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: 10/16/2009

ORDER RE IMPLEMENTATION ISSUES

I. INTRODUCTION

On September 30, 2009, the Public Service Board ("Board") issued an Order establishing a standard-offer program for qualifying sustainably priced energy enterprise development ("SPEED") resources. In the September 30 Order, we directed the SPEED Facilitator to begin accepting applications for the standard-offer program on October 19, 2009. Given the significant complexity of designing a standard-offer program under the time constraints imposed by the Vermont Energy Act of 2009 ("Act 45")[1] Board staff conducted additional proceedings to discuss any issues that needed to be resolved to effectively and efficiently implement the standard-offer program.

In this Order, we resolve the implementation issues that have been identified by participants and staff and rule on a motion to alter the September 30 Order, as our ruling on the motion has a direct bearing on the implementation of the standard-offer program.

II. BACKGROUND

On October 2, 2009, the Clerk of the Board issued a memorandum stating that Board staff would hold a workshop on October 8, 2009, to discuss any implementation issues to be resolved

1. Public Act No. 45 (2009 Vt., Bien. Sess.).

prior to the acceptance of applications for the standard-offer program. Participants were provided the opportunity to file comments on the issues identified at the workshop by October 12, 2009.

On October 9, 2009, the Group of Municipal Electric Utilities ("GMEU") filed a motion to alter the September 30 Order. Comments on the motion were due by October 13, 2009.

III. Implementation Issues

Utility Projects and the Queue

The September 30 Order describes the relationship of utility projects to the queue for the standard offer. In summary, the September 30 Order required projects owned and operated by utilities to enter the queue in a manner similar to other developers. Several utilities raised issues with respect to this requirement and this issue was discussed at the October 8 workshop and subject to comments.

On October 9, 2009, GMEU filed a motion to alter the September 30 Order. Given that the resolution of this issue could impact the ability of utilities and other project developers to enter the queue, a deadline of October 13 was established for comments on GMEU's motion.

GMEU requests that the Board alter the September 30 Order to withhold 10 MW from the 50 MW ceiling until January 15, 2010, and defer any decisions regarding the relationship of utility projects to the queue until that time. GMEU contends that allowing only 40 MW to be filled will benefit implementation of the standard-offer program by allowing time for a more thorough consideration of the issues associated with utility projects, allowing time to fix any mistakes, and reducing the likelihood of litigation, among other reasons.

Participants' Comments

The City of Burlington Electric Department ("BED") filed a letter generally supporting GMEU's motion but proposing a modification to GMEU's proposal. BED recommends that the Board reserve 10 MW of the 50 MW ceiling specifically for utility projects, but open this 10 MW to applications beginning on October 19, 2009. BED contends that Act 45 specifically requires that utility projects reduce the 50 MW ceiling, and that a 10 MW set-aside for utility projects would resolve this issue. BED states that, if the entire 10 MW is not filled, the Board could then reconsider the need for the utility project set-aside in January, 2010.

Southport Power, LLC, ("Southport") filed a letter opposing GMEU's motion. Southport contends that the Board has already addressed the issues raised in GMEU's motion, and GMEU has not provided sufficient rationale to overturn the Board's decision.

In addition to comments on GMEU's motion, several participants provided comments relevant to this issue. The Vermont Department of Public Service ("Department") and Central Vermont Public Service Corporation ("CVPS") support GMEU's and BED's comments on this issue. Green Mountain Power Corporation ("GMP"), Alteris Renewables ("Alteris"), Renewable Energy Vermont ("REV"), the Vermont Agency of Agriculture, Food and Markets ("AAFM"), and Longview Infrastructure, LLC ("Longview") all stated that utility projects should not be provided preferential treatment with respect to their positions in the queue.

Discussion and Conclusions

The plain language of Act 45 states that projects owned and operated by utilities "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."[2] In our September 30 Order, we established a queue for the standard-offer program in recognition that developers would need certainty as to their participation in the program prior to investing capital and obtaining the financing necessary to commence construction.[3] Further, the Board stated that

> 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.[4]

2. Section 8005(b)(2).

3. *See*, Docket 7533, Order of 9/30/09, at 10 - 11.

