STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket No. 8817

| Investigation into programmatic adjustments to the standard-offer program | |
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Order entered: 3/2/2017

# ORDER RE 2017 TECHNOLOGY ALLOCATION AND PRICE CAPS FOR THE STANDARD-OFFER PROGRAM

## I. INTRODUCTION

Pursuant to 30 V.S.A. § 8005a(c)(2), the Vermont Public Service Board ("Board") is directed to implement a standard-offer program for eligible new renewable energy plants until a cumulative plant capacity amount of 127.5 MW is reached. In this Order, the Board revises the mechanism, established in 2016, for the allocation of available capacity for the remainder of the standard-offer program established under 30 V.S.A. § 8005a.

In addition, in today's Order, pursuant to Section 8005a(f)(3), we determine the avoided costs that will serve as price caps on the standard-offer projects solicited through the 2017 Request for Proposals ("RFP"). We also determine the avoided costs that will serve as the prices for farm methane projects under the standard-offer program.

## II. BACKGROUND AND PROCEDURAL HISTORY

Pursuant to Section 8005a(f)(3), the Board is required to annually review the established avoided costs under the standard-offer program. In addition, Section 8005a(c)(2) requires the Board to allocate the 127.5 MW cumulative capacity of the standard-offer program among different categories of renewable energy technologies.

On March 1, 2013, the Board established, pursuant to Section 8005a(f)(1), an RFP mechanism to determine the standard-offer projects that will fill annual plant capacity available under the program, and directed the Standard Offer Facilitator,[1] by April 1 of each year, to issue an RFP to solicit standard-offer projects to meet the requirements of Section 8005a(c).[2] The 2013 Order also established technology-specific avoided costs to serve as caps on the standard-offer prices solicited through the RFP.

[1] VEPP Inc. serves as the Standard-Offer Facilitator under contract to the Board. The 2017 RFP will be available at: http://vermontstandardoffer.com.

[2] Dockets 7873 and 7874, Order of 3/1/13 (the "2013 Order").

On February 12, 2016, the Board issued an Order establishing a mechanism for the allocation of available capacity for the remainder of the standard-offer program pursuant to Section 8005a(c)(2).[3]

On March 7, 2016, pursuant to Section 8005a(f)(3), the Board determined the technology-specific avoided costs that will serve as price caps on the standard-offer projects solicited through the 2016 RFP.[4] In addition, the Board determined the avoided costs that will serve as the prices for farm methane projects under the standard-offer program.[5]

On June 13, 2016, Public Act 174 ("Act 174") became law. Act 174 codified Section 8005a(c)(1)(D), which mandates changes to the standard-offer program that require the Board to establish a pilot project for standard-offer projects located at "preferred locations." Act 174 requires that:

> For one year commencing on January 1, 2017, the Board shall allocate one-sixth of the annual increase to new standard offer plants that will be wholly located in one or more preferred locations other than parking lots or parking lot canopies and, separately, one-sixth of the annual increase to new standard offer plants that will be wholly located over parking lots or on parking lot canopies.

This change requires the Board to adjust the technology allocations established in the February 2016 Order.

Further, Act 174 codified Section 8005a(f)(5), which identifies the methodology the Board must employ to determine standard-offer prices for the preferred-location projects.

On September 16, 2016, the Board opened an investigation into programmatic adjustments to the standard-offer program that included the changes mandated by Act 174 and a review of the price caps on standard-offer projects solicited through the 2017 RFP.[6]

On October 4, 2016, Board staff conducted a workshop to discuss the programmatic adjustments to the standard-offer program.

On October 27, 2016, VEPP Inc. filed comments regarding the annual increase of standard-offer program capacity.

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[3] *Order Re Standard Offer Program Technology Allocation*, Dockets 7873 and 7874, Order of 2/12/16 ("February 2016 Order").

[4] *Order Re 2016 Prices for the Standard-Offer Program*, Dockets 7873 and 7874, Order of 3/7/16 ("March 2016 Order").

[5] Pursuant to Section 8005a(g), farm methane projects remain outside the programmatic cap, so these projects do not compete in the market-based RFP process.

[6] *Order Opening Investigation and Notice of Workshop*, Docket 8817, Order of 9/16/16.

On October 28, 2016, comments were filed by the Vermont Department of Public Service ("Department"), Allco Renewable Energy Limited ("Allco"), the City of Burlington Electric Department ("BED"), Fundamental Energy, LLC ("Fundmental Energy"), Green Mountain Power Corporation ("GMP"), Star Wind Turbines ("Star Wind"), and Vermont Public Power Supply Authority ("VPPSA"), and comments were jointly filed by Representative Tony Klein, Senator Brian Campion, and Representative Kesha Ram.

On November 10, 2016, reply comments were filed by the Department, the Vermont Agency of Natural Resources ("ANR"), and GMP.

On December 15, 2016, Sustainable-AG Services Company, LLC ("SASCO") filed comments.

In a December 14, 2016, memorandum, the Board requested the Department to file additional recommendations regarding the standard-offer price caps and established a deadline for reply comments.

On January 27, 2017, the Department filed additional recommendations for price caps, and on February 3, 2017, the Department filed follow-up recommendations.

On February 10, 2017, Allco, Essex Capital Partners ("Essex Capital"), GMP, Renewable Energy Vermont ("REV"), Triland Partners LP ("Triland"), and VPIRG filed reply comments.

On February 17, 2017, the Department filed reply comments that included revisions to the assumptions used to calculate the standard-offer price caps.

On February 22, 2017, Star Wind filed reply comments.

No other comments have been received.

## III. Technology Allocation

In the February 2016 Order, we adopted a technology allocation to remain in effect for the remainder of the standard-offer program unless changed by subsequent Board Order. Under the established mechanism, in years 2016-2018, 2.2 MW of the available Developer Block program capacity is available to projects of any technology category, awarded on bid price (the "Price-Competitive Developer Block"). The remainder of the Developer Block capacity – estimated to be approximately 4.175 MW for the years 2016-2018 – is allocated on an equal basis to non-solar technology categories[7], awarded on bid price within each category (the "Technology Diversity Developer Block").

