL-GIS. The Settlement Subgroup Report also recommends that the SPEED Facilitator apply for eligibility for the Renewable Portfolio Standards with applicable New England States, and implement "title transfer to the RECs on a pro rata basis to each utility's GIS account."[59] Given the central role of the SPEED Facilitator in addressing various aspects of SPEED projects, including the distribution of RECs, it appears efficient to give the SPEED Facilitator responsibility for registering RECs with NEPOOL-GIS and applying for eligibility among the New England states with Renewable Portfolio Standards. We agree with and adopt the recommendations of the Subgroup with respect to these responsibilities for the SPEED Facilitator. However, we note that Act 45 specifies that owners of farm methane projects "shall retain such credits to be sold separately at the owner's discretion."[60] Accordingly, the SPEED Facilitator's obligations to register and track RECs does not extend to farm methane projects.

The SPEED Facilitator may also play a role in meter interrogation, but we do not address this issue now, other than to observe that it will be the responsibility of the SPEED Facilitator to work with Vermont's electric utilities to satisfy the metering requirements associated with RECs and other relevant products of standard-offer projects.[61] And, as noted above, we require all projects accepting the standard offer to, at a minimum, utilize a meter with interval data storage.

CVPS notes that the Wheeling and Interconnection Subgroup Report describes the recommendations for SPEED standard-offer wheeling arrangements. CVPS recommends that the SPEED Facilitator coordinate with the utilities to finalize any settlement strategies associated with wheeling to assure compliance with applicable regulatory and other requirements involving the utilities. We agree and adopt this recommendation.

Also as indicated above, we are accepting the Settlement Subgroup's recommendation that SPEED standard-offer projects be treated as load reducers. Over time, it is possible that

59. Settlement Subgroup Report at 6.

60. Section 8005(g)(3).

61. It is possible that a third-party independent meter reader may be necessary to meet individual state requirements associated with RECs; if so, the SPEED Facilitator may be able to serve this function. We will require the SPEED Facilitator to provide periodic updates to the Board on the certification of RECs and the transfer to the utilities.

ISO-NE rules regarding registering generators as load reducers could change and alternative registration requirements may be imposed by ISO-NE. The standard contract shall include a requirement that producers assist the SPEED Facilitator in settling generation output, including electing to be considered a load reducer for ISO-NE settlement purposes if directed by the SPEED Facilitator.

Finally, we note that the procedures that this Board has relied upon in making these determinations have been expedited due to the need to meet statutory deadlines.[62] As circumstances change, new challenges emerge, or new evidence is presented, we may revise the requirements set forth in this Order. Also, despite our acceptance of the Settlement Subgroup Report's recommendations which rely on the SPEED Facilitator, distribution utilities, and VELCO to implement the settlement procedures outlined above, we expect generators to work cooperatively with these entities to comply with the applicable settlement requirements that exist today or in the future. As CVPS notes in its comments, this may also extend to the settlement of wheeling charges.

B. Wheeling

Wheeling is a term used to describe the transport of electric power over one utility's system to another utility. Any standard-offer generation project requiring the transfer of electric power beyond a distribution utility network, as defined by federal regulations, will require transmission wheeling. Federal Energy Regulatory Commission ("FERC") rules require utilities that own or control transmission facilities subject to its jurisdiction, and that wheel or transmit electric power, to file open access transmission tariffs.[63] Open access transmission tariffs establish rates, terms, and conditions to allow the entry of generating facilities into the electric grid.

Under the statutory scheme, the SPEED Facilitator purchases power from each producer. This power is then allocated to each of the distribution utilities on a pro-rata basis. The transfer

62. Act 45 required that the program be established by September 30, 2009.
63. FERC Order No. 888.

of power from the producer to the receiving utility will, of necessity, entail some transmission across other utilities. The transmitting utility typically receives compensation for its services.

