STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket Nos. 7523

Implementation of Standard Offer Prices for Sustainably)
Priced Energy Enterprise Development ("SPEED"))
resources Re: Interim Prices)

Order entered: 9/15/2009

ORDER RE INITIAL STANDARD OFFER PRICE DETERMINATIONS FOR SPEED RESOURCES

I. Introduction

Pursuant to the Vermont Energy Act of 2009 ("Act" or "Act 45"),[1] the Public Service Board ("Board") is required to open and complete, by September 15, 2009, a "noncontested case docket" to determine whether the statutorily-defined default prices for qualifying Sustainably Priced Energy Enterprise Development ("SPEED") resources, "constitute a reasonable approximation of the price that would be paid applying the criteria" established by the Act. Pursuant to the Act, if the Board determines that the default prices are not a reasonable approximation, the Board must set interim prices by September 15, 2009. Act 45 further requires that the Board update these interim prices by January 15, 2010, following an opportunity for more in-depth examination.

In this Order we determine that, with the exception of farm methane resources, for which we establish a higher interim price, the default prices established by statute are a reasonable approximation of the price that would be paid for renewable resources when applying the criteria established by the Act. In addition, we determine "the average residential rate per kWh charged by all of the state's retail electricity providers weighted in accordance with each such provider's share of the state's electric load," which the Act establishes as the statutory default price for hydroelectric power, biomass, and wind resources over 15 kW.[2] These determinations apply during the first few months of the program and will likely change following the more detailed determinations due on January 15, 2010. In this Order we establish the following interim prices for renewable resources:

Resource	landfill methane	farm methane	wind (15kW or less)	wind (over 15 kW)	solar PV	hydro-power	biomass
Price/kWh	$0.12	$0.16	$0.20	$0.125	$0.30	$0.125	$0.125

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

The Act provides the Board with the discretion to "consider different generic costs for subcategories of different plant capacities within each category of generation technology."[3] Several participants advocated that the Board include increased "granularity" in its price determinations. In this Order we conclude that based on the available information and the limited time for first-stage interim analysis, although further granularity than that provided in the statute may be appropriate, additional information and analysis are needed before reaching a conclusion. We will reexamine this issue during the process leading to our determination of prices by January 15, 2010.

II. 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 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.

On May 27, 2009, the Vermont Energy Act of 2009 took effect; the Act substantially modifies the SPEED program. It establishes a standard offer mechanism for potential project developers seeking a market for the energy produced from qualifying SPEED resources. The Act establishes default prices for the standard offer for different technologies, and largely cost-based criteria for determining the price paid to developers of renewable power purchased through the SPEED program. Pursuant to the Act, the SPEED Facilitator is required to purchase, on behalf of the Vermont electric distribution utilities, energy from developers who accept the standard offer. The energy, and attendant costs, are assigned to the utilities based on their pro rata share of total Vermont retail kWh sales for the previous calendar year.[5]

3. Section 8005(b)(2)(B)(i)(1)(bb). In this Order we use the term "granularity" to refer to this specific issue.
4. The SPEED program is codified in 30 V.S.A. § 8005.
5. Section 8005(b)(7) allows an exception to the purchase power requirements of subdivision (5) if the retail electricity provider establishes that it receives at least 25 percent of its energy from qualifying SPEED resources that were in operation on or before September 30, 2009.

The Act requires the Board to determine by September 15, 2009, whether there is a "substantial likelihood" that one or more of the default prices in the statute do not constitute a "reasonable approximation" of the prices applying the largely cost-based criteria in statute. If the Board determines that the statutory prices do not constitute a reasonable approximation, the Board must set interim prices. In addition, the Board must set, no later than January 15, 2010, the price to be paid to plant owners under a standard offer following an opportunity for more detailed analysis.

III. Procedural History

On June 3, 2009, the Board issued an Order opening Docket 7523, an investigation into the implementation of standard offer prices for SPEED resources. The Order stated:

> This Docket will address the review of the Act's standard offer prices and, if the prices are not a reasonable approximation, set interim prices by September 15, 2009. In addition, the Board will consider non-price terms and conditions for standard offer contracts in this Docket. A subsequent docket will more fully address the standard offer prices in accordance with the January 15, 2010, statutory deadline and will incorporate the record from this Docket.[6]

On June 29, 2009, the Board issued an Order in Docket 7533 opening a second investigation to build upon the record developed in Docket 7523, resolve all necessary implementation issues not addressed in that docket, and reevaluate the prices for SPEED projects set out in the statute. Docket 7533 was opened as a distinct proceeding primarily because the Act requires that the Board not only open the noncontested case docket that is Docket 7523, but also complete it by September 15, 2009.

In this Order issued in Docket 7523, we are making determinations as to (1) whether the statutory default prices are a reasonable approximation of the price that would be paid applying the statutory criteria, (2) the appropriate price where the default price is not a reasonable approximation, and (3) other factors necessary to determine the appropriate prices. By

6. Docket 7523, Order of 6/3/09 at 2.

September 30, 2009, the Board will issue an order in Docket 7533 that establishes the necessary framework for the standard offer program.[7]

Between June 6, 2009, when the Board opened this proceeding, and today, the Board embarked on a process that relied heavily on the renewable resource development community, the Vermont Department of Public Service ("Department" or "DPS"), and other stakeholders to develop the models and cost inputs that would be needed to make the price determinations.

In addition, the Board hired Power Advisory LLC ("Power Advisory") to assist Board staff and participants in the process. Power Advisory had prior experience assisting in the development of similar standard offer programs in Ontario and Florida, and provided an independent and expert voice in the process.

The parties and the Board staff organized the effort into four working groups, including the Cost Analysis Subgroup ("Subgroup"). The Subgroup was open to any interested party and was comprised of developers, state agencies, utilities, advocacy groups, and other interested parties. A list of the participants in the Subgroup is included as Appendix A.

The Subgroup utilized a model, initially constructed by a representative of Green Mountain Power Corporation ("GMP") and reviewed and modified by members of the Subgroup, to estimate the costs and returns to developers. The majority of the inputs to the model were provided by developers or their representatives. Those providing the information were instructed that the guiding principle in developing the inputs should be the efficient use of the technologies consistent with the general policy of the state contained in 30 V.S.A. §§ 202a and 218c, discussed further below. The Department was asked to provide the "hand's on" modeling and varied the inputs, especially those related to the treatment of grants and taxes, to reflect what the Department considered to be a reasonably efficient use of those incentives in the modeling. The Department also varied assumptions related to capital costs, capital structure and financing in ways that it intended to reflect as efficient use of those factors.

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7. Pursuant to Act 45, the Board must "no later than September 30, 2009, put into effect, on behalf of all Vermont retail electricity providers, standard offers for qualifying SPEED resources with a plant capacity of 2.2 MW or less." Section 8005(b)(2).

The Subgroup developed a report that included the model runs (including the Department's alternative runs), along with a set of recommendations to assist the Board in making its determinations.[8] The Subgroup report did not reflect a group consensus but instead reflected the fact that widely divergent views on the question of prices remained. The report was circulated to the wider distribution list for this docket for comment. The list of participants on that larger distribution list is included as Appendix B.

As part of the review, the Board's Technical Advisor was also asked to provide a review of other jurisdictions to provide further context for the determinations being made by Vermont. This was included as an Appendix C to the Subgroup Report and Recommendations.

As noted above, the Subgroup developed two sets of modeling runs. An "initial" set of model runs was based largely on the inputs and recommendations received from developers and their representatives. The Agency of Agriculture, Food and Markets ("Agency of Agriculture") also provided inputs and recommendations used in the initial runs. A second set of modeling runs was developed by the Department and are referred to as the "DPS" runs. Both sets of runs were presented in the Subgroup report released on August 28, 2009. In addition to these runs, and in light of the widely divergent modeling results, the Board also relied on the Board's Technical Advisor to provide recommendations for the modeling runs. A summary of the various modeling runs alongside the default rates contained in Act 45 is contained in the table below, along with the Board determinations that the Board reaches in this Order (and which are explained further, below).[9]

8. The "Report and Recommendations of the Cost Analysis Subgroup" can be found at http://psb.vermont.gov/sites/psb/files/docket/7523/CostAnalysis/Cost_Analysis_Subgroup_Final_Report.pdf.

9. These rates generally reflect constant nominal prices over a 20-year contract, except for solar PV, which is for 25 years, and landfill methane at 15 years, consistent with the assumptions used in the modeling of these projects by the Cost Analysis Subgroup.