Annual Increase

Pursuant to 30 V.S.A. § 8005a(c)(1)(A), the annual increase to the standard-offer program capacity is 7.5 MW for the year 2017. In addition, pursuant to Section 8005a(c)(1)(B)(ii), any unsubscribed capacity from the Provider Block is added to the annual increase. For the 2017 RFP, the unsubscribed Provider Block capacity is 1.125 MW, resulting in an actual increase of 8.625 MW.

Under the pilot program, in 2017, pursuant to Section 8005a(c)(1)(D), one-sixth of the annual increase shall be allocated to projects located over parking lots or on parking lot canopies and one-sixth of the annual increase shall be allocated to standard-offer projects at other preferred locations. In addition, in 2017, pursuant to Section 8005a(c)(1)(B)(i), 15% of the annual increase shall be allocated to the Provider Block.

Accordingly, for the 2017 RFP, the following shall be allocated:

- 1.4375 MW for projects located over parking lots or on parking lot canopies;
- 1.4375 MW for projects located at other preferred locations;
- 0.8625 MW for the Provider Block; and
- 5.75 MW for the Developer Block.

Participants' Comments

The Department recommends that the existing allocation mechanism approved by the Board in 2016 be adjusted to accommodate the pilot program for preferred locations. The Department's adjustments include replacing the Price-Competitive Developer Block with the pilot program allocations and distributing the remaining Developer Block capacity over the six technologies established in the Technology Diversity Developer Block.[8] The Department further recommends that any unused capacity be reallocated based on bid price to the Price-Competitive Developer Block.

GMP also recommends that the existing allocation mechanism approved by the Board in 2016 be adjusted to accommodate the pilot program for preferred locations. GMP's adjustments include adding a pilot program block at a 2.875 MW allocation, retaining the

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[7] The non-solar technology categories currently include hydroelectric, biomass, large wind, small wind, landfill gas, and food waste anaerobic digestion.

[8] The Department's analysis assumes the annual increase for the standard-offer program is 7.5 MW.

Price-Competitive Developer Block at 2.2 MW allocation, and retaining the Technology Diversity Developer Block with a 0.488 MW allocation to each of the six technologies. GMP contends that the Department's approach of replacing the Price-Competitive Developer Block "puts a great deal of weight on technology diversity and will likely result in higher program costs."

VPPSA also recommends that the existing allocation mechanism approved by the Board in 2016 be adjusted to accommodate the pilot program for preferred locations. VPPSA recommends retaining the Price-Competitive Developer Block and Technology Diversity Developer Block with adjustments to the technologies that compete in each block. VPPSA recommends that solar and all of the technologies with price caps determined to be lower than the solar price cap compete in the Price-Competitive Developer Block and the remaining technologies compete in the Technology Diversity Developer Block. VPPSA contends that this approach would promote technological diversity "while leveraging the competitive bidding mechanism to secure distributed resources at the lowest feasible cost to ratepayers."

REV recommends that the Board maintain the Technology Diversity Developer Block established by the Board in 2016. Star Wind recommends that the Technology Diversity Developer Block remain at 4.175 MW allocation, with each technology receiving an approximately 0.695 MW allocation. Star Wind further recommends that the Price-Competitive Developer Block be reduced by the allocation required for the pilot program block.[9]

BED, GMP, and VPPSA recommend that the 2017 RFP limit the size of the individual projects accepted in the two categories for the pilot program block to a size no larger than the 1.4375 MW allocation, rather than the standard-offer program project limit of 2.2 MW. VPPSA contends this is consistent with Board precedent under the Provider Block, another instance where the statute has limited the amount of available annual capacity to an amount lower than the per-project limit.

Discussion

As identified in previous Board Orders, our decision with respect to the creation of a technology allocation mechanism is guided by the applicable statutory goals and directives of

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[9] Star Wind's analysis incorrectly assumes that the annual increase for the standard-offer program is 2.5 MW.

Sections 8001 and 8005a as well as the goals expressed by stakeholders for a technology allocation that is stable, predictable, and transparent.[10]

Any technology allocation must balance statutory goals and directives that may seemingly be at odds — for instance, supporting the inclusion in Vermont's retail electric supply portfolio of a diversity of renewable energy projects, both in size and in technology, while at the same time ensuring the timely development of such projects at the lowest feasible cost. The allocation must also take into consideration the varying market interest in developing projects from each technology category.

Based on the introduction of the one-year pilot program for preferred locations and our review of the technology allocation methodologies recommended by participants, we are modifying the technology allocation established in our February 2016 Order. As described further below, we are continuing a structure that includes a Price-Competitive Developer Block and a Technology Diversity Developer Block, and for 2017, adding a Preferred Location Block.

Accounting for the unsubscribed capacity from the 2016 Provider Block and the Preferred Location Block, the size of the Developer Block for the year 2017 will be approximately 5.75 MW. The Developer Block will be approximately 6.375 MW for year 2018, and will be approximately 8.0 MW for each of the years 2019-2021. In the years 2017-2018, we direct the Standard Offer Facilitator to make 2.2 MW of this capacity available each year to the Price-Competitive Developer Block for projects of any technology category, awarded based on bid price. For the remainder of the Developer Block capacity — approximately 3.35 MW in 2017 and approximately 4.175 MW in 2018 — we direct the Standard Offer Facilitator to allocate this capacity to the Technology Diversity Developer Block on an equal basis for each non-solar technology category with an avoided-cost price cap greater than the solar price cap. For 2017, the Technology Diversity Developer Block will include small wind and food waste anaerobic digestion projects. Within each technology category, contracts will be awarded based on submitted bid prices, with the lowest-priced bids awarded contracts until each technology-specific set-aside has been fulfilled. The cap on a technology category may be exceeded if the marginal bid exceeds the remaining space for that category.

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[10] *See* February 2016 Order.

In the years 2019-2021, because the size of the Developer Block will be increasing, we direct the Standard Offer Facilitator to increase the size of the Price-Competitive Developer Block to 4.4 MW annually. For the remainder of the Developer Block capacity — approximately 3.6 MW for each of the years 2019-2021 — we direct the Standard Offer Facilitator to allocate this capacity in the same manner as described above for the Technology Diversity Developer Block.

