STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket No. 7780

Investigation into the Review of Standard Offer Prices	)	
under the Sustainably Priced Energy Enterprise	)	Hearing at
Development ("SPEED") program	)	Montpelier, Vermont
		November 29, 2011

Order entered: 1/23/2012

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

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I. Introduction

In 2009, the Vermont General Assembly passed Act 45,[2] which mandated the establishment of a standard offer for a limited amount of qualifying SPEED resources with a plant capacity of 2.2 MW or less.[3] On January 15, 2010, in Docket 7533, the Public Service Board ("Board") issued an Order establishing standard-offer prices pursuant to Section 8005. These prices replaced the statutorily set default prices which applied to standard-offer contracts entered into previously.

Section 8005(b)(2)(C) requires that on or before January 13, 2012, and on or before every second January 15 after that date, the Board shall review the established standard-offer prices and determine whether such prices are providing sufficient incentive for the rapid development and commissioning of plants. In addition, Section 8005(b)(2)(C) requires that, in the event the Board determines that such a price is inadequate or excessive, the Board shall reestablish the price for effect on a prospective basis commencing two months after the price has been reestablished.

With this proposal for decision, we recommend that the Board alter the standard-offer prices for solar photovoltaic ("PV") projects and wind projects with a nameplate capacity of 100 kW or less (referred to in this Order as "small wind"). In addition, we recommend that the standard-offer prices for the remaining technology categories remain the same as those established in the January 15, 2010, Order.

II. Statutory and Procedural History

A. Background

In 2005, the Vermont General Assembly established the SPEED program to encourage the development of renewable energy resources in Vermont, as well as the purchase of renewable power by the State's electric distribution utilities.[4] In response to the legislation, the Board

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

3. Sections 8001 et seq, set out the Sustainably Priced Energy Enterprise Development or "SPEED" program.

4. Those portions of Title 30 concerning renewable energy in general, and the SPEED program in particular, are set forth in 30 V.S.A. Chapter 89.

promulgated Board Rule 4.300 to implement the SPEED program. Board Rule 4.300 also established a SPEED Facilitator to encourage the development of resources under the program.[5]

Act 45 established a standard-offer component to the SPEED program. The Act required the Board to establish cost-based prices for renewable plants with a nameplate capacity of 2.2 MW or less and requires the SPEED Facilitator to enter into long-term contracts with such plants, up to a program ceiling of 50 MW. Pursuant to Act 45, the SPEED Facilitator distributes the energy and attendant costs to the Vermont distribution utilities based on each utility's pro rata share of total Vermont retail kWh sales for the previous calendar year.[6]

Section 8005(b)(2)(B)(i) sets out the following criteria for setting prices under the standard-offer program:

> (I) The board shall determine a generic cost, based on an economic analysis, for each category of generation technology that constitutes renewable energy. In conducting such an economic analysis the board shall:
>
> > (aa) Include a generic assumption that reflects reasonably available tax credits and other incentives provided by federal and state governments and other sources applicable to the category of generation technology. For the purpose of this subdivision (2)(B), the term "tax credits and other incentives" excludes tradeable renewable energy credits.
> >
> > (bb) Consider different generic costs for subcategories of different plant capacities within each category of generation technology.
>
> (II) The board shall include a rate of return on equity not less than the highest rate of return on equity received by a Vermont investor-owned retail electric service provider under its board-approved rates as of the date a standard offer goes into effect.
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> (III) The board shall include such adjustment to the generic costs and rate of return on equity determined under subdivisions (2)(B)(i)(I) and (II) of this

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5. 30 V.S.A. § 8005(b)(1) requires the Board to "name one or more entities" as SPEED Facilitator. When this Section was enacted in 2005, the use of a SPEED Facilitator was at the Board's discretion; the Board decided to establish the SPEED Facilitator to help promote renewable development.

6. The standard-offer program creates an exemption for any Vermont utility "that establishes that it receives at least 25 percent of its energy from qualifying SPEED resources that were in operation on or before September 30, 2009 . . . ." Section 8005(b)(7). To date, only Washington Electric Cooperative, Inc. has been exempted from the standard-offer program.

> subsection as the board determines to be necessary to ensure that the price provides sufficient incentive for the rapid development and commissioning of plants and does not exceed the amount needed to provide such an incentive.

In addition, Section 8005(b)(2)(C) requires that:

> On or before January 13, 2012, and on or before every second January 15 after that date, the board shall review the prices set under subdivision (2)(B) of this subsection and determine whether such prices are providing sufficient incentive for the rapid development and commissioning of plants. In the event the board determines that such a price is inadequate or excessive, the board shall reestablish the price, in accordance with the requirements of subdivision (2)(B)(i) of this subsection, for effect on a prospective basis commencing two months after the price has been reestablished.

On January 15, 2010, the Board issued an Order establishing the following standard-offer prices[7] pursuant to Section 8005:

solar photovoltaic	$0.24/kWh
hydroelectric	$0.1226/kWh
landfill gas	$0.09/kWh
farm methane	$0.1411/kWh
wind 1.5 MW	$0.1182/kWh
wind 100 kW	$0.2148/kWh
biomass	$0.125/kWh

These prices have been in effect since the establishment of the January 15 Order.

B. Procedural History

On September 13, 2011, the Board issued an Order Opening Investigation and Notice of Prehearing Conference.

On September 23, 2011, the Hearing Officers held a prehearing conference in this Docket. At the prehearing conference, the Hearing Officers requested comments regarding

7. The table represents levelized prices. The Board's January 15, 2010, Order stated that 30% of the standard-offer prices, for all categories except solar PV would increase by 1.6% each year to reflect the impact of inflation on operating and maintenance expenses. Docket 7533, Order of 1/15/10 at 21-22.

whether the Board should hire an independent consultant to assist with the price determinations. Parties agreed that it was appropriate for the Board to hire a consultant who would serve as an independent witness as in the same manner as in Dockets 7523 and 7533. The Board subsequently executed a contract with Power Advisory, LLC (the Board's Independent Witness") to assist in the determination of standard-offer prices.

On October 11, 2011, the Hearing Officers held a workshop.

On November 29, 2011, the Hearing Officers held a technical hearing.

On December 13, 2011, briefs were filed by the Department of Public Service ("Department"), Renewable Energy Vermont ("REV"), Central Vermont Public Service Corporation ("CVPS"), and Vermont Electric Cooperative, Inc. ("VEC"). Reply briefs were filed on December 20, 2011, by the Department and REV.

C. Standard-Offer Prices Under Review

In today's proposal for decision, we recommend that the Board alter the standard-offer prices for the following categories: solar PV and small wind. In addition, we recommend that the standard-offer prices for the remaining technology categories remain the same as those established in the January 15, 2010, Order.

Parties' prefiled testimony identified the standard-offer prices that parties believed required an update and the assumptions used in determining prices for which they request Board review. Testimony was provided on the following categories: solar PV, small wind, and biomass. The testimony regarding biomass provided a recommended standard-offer price; however no evidence was submitted in support of the recommended price.[8] Vermont Agency of Agriculture, Food and Markets ("VAAFM") indicated that an agricultural economist at the University of Vermont was currently reviewing the farm methane price modeling with the expected study to be completed by summer.[9] VAAFM requested the Board postpone its review of farm methane prices until data from that study is available.

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8. Stebbins pf. at 7.

9. Letter dated October 28, 2011, from Daniel Scruton, Dairy and Energy Chief, Vermont Agency of Agriculture, Food and Markets.