4. Docket 7533, Order of 9/30/09 at 35.

Finally, our September 30 Order stated that utility projects must join the queue in order to allow the SPEED Facilitator to successfully manage the queue.[5]

As we stated in the September 30 Order, the alternative to a queue is to only provide the standard offer to the first 50 MW of projects that are commissioned. Under the latter approach, utility projects would count toward the queue at the time that they are commissioned; this would place utility projects on an equal playing field with non-utility projects, which would receive the standard offer if they are commissioned when there is still space available under the 50 MW ceiling. Such an approach does not provide a utility project with preferential treatment with respect to whether it counts toward the 50 MW ceiling — the utility project would only count towards the 50 MW ceiling if it is commissioned prior to the 50 MW ceiling being reached. In addition, as we stated in the September 30 Order, such an approach would likely make it difficult for non-utility projects to raise capital or obtain financing as the developer would not know until the project was built whether the project will come in under the 50 MW ceiling or not.

Act 45 states that utility projects commissioned after September 30, 2009, shall count towards the 50 MW ceiling. However, the statute does not state the point in time that utility projects count towards the ceiling; in other words, there is no requirement that a project that is contemplated by a utility, but not yet built, would count toward the 50 MW ceiling. Our September 30 Order creates a queue process which all developers, utility and non-utility, must enter. In the case of non-utility projects, the place in the queue signifies whether the developer will receive the standard-offer prices; for utility projects, the place in the queue signifies whether the individual project shall count toward the 50 MW ceiling.

The alternative to entering the queue would be to rely on the statutory language that once utility projects are commissioned they shall reduce the 50 MW ceiling. Accordingly, to have a utility project count towards the 50 MW ceiling, the utility may obtain a spot in the queue, as contemplated by the September 30 Order, or it may wait until the project is commissioned. If a utility takes the latter approach, it takes the risk that 50 MW are already committed in the queue.

For these reasons, we reject GMEU's motion to alter.

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5. Docket 7533, Order of 9/30/09 at 35 - 36.

Over-subscription of the Queue

Longview expressed concern that an on-line application form, as envisioned in the Board's September 30, 2009, Order, could present opportunities for gaming if the queue was oversubscribed in a matter of minutes or hours. In particular, Longview expressed concern that developers could employ software to ensure a place in the queue; thereby putting other developers at a disadvantage.

During discussion of this issue at the October 8 workshop, participants generally agreed that the use of a lottery on the first day could prevent this behavior. Under this proposal, if the queue were filled in a matter of hours, any applications received within that time period would be given randomly assigned numbers which would then determine the producers who would receive a space in the queue. The time period was not finalized at the workshop, with some participants recommending a matter of minutes, and others recommending 24 hours.

Participants' Comments

AAFM, BED, the Department, and Green Mountain Electric Supply, Inc. ("Green Mountain Electric") support the use of a lottery.

Longview and Alteris support the use of a lottery, but recommend that each developer be limited to one project in the lottery.

REV supports the use of a lottery to determine a project's position in the queue, and a project's position in the waiting list.[6]

Discussion and Conclusions

We find that the concept of a lottery is reasonable and we direct the SPEED Facilitator to implement a lottery to assign queue position if the queue, or certain technology caps established by the September 30 Order, are filled by 5 p.m. October 19, 2009, the first day the SPEED Facilitator begins accepting applications. After October 19, to the extent that the ceilings on the

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6. Pursuant to the Board's September 30 Order, at 9, "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." The waiting list will also apply to caps on individual technologies.

queue or technology types are not reached, projects will enter the queue on a first-come, first-served basis. In addition, we accept REV's recommendation that a project's position in the waiting list, to the extent one is developed on the first day, would also be determined by this lottery.

Longview and Alteris have not provided sufficient rationale for the recommendation that developers be limited to one project in the lottery. The intent of Act 45 is to incentivize new renewable projects; there is no statutory basis for limiting the number of projects that one developer may enter in the queue.

Construction of Project in Accordance with Attachment A

Pursuant to the standard contract, a plant owner must provide a description of the project it intends to construct. The description must include: the capacity of the facility, the fuel type of the facility, the street address where the facility will be located, and the name of the interconnecting utility. In addition, Paragraph 9 states: "Producer shall construct the Project at the location and in a manner substantially consistent with the specifications set forth in Attachment A."

Participants' Comments

Southport requested clarification regarding the extent to which a project could be modified after it has entered the queue. Southport also noted that Paragraph 35c contemplates the possibility of waiving certain provisions of the standard contract, including, potentially, the requirement that the project be constructed in a manner substantially similar to that contained in Attachment A of the standard contract.

The Department states that it does not have an issue if there are minor changes to a project after the application is submitted, but believes that any increase in project size is a substantive change that should be brought to the Board for approval.

AAFM states that the existing phrase "substantially consistent" provides sufficient guidance, and if developers wish to change the size of the project, they can execute a new contract.