Summary of Model Results and Board Decision (all prices expressed in $ per kwh)							
	Hydro	Wind (>15kW)*	Wind (≤15 kW)	Biomass	Solar PV*	Landfill Gas	Farm Methane*
Statutory Default Prices	$0.125	$0.125	$0.200	$0.125	$0.300	$0.120	$0.120
Initial Assumptions	$0.150	$0.126			$0.471	$0.254	$0.175
DPS Assumptions	$0.132	$0.111			$0.177	$0.129	$0.149
Power Advisory Adjusted Modeling	$0.135	$0.119			$0.282		$0.157
Board Determination	**$0.125**	**$0.125**	**$0.200**	**$0.125**	**$0.300**	**$0.120**	**$0.160**

*Note: Values reflect the largest capacity project category modeled in the Subgroup report and the report of the Board's Technical Advisor.

IV. Legal Standards for Determining Standard Offer Prices

As noted above, the Board is required under Act 45 to determine whether there is a substantial likelihood that one or more of the prices contained in the Act do not represent a reasonable approximation of the prices when applying the general cost standards of the Act.

Pursuant to Section 8005(b)(2)(B)(I), the Board is required to use the following criteria in setting a price:

> (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.
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> (bb) Consider different generic costs for subcategories of different plant capacities within each category of generation technology.
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> (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.

> (III) The board shall include such adjustment to the generic costs and rate of return on equity determined under subdivisions (2)(B)(I) and (II) of this 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.

As Act 45 makes clear, the standard offer price is primarily determined by the cost of developing the SPEED resources.

The requirements of Act 45, however, exist within the broader framework established in Vermont statutes. For example, 30 V.S.A. § 218c requires Vermont utilities to prepare a least cost integrated plan

> for meeting the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs.

In addition, 30 V.S.A. § 202a(1) states that it is the general policy of the state that Vermont meet its energy needs in a manner "that is adequate, reliable, secure and sustainable; that assures affordability and encourages the state's economic vitality, the efficiency use of energy resources and cost effective demand side management; and that is environmentally sound."

In addition to the review of the broader statutory framework, it is helpful to highlight three features of Act 45 that affect the Board's determination of standard offer prices. First, the Vermont General Assembly, in instructing the Board in these determinations, required that the Board establish 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. Based on a review of past Board decisions, the highest return on equity currently allowed by this Board is for our smallest investor-owned electric utility, and was established in 1990; that return on equity is 12.13 percent. This compares to the current allowed return on equity for the other two retail investor-owned electric utilities in the state of 9.77 percent and 9.69 percent. The use of a 12.13 percent return on equity represents a significant return for project developers, is significantly higher than the return earned by Vermont's other investor-owned electric utilities, and is unlikely to be representative of a reasonable return at this time. We have used this figure in the determinations contained in today's Order. In our more detailed examination for January 15, 2010, we will look closely to determine whether we should adjust this value as permitted by Section 8005(b)(2)(B)(III).

Second, the Board was asked to "consider" different generic costs for different plant capacities within each category of generation technology. Increased granularity has the potential to provide more accurate price signals regarding the costs of different project sizes within a technology. However, as discussed further below, we conclude that there is insufficient information and time to make such a determination in this proceeding, but will reexamine whether additional granularity is appropriate in the process leading to our January 15, 2010, price determinations.

Third, the Board was given the discretion to adjust those costs and return on equity 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." Many organizations from differing perspectives recommended a cautionary approach and recommended that the Board err on the side of caution in setting the standard offer prices.[10] At least one participant suggested that the standard that requires the Board to establish rates sufficient for rapid deployment, but not excessive incentives, will indeed require time and experience to implement.[11]

In general, we agree with these comments and concerns, especially as they relate to our decisions at this early date. The criteria established in Act 45 that are used to establish the standard offer price are focused largely on the costs to developers. However, the Act expressly gives the Board discretion to deviate from those costs to establish prices that provide the appropriate level of incentives. This explicit discretion, combined with the Legislature's pronouncements on state energy policy and least-cost integrated planning and the fact that the prices set in this Order are intended by statute to be interim prices only, convince us that we should proceed cautiously in establishing these interim prices. In all but one instance we have

10. *See*, for example, comments of the Vermont Public Interest Research Group, dated September 3, 2009, the Vermont Department of Public Service, dated September 4, 2009, Associated Industries of Vermont, dated September 4, 2009, and Central Vermont Public Service Corporation, dated September 4, 2009.

11. *See*, for example, comments of the Vermont Department of Public Service, dated September 4, 2009.

maintained the prices at the statutory defaults. At this time, we are also exercising caution and deferring for further investigation the issue of whether to establish more granular capacity levels for any category of generation technology.

V. Participants' Comments

The opportunities for comment and participation were extensive throughout this docket. As indicated above, the Cost Analysis Subgroup was formed to facilitate a resolution of the determinations required of the Board in Docket 7523 and was open to any interested party. Participants in this Subgroup were given an opportunity to inform the choice of model, to contribute and refine the model, and to provide the initial inputs to the modeling process. In addition, participants were given an opportunity to challenge the assumptions and modeling used by the Department. Consequently, the Subgroup report reflected the guidance and input of any interested party that availed itself of the opportunity. Those providing inputs to the modeling were asked to provide further brief support and explanation of their assumptions as a supplement to the report in Appendix B. Further, the Board received both solicited and unsolicited comments in writing from the participants. Board staff attempted to quickly upload and make available almost all comments received among the broader group of Subgroup members on the Board's web site for added transparency.[12] This process culminated in two final rounds for comments from the participants which have been uploaded. The first allowed the participants to supplement the report on its release on August 28, 2009, with a second reply round on September 4, 2009. A brief summary of the comments received from the participants is discussed below in summary fashion supplemented by more detailed discussions in the various subsections of this Order.

12. There were also numerous instances of detailed communications among pockets of Subgroup members, especially with the modelers that were not uploaded. Also communications that were received only as an e-mail communication without attachments were generally not uploaded to the web site.

A. Associated Industries of Vermont ("AIV")

AIV indicated that it has serious concerns associated with the negative economic impacts stemming from the implementation of Act 45. As such, it "strongly" urges the Board to "seek to minimize rate impacts and otherwise protect the interest of ratepayers and the economy," while conforming to the statutory requirements of the Act.[13] Specific comments of AIV include recommendations that the Board reject proposals for granularity in establishing prices, adhere to the DPS modeled prices or the default prices contained in Act 45, and to consider further reductions if supported by "real-world" experience. In summary, AIV urges caution noting that the risks are asymmetric and favor lower price determinations in the early stages of the program.

B. City of Burlington Electric Department ("BED")

BED offered comments that were specifically focused on the solar photo-voltaic ("solar PV") cost estimates based on its own experience to date.[14] BED indicates that it has quantitative experience with solar photo-voltaic installation development in a number of size ranges. Based on BED's work with potential developers of mid-and large-size Solar PV, with developers using a price range of $250 to $300 per MWh, based on a long-term (20-25 year) contract, it "has not had developers indicate that this price level of payment presents a barrier to solar photo-voltaic resource development." Based on this, BED believes that the estimates in the report for the initial runs are more than 50% greater than the benchmarks used by BED. As such, BED encourages the Board to be conservative in its cost estimates where long-term commitments are being considered. BED highlights the asymmetric risks to ratepayers as a basis for erring on the low side of estimates in the early stages of the program. BED supports the estimates of the Department for the solar PV size categories below 500 kW as an appropriate basis for costs, but provided no further comments on the DPS estimates for projects 500 kW to 2.2 MW.

13. Letter to Susan Hudson from William Driscoll (AIV), dated September 4, 2009.
14. E-mail communication from William F. Ellis, sent August 8, 2009.

C. Central Vermont Public Service Corporation ("CVPS")

CVPS commented on the Subgroup report during the reply round of comments. CVPS also contributed to the discussion of interconnection costs in the Appendix to the Subgroup report.[15] CVPS notes the difficulty in establishing the prices in the compressed timeframes permitted under the Act. CVPS recommends that the Board "refrain from raising the default rates above those established under the Act."[16] CVPS joins other parties in supporting a "cautious approach" to setting prices. It also notes that risks associated with setting rates favor starting with lower prices and increasing rates at a later time if the Program prices prove inadequate to attract participants.

CVPS notes that its recommendations are guided by the fact that the least-cost planning principles apply to an electric utility for planning purposes under Vermont statutes. While Act 45 focuses on costs, it does not relieve the Board of its obligations to consider least-cost planning criteria.[17]

D. Green Mountain Power Corporation ("GMP")

GMP helped in the early stages of model development and modeling. GMP also provided suggested inputs for the wind modeling for larger projects. GMP also submitted comments during the Reply round of comments.