In the event that there is any unbid capacity within technology-specific set-asides for the Technology Diversity Developer Block in any given year, we direct the Standard Offer Facilitator to award such capacity to project bids from any technology, including solar, on the basis of bid price alone. We wish to make clear that although each set-aside in the Technology Diversity Developer Block will be smaller than the 2.2 MW maximum project capacity allowed, an individual project that exceeds a technology category's set-aside shall be eligible to submit an RFP bid as long as the project is not larger than the 2.2 MW standard-offer project cap.[11]

Pursuant to Section 8005a(c)(1)(D), for 2017, we direct the Standard Offer Facilitator to make available a Preferred Location Block consisting of two categories: 1.4375 MW of capacity for projects located over parking lots or on parking lot canopies; and 1.4375 MW of capacity for projects located at other preferred locations. Contracts will be awarded based on submitted bid prices, with the lowest-priced bids awarded contracts until each category set-aside has been filled. In the event that there is any unbid capacity within category set-asides for the Preferred Location Block, pursuant to Section 8005a(c)(1)(D)(iii), we direct the Standard Offer Facilitator to award such capacity to project bids from any technology, including solar, on the basis of bid price alone.

Pursuant to Section 8005a(c)(1)(B)(i), for 2017, we direct the Standard Offer Facilitator to make available a Provider Block consisting of approximately 0.8625 MW of capacity. In event there is any unbid capacity within the Provider Block, that capacity will be allocated to the 2018 annual increase for the standard-offer program. For year 2018, the Provider Block will be approximately 1.125 MW, and for years 2019-2021, approximately 2 MW for each year.

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[11] As noted below, this principle does not apply to the Provider Block or the Preferred Location Block.

Consistent with previous Board Orders, the annual capacity caps for the Preferred Location Block and the Provider Block will serve as a hard cap on the size of the eligible project, rather than the 2.2 MW standard-offer project cap.[12] Our determination of hard caps for projects in these blocks is guided by the enabling legislation for the standard-offer program establishing annual limits for these blocks. The Legislature set annual caps for these technology blocks with the full understanding that plants up to 2.2 MW were eligible to receive standard-offer contracts. Thus, it is reasonable to conclude that the annual limits for the Provider Block and the Preferred Location Block were intended to be a hard cap on the size of the projects in these blocks.

We conclude that the above technology allocation mechanisms — which include many of the elements proposed by stakeholders — properly balance the applicable statutory goals and directives while also providing stability, predictability, and transparency to standard-offer program participants.

The table below shows the approximate capacity allocation for the 2017 RFP.

**2017 Standard-Offer Program Technology Allocation**

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| Price-Competitive Developer Block | 2.2 MW |
| Technology Diversity Developer Block | |
| Small Wind | 1.675 MW |
| Food Waste Methane | 1.675 MW |
| Preferred Location Block | |
| Parking Canopies | 1.4375 MW |
| Other Preferred Locations | 1.4375 MW |
| Provider Block | 0.8625 MW |

## IV. Price Caps for Solar Projects

Participants' Comments

The Department proposes an avoided-cost price cap of $0.130 per kWh for solar projects solicited through the 2017 RFP.[13] The Department reviewed the assumptions and cash-flow model used to determine the existing solar price cap. The cash-flow model, which was developed collaboratively by stakeholders in Docket 7533, has been used by the Board in

[12] *Order Re 2014 Standard-Offer Provider Block*, Docket 7873 and 7874, Order of 8/6/14.

[13] The solar price cap for the 2016 RFP was $0.130 per kWh.

previous standard-offer proceedings to estimate the prices that a new project would need in order for the developer of that project to earn a reasonable return on investment.[14]

Specifically, the Department recommends that the following assumptions be used as inputs for the solar cash-flow model:

- Project Size: Assume 2.2 MW. (No change from 2016 assumption.)
- Capacity Factor: Assume 14.5%. (No change from 2016 assumption.)
- Installation Costs: Assume $1.82 per watt, derived by reducing the 2016 value by 1%. The 2016 installation cost was based on a 2016 study of Vermont solar installations.[15] The cost estimate includes the costs for the solar panels and other materials, installation labor, interconnection, and permitting. (The 2016 solar price cap assumed $1.84 per watt.)
- Inverter Replacement Costs: Assume a cost of $400,000 for inverter replacement in year 12 of the project life. (No change from 2016 assumption.)
- Annual Maintenance Cost: Assume $25,000 per year, adjusted annually for inflation. (No change from 2016 assumption.)
- Land Lease Costs: Assume 6.8 acres per MW (approximately 15 acres for a 2.2 MW project) at $1,500 per acre. Annual property taxes are assumed to be included with lease payment. (The 2016 solar price cap assumed $1,000 per acre.)
- Decommissioning Costs: Assume $528 per year, adjusted annually for inflation, for acquiring a letter of credit. Assume $60 per kW for decommissioning reserve fund. (The 2016 solar price cap assumed no reserve fund.)
- Insurance Costs: Assume 0.40% of total installation costs charged annually. (No change from 2016 assumption.)
- Income Tax: Assume state rate of 8.5% and federal rate of 35%. (No change from 2016 assumption.)
- Investment Tax Credit ("ITC"): Assume 100% realization of the 30% federal ITC and 50% realization of the 7.2% state ITC. Federal ITC applied to non-transmission-related installation costs (97.5% of total costs). State ITC applied to non-transmission-related

[14] See Docket 7533, Order of 1/15/10; Docket 7780, Order of 1/23/12; Docket 7874, Order of 3/1/13; Docket 7874, Order of 3/10/15; and Docket 7874, Order of 3/7/16.

[15] *See Vermont Solar Cost Study*, prepared for the Clean Energy State Alliance and the Vermont Department of Public Service, dated February 2016.

installation costs reduced by annual federal tax amount. (The 2016 solar price cap assumed 100% realization of both the federal and state ITC.)