Discussion and Conclusions

The purpose of the requirement contained in Paragraph 9 is to decrease the possibility of gaming the queue. When entering the queue, the plant owner must have a legitimate project to be developed. Accordingly, the location,[7] technology type, and interconnecting utility cannot be changed from the time that the project enters the queue. We recognize that the actual size of a project may be altered during the development of the project; for example, reducing the capacity of the project to address interconnection issues. In balancing the need to minimize the opportunity to game the queue with these real logistical concerns, we conclude that the capacity of projects as described in Attachment A of the standard contract may be altered by up to 5% or 5 kW, whichever is greater.

Additionally, as Southport noted at the October 8 workshop, the word "specification" in Paragraph 9 implies more detail regarding the proposed project than is contemplated. Accordingly, we modify the sentence to state: "Producer shall construct the Project at the location and in a manner substantially consistent with the description set forth in Attachment A."

Definition of Plant

The SPEED Facilitator raised the issue of how a plant is defined for purposes of implementing the 2.2 MW cap on qualifying SPEED resources that can participate in the standard-offer program.[8] In particular, the SPEED Facilitator stated that the tenor of some questions it had received from developers indicated that at least some developers were anticipating construction of multiple plants at a single location that, collectively, exceed the 2.2 MW cap.

Participants' Comments

CVPS states that separate projects would each need to enter into a separate interconnection agreement with the interconnecting utility, enter into separate standard contracts,

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7. The location of the project, as used here, refers to the location of the parcel of land on which the project is situated, not the location of the project on the parcel of land.

8. *See* Section 8005(b)(2).

and obtain separate certificates of public good pursuant to 30 V.S.A. § 248, or other necessary permits.

The Department states that its primary concern is that the definition of plant not provide an opportunity to exceed the 50 MW ceiling on program participation.

REV states that the statute is clear that "separate plants that share common infrastructure and interconnection should be considered as one plant and held to the 2.2 MW cap." REV requests that the Board clarify that adding incremental generation of 2.2 MW or less to an existing plant can qualify for the standard offer, regardless of the size of the existing plant.

Discussion and Conclusions

Section 8002(12) defines Plant as

> any independent technical facility that generates electricity from renewable energy. A group of newly constructed facilities, such as wind turbines, shall be considered one plant if the group is part of the same project and uses common equipment and infrastructure such as roads, control facilities, and connections to the electric grid.

To the extent that any generation components share common infrastructure, we direct the SPEED Facilitator to consider these components as a single plant. We direct the SPEED Facilitator to identify any developer of projects on the same parcel of land, or contiguous parcels of land that, collectively, would exceed the 2.2 MW cap, and inform the Board of such applications. To the extent required, the Board will make case-by-case determinations as to whether projects constitute a single plant for purposes of Section 8002(12).

Further, any collection of generation components that meets the definition of a plant, and exceeds the 2.2 MW cap, shall be removed from the queue, although the generation components may reapply for the standard offer if the scope of the project is adjusted to comply with the 2.2 MW cap.

With respect to REV's comments regarding incremental generation to an existing plant, the definition of plant specifically refers to "newly constructed" plants using common infrastructure. There does not appear to be any statutory barrier to existing facilities building a new qualifying SPEED resource at the site, and we direct the SPEED Facilitator to allow such projects in the queue, provided that they meet all other requirements.

Site Control

Pursuant to Paragraph 4 of the standard contract, a plant owner must provide proof of site control at the time that it accepts the standard offer.[9] Under the on-line application process for the queue, proof of site control must be submitted within five days after the SPEED Facilitator notifies the plant owner that it has received a position in the queue. Longview requested that the Board clarify that the plant owner must have control of the site at the time that it completes the application process and enters the queue.

Participants' Comments

REV and AAFM support Longview's proposal.

Discussion and Conclusions

We find this recommendation to be reasonable, as it will further decrease the possibility for speculative positioning in the queue. Accordingly, we require that plant owners demonstrate that they have control of sites at the time that they complete the application process to enter the queue. We further direct the SPEED Facilitator to remove any plant owner from the queue if it has not demonstrated compliance with this requirement. We note that proof of site control can be difficult to obtain for certain types of projects, such as hydroelectric projects on navigable waterways. The Board received a motion to alter the September 30 Order to allow hydroelectric facilities to demonstrate site control through a Federal Energy Regulatory Commission preliminary permit, however, this issue was raised too late in the process to resolve by the October 19 implementation date. We will resolve this issue as expeditiously as possible.