GMP reinforced the comments of others that the timeframes for considering the issues were extremely short and urges caution during the initial rate-setting.[18] GMP asserts that the character of risk favors conservative rates in initial stages of the program's evolution. GMP also supports the application of least-cost principles to the Board's determination of prices. In addition, GMP offers comments on prices for specific technologies.

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15. *See*, Cost Analysis Subgroup Report and Recommendations, Appendix E. The individual Subgroup participants actually included the interconnection costs in their estimates used for modeling. The Chair of the Subgroup requested additional information separate from the bundled estimates for further context and clarity in the report.

16. Letter to Susan M. Hudson from Morris L. Silver, Esq., dated September 4, 2009.

17. *Id.*, at 2.

18. E-mail attachment from Josh Costonguay (GMP), sent September 4, 2009.

With respect to Landfill Gas, GMP raises concerns with the information being relied upon for the one project that was modeled at 132 kW. GMP is concerned that the project is not representative of projects that are likely to be developed under the SPEED program and, in any event, is not representative of the price levels that would be appropriate for the vast majority of projects that would be eligible to participate under the program. GMP provides a summary of a database of working and planned landfill-gas generation projects in New England. Out of the 52 New England landfill-gas projects, only 2 projects (one operating) fall below the 150 kW level, with the "overwhelming majority sized 800 kW or more and most above 1.5 MW." Within Vermont, the two recent landfill gas projects feature engine sizes in that range.

GMP indicates that the Department's model for smaller scale landfill gas is much more in line with GMP's experience. For "larger projects" GMP is aware of long-term power purchase agreements that have been priced below the 12 cents per kWh that represents the legislative default for such projects, and estimates range from 6.1 cents/kWh to 9.2 cents/kWh in New York.

GMP also indicates that it is able to build solar PV projects for under $0.25/kWh and is planning other projects under that price due to the expectation of even lower costs for equipment in 2010.[19] GMP argues that the statutory prices "are a good place to start and will allow time for further development between now and January . . . ."

E. Great Bay Hydro Corporation

Great Bay filed comments on September 3, 2009.[20] Great Bay also participated in the modeling efforts of the Subgroup and provided text in Appendix B of the Subgroup report addressing the hydroelectric inputs.[21] Great Bay owns and operates a hydroelectric project in Newport, Vermont, and is seeking to develop new resources in the state. Great Bay also participated in the development of the Cost Analysis Subgroup report. In its comments, Great Bay addresses the issue of the Vermont Investment Tax Credit that the Department

19. *Id.*, at 3rd page.
20. Letter to Susan Hudson from Anthony M. Callendrello, dated September 3, 2009.
21. *See*, Cost Analysis Subgroup Report and Recommendations, Appendix B.

recommended reflecting in price determinations. Great Bay argues that the credit is not available to an entity that files a corporate tax return and, for solar PV projects, the tax credit is out of proportion to the amount of available tax liability. Finally, Great Bay indicates that if the income that creates the tax liability is from the renewable project, the prices necessary to create sufficient tax liability to make use of the credit would be extreme and unrealistic.

Great Bay also disagrees with what it alleges is the "DPS assumption that every project eligible for the standard price will apply and receive the maximum $250 thousand grant" from the Vermont Clean Energy Development Fund ("CEDF"). Great Bay states that it has been rejected for both a grant and a loan for one project based on its inability to demonstrate the "but for"[22] criteria that has been applied to CEDF projects in the past. Great Bay argues that given the past lack of availability of CEDF grants for hydroelectric projects, it is not reasonable to set rates for those projects assuming that they will receive the full CEDF grant. Great Bay argues that if CEDF funds are not guaranteed to be available to all projects that apply for grants at the maximum available, then the standard offer price should not include such grants in the price determinations.

Great Bay also takes issue with the property tax escalation assumptions used in the Department's analysis and argues that both the Great Bay analysis and the Department's analysis suggest that the prices are above the default price of $125/MWh and as such, should be set above the default price and ideally at the price of $150/MWh, which was determined through the initial model runs that relied on the Great Bay assumptions.

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22. The "but for" standard is intended to capture the fact that *but for* the grant, the project would be unable or unlikely to progress.

F. Group of Municipal Electric Utilities ("GMEU")[23]

The Group of Municipal Electric Utilities filed comments in the reply round on September 3, 2009.[24] GMEU raises concern that "the breadth of information offered to the Cost Analysis Subgroup, and the lack of procedural opportunity for parties (and the Board) to weigh and evaluate the information through a more formal hearing process, underscores the GMEU's concern that docket 7523 must be limited to the preliminary review of the rates set forth in the Act, and nothing else."

G. International Business Machines Corporation ("IBM")

IBM supports the recommendations of others for a conservative or cautious approach. IBM also notes that the risks in setting prices argues for the Board to err on the low side initially "and adjust upwards as determined necessary based on actual experience." IBM states that overpricing the standard offers will negatively impact Vermont's competitiveness for a generation.[25]

H. Vermont Public Interest Research Group ("VPIRG")

VPIRG provided comments on the Subgroup report on September 3, 2009.[26] VPIRG also supports a cautious approach. As VPIRG states in its letter, it agrees in principle:

> . . . that a cautious approach should be taken with regard to seeking the interim rates for the standard offer program. The prices found in the cost analysis subgroup vary significantly for some resources and it would be prudent to err on the lower end of the cost range to protect against Vermonters paying more than is necessary for any given resource.

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

24. Letter to Susan Hudson from David Mullet, Esq., dated September 3, 2009.

25. Attachment to e-mail sent by John Aldrich on September 4, 2009.

26. Letter to Susan Hudson from James Moore (VPIRG), dated September 3, 2009.

VPIRG supports limited granularity, and indicates that it believes that the intent of the law was to support the local development of many different types and sizes of projects.

I. Northern Power Systems ("Northern Power")

Northern Power provided both comments supplementing the report on August 28, 2009, and Reply comments on September 4, 2009.[27] Northern Power also contributed text for Appendix B of the Subgroup report, and provided a brief on granularity that has been posted to the Board's web site.[28] In its August 28, 2009, comments, Northern Power addresses the following topics that are discussed in more detail in the respective detailed subsections.

Granularity – Northern Power asserts that there is broad agreement that a cost curve (scale economies) exists for each technology and that Act 45 was intended to promote a wide range of project sizes.

Capacity Factor – Northern Power asserts that the capacity factor of 23.8 percent used in modeling wind costs is high for Vermont and recommends a capacity factor of 20 percent for modeling 100 kW wind resources.

Technology Sub-Caps – Northern Power supports reliance on sub-caps and an appropriate safety valve if the Board sets prices too high, resulting, for example, in a run on solar PV resources.[29]

Interconnection Costs – Northern Power is concerned that earlier estimates of initial costs that were modeled do not include some higher estimates of interconnection costs that were received after the initial modeling.[30]

Long-term Rates – Northern Power asserts that "no-one has been able to point to a bank or other financing entity willing to finance 20 years at 7 percent" and, accordingly, the 7 percent

27. See attachment to e-mail sent from Jim Stover, Northern Power Systems, dated August 28, 2009, and attachment to e-mail from Jim Stover, dated September 4, 2009.

28. *See*, Cost Analysis Subgroup Report and Recommendations, Appendix B. The Northern Power Brief on Granularity is available at the Board's web site at http://psb.vermont.gov/sites/psb/files/docket/7523/CostAnalysis/ost_Efficiency_and_FIT_Best_Practices_862009.pdf

29. This issue was reviewed separately by the Standard Contract Subgroup and will be addressed in a later Board decision.

30. These cost estimates were provided courtesy of CVPS at the request of the Subgroup Chair and are included in the discussion of interconnection costs in the Cost Analysis Subgroup Report and Recommendations at 12.

figure should not be accepted as the basis for the modeling. Northern Power instead recommends shorter terms at 10 percent.

Reliance on CEDF Grants – Northern Power questions whether there will be CEDF grants available for wind projects in light of potential competing demands on the solar PV funds that relate to the Vermont tax credit. Northern Power challenges the reliance on estimates of CEDF grants in the modeling if the grants cannot be assumed to apply to all projects.[31]

Average Retail Rate – In its reply comments, Northern Power agrees that the 12.5 cent per kWh determination recommended in the Subgroup Report and Recommendations is appropriate, but also recommends that this figure be updated at least every two years.

J. Renewable Energy Vermont ("REV")

REV provided supplemental comments to the Subgroup Report of August 28, 2009.[32]

REV raises a number of specific concerns with the assumptions used in the modeling, including the cost of debt used in all the models, and the capacity factor assumptions (for wind and solar PV) used by the DPS. REV raises concerns with DPS modeling of state and federal tax credits, noting that there are few entities with sufficient tax liability to take full advantage of the credits. REV also highlights uncertainties associated with the value of the Vermont Investment Tax Credit as it related to pending Vermont Tax Department determinations that have the potential to reduce the value of this credit.