Wheeling and Interconnection Subgroup Recommendations

The Wheeling and Interconnection ("W&I") Subgroup Report concluded that, in order to deliver to each electric distribution utility its share of the generation produced by standard-offer projects, the SPEED Facilitator will have to arrange to wheel such power. The W&I Subgroup Report also recognized that Act 45 does not appear to require that a pro rata share of the power from each SPEED standard-offer project be transmitted to each electric distribution utility. Instead, the Subgroup concluded that utilities are to receive a pro rata share of the total standard-offer costs and energy arising under the program.

The W&I Subgroup Report recommended that each standard-offer generator on a utility's system be treated as a network resource serving that utility's native load, up to a pro rata share of the total standard-offer generation. Since the load already pays for network service, adding the standard-offer project generation as additional network resources for that utility load would not result in any increase in transmission charges. For any standard-offer generation beyond the utility's pro rata share, the W&I Subgroup Report recommends that the Board authorize the SPEED Facilitator to arrange for such wheeling with the affected electric utilities as may be necessary or required. In addition the Report recommends that the SPEED Facilitator collect the associated costs and bill them to the purchasing utilities along with other program costs, including the cost for standard-offer power. Under this arrangement, wheeling costs would not need to be reflected in the standard-offer prices.

The W&I Subgroup also examined FERC jurisdictional issues. The Subgroup concluded that Central Vermont Public Service Corporation, Green Mountain Power Corporation, and Vermont Electric Cooperative, Inc., currently have tariffs authorized by FERC that establish rates, terms, and conditions for wheeling.[64] The W&I Subgroup Report also concluded that

64. *See* ISO New England Inc., FERC Electric Tariff No. 3 Section II, Open Access Transmission Tariff, Original Sheet No. 2400 Schedule 21-CV; Original Sheet No. 2800 Schedule 21-GMP; and Original Sheet No. 4400 Schedule 21-VEC.

FERC-jurisdictional utilities are required to provide open access transmission service and that such service would need to be utilized for the provision of wheeling required under the standard-offer program. The W&I Subgroup Report further stated that Vermont utilities not subject to FERC jurisdiction, or not currently providing wheeling services, would need to apply to FERC or the Board, as applicable, for approval of tariffs that establish the terms, conditions and rates for wheeling services, if these utilities wished to charge for wheeling services associated with the standard-offer program. Subgroup participants discussed the potential for the Vermont Public Power Supply Authority to consider filing a tariff to govern wheeling across and through member municipal utility systems.

The W&I Subgroup Report recommended that the SPEED Facilitator retain flexibility to arrange for required wheeling so as to minimize overall program costs. The electric distribution utilities' representatives on the Subgroup agreed to provide training and assistance to the SPEED Facilitator regarding the process for arranging for wheeling under the respective utility tariffs.

Participants' Comments

CVPS filed a letter supporting the adoption of the recommendations contained within the final report.

Renewable Energy Development ("RED") stated that it opposed "the imposition of a transmission charge on any of the output of a SPEED Facility," and that the "imposition of a transmission expense on SPEED power falsely inflates the cost of renewable energy in Vermont and unfairly enriches host utilities."

RED argues that a standard-offer facility should be treated similarly to a Qualifying Facility under PURPA and Board Rule 4.100. RED states that under Rule 4.100, a system was developed whereby an entity similar to the SPEED Facilitator was established to purchase and redistribute power from Qualifying Facilities on a pro rata basis, thereby spreading costs evenly across all ratepayers. RED further contends that PURPA and FERC rules do not require qualifying facilities to pay transmission tariffs in Vermont to transmit their power and that standard-offer projects will be transmitting power under largely identical circumstances.

RED states that a utility should be required to purchase the standard-offer project's entire output at the point of the interconnection and deliver it to the SPEED Facilitator at the nearest point of interconnection with the VELCO system. Under RED's proposal, the SPEED Facilitator would then purchase all but the interconnecting utility's share and redistribute it on a pro rata basis. RED argues that this mechanism would avoid the need to impose a transmission tariff and would also eliminate fictional line-loss charges for the interconnecting utility's own share of output.