Payment for Metering and Metering Equipment

The Group of Municipal Electric Utilities ("GMEU") requested that the Board clarify payment for metering and metering equipment. GMEU states: "It is the utilities' understanding

9. Pursuant to Attachment B of the standard contract: "In order to demonstrate site control, Producer shall provide evidence of: (i) fee simple title to such real property or (ii) a valid written leasehold interest for such real property or (iii) a valid written option, exercisable unconditionally by the Producer or its assignee, to purchase or lease such real property or iv) a duly executed contract for the purchase or lease of such real property."

that the project developer is responsible for paying for the meter, any associated metering equipment . . . , and the communications means by which the meter will be read remotely."

Participants' Comments

The Department generally agrees with the position that the costs of metering and interconnection are borne by the project developer and points out that such costs were generally included in the cost estimates used to set the standard-offer prices.

CVPS recommends that the Board clarify that the Producer is responsible for all of the costs for metering the output of its project sold, as this policy is consistent with generally accepted practice in connection with wholesale power supply arrangements.

BED states that "ambiguity remains related to whether meters will be required to meet individual host utility standards, which entity owns the meters (utility or project), and whether utility costs associated with meter data collection and/or installation will be recoverable." BED also requests that the Board clarify recovery of costs incurred by utilities to meet the program requirements. BED suggests that it would be helpful for the Board to further clarify whether each of the costs that the Board required utilities and the SPEED Facilitator to track[10] are recoverable by the utility and/or SPEED Facilitator.

Longview states that, in its experience, it is unusual for the developer to be required to pay the utility to read the meter. Longview further states: "Ownership of the revenue meter varies by jurisdiction, but is often held by the project to avoid the tax gross-up issues associated with contributions in aid of construction. Control of the revenue meter can be contractually extended to the interconnecting utility."

Discussion

We conclude that the costs of the meter and associated metering equipment as well as any costs associated with interrogating the meter shall be borne by the producer, consistent with existing practice for wholesale power supply arrangements. This would include the costs of the

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10. The September 30 Order required that the SPEED Facilitator and utilities track costs associated with the standard-offer program. *See* page 61.

meter and, to the extent that it is owned by the utility, payment as a contribution in aid of construction.[11] This would also include the costs of any communications lines or capabilities that are needed by the utility or the SPEED Facilitator to receive such communications, to the extent required.

The September 30 Order left a number of issues open for resolution by the SPEED Facilitator, in cooperation with the Vermont electric distribution utilities, regarding settlement of power produced from standard-offer projects. We expect the SPEED Facilitator to work with the Vermont utilities to identify the arrangements that are most efficient. Nevertheless, we will permit non-utility ownership provided circumstances (especially costs) warrant.

With respect to the cost recovery issue raised by BED, Act 45 states that "all reasonable costs of a Vermont retail electricity provider incurred under this subsection shall be included in the provider's revenue requirement for purposes of ratemaking under sections 218, 218d, 225, and 227 of this title."[12] We expect that traditional standards for cost recovery will be applied to costs incurred by Vermont electric utilities implementing the requirements of Act 45.

<u>Scope of data collection from projects</u>

The Department requested clarification on the types of data that developers are required to provide regarding project costs, including capital costs, financing arrangements, and operation and maintenance ("O&M") costs at a minimum.

<u>Participants' Comments</u>

After the workshop, the Department indicated that it

> ...would like a clarifying statement that would indicate that this data collection is not simply first cost data, but includes an obligation to submit ongoing O&M data as well. The Department envisions an annual data request sent by the SPEED facilitator to participating facilities with a simple data request for

11. In its comments, CVPS also states that it “does not believe” that compliance with the metering and interconnection requirements contemplated under the standard-offer program should give rise to the need for an “assessment to make the utility whole for taxes it would incur” for the transfer associated with contribution in aid of construction. CVPS Comments, October 12, 2009, at 2.

12. Section 8005(g)(5).

> annual costs. Further, the Department would like some clarification that the initial data request also includes the financial parameters of the project as well. The Department is willing to treat all data received with appropriate confidentiality.

REV indicates that it does not support the requirement of granular cost data for participating plants. REV is concerned about how such data collection would affect the confidentiality agreements that developers may have signed with their suppliers. REV believes that initial construction/development costs and generic annual O&M data would be sufficient data that will be part of a standard offer price setting procedures in the future.

AAFM indicates that confidentiality agreements with the Board and the level of data desired needs to be available to producers. AAFM states that some of the vendors on farm projects have confidentiality agreements with the farms and need to get the vendors' permission to gather the data. AAFM does not see the provision of information as a major problem provided agreements are in place.