REV questions whether the Clean Energy Development Fund grants should be recognized as incentives, and whether they are reasonably available in light of current CEDF Board discussions and financial limitations. Further, the inclusion of the CEDF in the modeling of costs may require all projects that apply to the CEDF to be profitable. Such a requirement undercuts that statutory principle of "‘rapid development' as there will be long delays as projects wait for the next CEDF grant round."[33] Further, REV raises a number of detailed concerns with the modeling of solar PV costs, including concerns over the availability factor in the model, the DC to AC conversion factor used in the model, available working capital, and the DPS modeling

31. Letter to Susan Hudson from Jim Stover (Northern Power), dated September 4, 2009, at 3.
32. Letter to Susan Hudson from Andrew Perchlik (REV), dated August 28, 2009.
33. *Id.*, at 2.

of the largest projects at only $3.95 per watt (relative to a cost of more than $6/watt which it asserts is more appropriate).[34]

K. Vermont Agency of Agriculture, Food and Markets ("Agency of Agriculture")

The Agency of Agriculture provided comments on August 28, 2009, on the issues of granularity and loan terms.[35] The Agency of Agriculture indicates that about half of the manure in the state is on farms where collection and digestion of manure is possible. If half of the cow manure were to go through anaerobic digesters, it would decrease greenhouse gas emissions by an amount equivalent to 200,000 tons of CO_2.

The Agency of Agriculture recommends two levels of granularity, one for farm systems up to 100 kW with a price of $0.345 per kWh and one for large farm systems in excess of 100 kW equal to $0.175 per kWh.[36] The Agency of Agriculture notes that while there are over 1,000 dairy farms in Vermont, only about 50 farms are milking in excess of 500 cows. The Agency of Agriculture argues that a price of $175/MWh will give a well-managed system a rate of return reasonably close to the required rate of 12.13 percent.

The Agency of Agriculture concedes that a price specifically for the small farms would not be economically viable at this point in time.

The Agency of Agriculture argues against details of the loan term used by the Department. The Agency of Agriculture argues that a 20-year loan term used in the Department's analysis is simply unavailable and that the Board should instead rely on a 7-year loan.

L. Vermont Department of Public Service ("Department" or "DPS")

The Department provided both supplemental comments on August 28, 2009, and Reply comments on September 5, 2009.[37] In its initial set of supplemental comments, the Department

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34. *Id.,* at 3.

35. E-mail communication from Dan Scruton (Agency of Agriculture), dated August 28, 2009.

36. According to the Agency of Agriculture, a 500-cow dairy would utilize about a 100 kW generator, and a 200-cow dairy would utilize about a 40 kW generator (5 cows per kW). *See* Supplemental Comments of Agency of Agriculture, dated August 28, 2009.

37. E-mails and attachments from Jim Porter, Esq., sent August 28, 2009, and September 5, 2009.

explains its modeling adjustment and the rationale for those adjustments. Further detailed references are contained in subsections below addressing each of the issues.[38]

In both sets of comments, the Department urges caution in the price determinations. The Department notes that the extreme variance in the estimates of costs between project developers and the Department, as ratepayer representative, is to be expected in the compressed time frames and the competing objectives of those supplying the information. Adding to the uncertainty is limited information that will allow the Board to make any additional determinations concerning the statutory requirement that the Board provide "sufficient incentive for the rapid development and commissioning of plants and . . . not exceed the amount needed to provide such an incentive."

The Department cautions against duplicating the experience of Spain, which it asserts is "often heralded as a Feed in Tariff" success story, noting that the government had to severely cut back the program "when they had invested 8% of their national debt in renewable projects in one year."[39]

The Department offered its own estimates of costs in the Subgroup report and provided additional explanation and foundation for those assumptions in its comments. The Department opposes further granularity in setting prices, arguing that it amounts to paying more for less, that is, "paying higher prices for resources with the same attributes . . . with no added value." In making its recommendations, the Department has generally assumed and encouraged the use of inputs based upon above-average projects based on its position that "rates should be set for above average projects . . . ." and that rates should be set "to at least attract the very best, most efficient projects." Indeed, the Department observes that this concept should extend, not only to projects from the standpoint of engineering efficiency, but also from the standpoint of business efficiency and the developer's ability to "take full advantage of the tax credits that are available."[40]

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38. In its August 28, 2009, supplemental comments, the Department addresses in detail the topics of granularity, grant availability, adjustments to the model employed by the DPS, and specific adjustments to solar PV addressing issues of installed costs and capacity factors.

39. Attachment to DPS e-mail communication from James Porter, Esq., sent to the Docket 7523/7533 distribution list on September 5, 2009.

40. Indeed, the DPS notes that a project's business entity can be structured in ways that allows it to better use the available tax credits. *Id.* at 3rd page.

The Department notes that the "value proposition" favoring granularity from the ratepayer perspective has not been addressed.

> There has been no justification put forward to support the notion that from a ratepayer perspective, there is some advantage to paying more for power from smaller installations of the same technology. Based on that, the Department supports . . . setting rates at the level required to support a well sited project of a cost efficient size owned by an entity that is able to maximize use of available financial incentives. This isn't saying that other projects cannot accept this same rate, but, in order to achieve the same level of profitability, such a project will require more innovation, improved project siting, a different value equation, or capturing some other advantageous characteristic of an individual project.[41]

Additionally, the Department argues that the rates set by the Board are forward-looking and as such should be based on "going forward" costs, and argues that such an approach results in lower costs of solar PV production in the future. The Department contends that the 7% lending rate used in the initial modeling and the Department's modeling is conservatively high. The Department acknowledges that recent lending practices may not be consistent with the length of loans available, but notes that the long-term nature of these standard contracts under development should influence lenders and allow more favorable terms for the loans looking forward. The Department highlights the additional uncertainties and the associated need for additional study created by the late entry of information about interconnection costs. The Department also responds to the various criticisms of assumptions relied upon by the Department in its models.

The Department further argues that approximately $10 million is allocated to the CEDF that would include the types of projects eligible for the standard offer prices being established by this Board, or roughly $250,000 each for 40 projects if all received the maximum $250,000 grant. The Department argues that the CEDF is well-funded and will continue to offer grants for renewable energy systems for the next two years. The Department notes that the CEDF Board is considering the issue of eligibility of CEDF grants for projects receiving rates under the standard offer SPEED program. Until a clear policy regarding this is established, the Department recommends that the Board err on the side of caution in setting prices.

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41. Attachment to e-mail from Jim Porter, sent August 28, 2009, at 1st page.

The Department also encourages the Board to apply similar caution in recognizing that the federal ITC may allow farms to potentially receive credits at some point over the 20-year life of projects.

Finally, the Department also summarizes its approach to estimating the capital costs of solar PV projects.

VI. Detailed Discussion and Determinations

A. Issues Affecting Multiple Resource Categories

The Subgroup process led to widely divergent views on price levels. A copy of the Subgroup report and recommendations are available on the Board's web site, and the conclusions of that report will not be repeated here except to the extent that they are needed for context.[42] Two sets of modeling runs were generated. An "initial" set of runs were based largely on information provided by the renewable resource developer community and their representatives, including Renewable Energy Vermont and a manufacturer. Information was also provided by representatives of the Agency of Agriculture and GMP. A second set of modeling runs were generated by the Department and were referred to in the Subgroup as the "DPS" model runs.

In all instances where the same resources and subcategories were modeled, the DPS model runs resulted in estimates of costs (or potential price determinations) that were lower than the initial model runs. The predominant reasons varied by resource categories, but included differences in the treatment of the Solar Business Investment Tax Credit, the personal income tax investment tax credit, differences in the initial capital costs (for solar PV), differences in the amortization period for the loans, and the inclusion of Clean Energy Development Fund grants in instances where the projects are eligible and there was no conflicting restriction on the tax credits already included in the analysis (e.g., solar PV).[43]

In light of the divergence, Board staff requested that the Technical Advisor provide further guidance and recommendations to help narrow the gap in assumptions and modeling

42. http://psb.vermont.gov/sites/psb/files/docket/7523/CostAnalysis/Cost_Analysis_Subgroup_Final_Report.pdf

43. *See*, Cost Analysis Subgroup Report and Recommendations, August 28, 2009.

results. A summary of the results is contained above in Section III and a copy of the Technical Advisor's report is available on the Board's web site.[44]

There was little disagreement over the modeling tool being used. The major issues associated with the modeling centered on the input assumptions and drivers. Residual concerns with the model largely centered on its ease of use, complexity, and presentation.

The key assumptions or modeling inputs that led to the divergence centered on the following areas.