Discussion and Conclusions

Section 8005(g)(2) states:

> (2) The SPEED facilitator shall distribute the electricity purchased and any associated costs to the Vermont retail electricity providers based on their pro rata share of total Vermont retail kWh sales for the previous calendar year, and the Vermont retail electricity providers shall accept and pay the SPEED facilitator for those costs.

Distributing the standard-offer power to the utilities will likely require wheeling. Power producers that participate in the standard-offer program will be sited in many different locations across Vermont. Under the program, the SPEED Facilitator must distribute this power to each utility on a pro-rata basis. The question for the Board is how to achieve this result without creating undue costs for utilities and ratepayers.

The Subgroup members have developed a solution to the wheeling issue that is intended to ensure that the statutory objective is accomplished while still minimizing transmission wheeling and wheeling charges and remaining consistent with federal requirements. Under this proposal, each standard-offer generator on a utility's system will be treated as a network resource serving that utility's native load, up to the utility's pro rata share of the total standard-offer generation for all utilities. For any standard-offer generation beyond the utility's pro rata share, the SPEED Facilitator would arrange for the allocation of any wheeling costs under existing wheeling tariffs. This will significantly reduce the need for the transmission of power from generators participating in the standard-offer program as only power in excess of the utility's share would be transmitted to other utilities.

Under this proposal, each utility providing wheeling services for generation beyond its pro rata share would provide these services under its applicable wheeling tariffs. These costs would then be assessed to the SPEED Facilitator. The SPEED Facilitator would, in turn, aggregate and net all billing and assess it to each utility on a pro-rata basis as prescribed by Section 8005(g)(2). The SPEED Facilitator would also be required to account for such wheeling and power in such format determined to be reasonably necessary to enable the utilities to satisfy their accounting, ratemaking and reporting requirements.

The Board recognizes that some Vermont utilities are not subject to FERC jurisdiction or do not currently have state or federal tariffs providing for the transmission of energy. If these utilities wish to charge for wheeling services provided to facilitate the administration of the standard-offer program, these utilities will need to apply to FERC or the Board, as applicable, for the approval of a tariff or other regulatory mechanism that establishes the terms, conditions and rates for wheeling services.

RED raised concerns that the inclusion of a transmission expense on standard-offer power would falsely inflate the cost of renewable energy in Vermont. However, the costs associated with wheeling are assessed to the SPEED Facilitator, and these costs will, in turn, be assessed on a pro-rata basis to each of the distribution utilities. Under subsection 8005(g)(5), the utilities may then seek recovery of these costs in rates. The costs have not, however, been incorporated into the standard-offer prices. Consequently, the wheeling cost described above will not falsely inflate the cost of renewable energy.

RED also recommends that the Board specify that no wheeling charges apply. RED cites to the practice for small power producers participating in the Rule 4.100 program. We cannot accept this proposal. Rule 4.100 was adopted prior to FERC's establishment of open-access transmission requirements and the requirement that utilities file tariffs with FERC to provide such services. While those pre-existing resources have not been subject to the wheeling requirements, FERC has made clear that all projects developed at this time must pay applicable tariffed wheeling rates. Thus, RED's proposal is not acceptable.

Consistent with the W&I Subgroup Report recommendation, the Board encourages the distribution utilities to work with the SPEED Facilitator regarding any additional training and assistance needed for the SPEED Facilitator to arrange for wheeling under the respective utility tariffs. Given the complexity of FERC requirements, it is possible that an alternative method would provide greater benefits to ratepayers and developers. We leave open the possibility that future proceedings could address improvements to the wheeling methodology approved here.

C. Interconnection

Act 45 directs the Board to "determine whether its existing rules sufficiently address interconnection, metering, and the allocation of metering and interconnection costs, and make such rule revisions as needed to implement the standard-offer requirements of this section."[65] In order to connect generation projects to a utility's electric system, there is a procedure to review such proposed interconnections and ensure that they do not present a threat to the public and utility line crews, and also will not cause instabilities and potential outages to the electric system. Board Rule 5.500 — Interconnection Procedures for Proposed Electric Generation Resources, governs all generation interconnections which are not subject to ISO-NE interconnection rules or the Board's net metering rule (Rule 5.100). The Wheeling and Interconnection ("W&I") Subgroup considered potential changes to Rule 5.500 to reconcile the requirements of the rule with the standard-offer program.