- State Uniform Capacity Tax: Assume $4.00 per kW of AC capacity or $8,800 per year. (No change from 2016 assumption.)
- Municipal Tax: Assume 0.50% tax rate applied to 70% of the net present value of the project's net cash flows in year one, fixed annual payment over life of project. Value based on current taxation rule. (The 2016 solar price cap assumed 0.75%, adjusted annually for inflation.)
- Inflation: Assume 1.86% annually, which reflects the increase in inflation over the past year. (The 2016 solar price cap assumed 1.80% annually.)
- Debt Repayment Reserves: Assume one half of the amount of the first-year long-term debt payment is placed into a reserve account earning interest at the rate of inflation until released into operating income at the end of the debt term. (The 2016 solar price cap assumed two-thirds of the amount of first-year long-term debt payment.)
- Working Capital: Assume that one half of the amount of the first-year operating expense is placed into a reserve account earning interest at the rate of inflation until released into operating income in the last year of the project life. (No change from 2016 assumption.)
- Financing Costs: Assume 3% charged on total debt principal for lender's fees plus an annual percentage rate ("APR") of 5% charged on the total amount of installation costs for 4.5 months to cover interest during construction ("IDC"). Assume no tax equity investor fee. (No change from 2016 assumption, except the removal of the tax equity investor fee of $150,000.)
- Capital Structure: Assume short-term debt is 30% of financing at starting rate of 3.5% for term of 6 years with rate increase of 20 basis points each year. Assume long-term debt is 30% of financing at a rate of 4.5% for term of 18 years with rate increase of 25 basis points each year for first 7 years. (The 2016 solar price cap assumed 3.0% for short-term financing and 4.5% for long-term financing.)
- Debt/Equity Ratio: Assume that the capital structure of a project would be 60% debt and 40% equity. (No change from 2016 assumption.)

- Weighted Average Cost of Capital ("WACC"): Calculated to be 6.01%, based on assumptions of 40% equity, 3.5% for short-term debt costs, and 4.5% for long-term debt costs.
- Rate of Return: Assume 9.02%, which is equivalent to GMP's current return on equity. (The 2016 solar price cap assumed 9.6%.)
- Depreciation Expenses: Assume all non-transmission-related installation costs (97.5% of total costs) reduced by half of federal ITC amount are expensed over 5 years per Modified-Accelerated Cost Recovery System ("MACRS") depreciation table. Assume all transmission-related installation costs (2.5% of total costs) are expensed over 15 years per MACRS depreciation table. Assume all financing costs, including IDC, expensed over 20 years per MACRS depreciation table. (No change from 2016 assumptions.)

Allco argues that the Department's assumptions on WACC are unrealistic and unsupported and that value should be 100 to 200 basis points higher. In support of its argument, Allco states that the value for GMP is 7.32% and that a non-utility project's WACC should be greater because GMP has the ability to cover its financial risk through a rate increase request. Allco also argues that the assumptions about short-term and long-term financing rates and capital structure are unrealistic and that permanent financing for solar projects is done on a long-term basis. With regard to the state ITC, Allco contends that solar projects are not eligible for the state ITC because corporations are prohibited from using the state ITC and passive activity loss rules limit the ability of individuals to use the state ITC.

With regard to installation costs, Allco argues that the component costs for interconnection ($85,300), permitting ($62,000), and general and administrative overhead ($8,900) are too low. In addition, Allco contends that the installation costs do not account for new screening requirements. With regard to maintenance costs, Allco contends that $25,000 per year is too low because the costs do not include monitoring costs, lawn mowing fees, utility fees, security measures, and phone and internet expenses. With regard to decommissioning costs, Allco contends that the costs associated with a letter of credit are low because they do not include the margin associated with acquiring the letter of credit.

REV recommends that the 2016 solar price cap be retained. REV further argues that the assumption about land lease costs do not reflect current market rates and should be 2 to 2.5

times greater. REV also contends that the Department's assumption concerning capital structure and debt financing underestimates the cost of financing a solar project. REV also claims that few projects are eligible for the state ITC.

VPIRG recommends that the solar price cap not be reduced from the 2016 value. VPIRG contends that the current RFP mechanism allows "the market [to] compete for the lowest bid," which is "an effective way of driving down project costs."

The Department recommends that the rate for short-term financing be changed to 3.5% from the 2016 assumption of 3.0%. The Department notes that the current commercial prime lending rate is 3.75%, and the Vermont Economic Development Association, a major lender to solar developers, offers subsidized variable rates starting at 3.0%.

The Department's land lease cost assumption is based on the average 2016 sales price for open land determined by the Vermont Department of Taxes. The Department assumes that the annual debt payment is $1,500 per acre, given the 2016 average sale price of $3,200 per acre. The Department maintains that this is a reasonable and documented assumption in comparison to REV's undocumented proposal of $2,500 per acre.

The Department recommends assuming a 50% realization for the state ITC, rather than the 100% realization assumed in 2016. The Department agrees that not all solar projects will be eligible to take advantage of the state ITC, but also recognizes that assumptions used for the solar price cap should be based on a cost-efficient project. The Department states that it is not aware of any tax law that prohibits an owner of an LLC or LLP from taking the state solar ITC.

Discussion

As in past standard-offer proceedings, we are establishing standard-offer prices based on the assumption that the projects being developed are reasonably efficient in an effort to balance the statutory directive to ensure sufficient incentive for rapid deployment against ensuring that the incentive is not excessive, and thereby unnecessarily costly for ratepayers. This means that projects are sited and financed so as to avoid excessive costs to electric ratepayers.[16] In addition, Section 8005a(f)(2)(B) identifies criteria the Board may consider in establishing an avoided-cost price cap.

[16] See Docket 7533, Order of 1/15/10, Docket 7780, Order of 1/23/12, and Docket 7874, Order of 3/7/16.

Based on a review of the assumptions and the cash-flow model analysis, we accept the Department's recommendation of an avoided cost of $0.130 per kWh for solar projects. The Department recommends several changes to the assumptions used to determine the 2016 solar price cap. The resulting price cap remains unchanged from 2016.

With respect to installation costs for solar projects, we are persuaded that $1.82 per watt, derived from a 2016 study of Vermont solar installations adjusted downward to reflect additional reductions in solar panel costs, represents an appropriate value of current costs. While Allco raises concerns about the accuracy of this assumption, we are persuaded that these installation costs are representative of an efficiently sited project.

Allco and other participants raise concerns about land lease costs, decommissioning costs, financing costs, weighted average cost of capital, and investment tax credits, but provide no project-specific information to challenge the accuracy of the cash-flow model assumptions. We agree with the Department's position that lending rates and debt financing support the assumption for 6.09% weighted average cost of capital. In addition, we conclude that there is a reasonable amount of flexibility in capital structures that should allow for a range of developers to bid below the proposed avoided-cost price cap, even if the capital structure assumptions in the cash-flow model do not apply to all developers equally. The Department's assumption on the state ITC appropriately recognizes that projects may have limited ability to claim the tax credit. Further, the Department has provided documented and reasonable assumptions concerning land lease and decommissioning costs.