(1) Granularity

As noted above, one of the critical policy assumptions that will guide this pricing analysis is whether separate prices should be established for different size projects within a technology classification. Act 45 only specifies interim prices for different size wind projects, distinguishing between wind projects with a rated capacity of 15 kW or less and projects between 15 kW and the maximum size of 2.2 MW for eligible projects. The Act also indicates that the Board shall "consider different generic costs for subcategories of different plant capacities within each category of generation technology."

There was a range of conflicting views concerning the issue of establishing different generic cost subcategories or "granularity" within the Subgroup. On the one hand, there is broad recognition that there are indeed scale economies (or a "cost curve") associated with the various categories of resources. As noted above, the Agency of Agriculture recommends that there be two capacity groupings for farm methane projects. Northern Power and Renewable Energy Vermont advocate for further granularity for wind and solar PV, and argue that the Board should address the issue at this stage of the process.[45] VPIRG also supports "limited" granularity but did not address the timing of such a determination.[46] For its part, the Department supports

44. *See*, http://psb.vermont.gov/sites/psb/files/docket/7523/CostAnalysis/.

45. *See,* comments of Northern Power, briefing the issue of granularity dated August 5, 2009. *Also see* the comments in Appendix B of the Cost Analysis Subgroup Report and Recommendations from REV's Technical Advisor for solar PV, and from the Agency of Agriculture. Comments were also received on this topic from Northern Power in both supplemental comments and reply comments discussed above, and from REV in their supplemental comments of August 28, 2009, also discussed earlier.

46. Letter to Susan M. Hudson from James Moore, dated September 3, 2009.

granularity only for the one category of wind resources expressly named in the statute and challenges the need for further granularity until there is some demonstration or assertion of ratepayer benefit.[47] Numerous comments were received from other parties urging caution at this time in the process on the issue of granularity generally, particularly in light of the limited data and high costs to ratepayers.[48] The Board's Technical Advisor did not make specific recommendations on this issue.

The evidence presented suggests that scale economies may exist and may be significant across at least several technologies, and likely extend to all technologies to a lesser degree. We also agree that the intent of the legislation supports due consideration by this Board into further granularity. Nevertheless, the existence of scale economies and clear legislative guidance calling for the Board to consider the issue does not *compel* the Board to make such granularity determinations for the interim prices due on September 15, 2009. Indeed, there are countervailing concerns raised by, among others, the Department.[49] In light of the high costs of smaller projects exhibited in the modeling runs by the Department, and to an even greater degree by those who supported further granularity at this stage.[50] We conclude that the issue deserves care and attention before rendering a determination. And, as various parties have observed, the statutorily-compressed time frames, and resultant expedited proceedings, have not allowed the Board adequate opportunity for review and determinations of additional granularity. For this reason, the Board will defer a determination at this point to allow time for consideration of appropriate criteria, a more vigorous examination of the assumptions underlying the prices, and any competing considerations consistent with statutory guidance.

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47. Department of Public Service, Supplemental comments received as an e-mail attachment, sent August 28, 2009, 2nd page.

48. *See*, for example, letter to Susan Hudson from GMEU, dated September 3, 2009; CVPS also urges caution in establishing additional granularity in its September 4, 2009, comments; in its September 4, 2009, comments, GMP urges caution noting that there has been inadequate time for review. In its August 28, 2009, comments, BED also urges caution in setting the rates, especially in the early stages of the program.

49. *See,* for example, letter to Susan M. Hudson from Morris Silver, Esq. (for CVPS), dated September 4, 2009, and IBM e-mail communication of September 4, 2009.

50. *See* the Supplemental and Reply comments on REV, Northern Power, and the Agency of Agriculture, dated August 28, 2009, and September 4, 2009.

Future process may include the establishment of appropriate criteria for setting the thresholds, the merits of a given technology size in addressing the criteria, and the establishment of an estimate of generic costs that represents a reasonable approximation of price using the statutory criteria.

(2) Grants/Clean Energy Development Fund

The Vermont General Assembly established the Clean Energy Development Fund ("CEDF") through Act 74 (10 V.S.A. § 6523). In 2009, the Vermont General Assembly appropriated $31.5 million in funds from the American Recovery & Reinvestment Act (ARRA) for the State Energy Program (SEP) and the Energy Efficiency Conservation Block Grant (EECBG) into the CEDF to be used for renewable and energy efficiency projects and programs. Due to the ARRA funding for fiscal years 2010 and 2011, the CEDF has budgeted $44 million to be used for renewable and energy efficiency projects and programs.[51]

There were divergent views of how to treat grants for purposes of setting the cost-based rates. The Department recommended that grants, such as CEDF grants, be recognized as available to fund projects eligible to receive the standard offer prices under the SPEED program. As such, the grants would be recognized in the modeling and serve to offset the effective cost to developers of a generic project in establishing the standard offer prices and, by September 15, 2009, in determining which prices represent a "reasonable approximation" of the costs pursuant to Act 45.

Some members of the Subgroup, however, challenged the use of such grants in making these price determinations.[52] Some questioned whether grants met the definition of "incentive" if the grants were available only through project-specific determinations and therefore not available to all those that are potentially eligible for the Board's Standard Offer prices. One hydroelectric developer questioned whether hydroelectric projects are actually likely to receive such grants.

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51. Docket 7523, Cost Analysis Subgroup, Report and Recommendations, at 15.

52. For example, Northern Power indicates that it is not appropriate to conclude that the CEDF Grants are "reasonably available" based on their claim that the Solar Business Investment Tax Credit represents a competing claim on the Credit and that only a "very small" proportion of projects that apply receive the grants.

Act 45 expressly recognizes tax credits *and other incentives* in setting the prices. It is inappropriate to exclude Clean Energy Development Fund program funds from this category of other incentives. The CEDF funds have been established under law to encourage technologies and research; that is, to provide incentives to encourage the technologies, research, and programs that are eligible for funding. We disagree with those that suggest that the CEDF should not be included in the price determination if it is not available to all projects. The standard in the law pertains to tax incentives that "are reasonably available." Clearly a substantial number of projects will receive such funding and a failure to recognize such funding would be inconsistent with the statute.

We recognize, however, that the CEDF does not represent an unlimited pool of funding. As such, the Public Service Board must exercise some caution in setting rates for the standard offer. In this respect further guidance and clarity from the Board of the Clean Energy Development Fund as to the application of the fund can be helpful. We received a letter from the Clean Energy Development Fund Board indicating that "the CEDF routinely receives more applications than it has funding to support" and historically has applied a broad range of criteria selecting projects to award loans and grants.[53] The CEDF Board will inevitably make project-by-project specific determinations. There is an inherent tension between the responsibilities of the CEDF Board in making such project-specific determinations and the responsibility of this Board to make a generic determination in a manner that ensures the efficient application of ratepayer dollars used to fund renewable projects through the Standard Offer program.

In general, the Board concludes that Clean Energy Development Fund grants can be recognized as an incentive that may serve to bring down the costs of the projects, and should be considered in setting the standard offer prices. However, this conclusion is based on the assumption that the grants are "reasonably available" incentives. The Clean Energy

53. Letter to James Volz, Board Chair, from Anne Margolis, CEDF Director. Between June 2007 to April 2009, the CEDF received 131 grant applications requesting $17.6 million in funding. Awards to 74 of those projects for a total awarded amount of $9.6 million was made. The criteria "range from Experience and Qualifications of the Project Team and Work Plan to Project Characteristics, Environmental, Economic & Social Impact, and Budget (financial need)."

Development Fund Board intends to further clarify of its policy in November.[54] In the meantime, we attempt to apply the statutory standard based on what is currently known about that policy and other relevant available information.

For purposes of setting generic prices and establishing whether the prices contained in Act 45 represent a reasonable approximation of costs, we have excluded CEDF funds from hydroelectric and larger wind resources because such projects were already among the more cost-effective technologies and less likely to receive the grants, thereby raising doubt as to whether grants for those technologies for which CEDF funds are "reasonably available" incentives. Further, CEDF funds were also excluded from explicit treatment in the model runs relied upon for solar PV because the modeling included the Solar Business Investment Tax Credit ("Solar ITC") benefit over a five-year period (as discussed further in the next section of this Order).

REV and others, however, have raised concerns that the tax liability for the solar PV projects may be too limited to properly include such a credit.[55] This was recognized in the calculations of the Technical Advisor by spreading receipt of the tax credit over a five-year period.[56] The Board relied primarily on the model runs of the Technical Advisor for its determinations. Additionally, we expect that projects will be eligible for either CEDF grants or the Credit. Reliance on the Solar ITC in the model thus serves as a proxy for reliance on the CEDF where the project has insufficient tax liability to justify reliance on the credit.