Given the evidence presented, we conclude that there is an inadequate factual basis at this time to evaluate the standard-offer price for wind projects with a nameplate capacity greater than 100 kW and less than 2.2 MW, biomass projects, farm methane projects, and hydro-electric projects. In addition, the opportunities for landfill gas are limited to already developed projects. Therefore, we are limiting our review to the standard-offer prices and the related assumptions used in determining those prices for the categories of solar PV and small wind (nameplate capacity less than or equal to 100 kW). If VAAFM proposes updated farm methane prices after completing its study, with sufficient support for such prices, the Board may conduct additional proceedings to consider updating the price for that category.

III. Context for Price Determinations Required under Act 45

Findings

1. There are currently 59 projects with executed standard-offer contracts totaling 50.55 MW of capacity. Approximately 25 projects have received a certificate of public good pursuant to 30 V.S.A. § 248. Spencer pf. at 1.

2. There is a waiting list of 154 projects for the standard-offer program. The majority of the projects (150 out of 154) are solar projects. Dalton pf. at 7-8; exh. JCD-2.

3. As of October 2011, the following standard-offer projects have been commissioned: four solar projects receiving prices of \$0.30/kWh; two farm-methane projects receiving prices of \$0.16/kWh; one landfill methane project receiving a price of \$0.12/kWh; and one hydroelectric project receiving a price of \$0.125 kWh. Spencer pf. at 1.

4. The SPEED Facilitator anticipates that the following standard-offer projects are likely to be commissioned by April of 2012: four solar projects receiving prices of \$0.30/kWh; three solar projects receiving prices of \$0.24/kWh; four farm-methane projects receiving prices of \$0.14/kWh; two farm-methane projects receiving prices of \$0.16/kWh; two biomass projects receiving prices of \$0.125/kWh; and one hydroelectric project receiving a price of \$0.12/kWh. Spencer pf. at 2.

5. The amount of standard-offer projects commissioned to date accounts for approximately 5.3 MW. The SPEED Facilitator anticipates that the pace of deployment will increase over the next year. Tr. 11/29/11 at 9-10 (Spencer).

6. Project attrition rates for projects that represent the first 50 MW in the queue with executed standard-offer contracts range from 12% for solar projects to 100% for biomass projects. Dalton pf. at 7-8; exh. JCD-3.

7. The low attrition rate for solar projects is not, by itself, evidence that the existing standard-offer price is adequate to ensure rapid deployment of solar projects given that the existing solar price is 20% below the price available to projects first offered a spot in the queue and the fact that future projects will not be able to utilize certain incentives that were previously available (federal Treasury Grant of 30% of the project cost or the state Solar ITC). Dalton pf. at 7-8.

8. The most significant factor in the high project attrition rate is probably the design of the standard-offer program. These design features include:

- Developers are required to provide a deposit of $10/kW of installed capacity; however, this deposit is fully refundable if the developer voluntarily withdraws from the queue within 12 months of contract execution, with 75% of the deposit returned if the developer voluntarily withdraws from the queue after 12 months, but before 24 months of executing the contract.
- The standard-offer program has a ceiling of 50 MW and technology caps were employed to ensure that no one technology represented more than 25% of the queue.
- With no meaningful entry costs, other than a $200 administrative fee paid to the SPEED Facilitator, and a program and technology cap, it is likely that developers were concerned that the program would be fully subscribed shortly after it opened. This would likely have induced developers to apply and secure a position in the queue even without completing the necessary due diligence to ensure that the proposed project was viable.
- Furthermore, for solar PV projects the potential for significant reductions in module and balance of systems costs created a speculative opportunity. The standard-offer contract does not require projects to be in service until three years after contract execution. Therefore, if costs decline by 10% per year, a solar PV project which was not economic in 2010 could offer attractive returns in 2013.

Dalton pf. at 8-9.

9. Plant owners have three years from the date that a standard-offer contract is executed to commission a standard-offer project. Dalton pf. at 10.

10. The three years, from the execution of a standard-offer contract, that plant owners have to commission a project is a reasonable amount of time for rapid deployment, given that a project must go through the permitting process, arrange for interconnection and financing, and be constructed. Tr. 11/29/11 at 23 (Spencer).

11. The standard-offer prices established by the Board should be based on representative costs of a well-designed system that is installed in a location with supportive resource availability, including transmission. The plant owner should also be deemed to take advantage of all the available financial support mechanisms available for such projects. The establishment of such prices will not preclude project owners that have projects in less-than-ideal locations from accepting standard-offer prices that assume a well-sited project. Instead, such developers will need to find other efficiencies in order to earn the calculated rate of return. Foley pf. at 2; Docket 7533, Order of 1/15/10 at 13.

Discussion

A key area of disagreement among parties is whether current experience meets the statutory mandate for rapid development and the extent that the need for rapid deployment requires higher prices than those established by the Board in January, 2010. REV contends that

> The current prices established in Docket 7533 for the Standard Offer Program are not providing sufficient incentive to ensure the rapid deployment of renewable projects. This is reflected in the low rate of commissioned projects (and high attrition rate), and the correspondingly low total overall capacity of operation projects relative to the 50 MW statutory cap.[10]

Although REV is correct that the number of projects actually commissioned to date provides some evidence of the extent to which rapid deployment is occurring, this figure does not provide the total picture. The standard-offer program establishes a queue for projects and contains certain milestones that projects must meet in order to stay in that queue: developers must file a completed interconnection application within six months; developers must file a

10. REV Brief at 5.

completed Section 248 petition within one year of executing the standard-offer contract;[11] and developers must commission the project within three years of executing the contract. Given that developers have three years to commission a project, even those plant owners that executed contracts as soon as the standard-offer program began would not be required to achieve commissioning at this point in time. Under the program, it would be possible for no projects to be commissioned to date. As the SPEED Facilitator stated during the technical hearing in this Docket in response to a question of whether the fact that 5.3 MW has been commissioned represents rapid deployment: "I think it is the deployment that was anticipated when the Board set a three-year commissioning deadline."[12]

In addition to the three-year commissioning milestone, the standard-offer program includes low barriers to entry. Although a plant owner would need to provide a deposit of $10 per kW, this deposit was fully refundable if the project was withdrawn within one year of executing a contract and 75% of the deposit was refundable if the project was withdrawn within two years. These components of the standard-offer program were developed through a working group that included interested parties, including renewable resource developers. At the time the program was developed, no interested party objected to the low barrier of entry or the three-year commissioning deadline.[13] This low barrier, however, led to the inclusion of a number of projects that have been more speculative and likely to drop out. Accordingly, the number of plants commissioned and the attrition rate are incomplete metrics for determining whether rapid deployment has occurred.

Deployment also slowed because a large number of biomass plants eventually dropped out. A number of these appeared to have been unable to meet the statutorily mandated efficiency requirement pursuant to Section 8005(j).

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11. The requirement that developers file a Section 248 petition was not added to the standard-offer contract until July 7, 2011, when it was added at the suggestion of the SPEED Facilitator to "ensure that projects move through the queue expeditiously." Docket 7533, Order of July 7, 2011, at 4-6.