The 2016 RFP results support our conclusions concerning the recommended solar price cap, with multiple bids to develop solar projects under the recommended price cap. In addition, the 2013 through 2016 RFPs have resulted in the available plant capacity being filled, standard-offer contracts issued, and plants built or under construction, meeting the statutory mandate for rapid deployment.

Using the assumptions recommended by the Department, the cash-flow model calculates an avoided cost of $0.130 per kWh for solar projects. Accordingly, for the 2017 RFP, we establish an avoided cost for solar projects of $0.130 per kWh, fixed over the life of the project.

## V. Price Caps for Small Wind Projects

Participants' Comments

The Department proposes an avoided-cost price cap of $0.232 per kWh for small wind projects solicited through the 2017 RFP.[17] The Department reviewed the assumptions and cash-flow model used to determine the existing small wind price cap. As discussed above, the cash-flow model has been used by the Board in previous standard-offer proceedings to estimate the prices that a new project would need in order for the developer of that project to earn a reasonable return on investment.

Specifically, the Department recommends that the following assumptions be used as inputs for the solar cash-flow model:

- Project Size: Assume 100 kW. (No change from 2016 assumption.)
- Capacity Factor: Assume 19%. (No change from 2016 assumption.)
- Installation Costs: Assume $5.50 per watt, based on review of recent Lawrence Berkeley National Laboratory study. The cost estimate includes the costs for the wind turbines and other materials, installation labor, interconnection, and permitting. (The 2016 small wind price cap assumed $5.77 per watt.)
- Annual Maintenance Cost: Assume $3,000 per year, adjusted annually for inflation. (No change from 2016 assumption.)
- Land Lease Costs: Assume $4,000 per MW (approximately 4 acres per MW at annual lease cost of $1,000 per acre). Annual property taxes are assumed to be included with lease payment. (The 2016 small wind price cap assumed no lease costs.)
- Insurance Costs: Assume 0.40% of total installation costs charged annually. (No change from 2016 assumption.)
- Decommissioning Costs: Assume $60 per kW for decommissioning fund. (The 2016 small wind price cap assumed no decommissioning costs.)
- Income Tax: Assume state rate of 8.5% and federal rate of 35%. (No change from 2016 assumption.)
- ITC: Assume 100% realization of the 18% federal ITC and 50% realization of the 7.2% state ITC. Federal ITC applied to non-transmission-related installation costs (95% of total costs). State ITC applied to non-transmission-related installation costs reduced by

[17] The levelized small wind price cap for the 2016 RFP was $0.253 per kWh.

annual federal tax amount. (The 2016 small wind price cap assumed 100% realization of the 24% federal ITC and 50% realization of the 7.2% state ITC.)

- State Production Capacity Tax: Assume $0.003 per kWh of AC capacity produced. (The 2016 large wind price cap assumed a combined municipal and state production capacity rate of 1.78% applied to 100% of the net present value of the project's net cash flows.)
- Municipal Tax: Assume 0.50% tax rate applied to 70% of the net present value of the project's net cash flows in year one, with a fixed annual payment over life of project.
- Inflation: Assume 1.86% annually, which reflects the increase in inflation over the past year. (The 2016 small wind price cap assumed 1.80% annually.)
- Debt Repayment Reserves: Assume one half of the amount of the first-year long-term debt payment is placed into a reserve account earning interest at the rate of inflation until released into operating income at the end of the debt term. (The 2016 small wind price cap assumed no debt payment reserve.)
- Working Capital: Assume that one half of the amount of the first-year operating expense is placed into a reserve account earning interest at the rate of inflation until released into operating income in the last year of the project life. (The 2016 small wind price cap assumed one quarter of the amount of the first-year operating expense is placed into a reserve account.)
- Financing Costs: Assume 3% charged on total debt principal for lender's fees plus an APR of 5% charged on the total amount of installation costs for 4.5 months to cover IDC. (The 2016 small wind price cap assumed an APR of 5% charged on the total amount of installation costs for 2.5 months to cover IDC.)
- Capital Structure: Assume short-term debt is 30% of financing at starting rate of 3.5% for term of 6 years with rate increase of 20 basis points each year. Assume long-term debt is 30% of financing at a rate of 4.5% for term of 18 years with rate increase of 25 basis points each year for first 7 years. (The 2016 small wind price cap assumed no short-term debt and assumed long-term debt is 45% of financing at a rate of 5.5% for term of 18 years.)
- Debt/Equity Ratio: Assume that the capital structure of a project would be 60% debt and 40% equity. (The 2016 small wind price cap assumed 60% equity.)

- Rate of Return: Assume 9.02%, which is equivalent to GMP's current return on equity. (The 2016 small wind price cap assumed 9.6%.)
- WACC: Calculated to be 5.86%, based on assumptions of 40% equity, 3.5% for short-term debt costs, and 4.5% for long-term debt costs.
- Depreciation Expenses: Assume all non-transmission-related installation costs (95% of total costs) reduced by half of federal ITC amount are expensed over 5 years per MACRS depreciation table. Assume all transmission-related installation costs (5% of total costs) are expensed over 15 years per MACRS depreciation table. Assume all financing costs, including IDC, expensed over 20 years per MACRS depreciation table. (No change from 2016 assumptions.)
- Bonus Depreciation: Assume an additional 40% of allowable federal ITC is depreciated in year one as provided by the Consolidated Appropriations Act of 2015. (The 2016 small wind price cap assumed no bonus depreciation.)

Fundamental Energy maintains that the 2016 small wind price should not be lowered, and that the past RFP results demonstrate the risks and costs of development.

REV also contends that the Department's assumptions concerning capital structure and debt financing underestimate the cost of financing a wind project. REV asserts that the federal ITC should be 18% for 2018. REV maintains that the assumption for property tax should be $10,000 per year. In addition, REV states that cash flow analysis does not reflect stricter sound and winter operational regulations that may require increased land requirements for small wind projects due to the need for project setbacks.