W&I Subgroup Recommendations

The W&I Subgroup Report identified the following concerns with Rule 5.500: (1) applicants cannot always fill out a complete application as they do not have all of the necessary information on their proposed generators at the time they start the planning and permitting processes for their projects; (2) small generation projects may not need the higher level of review called for under Rule 5.500; and (3) the complexity of the Rule 5.500 application process can be a barrier for smaller projects.

The W&I Subgroup Report also recommended that the Board develop a unified set of interconnection requirements that would apply to all generation interconnection applications, based on the project's size and characteristics, regardless of whether the applicant seeks an

65. Section 8005(i).

interconnection under PSB Rule 5.500 or pursuant to the net-metering terms of PSB Rule 5.100. Recognizing that the Board's ability to make changes to Rules 5.500 and 5.100 is governed by the rulemaking procedures set forth in Vermont's Administrative Procedures Act,[66] the Subgroup recommended that the Board take such actions as it could to quickly resolve interconnection implementation concerns.

The Subgroup stated that the Application form for Rule 5.500 *Standard Application for Interconnection* could be reviewed and updated outside of a rulemaking proceeding. The Subgroup Report made an initial proposal for changes to the Rule 5.500 Application and a revised draft application form was included in the W&I Subgroup Report.

The W&I Subgroup Report discussed the possibility that the standard-offer program will result in a substantial increase in the workload to process applications for interconnection pursuant to Rule 5.500. Board Rule 5.500 includes deadlines for utilities to respond to requests for interconnection. The W&I Subgroup Report recommended that the Board advise interconnection applicants that it recognizes that the utilities will have difficulty meeting the schedules called for under Rule 5.500 if there is heavy enrollment in the standard-offer program. The W&I Subgroup Report further recommended that the Board acknowledge this potential workload issue when assessing the reasonableness of the timeframes within which the utilities complete required interconnection assessments.

The W&I Subgroup Report recommended that the individual utilities each maintain their independent interconnection application queues, and that these queues be separate and distinct from the standard-offer program queue managed by the SPEED Facilitator. The Subgroup Report recommended an examination of whether a procedure could be developed to keep the distribution utilities on notice of projects within their individual service areas, thereby enabling the utilities to plan for upcoming interconnection applications. Some Subgroup members also suggested that information regarding the standard-offer program queue should be provided by the

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66. *See* 3 V.S.A. §§ 817 *et. seq.*

SPEED Facilitator to the Vermont System Planning Committee ("VSPC")[67] so that this information could be integrated within the long-term transmission planning processes developed under Docket 7081.

Participants' Comments

CVPS filed comments supporting the adoption of the recommendations contained within the Subgroup Report, including the interconnection recommendations contained in the Report.

Ag Energy Consultants, LLC ("Ag Energy") raised comments that were specific to the 5.500 application form, including suggestions to make the form less confusing for applicants and improvements to the quality of data collected on the form. Ag Energy also stated that further discussion related to the provisions of Rule 5.500 as they relate to standard-offer projects should include: (1) the definition of what constitutes a System Impact Study, Stability Study, and Facilities Study; (2) the lack of common contacts for these studies; (3) evaluation of the need for confidentiality of study results; (4) a mechanism to determine reasonable costs for the studies; and (5) a process to resolve disputes surrounding study conclusions.

Discussion and Conclusions

Section 8005(i) requires that, with respect to the standard-offer program:

> the board shall determine whether its existing rules sufficiently address interconnection, metering, and the allocation of metering and interconnection costs, and make such rule revisions as needed to implement the standard offer-requirements of this section.