12. Tr. 11/29/11 at 9 (Spencer).

13. Docket 7533, Order of 9/30/09 at 28-30.

Given that the standard-offer queue is fully subscribed with a sizable waiting list, we cannot conclude the standard-offer prices are insufficient to ensure rapid deployment. Instead, it is likely that the most effective method of ensuring rapid deployment is modifying the standard-offer program to implement more stringent barriers to entry to ensure that only projects that have undergone due diligence are likely to enter into the program. Such a modification to the program, in addition to a shorter time frame for commissioning, would likely increase costs for developers but facilitate rapid deployment by more quickly weeding out projects that are not themselves ready to proceed toward commissioning.

At the prehearing conference parties indicated that it may be appropriate to revisit the design of the standard-offer program. Given that the program has been in place for two years, it would be worthwhile to conduct a review of the program and determine whether changes should be made. We recommend that the Board initiate a review of the program in a separate proceeding, although the timing of that review may be dependent on the legislative session, as several bills that would alter the standard-offer program are currently under consideration. For purposes of the price review under consideration in this Docket, we recommend that the Board conclude that the commissioning of standard-offer projects to date, by itself, is insufficient evidence that the standard-offer prices need to be updated.

IV. Issues of General Applications

A. Financial Model

Findings

12. The Board's Independent Witness helped develop a financial model that was used to make the standard-offer price determinations in Docket 7533. The Department and REV agreed in this proceeding to the use of this financial model with the structural updates made by the Board's Independent Witness. Dalton pf. at 9-12; Seddon pf. at 3-6; Foley pf. at 3.

13. The financial model projects the after-tax cash flows that would be available to the project developer. The basic structure of the model is to determine a revenue stream over a given contract period (typically 20 years) that allows the developer to recover the costs of developing, building and operating a renewable energy generation project and earn the target return on equity.

The model calculates the price in dollars per megawatt hour that will yield the annual after-tax cash flow necessary to achieve the target return on equity. Dalton pf. at 9-10.

14. To compute the net annual after-tax cash flow in the model, annual cash expenditures based on technology-specific cost and performance assumptions are subtracted from the cash inflows. These annual cash expenditures include insurance, operations and maintenance expenses, interest and principal payments, and income and property taxes. Cash inflows are typically limited to revenues from the sale of electricity under the standard-offer contract, but for farm-methane projects include other revenues. Dalton pf. at 10.

15. Cash flow models provide a reasonable basis for assessing the price that is required to provide lenders with sufficient debt coverage ratios and investors with the after-tax cash flows they require to earn their target return. Dalton pf. at 11.

16. The financial model structure was updated to separate out previously aggregated capital costs for interconnection, land lease payments, and project permitting. The updated model includes costs for a decommissioning fund for projects greater than 1 MW and a revision to the model's calculation of property taxes to reflect the guidance provided by the Department of Taxes regarding property tax assessments. Dalton pf. at 11-12.

17. REV agrees with updated model assumptions with regard to costs for interconnection, land lease payments, project permitting, and property taxes for small wind and solar projects. Seddon pf. at 3-4.

<u>Discussion</u>

The Board's Independent Witness assisted in the development of a financial model that was used to calculate the January 15, 2010, standard-offer price determinations in Docket 7533. The model was updated in the current proceeding by the Board's Independent Witness.[14] The Department and REV agreed in this proceeding to the use of this financial model with structural updates made by the Board's Independent Witness. No other parties raised concerns with the model. The model, along with the input assumptions, are posted on the Board's web site.

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14. The Board's Independent Witness had served as an independent consultant during the proceedings leading to the January 15, 2010, price determinations and had assisted with the development of the model at that time.

While parties agree with the model structure, parties disagree on some of the model input assumptions. The Department supports the Board's Independent Witness recommendations on input assumptions. REV agrees with assumptions that the Board's Independent Witness has made with regard to costs for interconnection, land lease payments, project permitting, and property taxes for wind and solar projects. REV does not support the Board's Independent Witness assumptions pertaining to capacity factors, solar module capital costs, modeling of the federal investment tax credit, interest rates, and the use of personal guarantees and state credit facilities. These areas of disagreement are addressed below.

B. Financial Assumptions

Findings

18. The financing environment for large standard-offer projects is challenging. To date, no project commissioned to date has been financed through "project financing," contemplated in the 2010 price Order. Spencer pf. at 3; Dalton pf. reb. at 2.

19. Limited data exists from completed standard-offer projects on which to reliably base modeling assumptions. Tr. 11/29/11 at 161 and 183 (Dalton).

20. Two large solar projects were recently built by Chittenden County Solar Partners ("CCSP") and Ferrisburgh Solar Farm ("FSF"). Chittenden County Solar Partners obtained a loan with a favorable interest rate, but it required 30% cash collateral. Ferrisburgh Solar Farm secured 20-year variable interest rate loans from TD Bank and the Vermont Economic Development Authority ("VEDA") for 30% of the project costs and a five-to-six-year variable rate loan with the same two lenders backed by a personal guarantee for an additional 30% of the project cost. Equity was used to cover the remaining forty percent of project costs. Dalton pf. at 5.

21. A number of the solar project developers have had to rely on personal guarantees to secure bank loans and it appears that as a result of these personal guarantees favorable interest rates were secured. Dalton reb. pf. at 2.

22. Personal guarantees or the posting of collateral have opportunity costs given that they tie up financial resources or credit that could be used in other transactions. Tr. 11/29/11 at 157 (Dalton).

23. A significant portion of the value of the standard-offer projects is attributable to the favorable tax treatment, including federal and state investment tax credits and accelerated depreciation rates that such projects are afforded. Many renewable project developers do not have sufficient taxable income to fully utilize the significant tax benefits. This has typically resulted in the participation of tax equity investors, but securing this participation can be costly and the tax equity market is limited. The *American Recovery and Reinvestment Act of 2009* instituted Treasury Grants to help overcome the limited amount of tax equity available during the financial crisis. However, these Treasury grants expired on December 31, 2011. Dalton reb. pf. at 2.

24. A number of tax credits, treasury grants, and other incentives have either been fully expended, are set to expire this year, or will do so within the next few years. Specifically, the 1603 Treasury Grant Program expires at the end of 2011. The full 30% Vermont Solar Tax Credit has expired, although developers are still utilizing the state 7.2% Investment Tax Credit. Spencer pf. at 4; Stebbins pf. at 4.

25. Once the Treasury Grant expires, developers will try to take the 30% Federal Tax Credit. Stebbins pf. at 4.

26. Although the Vermont solar investment tax credit ("ITC") is no longer available, the Vermont state ITC of 24% of the federal ITC is still available. It is reasonable to assume that 75% of the federal ITC and 50% of the state ITC would be utilized in the first year of commercial operation, with no carry forward of these tax benefits to future years. This treatment of the federal ITC is consistent with the recommendation made by the SPEED Facilitator based on his research on the appropriate treatment of the federal ITC. Dalton reb. pf. at 8.

27. It is likely that a larger number of potential investors have more significant federal taxable income than state taxable income, so it is reasonable to assume that a higher proportion of the federal ITC than the state ITC would be utilized. Given the higher federal income tax credit, capturing this benefit would be of greater value. Dalton reb. pf. at 9.

28. The costs of tax equity will vary with the transaction, but appear to be just above 9%. This figure does not provide any consideration for developer returns. Dalton reb. pf. at 3.