Star Wind contends that a sales tax should be included in the cash flow analysis for small wind projects. Star Wind maintains that small wind projects are not eligible for the state ITC and that small wind projects do not have the income to take advantage of the bonus depreciation tax benefit. Star Wind also contends that the Department has under-estimated financing costs. Star Wind maintains that installation costs should be assumed to be $6.90 per watt, given sound standards and permitting costs. Star Wind argues that sound standards will require increased land requirements for wind projects, and that small wind projects will need between 25 and 80 acres. Star Wind recommends a land lease assumption of $2,000 per year. Star Wind maintains that the Department's cash flow analysis has not accurately captured the costs of project decommissioning.

Discussion

Based on a review of the assumptions and the cash-flow model analysis, we accept the Department's recommendation of an avoided cost of $0.232 per kWh for small wind projects. With respect to installation costs for small wind projects, we are persuaded that $5.50 per watt, derived from a recent Lawrence Berkeley National Laboratory study, represents an appropriate value of current costs. While Star Wind raises concerns about the accuracy of this assumption, Star Wind has not presented information demonstrating that a higher cost is reasonable and that these installation costs are not representative of an efficiently sited project.

Participants raise concerns about land lease costs, decommissioning costs, and financing costs, but provide no project-specific information to challenge the accuracy of the cash-flow model assumptions. We agree with the Department's position on lending rates and debt financing. The Department notes that the current commercial prime lending rate is 3.75%, and the Vermont Economic Development Association offers subsidized variable rates starting at 3.0%. Further, the Department assumptions concerning decommissioning costs are consistent with the assumptions for solar projects. Land lease costs are assumed lower than solar projects, recognizing that wind projects have different land use patterns. In addition, the assumption about land lease costs recognizes that an efficiently sited wind project need not lease all the land between the project and the nearest non-participating residence to be in compliance with any applicable sound standards.

Using the assumptions recommended by the Department, the cash-flow model calculates an avoided cost of $0.232 per kWh for small wind projects. Accordingly, for the 2017 RFP, we establish an avoided cost for small wind projects of $0.232 per kWh, fixed over the life of the project.

## VI. Price Caps for Large Wind Projects

Participants' Comments

The Department proposes an avoided-cost price cap of $0.107 per kWh for large wind projects solicited through the 2017 RFP.[18] The Department reviewed the assumptions and cash-flow model used to determine the existing large wind price cap. As discussed above, the

[18] The levelized large wind price cap for the 2016 RFP was $0.116 per kWh.

cash-flow model has been used by the Board in previous standard-offer proceedings to estimate the prices that a new project would need in order for the developer of that project to earn a reasonable return on investment.

Specifically, the Department recommends that the following assumptions be used as inputs for the large wind cash-flow model:

- Project Size: Assume 2.0 MW. (The 2016 large wind price cap assumed 1.5 MW.)
- Net Capacity Factor: Assume 26.0%. (The 2016 large wind price cap assumed 25.8%.)
- Installation Costs: Assume $3.00 per watt, based on review of market research conducted by the National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory. The cost estimate includes the costs for the wind turbines and other materials, installation labor, interconnection, and permitting. (No change from the 2016 assumption.)
- Annual Maintenance Cost: Assume $49,080 per year, adjusted annually for inflation. (No change from 2016 assumption.)
- Land Lease Costs: Assume $4,000 per MW (approximately 4 acres per MW at annual lease cost of $1,000 per acre). Annual property taxes are assumed to be included with lease payment. (The 2016 large wind price cap assumed $3,000 per MW.)
- Insurance Cost: Assume 0.40% of total installation costs charged annually. (No change from 2016 assumption.)
- Decommissioning Costs: Assume $60 per kW for decommissioning reserve fund. (The 2016 large wind price cap assumed no decommissioning costs.)
- Income Tax: Assume state rate of 8.5% and federal rate of 35%. (No change from 2016 assumptions.)
- ITC: Assume 100% realization of the 18% federal ITC and no state ITC. Federal ITC applied to non-transmission-related installation costs (95% of total costs). (The 2016 large wind price cap assumed 100% realization of the 24% federal ITC and 50% realization of the 7.2% state ITC.)
- State Production Capacity Tax: Assume $0.003 per kWh of AC capacity produced. (The 2016 large wind price cap assumed a combined municipal and state production capacity rate of 1.78% applied to 100% of the net present value of the project's net cash flows.)

- Municipal Tax: Assume 0.50% tax rate applied to 70% of the net present value of the project's net cash flows in year one, with a fixed annual payment over the life of project.
- Inflation: Assume 1.86% annually, which reflects the increase in inflation over the past year. (The 2016 large wind price cap assumed 1.80% annually.)
- Debt Repayment Reserves: Assume one half of the amount of the first-year long-term debt payment is placed into a reserve account earning interest at the rate of inflation until released into operating income at the end of the debt term. (The 2016 large wind price cap assumed no debt payment reserve.)
- Working Capital: Assume that one half of the amount of the first-year operating expense is placed into a reserve account earning interest at the rate of inflation until released into operating income in the last year of the project life. (The 2016 large wind price cap assumed one quarter of the amount of the first-year operating expense is placed into a reserve account.)
- Financing Costs: Assume 3% charged on total debt principal for lender's fees plus an APR of 5% charged on the total amount of installation costs for 4.5 months to cover IDC. (The 2016 large wind price cap assumed an APR of 5% charged on the total amount of installation costs for 2.5 months to cover IDC.)
- Capital Structure: Assume short-term debt is 30% of financing at starting rate of 3.5% for term of 6 years with rate increase of 20 basis points each year. Assume long-term debt is 30% of financing at a rate of 4.5% for term of 18 years with rate increase of 25 basis points each year for first 7 years. (The 2016 large wind price cap assumed no short-term debt and assumed long-term debt is 40% of financing at a rate of 7.25% for term of 20 years.)
- Debt/Equity Ratio: Assume that the capital structure of a project would be 60% debt and 40% equity. (The 2016 large wind price cap assumed 60% equity.)
- Rate of Return: Assume 9.02%, which is equivalent to GMP's current return on equity. (The 2016 large wind price cap assumed 9.6%.)
- WACC: Calculated to be 6.01%, based on assumptions of 40% equity, 3.5% for short-term debt costs, and 4.5% for long-term debt costs.

- Depreciation Expenses: Assume all non-transmission-related installation costs (95% of total costs) reduced by half of federal ITC amount are expensed over 5 years per MACRS depreciation table. Assume all transmission-related installation costs (5% of total costs) are expensed over 15 years per MACRS depreciation table. Assume all financing costs, including IDC, expensed over 20 years per MACRS depreciation table. (No change from 2016 assumptions.)