In general, the Board agrees with the W&I Subgroup Report's conclusions that modifications to Rule 5.500 appear to be warranted to address standard-offer projects. In a process separate from Docket 7533, the Board will examine the interconnection process, with a focus on the impact of Rule 5.500 on generators likely to participate in the standard-offer

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67. The Vermont System Planning Committee ("VSPC") was created by a Board Order in Docket 7081. The VPSC and its associated planning process are designed to facilitate full, fair, and timely consideration of cost-effective non-transmission alternatives to new transmission projects. The VSPC increases collaboration among utilities, lengthens the planning horizon to ensure there is time to fully consider all alternatives, increases transparency of the process, and involves the public in decisions about alternatives.

program. This examination will include short-term steps, such as the changes to the Rule 5.500 Application Form, and longer-term steps, such as a proceeding to determine whether a rulemaking is needed to revise Rule 5.500 to address standard-offer projects. The Board will use as a starting point for those proceedings the recommendations made in the W&I Subgroup Report and the comments, including those submitted by Ag Energy, on the W&I Subgroup Report.

The Board recognizes the possibility that the standard-offer program will result in a substantial increase in the workload of utilities to process applications for interconnection pursuant to Rule 5.500. The Board accepts the W&I Subgroup Report's recommendation that the individual utilities maintain their independent interconnection application queues that are separate and distinct from the standard-offer program queue managed by the SPEED Facilitator.

The W&I Subgroup Report recommended that the Board examine whether a procedure could be developed to notify the distribution utilities of applications for projects within their individual service territories, to enable the utilities to plan for upcoming interconnection applications. The Subgroup Report further stated that such information may be of use if integrated with the long-term transmission planning process and the VSPC developed in Docket 7081. We agree that such information will be useful for the planning purposes of the distribution utilities and the long-term transmission planning process. In this Order we direct the SPEED Facilitator to maintain an updated website that will list the projects that accept the standard offer by executing the standard contract, along with other information, such as the size of the project and the interconnecting utility. Given that this information will be publicly accessible, there is no need for the SPEED Facilitator to report information regarding potential interconnections to the utilities or the Vermont System Planning Committee.

VII. SPEED Facilitator

Pursuant to Act 45, and the decisions made in this Order, the responsibilities of the SPEED Facilitator will increase. The Board holds a contract with VEPP, Inc., to act as the SPEED Facilitator, and given the changes in responsibility, that contract will need to be amended. Board staff are working with VEPP, Inc., on such contract amendments.

A. Allocation of costs

A significant issue with respect to the SPEED Facilitator is the question of how to pay the costs associated with the SPEED Facilitator's administration of the standard-offer program. Act 45 requires that the Board "[d]etermine a SPEED Facilitator's reasonable expenses arising from its role and the allocation of such expenses among plant owners and Vermont retail electricity providers."[68]

Board staff issued a memorandum outlining the issues involved, and requested comments on specific questions dealing with: the method of allocating costs between developers and utilities; the methodology for recovering costs from the developers; whether a different allocation methodology should apply to developers accepting the standard offer after January 15, 2010 (the deadline for the Board to establish more refined prices); whether amortization of the program costs for the first two years would be appropriate; and the appropriate connection between the application fee and the administrative costs of the SPEED Facilitator.

Participants' Comments

GMEU filed a letter[69] recommending that the costs of the SPEED Facilitator be split evenly between the utilities and the developers, and further stated that the costs allocated to developers should not be passed on to utilities. GMEU contends that the SPEED Facilitator is in the best position to address the methodology for allocating costs among developers. In addition, GMEU states that there is no reason to decide at this time whether the allocation structure should be changed for the standard offers accepted after January 15. GMEU contends that capitalization and amortization of the SPEED Facilitator's costs is not appropriate to the extent that it would require a loan from the utilities. Finally, GMEU recommends that administrative fees be considered part of a developer's contribution to the allocation of costs.

AAFM states that the simplest method is to allocate the administrative costs to the utilities, as "consumers are ultimately paying for the program any way that it is implemented."

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68. Section 8005(h)(1).

69. The letter represents that VEC, Vermont Marble Power Division of Omya, Inc., BED, GMP, and CVPS join in GMEU's response.