29. There are a range of different leasing structures that can be used to finance standard-offer projects which allow third parties that are better able to utilize these tax benefits to capture them. One financing approach that is well suited to standard-offer projects is a Master Financing Facility under which a developer bundles various projects together to reduce transaction costs and the overall risk profile. Under such a financing facility, the financier agrees to finance every project that a developer puts in service between specific dates up to some dollar amount, assuming that the projects satisfy specific criteria agreed to by the developer and financier. These criteria are likely to include the project capacity factor, cost, and credit quality of the buyer (recognizing that the developer might also seek to finance projects in other jurisdictions or with other buyers). Alternatively, the developer will have the projects under contract allowing the financier to have a high level of comfort regarding the specific projects. Dalton reb. pf. at 3-4.

30. The Board adopted a return on equity of 9.75% in Docket No. 7533. Dalton reb. pf. at 13.

31. A return on equity of 9.75% is not guaranteed to the developer. Tr. 11/29/11 at 166 (Dalton).

32. A lower return on equity or cost of capital is appropriate for use in setting the prices for small wind projects. Investors in these projects are likely to include entities that require a lower return. Households and individual consumers have a wide range of hurdle rates (minimum return on investment that is required for a party to pursue an investment). Given this disparity in hurdles rates some parties may require lower returns to pursue a renewable energy investment. Furthermore, some individual customers are likely to be more willing to pursue renewable energy investments to reduce the environmental impacts of their energy consumption and to realize their preferences for renewable energy. Dalton reb. pf. at 14.

33. Municipalities typically have access to lower cost capital and as such are more willing to accept lower internal rates of return for investments. Furthermore, many municipalities, reflecting the values of their constituents, have strong environmental objectives and are committed to promoting renewable energy where feasible. Dalton reb. pf. at 14.

34. One variant on municipal projects are community renewable projects which can tap into a latent and potentially lower-cost source of capital to fund development because these community based investors may settle for a lower return on equity than commercial investors would be willing to accept. Dalton reb. pf. at 14.

35. Parties investing in small wind turbines should be able to secure 20-year debt at a 5.5% interest rate. Such a debt term and interest rate represents a premium compared to what is being offered for home mortgages and is consistent with interest rates available to municipalities which are a major market for these size wind turbines. Dalton reb. pf. at 12-13.

Discussion

A significant portion of the price determination depends upon various financial assumptions, including the cost and availability of debt, the utilization of tax credits and grants by developers, collateral requirements, and the rate of return that the Board should find is appropriate for small renewable projects. The parties and the Board's Independent Witness started with the financial model developed in Docket 7533 and the input assumptions that the Board found reasonable. In the updated models and testimony, they then proposed various adjustments.

As required by Section 8005, standard-offer projects should receive prices designed to cover the cost of the project. In order to develop appropriate prices, the inputs to the pricing model need to reflect the lending and financial environment that actually exists for the typical developer.

In this proceeding, we are presented with two views of this environment. The Board's Independent Witness largely relied upon the financing determinations the Board adopted in Docket 7533, with proposed updates to some assumptions. The proposed modifications included the following:

- adjustments to financing costs to reflect the development of two recent large solar projects under the standard-offer program;
- modified debt assumptions;
- reduced grant and tax credit assumptions based upon the phase-out of certain programs and projections concerning the ability of producers to use tax credits; and

- increased transaction costs for securing the participation of investors which can use tax credits.

The Department and CVPS both support the recommendations of the Board's Independent Witness.

REV argues that the assumptions of the Board's Independent Witness are too optimistic in a number of ways. REV asserts that the Board's Independent Witness places too much reliance on what it characterizes as atypical projects (CCSP and FSF) that are unlikely to be replicated by the vast majority of standard-offer projects. In particular, REV cites to the use of a personal guarantee, non-project collateral, and the participation of VEDA with correspondingly low rates for these projects. REV also argues that the Board's Independent Witness assumes in the model, based on these two projects alone, that all future projects will be backed by a personal guarantee.

REV further maintains that the assumptions of debt costs are unrealistically low. According to REV, this arises from the Board's Independent Witness' incorporation of debt rates based upon loans from VEDA.[15] REV contends that these loans have not been available to other projects to date. Moreover, REV argues that loans should be assumed to be of a 5-8 year duration, rather than the longer term assumed by the Board's Independent Witness.[16]

REV argues that a number of Vermont entities who have developed or are developing standard-offer projects have found that the current lending environment is considerably risk averse. REV asserts that the high up-front capital investment, combined with lenders' lack of understanding of these plants and changing government incentives, has created an environment in which lending institutions are wary of financing renewable projects. REV maintains that this has required some developers to post collateral for loans related to standard-offer projects, which do not represent typical development experience and, as such, should not be the basis for the financial inputs to the pricing model.

REV also challenges the assumptions by the Board's Independent Witness concerning the availability of tax credits and the ability of producers to take advantage of such credits. REV

15. *See* Dalton reb. pf. at 4-5.

16. *Citing* Stebbins pf. at 3-4; exh. REV-GS-1.

asserts that the 30% Federal Tax Credit should be modeled over a five-year payout period as opposed to one, as this more realistically represents developers' ability to utilize the credit. REV also contests the assumption by the Board's Independent Witness that a developer could reasonably use 75% of the Federal ITC, arguing that is not discounting the use of the ITC appropriately.

Finally, REV argues that a 9.75% return on equity is not high enough to assist with potential project-construction-related risks due to delays and cost overruns (e.g., a project permit is appealed).[17] According to REV, the current lending environment is risk averse. Coupled with the diminished federal and state financial incentives, discussed above, REV asserts that new standard-offer projects in Vermont cannot be expected to be totally financed by Vermont businesses and Vermont capital alone. REV also maintains that Vermont is in a regional market, and the 9.75% rate of return may not meet the opportunity cost for capital given the higher rates of return out-of-state developers can achieve in the solar markets in New Jersey or Massachusetts. REV thus contends that the rate of return needs to be 15% or above. Failure to do so, argues REV, will fail to ensure rapid development and commissioning of standard-offer projects.

As we discussed above, in Docket 7533, the Board determined that standard-offer prices should be based on representative costs of a well-designed system that is installed in a location with supportive resource availability, including transmission. The Board stated that: "this means that they use efficient renewable energy technology, are favorably sited (from both the standpoint of optimizing output and minimizing transmission costs), and take advantage of economies of scale."[18]

Applying this standard of review, we conclude that the financial assumptions put forward by the Board's Independent Witness and the Department are reasonable and recommend that the Board adopt them. In large part, the model's financial inputs are based upon the actual experience of renewable developers in Vermont. The sample size is small (two solar plants), but

17. REV Brief at 12, citing Seddon pf. at 5; tr. 11/29/11 at 43 (Seddon).

18. *See* Foley pf. at 2; Docket 7533, Order of 1/15/10 at 13.

it represents efficient use of renewable technology, reasonable economies of scale, and effective financing techniques. Moreover, it is the only evidence presented concerning specific projects and costs.

REV has highlighted concerns that the experience of these two facilities may not be typical. However, we are not persuaded that REV has demonstrated that the alternative assumptions are more reasonable or that developers could not construct other projects with different financial structures of similar efficiency. In fact, if the Board adopted REV's assumptions, it is likely to be setting a price that for efficient projects, such as the two modeled by the Board's Independent Witness, would produce an excessive rate of return. Such an outcome is inconsistent with the statute.

REV's objections also fail to reflect various assumptions included in the cost models of the Board's Independent Witness that add conservatism. For example, the Board's Independent Witness adjusted the interest rate for both long-term and short-term debt over time, which may overstate the risk of interest rate increases. The Board's Independent Witness also included a transaction cost of $150,000 to secure the participation of investors that could utilize the tax credits, which would not be necessary for Vermont investors with sufficient ability to use the tax credits themselves.