REV argues that land lease costs should be $1,500 per year per MW. REV also contends that the Department's assumptions concerning capital structure and debt financing underestimate the cost of financing a wind project, with short-term rates starting at 6% and long-term rates fixed at 7%. REV maintains that the net capacity factor should be 26.5% to reflect losses from availability, operational restrictions, and system losses. REV asserts that the state ITC does not apply to large wind projects and the federal ITC should be 18% for 2018 and determined on 90% of the installed costs. REV also maintains that an additional $10,000 per year of operational expenses should be included in the cash flow analysis. With the assumption changes recommended by REV, REV states that the cash flow model would yield a levelized price cap of $0.129 per kWh. In addition, REV states that the cash flow analysis does not reflect stricter sound and winter operational standards that may reduce large wind operational hours.

Discussion

Based on a review of the assumptions and the cash-flow model analysis, we accept the Department's recommendation of an avoided cost of $0.107 per kWh for large wind projects. With respect to installation costs for large wind projects, we are persuaded that $3.00 per watt, derived from review of market research conducted by the National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory, represents an appropriate value of current costs. We are persuaded that these installation costs are representative of an efficiently sited large wind project.

REV raises concerns about land lease costs, financing costs, and sound and operational standards, but provides no project-specific information to challenge the accuracy of the cash-flow model assumptions. We agree with the Department's position on lending rates and debt financing. The Department notes that the current commercial prime lending rate is 3.75%, and the Vermont Economic Development Association offers subsidized variable rates starting at 3.0%. Further, land lease costs are assumed to be lower than for solar projects, recognizing that wind projects have different land use patterns.

Using the assumptions recommended by the Department, the cash-flow model calculates an avoided cost of $0.107 per kWh for large wind projects. Accordingly, for the 2017 RFP, we establish an avoided cost for large wind projects of $0.107 per kWh, fixed over the life of the project.

## VII. Price Caps for Biomass, Hydroelectric, Landfill Gas, and Methane Projects

Participants' Comments

The Department recommends no changes to the price caps for biomass, hydroelectric, landfill gas, food methane, and farm methane projects.

SASCO recommends that no adjustments be made to the standard-offer program prices for farm methane projects. SASCO contends that current prices are not excessive and that the current prices should remain in place to allow interest in the technology to grow and begin to drive new projects.

Discussion

No participant provided evidence to evaluate the existing standard-offer price caps for biomass projects, hydroelectric projects, or food waste anaerobic digestion projects. In addition, based upon past information presented to the Board on landfills in Vermont, the opportunities for landfill gas appear to be limited to already developed projects. Accordingly, we are maintaining the avoided-cost price caps for these technologies from the March 2016 Order.

Pursuant to Section 8005a(g), farm methane projects remain outside the programmatic cap. No party provided information to evaluate the existing standard-offer price caps for farm methane projects. Therefore, we are maintaining the avoided costs from the March 2016 Order for farm methane projects.

## VIII. Price Caps for Projects at Preferred Locations

Participants' Comments

In order to establish a price cap for preferred locations, the Department recommends applying multipliers to the solar price cap described above to establish price caps for each category of preferred locations. The Department's approach to developing price cap multipliers relies on information collected in a 2016 study of Vermont solar installations. The Department developed multipliers for the preferred locations by using the 2016 study data on typical installation costs for six different scales and types of solar projects. The Department recommends that the following multipliers be applied to the solar price cap to obtain price caps for the preferred locations:

- Pre-existing structure – 1.21
- Parking canopy – 1.40
- Previously developed site – 1.10
- Brownfield site – 1.10
- Landfill site - 1.10
- Previously disturbed site – 1.10
- Municipally designated site – 1.00 (or no multiplier)

The Department contends that the price multipliers could also, where applicable, be applied to other technology categories. For example, the Department maintains that wind projects are likely to be developed at previously developed, brownfield, landfill, and previously disturbed sites.

GMP supports the use of price caps for projects at preferred locations and contends that "controlling program costs is desirable because this pilot is designed to encourage projects that are likely more costly than the larger, most price-competitive projects" that the standard-offer program has attracted in recent years. GMP states that the Department's recommended approach and multiplier values are a reasonable basis upon which to launch the pilot program.

BED and VPPSA do not support an RFP without price caps for projects located at preferred locations. BED and VPPSA recommend that price caps be determined based on development costs of similar projects in Vermont and other parts of the country. BED and VPPSA contend that without price caps ratepayers would be exposed to unnecessarily high costs.

Essex Capital contends that the price multiplier for parking canopies, and the 2016 study used to develop the multiplier, does not accurately reflect Vermont weather conditions and the resulting cost to build a parking canopy solar project. Specifically, Essex Capital requests that the Department examine a case study that includes an array at a 7.5 degree slope rather than the 15 degree slope of the solar panels contained in the 2016 study.

REV contends that the 2016 study report the Department used to make its multiplier recommendations reflects national data that would be very different for application in Vermont.[19] REV maintains that parking lot canopies have been largely developed in warmer climates, where solar installations do not need the steep pitch that would be necessary to accommodate Vermont weather conditions. REV also maintains that projects on gravel pits and landfills require extensive additional permitting, design, environmental considerations, and constructions costs compared to other standard-offer projects.

Triland recommends no price caps for preferred location projects. Instead, Triland recommends that developers, working closely with the Department and host utility, develop these projects "open-book" with all parties knowing the costs involved to plan, study, design, and complete a project.

VPIRG recommends that no price caps be established for projects solicited under the pilot project. VPIRG is concerned that establishing price caps for the pilot project is "counter to the legislature's intent" and that price caps may be set "too low," resulting in no projects being deployed.

Representative Klein, Senator Campion, and Representative Ram collectively argue that price caps should not be established for projects at preferred locations and contend that instituting price caps will harm the goal of determining the feasible cost of these projects. They also contend that because the program is limited in size, any costs to ratepayers will be limited.