AAFM recommends that, in the alternative, the standard-offer prices be adjusted each year to reflect the SPEED Facilitator's costs. AAFM contends that the costs allocated to developers should be "based on total kWh going through the program and allocated based on total kWh sold . . . ." AAFM states that, as there will not be sufficient power sold in the early years of the program to support the SPEED Facilitator's administrative costs, the costs should be either borne entirely by utilities, or if the costs are allocated between utilities and developers, the utilities could provide essentially a loan that would be repaid as generators produce power. Finally, AAFM states that the administration fee that would accompany the standard-offer application should cover only the cost of processing the application, and should not be used to cover the start-up costs of the program.

Discussion and Conclusions

The costs associated with the work performed by the SPEED Facilitator were considered by the Cost Analysis subgroup. The group's final report stated the following:

> The SPEED Facilitator estimated that the administrative budget for the first year that most of the projects are operational to be $329,800 and $399,000 if the costs of the first two years are amortized. Assuming a 50-50% split of the administrative costs, the producer's share of the administrative costs is estimated to be $199,500. These costs would have to be allocated and included in the costs to producers, but were estimated to be approximately $119/mo, or $1425 per year. A figure this small is unlikely to have a material impact on modeling results except for the smallest projects. However, the impacts on the smaller projects can be managed by socializing the allocation of the costs associated with the program.[70]

As the report suggests, the costs to smaller projects could be significant, depending on the allocation methodology. For example, an allocation based upon kWh production would probably have minimal impact. But the SPEED Facilitator's costs are probably more closely related to the number of projects than to kWh generation. Allocation of costs on the basis of the number of projects could add proportionately large costs to smaller projects. In addition, there is substantial

70. Cost Analysis Report at 13. The Board has not yet agreed to the SPEED Facilitator's proposed budget or the allocation of all of the SPEED Facilitator's costs.

uncertainty regarding the number and size of projects that would apply to the standard-offer program in any given year, making it difficult to accurately calculate the cost per project.

Section 8005(h)(1) directs the Board to determine the SPEED Facilitator's reasonable expenses and allocate these costs among the utilities and developers. Given the significant uncertainty regarding the number and type of projects there is insufficient information to make such a determination at this time. However, this is an issue that could impact developers' decisions to participate in the program. Accordingly, we provide the following guidance regarding the allocation, and will provide a final determination after receiving additional information from the SPEED Facilitator, as well as input from participants to these proceedings.

A portion of the SPEED Facilitator's costs will be assigned to developers, and these costs will be considered a cost item in setting the January 15 prices, to the extent that such costs are material. It is our intent to design an allocation methodology that does not impose material costs for any standard-offer projects receiving the pre-January 15 interim prices. This may require a different allocation methodology for projects receiving the interim prices than for those receiving the subsequent prices.

We direct the SPEED Facilitator to propose a methodology or methodologies for allocating costs between developers and utilities that meets these guidelines. The Board will provide participants the opportunity to comment on the proposal.

VIII. SUBSEQUENT PROCEDURES

A. Board Rule 5.500 - Interconnection

The Wheeling and Interconnection Subgroup recommended that the Board revise Board Rule 5.500. Given the process for amending an existing rule, the group further recommends that, during the process to amend the rule, the Board modify the existing application form appended to Rule 5.500.[71] The Board directs staff to undertake any process necessary to amend the application form for Board Rule 5.500 and further directs staff to convene a workshop to

71. The Board may amend the application form at any time without undertaking the rulemaking process.

determine what changes should be made to the Rule 5.500 Application form, and to determine whether modifications to the Rule are warranted as a result of the standard-offer program.

B. Settlement and Wheeling

The decisions with respect to settlement and wheeling were arrived at within the constraints of a compressed time frame. As noted earlier, these issues are complex and involve state, regional, and federal rules and statutes. We require the SPEED Facilitator to promptly inform the Board if issues related to wheeling and settlement arise during the course of implementing the standard-offer program, such that revisiting the decisions in this Order may be required.