Discussion and Conclusions

We agree with the Department that the data received from developers include not only initial capital costs, but ongoing operation and maintenance costs as well as financing terms. The absence of such information made the September 15 determination of the standard-offer prices difficult. We will require project owners to provide information sufficient to demonstrate the reasonableness of key components of costs as described by the Department and as determined later by this Board. Our September 30 Order made clear that the standard contract will provide certain provisions to protect the confidentiality of project-specific proprietary information.[13]

Definition of Other Products Related to Electrical Generation

In the September 30 Order, we concluded that the other products related to electrical generation, including those that may be developed over time, should be transferred to the SPEED Facilitator for the benefit of utility ratepayers. We included the following definition in the standard contract:

13. Docket 7533, Order of 9/30/09 at 24.

> 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.

At the October 8, 2009, workshop, participants were asked to provided further comments on the definition of other products, including whether waste heat should be included in the definition.

Participants' Comments

The Department supported the definition of other products in the September 30 Order and stated that products which were not included in the costs developed for the project should be available to be sold for the benefit of ratepayers. CVPS also supported the concept that products that produce revenue streams, or avoid costs that were not taken into account as a price offset in the rate-setting process, should pass to the SPEED Facilitator.

Comments filed by BED, the Biomass Energy Resource Center ("BERC"), Carbon Harvest Energy, Delta Energy Group, REV, and AAFM argued that ancillary heat or waste heat from combined heat and power or engine exhaust should not be included in the definition of other products since they are not directly connected to the production of electricity or tradeable commodities. Commenters argued that the thermal energy was a valuable onsite asset in the determination of the economics of a biomass, combined heat and power, or methane project.

Comments filed by BED, Carbon Harvest Energy, CVPS, and REV supported the inclusion of renewable energy credits ("RECs"), capacity credits, carbon offsets, or greenhouse gas credits in the definition of other products. AAFM argued that the definition should include all products that are related to generation that the utility can reasonably monetize and not the CO_2 in the exhaust gases or other physical product that may be developed in the future.

BERC further argued that Act 45 authorizes the assignment of only tradeable RECs and capacity rights to the SPEED Facilitator and the standard-offer contract should only assign these two commodities to the SPEED Facilitator.

Discussion and Conclusions

The September 30 Order concluded that the standard contract should transfer any and all future products that arise from the generation of projects accepting the standard offer. We are persuaded by the commenters' arguments that ancillary or waste heat should not be included in the definition of other products, given that they are not associated directly with the production of electricity or tradeable commodities.

We are therefore revising the definition in the standard contract to include the following:

> 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 (1) tradeable renewable energy credits, as defined in 30 V.S.A. § 8002(8), directly attributable to plants using methane from agricultural operations; and (2) ancillary heat associated with engine exhaust, combined heat and power systems, or biomass systems.

As discussed in the September 30 Order, we clarify that the definition of other products includes carbon offsets, greenhouse gas credits, or other tradeable emission credits. With respect to AAFM's argument that CO_2 in the exhaust gases should not be included in the definition of other products, there is insufficient information to make such a determination at this time. We will address such issues as they arise.

With regard to BERC's comment that only tradeable RECs and capacity rights should be assigned to the SPEED Facilitator, we concluded in the September 30 Order that other products related to electrical generation are transferable and BERC has not provided sufficient rationale for us to revisit that issue.

Rating of Nameplate Project Capacity

Section 8002(13) defines plant capacity as "the rated electrical nameplate for a plant." In response to prior comments, at the October 8, 2009, workshop, participants were asked to provided further comments on plant capacity.

Participants' Comments

The Department contends that the legislation specifically defined the plant capacity as the rated electrical nameplate for a plant and that the definition of plant refers to an independent technical facility that generates electricity from a renewable source. The Department concludes that these definitions imply that the rated value of the generating equipment should apply. The Department points out that every energy technology has interconnecting and transformation equipment that effects its energy production and reduces the capacity value from the nameplate value and the legislation has defined capacity as “nameplate” value.

Comments filed by Alteris, CVPS, Green Mountain Electric, Longview, and REV argued that the nameplate capacity of a plant should be a measurement of its ability to deliver electricity to the grid. Commenters contended that nameplate capacity should account for losses associated with mismatch of panels, conversion from DC to AC in the inverter, and line losses within the wire of the plant. Commenters stated that plant capacity could be determined by calculation or be certified by an independent engineer.

AAFM argues that the nameplate capacity should be determined by a qualified engineer. AAFM contends generator output could be significantly different from the nameplate capacity, giving the example of a generator rated at 600 kW for three-phase system but the output rating is 200 kW on single-phase.