As to the return on equity ("ROE"), our analysis starts with the statute. Section 8005(b)(2)(i)(II) requires that the prices "include a rate of return on equity not less than the highest rate of return on equity received by a Vermont investor-owned retail electric service provider under the board-approved rates as of the date standard offer goes into effect." In Docket 7533, the Board found that it should employ a rate of 9.75% based upon existing returns for Vermont utilities.[19]

REV's request for a higher rate appears to be inconsistent with this statutory directive. There are doubtless developers who will only construct small renewable projects if there is a high return on equity. However, under the statute, the Board's task is to adjust the rate only to the

19. Docket No. 7533, Order of 1/15/10 at 80. The Board concluded that it should not consider the ROE for one Vermont utility, Vermont Marble, that had a higher return that had been unchanged for many years. The Board found that this return provided sufficient incentive for the rapid deployment and commissioning of plants.

extent necessary to ensure rapid deployment of renewable projects. As we find above, the legislature's mandate appears to be attained with the existing ROE's. In these circumstances, we cannot recommend that the Board adopt a higher ROE than the existing 9.75%.

V. Resource-Specific Issues

A. Solar PV

Issues related to financing and debt term were addressed above. The inverter efficiency and cost and solar degradation factor remain the same as the January 15, 2010, price determination. The remaining issues are addressed below.

(1) Solar PV Capacity Factor

Findings

36. Capacity factors for solar PV plants will vary depending on module technology, mounting arrangements and locations, inverter efficiency, and wiring losses. For example, roof top arrays are less efficient due to higher temperatures of the roof surface. Seddon pf. at 2-3.

37. An appropriate capacity factor for a fixed axis solar PV module is 14.5%, which was adopted by the Board in Docket 7533. A capacity factor for a dual-axis solar project of 16.7% is consistent with the capacity factor indicated for the South Burlington Solar Farm which has dual axis trackers. Dalton pf. reb. at 9.

38. Solar systems that utilized dual axis trackers are reported to have capital costs which are 10% higher than fixed axis projects, yet result in project outputs that are up to 35% higher. The dual axis project was estimated to have a marginally higher standard-offer price than a fixed-axis system, with increased capital costs, higher operations and maintenance expenses, and higher land lease costs offsetting the benefit provided by a higher output. Dalton pf. reb. at 7-10.

39. Based on almost 11 months of operating data, the Ferrisburgh Solar Farm has operated at an annual capacity factor of 13.2%. The Ferrisburgh Solar Farm operates with high efficiency inverters and low equipment losses. Seddon pf. at 3.

40. Long-term performance of solar energy systems can be assessed through the use of "typical meteorological year," or TMY, data sets, which are produced and updated periodically

by the National Renewable Energy Laboratory ("NREL"). The TMY typifies the climate in an abbreviated one-year data set by attempting to match long-term distributions of solar radiation, temperature and wind, while retaining the natural variability of daily or monthly measurements. The advantage of using TMY is that it includes short-term variations, such as partly cloudy conditions, but is typical of what can be expected in the future and consists of only "one year" of data. Foley pf. reb. at 1-2.

41. Snow will reduce the amount of energy produced for non-tracking solar systems for northern locations in winter, with the severity of the reduction a function of the amount of snow received and how long it remains on the solar modules. The use of a single year's data is not a good indicator for long-term effects of snow cover for fixed tracking systems. Foley pf. reb. at 2.

<u>Discussion</u>

The solar PV modeling in Docket 7533 relied upon a capacity factor of 14.5%. The capacity factor of 14.5% was determined in part by calculating a value using the PVWatts.com tool assuming an inverter efficiency (the DC to AC conversion) of 96% and the use of fixed axis solar modules. In addition, in Docket 7533, the Board took into consideration in establishing an appropriate value that the determined prices reflect best practices, efficient investment, and the location of projects in reasonable sites.

In this docket, REV's expert contends that typical capacity factors for well-designed fixed solar arrays in Vermont will range from 12.5% to 13.5% and that an appropriate factor is 13%, particularly given the effects of snow soiling. REV's expert provides 11 months of operating data from one solar installation to support its claim.

The Department recommends a capacity factor of 14.5% as used in Docket 7533 and suggests that even higher conversion efficiencies can be justified if it is assumed that standard-offer projects will utilize trackers. The Department expresses concerns that REV based its recommendation upon a methodology that uses less than a single year's worth of data. The Department contends that not only is this amount of data statistically insignificant, it is not the standard practice in the industry to rely upon this amount and type of data. The Department agrees that, for northern locations in winter, snow will reduce the amount of energy produced for non-tracking systems, with the severity of the reduction a function of the amount of snow received and how long it remains on the PV modules. The Department further notes that the capacity factor of 14.5% established in Docket 7533 took into account snow soiling because the calculation of the capacity factor using the PVWatts.com tool employed the use of TMY data for the Burlington area.

We are persuaded that a capacity factor of 14.5% remains an appropriate value for use in determining the standard-offer price for a solar generation facility. REV has recommended a capacity factor of 13%, but presented only 11 months of data from one solar installation in Vermont to support its claim. This amount of data is not statistically significant for making a determination on a value for a capacity factor. The capacity factor of 14.5% determined in Docket 7533 was based on a calculation using the PVwatts.com tool and properly considered snow soiling by employing TMY data for Vermont.

In addition, as in Docket 7533, we are persuaded that the capacity factor used in solar cost modeling should not be based on mechanized trackers. Our goal in determining appropriate prices is not merely to reflect an average of past practice, but to assume capacity factors based upon a project that uses cost-effective, efficient technology and reasonable siting practices. We are persuaded that a capacity factor of 14.5% represents an efficiently operating fixed-axis solar facility in Vermont. Moreover, it appears that assuming the use of trackers has little effect on the standard-offer price. The higher capacity factor for the trackers is offset by higher capital and operation and maintenance costs. Therefore, we conclude that a capacity factor value of 14.5% is an appropriate value and recommend its use in the solar cost modeling.

(2) Solar PV Capital Costs

Findings

42. Solar module costs have continued to decline dramatically, with recent price declines driven by lower demand growth and increases in production capacity. Declines in module prices of almost 40% have been reported since the first quarter of 2011, with a 30% decline in module prices forecast for 2012. Dalton pf. reb. at 5-6.

43. The financial model was updated to include solar project capital costs for fixed axis modules to reflect current market conditions. The starting point for this analysis was a NREL

study which contained actual 2009-2010 project costs. The installed costs presented in this study were adjusted to reflect the decline in module prices in 2011 which resulted in a $1.10 per watt module cost estimate. There were no adjustments made in capital costs for other elements of the solar system even though there is the potential for significant declines in inverter costs. Dalton pf. reb. at 6.

44. The total capital costs for solar projects are $3.89 per watt when the costs for permitting, interconnection, decommissioning, land lease, and Vermont sales tax are included. Dalton pf. reb. at 6.

45. Projected decommissioning costs for solar projects that have been issued a CPG range between $38,000 and $133,000. The financial model was updated to include decommissioning costs of $85,000 for 2.2 MW solar projects. Tr. 11/29/11 at 79-80 (Stebbins); Dalton pf. at 11-12; exh. JCD-5.