C. Permitting of Standard-Offer Projects

Act 45 does not address the siting process for standard-offer projects. All projects eligible for the standard offer must be reviewed under 30 V.S.A. § 248,[72] while projects that choose to be net metered are reviewed under 30 V.S.A. § 219a. Section 219a is intended for smaller, primarily residential, projects, and consequently, the application, notice, and review process for projects under this statute is simpler than the requirements for projects reviewed under Section 248. For example, the net-metering statute (30 V.S.A. § 219a) allows the Board to waive certain substantive criteria contained in Section 248(b). This creates a difference in our review of similar-sized projects that choose to interact with the grid through net metering, compared to the standard-offer program. Additionally, if a significant number of petitions are filed under Section 248, the Board may need to establish a more standardized process for filing such petitions. To address these issues, the Board directs staff to convene a workshop to address the Section 248 review process, including potential changes to Board Rule 5.400 and potential recommended legislative changes to Section 248.

In addition to concerns regarding Board resources available to process petitions, there are also budgetary impacts associated with the notice requirements contained in the statute. Section

72. *See* Dockets 7523 and 7533, Order of 8/18/09 at 11-12.

248 requires that notice be published on two occasions at least one week apart.[73] There are costs associated with this notice,[74] and although the costs may be immaterial to an individual applicant, it is possible that a large number of applicants will apply for Section 248 approval in order to be eligible for the standard-offer prices. The Board does not have the necessary budget for a large number of such notices. Given that review under Section 248 is necessary in order for projects to be eligible for the standard offer, we find it necessary and appropriate to require applicants to pay for the costs associated with the notice requirements of Section 248. Otherwise, there could be unaccpetably long delays in processing applications under Section 248.

D. Tracking Program Costs

The Settlement Subgroup Report states that "it is in the best interests of all stakeholders, including utility customers, legislators and regulators, to have transparent and accurate cost information maintained and available as the program evolves in order to aid future decision-making processes."[75] The Settlement Subgroup Report recommends that the Board direct the SPEED Facilitator and the utilities to track costs such as incremental metering costs, incremental administrative and other labor costs, legal costs, costs associated with VELCO's settlement efforts at ISO-NE, and equipment costs. We conclude that such information is necessary to fully assess the standard-offer program. Accordingly, we direct the utilities and the SPEED Facilitator to provide an annual report, on or before October 31 of each year, of the costs listed above, and any other costs directly attributable to the standard-offer program. The cost report should be categorized in the manner listed above.

IX. Conclusion

As we noted earlier, the standard-offer program involves a complex undertaking among developers, utilities, the SPEED Facilitator, and the regional grid operator. We expect that the

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73. Section 248(j) allows for expedited review of projects of limited size and scope. It is anticipated that many of the projects that would qualify for the standard offer would apply under this subsection.

74. The cost to publish notice varies depending on which publication the notice appears in; however, the costs typically are a few hundred dollars.

75. Settlement Subgroup Report at 7.

determinations reached today may need to be modified, on a going-forward basis, as we gain experience with the standard-offer program and as we gather additional information on these issues.

We intend to proceed expeditiously with the subsequent procedures described in Section VIII of this Order, and to take all other steps necessary and appropriate to ensure that the standard-offer program operates effectively, efficiently, and in accordance with the directives of Act 45.

SO ORDERED.

Dated at Montpelier, Vermont, this 30th day of September, 2009.

s/James Volz	)	
	)	PUBLIC SERVICE
	)	
s/David C. Coen	)	BOARD
	)	
	)	OF VERMONT
s/John D. Burke	)	

OFFICE OF THE CLERK

FILED: September 30, 2009

ATTEST: s/Susan M. Hudson
Clerk of the Board

NOTICE TO READERS: This decision is subject to revision of technical errors. Readers are requested to notify the Clerk of the Board (by e-mail, telephone, or in writing) of any apparent errors, in order that any necessary corrections may be made. (E-mail address: psb.clerk@state.vt.us)

Appeal of this decision to the Supreme Court of Vermont must be filed with the Clerk of the Board within thirty days. Appeal will not stay the effect of this Order, absent further Order by this Board or appropriate action by the Supreme Court of Vermont. Motions for reconsideration or stay, if any, must be filed with the Clerk of the Board within ten days of the date of this decision and order.