Discussion and Conclusions

In defining plant capacity, Section 8002(13) specifically refers to "the rated electrical nameplate for a plant." The Energy Information Agency defines generation nameplate capacity as: "The maximum rated output of a generator under specific conditions designated by the manufacturer. Generator nameplate capacity is usually indicated in units of kilovolt-amperes (kVA) and in kilowatts (kW) on a nameplate physically attached to the generator."[14]

Even if the statute were not clear, commenters have not provided a sufficient rationale for including conversion and ancillary losses in the definition of plant capacity. The use of ancillary

14. Energy Information Agency at www.eia.doe.gov/glossary/glossary_g.htm#gen_nameplate.

losses in defining capacity would result in a moving target. Any efficiency improvements in the system that reduced ancillary losses could result in a change in plant capacity.

We conclude that the statute clearly intends for plant capacity to be defined as the maximum output of the generating equipment, as rated by the manufacturer and defined by the nameplate rating, and not to include adjustments for losses from ancillary equipment or transformation from DC to AC.

Allocation of Facilitator Costs

In our September 30, 2009, Order, we addressed the allocation of SPEED Facilitator costs, stating as follows:

> 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.

The Board received an inquiry about the potential range of costs that could be allocated to producers, particularly small ones. The developer was uncertain about the potential for significant cost allocations that could affect the cost-effectiveness of projects.

Participants' Comments

In comments, ReKnew Energy Systems ("ReKnew") argues that some possible allocations could lead to higher costs for certain categories of SPEED resources, in particular those of smaller sizes.

The SPEED Facilitator commented that because of the uncertainty regarding the number and size of projects that would apply under the Standard Offer program in a given year it is not productive to suggest a methodology for allocating the SPEED Facilitator's costs. The SPEED Facilitator also observed that the effort necessary to administer a project often is not proportional to the size of the project. Nonetheless, the SPEED Facilitator proposed that it may be appropriate to make some accommodation for projects under 15 KW. The SPEED Facilitator proposes a minimum fee of $120 per month, which would be split between the producer and utilities.

Discussion and Conclusions

The statute provides the Board substantial flexibility in determining how to recover the costs of the SPEED Facilitator, specifying only that we allocate the expenses "among plant owners and Vermont retail electricity providers."[15] No party has proposed a specific allocation methodology, although the SPEED Facilitator has now suggested a minimum fee for smaller projects. We also do not know what the level of expenses will be each year nor the specific projects to which such expenses would be allocated, particularly since the Board has no concrete information on the number and size of projects that will begin producing power within the next year. Nonetheless, we recognize the concerns expressed by ReKnew that certain allocation methodologies could lead to material cost impacts for some producers. In particular, certain methodologies could result in an allocation of expenses that would be immaterial for most plant owners, but would be large enough as to materially alter the expected revenue stream from smaller projects.

Considering the uncertainty over the level of expenses and number of projects and the absence of a concrete proposal, the Board is not in a position to specifically establish the

15. 30 V.S.A. § 8005(h)(1).

methodology that will be used to allocate expenses between the SPEED Facilitator and the project owners. Nonetheless, we reiterate what we stated previously: it is our intention that whatever methodology that is adopted will ensure that the expenses allocated to individual projects will not represent material costs for those projects. This is consistent with the assumptions of the Cost Subgroup.[16]

Status of Utility Purchase Power Agreements

Following the September 30 Order, BED commented that the Order did not "fully address whether purchase power agreement ("PPA") structures will be allowed to qualify as utility projects." In particular, BED noted that the Order did not explicitly address the definition of "ownership," which it states raises some ambiguity.

On October 14, 2009, BED filed a motion to alter the September 30 Order to allow PPAs between utilities and developers to be considered utility projects for the purpose of the standard-offer program. BED does not present new arguments in its motion that have not been considered here.

Participants' Comments

In its comments, BED argues that, under a PPA arrangement, the utility would be the plant owner, and thus the project would be considered a utility project for purpose of the standard-offer program. In addition, BED observes that while Section 8005(b)(2) states that only plants owned and operated by a utility count toward the 50 MW cap, in Section 8005(g)(2), the statute provides credits for utilities if they own *or* operate a plant. Thus, according to BED, the utility would still get a credit if it either owned or operated the facility. BED asserts that ratepayer interest is best served by allowing PPAs to qualify as resources under the standard-offer program and that, unless the Board allows such an outcome, utilities would be at a substantial disadvantage.

16. It is not clear whether the SPEED Facilitator's proposed allocation would meet this standard. The proposal could lead to costs of $660 annually for producers which, over the 25-year life of a small solar project, could materially affect the expected returns from such a project.

Longview asserts that utility projects should not have any advantage over non-utility projects.