46. An annual cost for site lease is $17,600 per year which escalates at inflation. This lease cost is based on a lease rate of $2,000 per acre and 4 acres per MW for a fixed axis project. Dalton pf. reb. at 7.

47. Using the financial model and the solar assumptions identified in today's Order, the standard-offer price for a solar project is $0.289 per kWh assuming $3.89 per watt capital costs. Dalton pf. reb. at 10.

48. Solar project capital costs are $3.59 per watt assuming an additional 20 percent decline in module prices in 2012. The standard-offer price for this solar capital cost is $0.271 per kWh. Dalton pf. reb. at 10.

Discussion

The Board's Independent Witness provided two estimates of solar project capital costs, one scenario that reflects "current solar capital cost" estimates and a second scenario which assumes an additional 20 percent decline in module prices in 2012. The first scenario estimated a solar module cost of $1.10 per watt and a total capital cost of $3.89 per watt with permitting, interconnection, land leasing, and decommissioning costs. The second scenario estimated a solar module cost of $0.88 per watt and a total capital cost of $3.59 per watt.

The Department agrees with the assumptions and methodologies that supported a standard-offer price of $0.289 per kWh.[20] REV recommended that the modeling should assume a solar module cost of $1.10 per watt. The estimate is based on an NREL study of actual 2009-2010 solar project costs adjusted to reflect the decline in module prices in 2011. REV asserts the solar module market is volatile and forecasting future prices is uncertain, with some future forecasts projecting prices higher than those suggested by the Board's Independent Witness.[21]

We are persuaded that current trends suggest continued declines in the cost of solar modules and systems, and a value of $3.59 per watt presented by the Board's Independent Witness in his alternate case is appropriate. While REV asserts that the forecasting of future prices of solar modules is uncertain, we conclude that the forecast of additional declines in module prices in the year 2012 is reasonable. Therefore, we recommend that the Board adopt a value of $3.59 per watt.

Using these capital costs assumptions and the financing and capacity factor assumptions identified above, the financial model calculates a standard-offer price of $0.271 per kWh. We recommend that the Board reestablish a standard-offer price for solar projects of $0.271 per kWh. Pursuant to Section 8005(b)(2)(C), the reestablished price will be in effect on a prospective basis commencing two months after the date of today's Order.

A summary of the model inputs for solar PV projects and recommended standard-offer price is listed below.

Net Capacity (kW)	2,200
Capital Costs ($/kW)	3,590
1st Year O&M Expense ($/kW-yr)	6.67
Lease Costs ($)	17,600
Capacity Factor (%)	14.5
Asset Life	25

20. Department Brief at 13.

21. REV Brief at 17-18.

Contract Term (years)	25
Degradation Factor (% annual)	0.5
Inverter Replacement (year)	12th
Inverter Cost ($)	517,000
ROE (%)	9.75
Standard-Offer Price ($/kWh)	0.271

B. Small Wind

Issues related to financing are addressed above. The remaining issues are addressed below.

(1) Small Wind Capacity Factor

Findings

49. The capacity factor employed for calculating the appropriate standard-offer price for 100 kW wind projects under the Board's initial price determination on January 15, 2010, was 23.8%. Docket 7533, Order of 1/15/10 at n. 43.

50. Wind turbines sited in areas with varying average wind speeds have correspondingly varying capacity factors, represented below:

i. 5.8 meters per second ("m/s") = 21% capacity factor;
ii. 5.5 m/s = 18.6% capacity factor;
iii. 5.3 m/s = 17.1% capacity factor;
iv. 5.2 m/s = 16.3% capacity factor; and
v. 5.0 m/s = 14.8% capacity factor.

Jennings pf. at 4; exh. REV-JJ-2; tr. 11/28/11 at 133 (Jennings).

51. Assuming an average wind speed of 5.5 m/s would make approximately 500 sites available for small wind project development statewide that have favorable characteristics. Tr. 11/28/11 at 124 (Jennings).

Discussion

REV initially recommended that the Board model the price for small wind using a capacity factor based on sites with a wind speed of 5.0 m/s or higher. REV based this recommendation on the point at which its wind expert believed projects become viable for developers, based on a project's anticipated annual energy output and proximity to roads and three-phase distribution lines.[22] REV's wind expert asserted that employing an average wind speed of 5.8 m/s, as initially recommended by the Board's Independent Witness, would restrict the locations available for small wind project development to approximately 5% of Vermont's surface area.[23] REV's wind expert also stated that an "inflection point" exists between areas with average wind speeds of 5.3 m/s and 5.2 m/s and that if an average wind speed of 5.2 m/s was used for determining the appropriate capacity factor, there would be a large enough population of efficient sites for movement in the small wind sector. In its December 21 Reply Brief, REV states that "the only way to ensure rapid deployment and commissioning is to select a wind speed of 5.2 m/s."

The Board's Independent Witness based his initial modeling for small wind projects on information regarding wind speeds in Vermont provided by REV's wind expert.[24] To calculate the appropriate capacity factor for small wind projects in Vermont, the Board's Independent Witness essentially averaged the 5.5 m/s wind speeds and the 6 m/s wind speeds provided by REV's wind expert to arrive at an average wind speed of 5.8 m/s, which translates into the initially recommended 21% capacity factor.[25] After hearing the testimony of REV's wind expert at the technical hearing, the Board's Independent Witness stated that he thought the "21 percent capacity factor is an aggressive number" and would "limit the amount of small wind projects that

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22. REV's wind expert also discussed additional considerations, such as having a sufficient number of potential sites based on wind speeds to attract enough landowners that would want to develop a project. REV's wind expert asserts that employing an average wind speed of 5.0 m/s would make approximately 20% of Vermont's surface area open to small wind project development. REV's wind expert's assumptions about the availability of locations for small wind development are based on average wind speeds and proximity to roads and three-phase distribution lines. REV's wind expert represented that the average wind speed in Vermont is 4.2 m/s and that 5.0 m/s is an above-average wind speed. Jennings pf. at 4; exh. REV-JJ-2; tr. 11/28/11 at 123-30 (Jennings).

23. Jennings pf. at 4.

24. Tr. 11/28/11 at 172 (Dalton).

25. Tr. 11/28/11 at 191 (Dalton).

could be developed in Vermont."[26] The Board's Independent Witness also stated that a "slight reduction in the capacity factor is probably appropriate" and reiterated that employing a wind speed of 5.5 m/s would make 500 locations available for wind development.[27]

The Department, in its December 13 Brief recommended that the Board employ an 18% capacity factor to make more potential small wind sites available than would be available with a 21% capacity factor.

The testimony presents a choice. Selecting a higher wind speed (and capacity factor) reduces the number of potential sites in Vermont for small wind. At the same time, adopting a lower capacity factor is likely to provide more incentive than necessary to promote the development of small wind, particularly for developers that can site a project to take advantage of higher wind speeds. By employing an average wind speed of 5.5 m/s for determining an appropriate standard-offer price the Board would be lowering the capacity factor for small wind from 23.8% to 18.6% and, in doing so, making approximately 500 efficient sites available for small wind development. This strikes a reasonable balance between encouraging development without providing excessive incentive for favorably located projects. Therefore, we recommend that the Board adopt a capacity factor of 18.6% for small wind projects.

(2) Small Wind Loan Terms

Findings

52. A loan life of 20 years is appropriate for modeling a 100 kW wind resource. Dalton pf. reb. at 12; exh. JCD-7.

53. An interest rate of 5.5% is appropriate for modeling a 100 kW wind resource. Dalton pf. reb. at 12.

54. Municipalities are a major market for 100 kW wind projects and will likely develop the majority of small wind projects under the standard-offer program. Dalton pf. reb. at 12-13; tr. 11/28/11 at 194 (Dalton).