We have recognized the availability of Clean Energy Development Funds in our determination of costs for farm-based methane projects. CEDF funds were included in the original round of inputs used in the "initial" modeling runs and these projects are both eligible and typically receive CEDF grants when they apply.[57]

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54. Letter from Anne Margolis (Director CEDF) to James Volz (Board Chair), dated September 9, 2009.

55. E-mail communication from REV, dated August 28, 2009.

56. Power Advisory LLC, Independent Analysis of Prices Required for Vermont's Standard Offer, September 12, 2009, at 3 and 4.

57. *See*, Cost Analysis Subgroup Report and Recommendations, August 28, 2009, Appendix B Tables.

(3) Treatment of Taxes

Tax incentives were generally recognized in the modeling. The language of Act 45 makes explicit provision for "tax credits and other incentives."[58] Tax incentives include the Federal Investment Tax Credit ("Federal ITC"), the Vermont Solar Business Investment Tax Credit ("Solar ITC"), and a Vermont investment tax credit to individuals on their personal income tax returns that would also be available to S-Corporations and partnerships. Other tax incentives, including accelerated depreciation, were also recognized in the modeling. Indeed, reliance on tax credits and grants appears to be one of the primary factors distinguishing the Vermont standard offer approach to calculating prices from other jurisdictions, particularly those in Europe, that have relied on wholesale cost-based pricing determinations.[59]

A considerable number of comments were received from participants on the treatment of taxes in the modeling. The Federal ITC equal to 30 percent of the project costs was incorporated in all the modeling runs, with no participant disputing the use of this input. Businesses can apply the credit against all federal tax liability, with businesses that do not have sufficient income having the ability to take the credit over several years. The Federal ITC serves as an alternative to the Production Tax Credit that was not included in any of the modeling, nor by the Board in its determinations.[60]

As noted above, all model runs included some adjustments for the available investment tax credits. The initial runs included adjustments for the federal tax credits, but not for the state investment tax credits. The Department's runs included full recognition of both the federal and state investment tax credits (of 30 percent and 7.2 percent) in the first year. The Department argues that the most efficient or least-cost form of raising capital includes obtaining all available

58. For a more complete description of taxes and how they were treated in the modeling in the "initial" model runs and the "DPS" model runs, *see* Cost Analysis Subgroup Report and Recommendations, pages 13 and 14.

59. Docket 7523, Cost Analysis Subgroup Report and Recommendations, Appendix C contains a fairly detailed summary of cost-based rates under feed-in tariff regimes in Europe and Ontario.

60. Cost Analysis Subgroup Report and Recommendations, August 28, 2009, at 13 and 14. Prior to the expansion of the Federal ITC, the Production Tax Credit provided an incentive for producers of renewable electricity. The credit is for project developers that are selling electricity from renewable sources. The credit is worth between 1.1 and 2.1 cents per kilowatt hour sold to the grid (depending upon source), but is only available when that power is sold at a rate lower than a reference price.

tax incentives that are available to potential developers.[61] The Board's Technical Advisor included full consideration of the Federal ITC and the Solar ITC, but spread the Vermont income tax liability over five years. In addition, the Board's Technical Advisor reduced the amount of the Vermont investment tax credit applied to other categories of renewable technologies by 50%, and spread the credit over a two-year period.

In general, the Board concludes that fully offsetting the federal tax obligation with the Federal ITC is appropriate in light of the fact that businesses developing projects in Vermont will have sources of income and associated federal tax obligations from both inside and outside Vermont and therefore would be eligible for the credits. We conclude that the value of Solar ITC and the personal investment tax credits should be adjusted over time to reflect the more limited pool of Vermont tax obligations. That said, and as noted above, we view the Solar ITC as a proxy for CEDF funds, in the event that there is insufficient tax liability to justify reliance on the Solar ITC. While CEDF eligibility is broad,[62] the personal investment tax credit has limited applicability, and a further adjustment seems warranted. The Board's Technical Advisor adjusted the Solar ITC to reflect its capture over a longer period and also reduced the investment tax credit by half. We conclude that these adjustments are reasonable for purposes of reaching a determination for September 15, 2009, but will review these assumptions further for the January 15, 2010, price determinations.

The initial cost analysis modeling used a 35 percent federal and 8.5 percent Vermont income tax rate, resulting in a combined state and federal income tax rate of 40.53 percent.[63] For farm methane projects, which are generally owned by the farms, owners of large farm projects (300 kW) were assumed to have a marginal federal tax rate of 20% and state tax rate of 5%, and owners of medium and small farm projects (65 and 35 kW) were assumed to have a marginal federal tax rate of 15% and state tax rate of 5%. These rates were not in dispute and we find that they are reasonable.

61. *Id.*, at 14.
62. *See*, Clean Energy Development Fund Annual Report 2008 at 10 and 11.
63. *Id.*, at 15.

(4) Initial Capital Costs

The estimates of costs for purposes of making the "reasonable approximation" determinations required under Act 45 were made by first soliciting and receiving input assumptions largely from project developers and their representatives as part of the Subgroup process used in modeling the costs.[64] In almost all instances, the Board has relied upon the estimates of capital costs. We conclude that these estimates of costs are reasonable for purposes of our September 15, 2009, determination with the exception of solar PV.

The costs of solar PV energy have been declining over time, particularly since the beginning of 2009.[65] Cost estimates based on more recent and forward-looking data developed by the Department suggest that solar PV costs are considerably below those developed for the initial model runs.[66] Further validation of the Department's estimates for projects between 15 kW and 500 kW were provided in comments received from BED and GMP. As explained further under discussion of solar PV in Section VI.B.(5), the modeling assumptions relied upon by the Board were based on cost estimates contained in a data-base maintained by the Massachusetts Technology Collaborative ("MTC"). Because the MTC database reflects actual results, it represents a valuable source of information that is firmly based on actual experience. However, in light of reports of decreasing costs of solar PV projects, we are concerned with relying solely on this historical data without adequate consideration of the vintage of the investments. We are also concerned with simply relying on such data without screening out the less efficient investments.

The Technical Advisor filtered the data for the least efficient projects by removing the highest cost projects from the data. For the smallest category of projects (below 150 kW), the technical advisor took an average of only those projects placed into service after the first quarter

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64. Cost Analysis Subgroup Report and Recommendations, Appendix B.

65. In its August 28, 2009, comments, the Department states that "[b]ased on recent information in both the trade and popular press, backlash from excessive feed in tariff prices in Spain has resulted" in a declining cost of PV panels. " For that reason it is important that costs for solar installations, . . . be based on a forward looking estimate of prices." Similarly, GMP notes that costs of PV are low relative to the initial model runs and are expected to be "even lower . . . because the price of equipment is decreasing in 2010. Attachment to e-mail communication of September 4, 2009. Similar trends were observed by the Board's Technical Advisor in the MTC database.

66. Cost Analysis Subgroup Report and Recommendations, August 28, 2009, at 5 and 6. For a description of the method used by the Department in developing these costs, *see* comments filed August 28, 2009.

of 2009. For all categories of projects, the Technical Advisor reduced project costs by 5 percent to account for current trends in component costs that are unlikely to be adequately reflected in the historical data.[67] For the largest category of projects, the Technical Advisor adjusted costs by an additional 5 percent to account for scale economies in the technology relative to the larger projects that were reflected in the data. In general, we find that the adjustments made by the Department, as modified by the Technical Advisor, are appropriate and reflect reasonable adjustments to account for factors that should be included in estimating the forward-looking costs of a reasonably well-sited solar PV generator.

(5) Capacity Factors

There was only limited disagreement regarding the appropriate capacity factors for the different categories of resources.[68] The initial modeling runs of the Subgroup were based on information provided by project developers and their representatives. For the most part, the Department relied on this same set of assumptions for its own runs, including the assumptions regarding capacity factors. The exception here related to solar PV energy. The initial runs included a capacity factor of 13 percent; the DPS runs used a higher capacity factor of 15 percent for the largest two subgroups of resources modeled. The DPS based its estimates on the applications for Clean Energy Development Funds. A review of the data suggests that there is in fact a wide range of estimates contained in the grant applications. Together with the information provided by Renewable Energy Vermont and project developers, we concluded that a value of 14 percent is reasonable, and we have relied on a 14 percent capacity factor in the modeling of the solar PV resources for purposes of the Board's determination at this time. However, we will revisit the issue in subsequent determinations.

As noted above, Northern Power raised concerns with the capacity factor of 23.8 percent used in modeling 100 kW wind resources.[69] Since this category of resources was not relied on

67. These percentage adjustments were simply judgments used by the Technical Advisor based on a review of the data.

68. The disagreements were primarily limited to solar PV and wind resources. For solar PV, the disagreements pertained to resources greater than 15 kW and for wind, the disagreement pertained to the 100 kW size resources.