AAFM contends that unless the utility owns the project, it is not part of the program. In the case of a PPA, AAFM argues that the PPA would need to be in place before the utility project enters the queue.

REV supports the use of PPAs as a way of establishing ownership and/or operation of a standard-offer plant.

Discussion and Conclusions

As we explained in the September 30 Order, Section 8005 contains some ambiguity as to how the standard-offer program mandated by subsection (b) would operate, including issues relating to project eligibility, the size of the program, and the relationship of utility projects. In that Order, we concluded that the legislature intended that the program would be capped at 50 MW and that utility projects would need to participate in the queue if they were to be counted as part of the standard-offer program. As BED observes, we did not specifically address the issue of whether a project in which the utility enters into a PPA with a developer would constitute a utility owned-and-operated project.

Based upon Section 8005, we conclude that a PPA between a utility and a producer would not grant the utility ownership for purposes of Section 8005. Section 8005(b)(2) states that "a plant owned and operated by a Vermont retail electricity provider shall count toward th[e] 50-MW ceiling." Similarly, Section 8005(g)(2) grants utilities credits against the allocation of costs and power from the SPEED Facilitator if the utility owns or operates the facility. The statute does not specifically define these terms. However, the common sense understanding of ownership would not extend to a PPA. For example, Black's Law Dictionary defines owner as the "person in whom is vested the ownership, dominion, or title of property." A PPA does not meet such a standard. Typically, under a PPA, the purchaser acquires the right to some or all of the output of a generating facility for a specified period of time. The purchaser does not thereby acquire title to the plant itself.

We also find BED's citation to the statutory definition of Plant Owner to be unpersuasive. As BED argues, Section 8002(14) does define "Plant owner" to be "a person who has the right to sell electricity generated by a plant." This definition does not apply to utility projects, however, as the statute uses different terminology (owned and operated). Moreover, we also interpret the definition more narrowly than does BED and do not find that it was intended to classify an entity that acquires the right to essentially resell the power output as the plant owner; the plant owner is the person who has the right to sell the output the first time.

We also note that, in order to qualify as a resource that would reduce the 50 MW cap, a project would need to be both owned *and* operated by the utility. Thus, the utility would also need to be the operator of the qualifying SPEED resource in order to enable the generation facility to reduce the 50 MW cap. Moreover, as we discuss elsewhere in this Order, the proposed project would still need to participate in the queue that we established in the September 30 Order.

Transferability of Queue Position

In the September 30 Order, we concluded that standard-offer contracts could be transferred between counterparties. This is specifically permitted by Section 8005(g)(1). BED requests that the Board clarify that projects also may be transferred between parties (including from a developer to a utility) prior to execution of the standard-offer contract.

Participants' Comments

BED contends that this transferability is necessary to account for the fact that utilities are not required to execute standard-offer contracts (which themselves can be transferred).

Green Mountain Electric asserts that the Board should not permit the transfer of a queue position from a utility to the developer.

REV contends that queue positions should be transferable. However, REV asserts that once a standard-offer contract is signed, the contract (and queue position) may not be transferred to a utility since the change in terms would constitute a breach of the contract.

Longview argues that, while a standard-offer contract is transferable, queue positions should not be. This, Longview maintains, is necessary to prevent misuse of the application process.

Discussion and Conclusions

We agree with BED that, prior to execution of the standard-offer contract, a project in the queue may be transferred to another party. This is consistent with the intent of Section 8005(g)(1), which allows such a transfer after execution of the standard-offer contract. It is important to stress, however, that what is being transferred is the specific project that has been proposed to the SPEED Facilitator in the application, not simply a position in the queue. It is not permissible to simply transfer a queue position and then construct a project that is different from that originally proposed (except to the degree permitted by the standard contract).

The concern of participants about transferability raises broader questions about methods by which applicants may seek to gain unfair advantage in the application process. To the extent possible, in this Order and in the September 30 Order we have defined standards that seek to minimize this risk. Thus, we require that an applicant identify a specific project at a specific location. We also expect the SPEED Facilitator to look closely at projects that are filed separately, but appear to be closely related so that they may be properly viewed as one project. Moreover, we want to make clear that only one application for a particular project may be submitted; a prospective plant owner may not cause to be submitted multiple applications describing essentially the same project.

Sharing of Costs and Benefits of Utility Projects

In the September 30 Order, we examined the disposition of electricity, RECs and other benefits associated with the generation produced by utility-developed projects. We concluded that the statute was unclear. In addition, we stated that:

> 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.

Participants' Comments

BED argues that the products should follow the revenue stream paying for them. Thus, if the utility is receiving monetary compensation from the SPEED Facilitator for the products, then they should be transferred; if not, the utility should retain the right to the products.