Discussion

As described above, for the 2017 RFP, pursuant to Section 8005a (c)(10(D), the Preferred Location Block requires an allocation for two categories: (1) projects located over parking lots or on parking lot canopies; and (2) projects located at other preferred locations. Pursuant to Section 8005a(c)(1)(D)(iv), preferred locations include: (1) a new or existing structure whose primary use is not the generation of electricity; (2) a parking lot canopy; (3) a tract previously developed for a use other than siting a plant; (4) a brownfield site; (5) a

[19] REV appears to misunderstand that the 2016 study contains case studies of Vermont solar project installations.

sanitary landfill; (6) a disturbed portion of a gravel pit, quarry, or similar site; (7) a specific location designated in a duly adopted municipal plan; (8) a site listed on the National Priorities List ("NPL"); and (9) a new hydroelectric generation facility at a dam in existence as of January 1, 2016, or a hydroelectric generation facility not in service for a period of at least 10 years prior to January 1, 2016.

Some participants argue that no price caps should be established for the pilot program and that price caps may be counter to legislative intent. We are persuaded that price caps are necessary and consistent with statutory intent. Section 8005a(f)(5) identifies the methodology the Board must employ to determine standard-offer prices for the preferred location projects. The applicable goals and directives under Section 8005a require the Board to balance the statutory directive to ensure sufficient incentive for rapid deployment while also ensuring that the incentive is not excessive, and thereby unnecessarily costly for ratepayers.

The Department has recommended a reasonable approach for establishing price caps for preferred locations based on a cost study of Vermont solar installations. While some participants raised concerns about the study, no participant provided specific cost information to challenge the conclusions of the Vermont study or the Department's application of the study. In addition, we are persuaded the price multipliers can be applied to other technology projects besides solar projects. The Department did not make recommendations for preferred sites located on the NPL or new hydroelectric projects at existing dams. Given the limited information, we will apply the brownfield multiplier for use at NPL sites. Given the similar site characteristics for hydroelectric projects at preferred sites and other standard-offer hydroelectric projects, we apply no multiplier for new hydroelectric projects.

Accordingly, for the 2017 RFP, the following multipliers will be applied to all the standard-offer price caps to obtain price caps for the preferred locations:

- Pre-existing structure – 1.21
- Parking canopy – 1.40
- Previously developed site – 1.10
- Brownfield site – 1.10
- Landfill site - 1.10
- Previously disturbed site at gravel pit, quarry, or similar site – 1.10
- Municipally designated site – 1.00 (or no multiplier)
- NPL site – 1.10
- New hydroelectric at preferred site - 1.00 (or no multiplier)

## IX. Conclusion

Pursuant to 30 V.S.A. § 8005a(c)(2), the Board establishes a mechanism for the allocation of available capacity for the remainder of the standard-offer program that includes the Price-Competitive Developer Block and the Technology Diversity Developer Block. For 2017, the Board also establishes a Preferred Location Block.

Pursuant to 30 V.S.A. § 8005a(f)(3), the Board is required to annually review the established avoided costs "to decide whether they should be modified in any respect in order to achieve the goal and requirements of this subsection." Pursuant to Section 8005a(f)(2)(A)(ii), the avoided costs serve as caps on the prices solicited through the annual RFP.

The following avoided-costs will serve as price caps for the 2017 RFP:

- Biomass – $0.125 per kWh (levelized over 20 years)
- Landfill Gas – 0.090 per kWh (levelized over 15 years)
- Wind > 100 kW - $0.107 per kWh (fixed for 20 years)
- Wind ≤ 100 kW - $0.2332 per kWh (fixed for 20 years)
- Hydroelectric - $0.130 per kWh (fixed for 20 years)
- Food Waste Anaerobic Digestion - $0.208 (fixed for 20 years)
- Solar - $0.130 per kWh (fixed for 25 years)

As discussed above, price multipliers, ranging between 1.10 and 1.40, will be applied to the above caps to establish price caps for the 2017 pilot program.

Pursuant to Section 8005a(g), farm methane projects remain outside the programmatic cap. For farm methane projects with a nameplate capacity greater than 150 kW, we retain an avoided cost of $0.145 per kWh, fixed over the term of the 20-year contract. For farm methane projects with a nameplate capacity less than or equal to 150 kW, we retain an avoided cost of $0.199 per kWh, fixed over the life of the project.

Section 8005a(e) requires that the term of a standard offer "shall be 10 to 20 years, except that the term of a standard offer for a plant using solar power shall be 10 to 25 years." Consistent with the Board's determination in Dockets 7533, 7780, and 7874, we conclude that the term of a standard-offer contract should be based on the term used to calculate the standard-offer avoided cost, and that the term should be based on the assumed life of the project capped by the statutory requirement of 20 or 25 years.[20]

As required by the 2013 Order, by April 1, 2017, the Standard-Offer Facilitator will issue an RFP, consistent with the requirements of this Order and prior Orders in other standard-offer proceedings, to solicit standard-offer projects to meet the requirements of Section 8005a(c).

## X. Order

It Is Hereby Ordered, Adjudged, and Decreed by the Public Service Board ("Board") of the State of Vermont that:

1. Pursuant to 30 V.S.A. § 8005a(c)(2), the Board establishes a mechanism for the allocation of available capacity for the remainder of the standard-offer program as specified in this Order.

2. Effective for any standard-offer contract executed after March 1, 2017, the standard-offer prices for renewable power under 30 V.S.A. § 8005a(b)(2) shall be determined through a request for proposal issued by the Standard Offer Facilitator and shall be no higher than the avoided costs as specified in this Order.

3. Effective for any standard-offer contract executed after March 1, 2017, pursuant to 30 V.S.A. § 8005a(f)(2), the following avoided costs will serve as the prices for farm methane projects under the standard-offer program: (1) $0.145 per kWh fixed over the 20-year contract for projects with a nameplate capacity greater than 150 kW; and (2) $0.199 per kWh fixed over the 20-year contract for projects with a nameplate capacity less than or equal to 150 kW.

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[20] The Board set a term of 15 years for standard offers for landfill gas projects; this assumption is based on the fact that the fuel source for landfill gas will decline over time. Docket 7533, Order of 1/15/10 at 65.

Dated at Montpelier, Vermont this 2nd day of March, 2017.

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| James Volz | ) | PUBLIC SERVICE |
| | ) | |
| Margaret Cheney | ) | BOARD |
| | ) | |
| Sarah Hofmann | ) | OF VERMONT |

OFFICE OF THE CLERK

Filed: March 2, 2017

Attest: Judith C. Whitney
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@vermont.gov)*

*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.*