69. *See*, Supplemental and Reply comments of Northern Power, August 28, 2009, and September 4, 2009.

as the basis for the Board's determinations, this issue can be addressed in the context of future determinations and in relation to the Board establishing sub-caps for smaller wind projects associated with the review efforts for January 15, 2010.

(6) Loan Terms and Capital Costs

Most of the modeling included a cost of debt equal to 7 percent and a loan term that approximated the life of a 20-year power contract. In the initial model runs, the debt term was 18 years for hydroelectric, solar PV, and wind. For landfill methane the initial model runs assumed 10 years, and 7 years was assumed for farm methane. The Department indicated that the rate may be high, while developers suggest that the rate may be low.[70] The DPS model runs generally assume a longer, 20-year period for the debt, except solar PV, for which the DPS assumed a 25-year debt term.

The Board's Technical Advisor relied on a rate of 7.5 percent, a slight increase from the rate used in both the initial model and the DPS model. Under such a project finance structure, lenders will establish cost of debt based on their assessment of the projects's overall risk and general credit market conditions at the time of financing. With the program underpinned by legislation and a Board order approving the contract, there is likely to be relatively limited regulatory risk, and should be viewed as such by lenders.[71]

In general, we are persuaded that the standard offers here represent secure contracts with utility-like entities that deserve low rates and should expect reasonable terms for the debt. Thus,

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70. The Department indicates that, based on its conversations with the Vermont Economic Development Authority (VEDA), VEDA's current rate for their Direct Loan Program is a 2.75% variable rate, and for farms a 4.5% variable rate. VEDA rates are lower then a typical commercial bank and VEDA does not take a full position in any project, so a VEDA loan would need to be combined with another commercial bank loan to fully fund a project. VEDA's Loan Officer suggested that commercial banks are lending at rates between 6 to 7 percent for recently completed business mortgages. In addition, the Department notes that a number of utilities have recently secured financing around the 7% interest rate range. *See,* Reply Comments from James Porter, Esq., dated September 4, 2009. In contrast, Northern Power argues for longer terms and higher rates. Northern power indicates that "[s]ince none of the parties have been able to identify a bank willing to finance 20 years at 7%, the DPS assumptions should be changed and notes that VEDA only offers 7-year terms. Northern Power believes rates of "at least 10%" might more realistically represent market costs." Letter to Susan Hudson from James Stover (Northern Power), dated September 4, 2009.

71. Policy Advisory LLC, Independent Analysis of Prices Required for Vermont's Standard Offer, September 12, 2009, at 6.

we agree that a rate of 7.5 percent is appropriate for the modeling at this time, but believe that even lower rates may prevail in the future as the lending climate improves and experience is gained with these contracts.

The Board's Technical Advisor generally relied on a term of 18 years for all categories of resources except farm methane projects, which were assumed to have a debt term of 10 years. The Technical Advisor's debt financing recommendations and assumptions assume continued improvements in credit market conditions by the time that projects need to secure financing. We generally agree that forward-looking determinations should reflect such expectations and conclude they are reasonable for purposes of our determinations.

(7) Other Issues

There were a number of other areas which there were some questions regarding the results and the sensitivity of the results to the various parameters. The initial model runs assumed that property taxes would be based on the installed costs and increase by 2.5 percent per year. The DPS runs, however, relied on estimates for several categories of technologies (wind, solar PV, and landfill gas) that actually reflected declining assessments, based on their conclusion that the value of the asset declines as it approached the end of the project life.[72] The Vermont Department of Taxes recommended that property tax assessment be based on the facility's net income with an 8% capitalization rate applied. The Board's Technical Advisor concluded that there is little material impact on prices between the Vermont Department of Taxes's and the DPS's approaches.[73] The approach adopted by the DPS appears reasonable, and was relied upon by the Technical Advisor for purposes of the modeling runs produced for the Board.

The costs of interconnection were generally sought and incorporated in the modeling runs as part of the installed capital costs. However, more specific information from a Vermont utility, by size of resource, raised some questions late in the process over the adequacy of what was included in the model. There was inadequate time available for the Subgroup to address these

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72. *See,* August 28, 2009, Supplemental comments, Vermont Department of Public Service.

73. Power Advisory LLC, Independent Analysis of Prices Required for Vermont's Standard Offer, September 12, 2009.

questions prior to our determinations here. We intend to review this issue further in conjunction with subsequent price determinations required under the Act.

The costs settlement and the SPEED facilitator potentially add further costs to the system that were not included in the modeling. However, based on guidance from the Cost Analysis Subgroup, they were viewed as small in proportion to the larger size projects that served as the basis for the Board's determinations.[74] This is another issue that will need to be revisited in the context of determinations that relate to smaller project sizes in the context of reviewing further granularity.

B. Individual Resource Categories

The Subgroup reviewed each of the separate categories of renewable resources for purposes of the modeling. While some information and input assumptions were developed for all categories of resources, it was generally acknowledged that the information provided for biomass CHP was not sufficient for modeling costs, and that the landfill methane information was limited in scope and may need further refinement before it would be well suited to the task of a rate determination. No information was provided for wind projects of the smaller capacity category established in the law. As such, the Board has no basis for concluding at this time that the default rate for the smaller wind classification does not represent a reasonable approximation of price using the statutory factors.

(1) Biomass

As indicated in the Subgroup report, we received no information sufficient for the Subgroup or this Board to conclude that the statutory default rates do not represent a reasonable

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74. As noted below, the issue was address in part by the Cost Analysis Subgroup Report and Recommendations, August 28, 2009 at 13.

> [t}he SPEED Facilitator estimated that the administrative budget for the first year that most of the projects are operational to be $329,800 and $399,000 if the costs of the first two years are amortized. Assuming a 50-50% split of the administrative costs, the producer's share of the administrative costs is estimated to be $199,500. These costs would have to be allocated and included in the costs to producers, but were estimated to be approximately $119/mo, or $1425 per year. A figure this small is unlikely to have a material impact on modeling results except for the smallest projects. However, the impacts on the smaller projects can be managed by socializing the allocation of the costs associated with the program.

approximation of the costs applying the criteria of Act 45. Act 45 establishes that the default rate for biomass will be set "at a price equal, at the time of the plant's commissioning, to the average residential rate per kWh charged by all of the state's retail electricity providers weighted in accordance with each such provider's share of the state's electric load." The Subgroup identified significant concerns with adopting a price that would be based on the weighted average residential retail rate at the time of a project's commissioning:

> Such a price term would raise concerns to potential project lenders because of uncertainty surrounding the rate in relation to the timing of commissioning. A literal rate determination is also potentially unknowable because it would depend on an uncertain denominator (provider loads) that presumably could only be calculated well after the establishment of a contract.[75]

The Subgroup recommended, instead, that the default rate be calculated using currently available data. The Department estimated that value to be 12.5 cents per kWh, which the Subgroup recommended we adopt. We conclude that these recommendations are reasonable and that, absent further foundation, a rate of 12.5 cents per kWh should represent a reasonable approximation of price based on the statutory requirements of Act 45.

(2) Landfill Methane

For landfill methane, the Cost Analysis Subgroup received only limited information. The Cost Analysis Subgroup received information on the capital cost and annual maintenance cost for a project that involved tapping methane from a single closed landfill. Itemized capital and O&M (operating and maintenance expenses), plant capacity factor, and grant support information were also provided by the project developer. The working group applied this project-specific information in the cost model. The model uses assumptions about capital structure and debt terms that are not related to the actual project.[76]

Under the initial model runs, credit was taken for a $200,000 grant or $1,515/kW. The assumed project life was ten years given the available landfill gas reserves. The project developer indicates that the project would be fully depreciated at the end of the ten-year life. Using these assumptions, the initial model run produced a price of $254/Mwh.

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75. Cost Analysis Subgroup Report and Recommendations, August 28, 2009, at 9.

76. Cost Analysis Subgroup, Report and Recommendations at 22.

The DPS's model run produced a price of $129/MWh. The DPS model assumed a $250,000 grant, a Federal and State ITC, and a 15-year asset and loan life, and declining property taxes as the contract value decreases.[77]

GMP provided detailed commentary on the size of the project and assumptions used by the Subgroup in developing the Subgroup Report and Recommendation. It suggests that most projects in New England, even those below the 2.2 MW threshold, are significantly larger than the 123 kW facility modeled.[78] Indeed, out of a database of 52 projects in New England that have been built or are under consideration, only 2 projects (one operating) fall below the 150 kW level, with the "overwhelming majority" above 800 kW. GMP is aware of larger projects priced below the 12 cent per kWh figure that serves as the statutory default.