The Department maintains that utility ownership of SPEED projects should be encouraged. Thus, the Department supports measures that would encourage utility ownership of projects, which would counsel in favor of the utility retaining the RECs and other attributes.

GMEU asserts that resolution of issues related to the treatment of the costs and benefits of utility projects is essential for utilities. GMEU suggests that utilities need such information in order to decide how to participate in the program.

CVPS concurs with the comments of BED and GMEU suggesting the need for resolution of issues of utility credits. CVPS contends that, to the extent that the Board does not resolve the issues associated with the allocation of project costs and benefits, the Board should permit the utility to withdraw the project upon request (even if the project has been commissioned). CVPS maintains that otherwise, the utility would need to make a binding commitment without knowing the full range of costs and benefits.

Discussion and Conclusions

As we stated previously, the allocation of RECs and other attributes of utility-owned projects is a complex issue. We remain convinced that this issue will require more time to evaluate than we now have available. Thus, we reach the same conclusion we did in the September 30 Order: we will resolve issues related to the allocation of utility costs and benefits subsequent to the October 19, 2009, commencement of the standard-offer program.

We understand that the absence of a final decision at this time may affect a utility's decision to develop SPEED projects that would serve as a reduction to the 50 MW cap. Based upon the benefits of new renewable generation that pursuant to Section 8005(g)(2) results in a credit against the allocation of power and costs from standard-offer projects, it would appear that utilities have sufficient incentive to develop projects on their own even without knowing the disposition of RECs and other products. Nonetheless, to provide increased certainty to the utilities, we adopt CVPS's proposal that a utility may withdraw a project from participation under the program in Section 8005 once the Board resolves the allocation of costs and benefits of utility projects. This would include the ability to withdraw an already-commissioned resource. This decision should be made promptly following our resolution of those issues.

Eligibility for Queue Position

Longview argues that the Board should institute some good faith requirements for who can occupy a space in the queue. Longview asserts that the entity submitting the application should be responsible for all steps in the qualification process.

Participants' Comments

AAFM contends that any entity in the queue must be capable of completing the project and fulfilling the contract.

Discussion and Conclusions

The comments expressed at the workshop and in writing indicate some uncertainty concerning the eligibility for participation in the standard-offer program, but it is unclear on what precise issue the commenters seek guidance. We will therefore provide narrow guidance that we expect will address these concerns.

It is clear that the responsible party that must sign a standard-offer contract is the plant owner (or an agent duly authorized to bind the plant owner). Under the program, the plant owner is the entity entitled to receive payments for power.[17] It is appropriate to have the entity that receives the benefits of the contract be the same one that bears the responsibility for fulfilling the contractual obligations.

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17. *See, e.g.*, Section 8005(b)(2).

For the application process by which entities gain access to the queue, we do not find it necessary to limit the permissible signatories to the plant owners. Nonetheless, any entity that submits a project for the queue must be in a position to demonstrate a bona fide project and the fact that the applicant has site control. Under the process developed by the SPEED Facilitator, this demonstration occurs soon after the application. The relatively short period of time between the application and the requirement for this demonstration (and tendering of deposits) should ensure that projects that may not be bona fide are rapidly identified and removed from the queue without the need for us to precisely define who must sign an application.

Utility Payment of Deposits

In our September 30 Order, we required that utility projects enter the queue if they seek to qualify under Section 8005 (as reducing the 50 MW cap and being eligible for credits against the allocation of power and SPEED Facilitator expenses). We observed that:

> 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.[18]

GMEU has requested us to consider whether utilities must pay project-based SPEED Facilitator fees or deposits. GMEU notes that utilities will already be paying a significant portion of the SPEED Facilitator's expenses.

No other party commented on this issue.

We specifically addressed this issue in the September 30 Order (in the passage quoted above). GMEU has presented no information that causes us to reconsider that determination. We understand, as GMEU argues, that the utilities are already paying a substantial portion of the SPEED Facilitator's costs. The administrative fee under the program, however, is quite small, and thus should not represent a burden. The deposit, while larger, remains refundable, so it is not

18. Order of 9/30/09 at 35.

a long-term cost to the utility. We continue to find that requiring the utility to pay these fees is appropriate.

Future Issues

We recognize that additional implementation issues are likely to arise in a new, complex program such as this. We will address future issues as they arise.

SO ORDERED.

Dated at Montpelier, Vermont, this 16th day of October, 2009.

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

OFFICE OF THE CLERK

FILED: October 16, 2009

ATTEST: s/Judith C. Whitney
Deputy 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.