January 25, 2021

Mr. Jack Forgues
Rusty-John Farm
6089 Route 17W
Addison, VT 05491

Re: Standard Offer Commissioning Milestone –Forgues Dairy Wind

Dear Mr. Forgues,

Congratulations! You have satisfied your Standard Offer Commissioning Milestone as of January 23, 2021. I will direct the bank to return your refundable deposit in the amount of $500.

Best regards,
VEPP Inc.

Carolyn M.X. Alderman, Esq.
Executive Director

cc: Vermont Public Utility Commission;
Tom Halnon

112 State Street
4th Floor
Montpelier, VT 05620-2701
TEL: 802-828-2358

TTY/TDD (VT: 800-253-0191)
FAX: 802-828-3351
E-mail: puc.clerk@vermont.gov
Internet: http://puc.vermont.gov

State of Vermont
Public Utility Commission

To: John E. Forgues

From: Elizabeth Schilling EBS

Re: 21-9003-RES – Renewable Energy Standard Statement of Qualification

Date: March 3, 2021

On March 1, 2021, John E. Forgues, filed a registration form requesting a statement of qualification under the Vermont Renewable Energy Standard ("RES") for a wind project located in Addison, Vermont.

This memorandum signifies that the facility described below qualifies under Tier I and Tier II of the RES as of January 23, 2021.

GIS Unit ID #	NON161724
Name of Generation Unit	Forgues Wind
Nameplate Capacity, MW (AC)	0.05 MW
Authorized Representative's Name and Address	John E. Forgues 6211 Route 17W Addison, Vermont 05491
City (where the unit is located)	Addison
State (where the unit is located)	Vermont
Commissioning Date	January 23, 2021
Fuel Type	Wind
RPS Eligibility	Tiers I and II
State RES Approval Number	21-9003-RES
Date of Eligibility	January 23, 2021
Independent Verifier	VEPP Inc.

PUC Case No. 21-9003-RES - SERVICE LIST

<u>Parties:</u>

John E Forgues, *pro se*
6211 Rt 17
Addison, VT 05491
forguesdairy@gmail.com

Alexander Wing (for Vermont Department of Public Service)
Vermont Department of Public Service
112 State Street
Montpelier, VT 05620
alexander.wing@vermont.gov

Subject: Vermont Standard Offer program PUC Order and Vermont Statute
Date: Wednesday, October 4, 2017 at 11:59:03 AM Eastern Daylight Time
From: Meghan vonBallmoos
To: michael.woods@gdsassociates.com
CC: Lauren Keyes, Carolyn Alderman
Attachments: PUC Order 9_30_2009.pdf, image001.png

Michael,

Thank you for the call today to address the RI-RES Certification applications for RI PUC Docket No. 4722-4731 and 4733-4744, as well as subsequent applications from VEPP Inc. for Vermont Standard Offer Program projects. We want to confirm for you that the Standard Offer Program projects are NOT net metered projects. The entire output from these facilities goes to the grid and is distributed pro rata to the Vermont utilities pursuant to the Vermont statute governing the Standard Offer Program referenced below.

Firstly, I have attached the Vermont Public Utility Commission Order in Docket No. 7533, which established the Standard Offer Program in 2009 and describes it at length.

Secondly, please follow the following link to 30 V.S.A. § 8005a (k)(2) the Vermont statute governing the Standard Offer Program http://legislature.vermont.gov/statutes/section/30/089/08005a.

Please let me know, if you have any questions. I can be reached today at 802-362-0748, but will be out of the office from 10/5 to 10/13. During that time, please contact Lauren Keyes at 802-362-0748 or lkeyes@veppi.org and she will be happy to assist.

Thank you so much!

Best regards,
Meghan von Ballmoos

VEPP INC

802-362-0748
meghan@veppi.org