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26. Tr. 11/28/11 at 191 (Dalton).

27. Tr. 11/28/11 at 191 (Dalton).

Discussion

The Board's Independent Witness assumed that parties investing in small wind turbines would be able to secure 20-year debt at a 5.5% interest rate. The Board's Independent Witness represents that such a debt term and interest rate represents a premium compared to what is being offered for home mortgages and is consistent with interest rates available to municipalities, which are a major market for small wind turbines. The Department supports the Board's Independent Witness' assumptions.[28] Alternately, REV asserts that the modeling should assume that parties would be securing five- to eight-year debt terms at commercial interest rates.[29] However, REV failed to provide sufficient evidence to support its assertion and we find that the Board's Independent Witness' assumptions are reasonable. Therefore, we recommend that the Board adopt the assumption that a loan life of 20 years and an interest rate of 5.5% are appropriate for modeling small wind projects.

(3) Small Wind Capital Costs

Findings

55. The price level established for small wind projects with a capacity greater than 15 kW and 100 kW or less, under the Board's initial price determination on January, 15, 2010, was \$0.216 per kWh. Docket 7533, Order of 1/15/10 at 84; Docket 7523, Order of 9/15/09.

56. Currently, the standard-offer price for small wind projects based on: (a) a 21% capacity factor would be \$0.217 per kWh; (b) an 18.6% capacity factor would be \$0.245 per kWh; and (c) a 14.8% capacity factor would be \$0.308 per kWh. Dalton pf. reb. at 13; tr. 11/28/11 at 191-92 (Dalton).

57. The installed costs appropriate for analysis of 100 kW wind projects are \$5,770 per kW. Exh. JCD-7; Jennings pf. at 5.

58. The operating and maintenance costs appropriate for analysis of 100 kW wind projects are \$5,000 per year. Exh. JCD-7.

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28. DPS Initial Brief at 13.

29. REV's Reply Brief at 7.

59. The insurance cost appropriate for analysis of 100 kW wind projects is $1,000 per year. Exh. JCD-7.

60. The property tax appropriate for analysis of 100 kW projects is $3,000. Exh. JCD-7.

<u>Discussion</u>

Since the Board opened the standard-offer program in 2010, no small wind projects have been commissioned or are in development under the program. In fact, the cancellation rate for small wind projects is 100%.[30] REV argues that the high cancellation rate suggests the possibility that the initial price established by the Board did not create sufficient incentive for developers. REV recommends adopting a price of over $0.30 per kWh.

In general, the Board's Independent Witness recommended that the Board adopt the same assumptions used to calculate the appropriate standard-offer price for small-wind projects in this proceeding as used in the Board's initial price determination.[31] However, the Board's Independent Witness recommends altering the useful life of small wind turbines from 20 to 25 years, reducing the annual variable operations and maintenance expenses of $54 per kW to $3,000 per year, and reducing the debt interest rate from 6% to 5.5%.[32] The Department supports this position.

As we stated above, we cannot conclude that existing prices and approaches are failing to create an environment that encourages rapid deployment. Similarly, the evidence does not demonstrate that the absence of small wind projects in the standard-offer program is a function of price, as REV argues, rather than other factors. Thus, we see no basis to recommend significant additional incentive to small wind projects. Moreover, our inclusion of a lower capacity factor should facilitate the development of small wind projects. Therefore, we recommend that the Board increase the current standard-offer price for small wind from $0.216 per kWh to $0.245 per kWh, based on the findings and discussions above.

30. Jennings pf. at 5.

31. Docket 7533, Order of 1/15/10.

32. Docket 7533, Order of 1/15/10 at 60.

A summary of the assumptions and recommended standard-offer price for small wind projects is listed below.

Net Capacity (kW)	100
Installed Cost ($/kW)	5,770
O&M Expense ($ per year)	3,000
Property Tax (per year)	5,000
Capacity Factor (%)	18
Asset Life (years)	25
Contract Term (years)	20
Debt Interest Rate (%)	5.5
ROE (%)	9.75
Standard-Offer Price ($/kWh)	0.245

C. VEC's Comments

In its brief, VEC stated that it was "leery" of the solar and small wind prices recommended by the Board's Independent Witness "not because they are unreasonable or ill-conceived, but rather because of the several different prices (particularly for solar) available to different projects that are dependent upon timing, interpretation of legislation, and luck." VEC provides an example of its concerns by noting that the same solar project can potentially receive prices for its electricity generation of anywhere from less than $0.20 per kWh to $0.30 per kWh "depending upon which utility serves it, what that utility has had approved for a 'solar adder' when it was applied for, and whether its number was selected in the lottery." VEC further states "that policies that are fair, consistent, and predictable will foster more and sustained deployment of renewables."

VEC appears to be raising concerns regarding Vermont statutes rather than the Board's implementation of these statutes. Those statutes provide the opportunity for renewable generation projects to have different opportunities for power purchase depending on whether the generator participates in the net metering program or standard-offer program and when the developer enters into a contract under the standard-offer program. If VEC finds these options confusing or unwise, it needs to address these concerns with the Legislature, not the Board, which is charged with applying the law.

Pursuant to the Vermont Energy Act of 2009, the Board established cost-based prices for renewable plants with a nameplate capacity of 2.2 MW, and pursuant to Section 8005(b)(2)(C), the Board is required to review, on or before January 13, 2012, and on or before every second January 15 after that date, the standard-offer prices and determine whether such prices are providing sufficient incentive for the rapid development and commissioning of plants. We are confining our review in today's proposal for decision to those required by statute.

VI. Conclusion

We recommend that the Board accept the input assumptions set forth in this proposal for decision and alter the standard-offer prices for solar PV and small wind. In addition, we recommend that the standard-offer prices for the remaining technology categories remain the same as those established in the January 15, 2010, Order.

Dated at Montpelier, Vermont, this 17th day of ______________, 2012.

s/George E. Young
George E. Young, Esq.
Hearing Officer

s/Mary Jo Krolewski
Mary Jo Krolewski
Hearing Officer

VII. Board Discussion

After reviewing the comments on the Proposal for Decision ("PFD"), we adopt the Hearing Officers' PFD, with one clarification, for the reasons set forth below.

Summary of PFD Comments

The Board received comments on the PFD from the Department, CVPS, and REV.

The Department recommends that the Board adopt the PFD.

REV challenged two elements of the PFD: solar capacity factor and solar capital costs. With regard to the solar capacity factor, REV contends that the Hearing Officers incorrectly characterized its testimony in concluding that REV's expert used 11 months of operating to determine an appropriate solar capacity factor of 13%, and clarifies that REV's expert used the PVwatts.com tool to determine a capacity factor of 13.4%. REV contends that the use of TMY data for Vermont in the PVwatts.com tool does not account for snow soiling, and that the derate factors for soiling in the tool need to be adjusted to reflect snow soiling.

With regard to solar capital costs, REV contends that Finding 42 is incorrect with regard to "a 30% decline in module prices forecast for 2012," because the source cited by the testimony of the Board's Independent Witness did not predict a further 30% decline but rather stated that there might be a further decline in module prices of 30%. REV further notes that the testimony source also states, "Market prices . . . are likely to remain at levels approximately $1.00/watt in the long-term." In addition, REV claims that the Department recommended the use of a solar module cost of $1.10 per watt and the parties and the factual record do not support an assumption of $0.88/watt.

CVPS contends that the Hearing Officers incorrectly characterized its comments and recommendations by stating in Section IV.B that CVPS supports the recommendations of the Board's Independent Witness. CVPS contends rather that its comments stated that it "does not see a pressing need to increase the rates offered under the program at this time." CVPS recommends that this reference be removed from the final form of the Order to be issued by the Board.

Discussion

The solar PV modeling in Docket 7533 relied upon a capacity factor of 14.5%. In establishing that value, we considered the values presented by the parties (calculated using the PVwatts.com tool) and established an appropriate capacity value that reflects best practices, efficient investment, and the location of projects in reasonable sites. In this docket, the Hearing Officers concluded that a capacity factor of 14.5% continues to represent an efficiently operating fixed-axis solar facility in Vermont and properly considers the weather conditions in Vermont.

REV and the Department disagree on how to include the effects of snow soiling in the PVwatts.com tool. REV's expert recommended a solar capacity factor of 13.4%, as REV recommended in Docket 7533, calculated using the PVwatts.com tool assuming the tool's default derate factors.[33] REV's expert also recommended a capacity factor of 13% based on its contention that the typical capacity factors for well-designed fixed solar arrays in Vermont will range from 12.5% to 13.5%.[34] As noted by the Hearing Officers, REV supported this claim using data from 11 months of operating data from one solar installation. REV contends that a capacity factor of 13.4% calculated using the default values in the PVwatts.com tool is appropriate because it accounts for snow accumulation on the solar modules by using a soiling derate factor of 5%.

In Docket 7533, the Department recommended a solar capacity factor of 14.9% calculated using the PVwatts.com tool and assuming an inverter efficiency derate (the DC to AC conversion) of 4%, a system availability derate of 0.5%, and a soiling derate factor of 0.5%.[35] In this docket, the Department recommends the continued use of a capacity factor of 14.5% that was determined in Docket 7533, implicitly incorporating these same factors. The Department contends that the PVwatts.com tool properly considered snow soiling by employing TMY data for Vermont and thus does not need an adjustment to the soiling derate factor to account for snow.

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33. Seddon pf. at 2.

34. Seddon pf. at 3.

35. Docket 7533, exh. REV-DPS_1-1_DPS_PV_cap_factor_adj_tracking.xls.

We are not persuaded by REV's cited flaws in the 14.5% capacity value. REV's analysis fails to address the derate factors for inverter efficiency and system availability that were used to develop the capacity value. The adjustments for inverter and system availability have a significant impact on the capacity value calculated using the PVwatts.com tool.[36] The appropriate solar capacity factor must reflect best practices and efficient investment. An inverter efficiency of 96% and system availability of 95.5% reflect this efficient operation.

Moreover, a capacity factor of 14.5% is not directly derived from the PVwatts.com tool and reflects further downward adjustment from a 14.9% calculated value. Thus, a capacity factor of 14.5% reflects some impacts of snow soiling beyond those included in the TMY data used in the tool.[37] We are also persuaded by the Hearing Officers' and Department's conclusions that the 11 months of data REV presented in support of its arguments is not statistically significant for determining a capacity factor value. We therefore accept the Hearing Officers' recommendation and conclude that a capacity factor value of 14.5% is appropriate for the use in the solar cost modeling.

The Hearing Officers concluded that current trends suggest continued declines in the cost of solar modules and systems, and that capital costs of $3.59 per watt presented by the Board's Independent Witness in his alternate case are appropriate. REV claims the Hearing Officer's conclusions that the cost of solar modules are likely to decrease in 2012 is not supported by the factual record because differing opinions exist on the future prices of solar modules. We disagree. The Board's Independent Witness examined multiple sources of expert data to support the conclusion of a 30% decline in module price forecast for 2012.[38] Based on his analysis of the data, the Board's Independent Witness recommended the Board consider a solar module cost

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36. Using the PVwatts.com tool and assuming an inverter efficiency derate of 4%, system availability derate of 0.5%, and a soiling derate of 5% (as recommended by REV), the resulting capacity factor is 14.3%.

37. Using the PVwatts.com tool and assuming an inverter efficiency derate of 4%, system availability derate of 0.5%, and a soiling derate of 3.5%, the resulting capacity factor is 14.5%.

38. The rebuttal testimony of the Board's Independent Witness cites two sources to support Finding 42: *Solar Market Sees Pickup, but a Flat Market is Predicted for 2012*, PV Magazine, November 8, 2011, and *Risky Capacity Increases Set the Global Stage for Manufacturer Struggles*, PV Magazine, October, 2011, p. 64. REV cites the October 2011 PV Magazine source in support of its claim.

decline of 20% to establish a standard-offer solar price. The Hearing Officers recognized that the forecasting of prices of solar modules is uncertain, but concluded that the forecast of additional declines in module prices in the year 2012 was reasonable. We accept that conclusion.

In addition, REV claims that the Department supported the $1.10 per watt module cost (i.e., assuming no decline in 2012 prices), when in fact the Department's briefs only voiced its support for the standard-offer price of $0.289 per kWh. The Department stated that it supports the PFD.

Therefore, we adopt a value of $3.59 per watt for solar capital costs. Using these capital cost assumptions and the financing and capacity factor assumptions identified above, the financial model calculates a standard-offer price of $0.271 per kWh. Accordingly, we revise the standard-offer price for solar projects to $0.271 per kWh.

The Hearing Officers recommended a that the Board revise the standard-offer price for small wind to $0.245 per kWh. We clarify that the first year annual price for small wind is $0.245 per kWh and that over a 20 year period the levelized price is $0.253 per kWh. Accordingly, we revise the standard-offer price for small wind to $0.253 per kWh. This clarification does not change the overall conclusions of the PFD, or our decision to adopt the Hearing Officers' recommendations.

In comments on the PFD, CVPS contends that the Hearing Officers incorrectly characterized its comments and recommendations by stating in Section IV.B that CVPS supports the financial recommendations of the Board's Independent Witness. We clarify that CVPS "does not see a pressing need to increase the rates offered under the program at this time." This clarification does not change the overall conclusions of the PFD, or our decision to adopt the Hearing Officers' recommendations.

<u>Conclusion</u>

In conclusion, we adopt the Hearing Officers' PFD, including accepting the input assumptions and recommended standard-offer prices set forth in the PFD. We revise the standard-offer prices for solar photovoltaic projects to $0.271 per kWh and wind projects with a nameplate capacity of 100 kW or less to $0.253 per kWh (as specified in Attachment I to this Order). In addition, we retain the standard-offer prices for the remaining technology categories as established in the January 15, 2010, Order. Pursuant to Section 8005(b)(2)(C), the revised prices will be in effect on a prospective basis commencing two months after the date of today's Order.

VIII. ORDER

IT IS HEREBY ORDERED, ADJUDGED AND DECREED by the Public Service Board of the State of Vermont that:

1. The findings and recommendations of the Hearing Officers are adopted.
2. Effective for any standard-offer contract executed two months subsequent to the issuance of this Order, the standard-offer prices for renewable power under 30 V.S.A. § 8005(b)(2) shall be as specified in Attachment I to this Order.

Dated at Montpelier, Vermont, this 23rd day of January, 2012.

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

OFFICE OF THE CLERK

FILED: January 23, 2012

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

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

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