Information provided about other landfill methane projects was limited but suggests that the costs for larger landfill projects are substantially below either model run's estimate of costs. For example, the statutory rate is approximately 3 times the costs of developing the Washington Electric Cooperative, Inc., project at the Coventry landfill, without considering the value of the RECs. However, on the basis of the information provided to the Subgroup, we are unable to gain sufficient confidence in the estimate for the specific project that was modeled, nor can we conclude that the default rate in Act 45 does not represent a reasonable approximation of a price based on the statutory criteria. Indeed the information provided by GMP, together with the Department's modeling and comparable projects in other jurisdictions, suggest that the statutory default may not be unreasonable. The Vermont General Assembly established a default price of 12 cents per kWh as the price that should be paid to developers of qualifying landfill methane projects under the SPEED standard offer. The Board is scheduled to review this rate for its determinations on January 15, 2010. Until that determination is made, we conclude that the default price of 12 cents per kWh should apply.

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77. *Id.*, at 21 and 22.
78. E-mail communication from Josh Castonguay, sent September 4, 2009.

(3) Farm Methane

As part of the Subgroup process, three categories of farms were modeled. The largest project size is intended to be representative of a 1,000-cow farm. The assumptions were provided by the Agency of Agriculture based on existing projects for large farms (300 kW).[79] These data were then used to estimate the costs for the smaller farm projects of 65 kW and 35 kW. These groupings were intended to roughly represent three categories of farms. The Agency of Agriculture estimates that Vermont has about 50 farms with over 500 milk cows, about 150 between 200 and 500, and the remaining farms have less than 200 cows each.[80]

Estimates of costs varied considerably among the different farm sizes. As reflected in the initial model runs, the costs per kWh varied from 17.5 cents per kWh to 55.4 cents per kWh depending on the size of the farm in question. The DPS model runs varied only in the terms of the loan that a farmer might find available. While the Agency of Agriculture indicated that loans of 7 years are appropriate based on typical loans, the Department relied on a 20-year loan and concluded that the cost for purposes of the price determination is more likely to be 14.9 cents per kWh.

The Board's Technical Advisor was asked to provide an independent perspective and recommended a loan term of 10 years based on consideration of the life of the equipment and the associated risk. This recommendation was informed by conversations with lending officials who provide loans to agricultural projects, including farm methane projections. The Board's Technical Advisor also recommended an interest rate of 5.5% given that the loan is likely to be based on real estate.

We conclude that these recommended adjustments to the models are reasonable. Based on these adjustments, the spreadsheet model produces prices equal to $187 per MWh, $359 per MWh, and $569 per MWh, respectively, for the large, medium, and small categories of farms,

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79. This suggests that for larger farms, there may be more efficiencies in the ratio of production capacity for a given number of cows. The 1000-cow farm produces about 300 kW of capacity (roughly 3.33 cows per kW). Earlier figures in the comments received from the Agency of Agriculture suggests that the ratio is closer to 5 cows per kW). *See,* Section V.k, above.

80. Cost Analysis Subgroup Report and Recommendations, August 28, 2009, Appendix B.

figures that are higher than the initial or DPS model runs.[81] These runs lead to the conclusion that the default price of 12 cents per MWh does not represent a reasonable approximation of prices based on the statutory criteria. Instead, we find that a price of 18.7 cents per kWh is appropriate based on the statutory criteria. Because the statutory criteria expressly exclude offsetting revenues or benefits from RECs or the sale of RECs in the initial calculation of costs for farm methane projects, such an offset was ultimately excluded from the model inputs used by the Board for its determination. Nevertheless, Act 45 permits the Board to make adjustments of those costs to ensure that the price is set to encourage rapid deployment but no more than is necessary to do so. Given the preliminary nature of our modeling and the fact that projects are being actively developed at lower rates than those suggested by the model, we conclude that a rate that does not include the offset of revenues from renewable energy credits ("RECs" would likely be excessive. Therefore, we adjust the 18.7 cents rate downward to reflect the expected value of RECs (approximately 2.5 cents/KWh),[82] and accordingly we adopt a rate of 16 cents/kWh.

For our January 15, 2010, determinations, we intend to focus our efforts on better understanding the offsetting benefits and potential grants and incentives that time constraints did not yet permit us to fully investigate.

As discussed above, we will not address the issue of further granularity at this time and will defer the issue for review in the context of our determinations under Docket 7533, to afford an opportunity for more detailed examination of the costs.

(4) Hydroelectric

Subgroup assumptions for estimates of costs for hydroelectric came from two separate sources representing three projects. In the initial model runs, a price of $150/MWh was determined to be the appropriate cost-based estimate. The DPS model runs included additional state investment tax credits and funds from the Clean Energy Development Fund and slightly

81. These runs were independent of the Subgroup work or that included in the Technical Advisor's report presented in Section III. These runs were needed in order to estimate costs that did not remove the value of the renewable energy credits ("RECs") prices in estimating the costs. *See*, Section 8005(b)(2)(B)(i)(aa).

82. Cost Analysis Subgroup Report and Recommendations, August 28, 2009, at 16.

longer debt financing terms. The Board's Technical Advisor provided a third estimate based on debt terms of 18 years consistent with the initial model runs, and included a capacity factor of 44.9 percent that was used in earlier runs.[83] The Board's Technical Advisor also recommends use of a cost of debt equal to 7.5 percent compared to 7 percent used in both the initial and the DPS modeling runs. The Board's Technical Advisor also recommends that the presumption of reliance on Clean Energy Development Fund grants not apply here given that hydroelectric projects generally are closer to market price and therefore less likely to receive a Clean Energy Development Fund grant based on the traditional criteria applied. However, the Board's Technical Advisor did adjust for the available personal investment tax credit as described above in VI.A.(3).[84]

We conclude that the adjustments recommended by the Board's Technical Advisor are reasonable. The modeled price based on these revisions is equal to a price of $135/MWh. The default price contained in Act 45 is $125/MWh. Given the inherent uncertainties associated with these estimates, we cannot conclude that the statutory default of $125/MWh does not represent a reasonable approximation of the price that would meet the statutory criteria. We therefore conclude that a price of 12.5 cents per kWh is the standard offer price that should apply to hydroelectric resources until a more thorough examination of the costs can be completed in the context of Docket 7533 for the January 15, 2010, determinations.

(5) Solar PV

The critical assumptions for solar PV projects are the installed capital costs, fixed O&M expenses (which include all annual recurring non-capital expenses such as property taxes and insurance) and the capacity factor. The initial model runs relied on estimates of underlying inputs from Renewable Energy Vermont's consultant, Meister Consultant's Group, Inc. ("MCG"). MCG indicated that its capital cost estimates were based on a survey of members.[85] It provided various alternative sources to demonstrate the reasonableness of the estimates. One source that

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83. Cost Analysis Subgroup Report and Recommendations, August 28, 2009, at 21.

84. "Given the constraints on the utilization of this credit, in particular the constraint on its utilization in corporate income tax returns, Power Advisory assumed that 50% of the credit is taken over a two-year period." Power Advisory LLC, Independent Analysis of Prices Required for Vermont's Standard Offer, September 12, 2009, at 3.

85. *See*, Cost Analysis Subgroup Report and Recommendations, August 28, 2009, Appendix B.

was identified was the Massachusetts Technology Collaborative ("MTC") PV project installation database.[86] The database indicated total project installation costs and the date installed. This database could be sorted and screened to establish installation costs for recent projects (recognizing that PV projects are experiencing significant cost declines) and to reflect the most cost-efficient project installations. Based on the comments received and an analysis of the database, we concluded that the capital costs have declined considerably and are likely low relative to the costs proposed in the MCG report.

For its part, the Department developed its assessment of installed capital cost by reviewing the MTC database together with the Clean Energy Development Fund July 2009 round of grant proposals. The DPS estimates of capital costs relied on the average of the most cost-efficient half of the reported installations.[87]

The Board's Technical Advisor relied on the same database but sorted and filtered the data by time and applied a 5% reduction in project costs to reflect the likelihood that additional cost reductions can be realized that are not reflected in the historical information contained in the MTC database, to recognize that solar PV costs have been declining.[88] Using the same data, the Board's Technical Advisor also assumed efficiencies of an additional 5 percent in estimating the cost per kW for larger projects (the largest project contained in the MTC database was 400 kW).[89] This approach yielded a significantly higher installed cost than the DPS estimate for the largest project category, but slightly lower installed costs for the 115 kW and 500 kW categories.[90]

For the reasons explained above, we are concerned with unfiltered reliance on the MCG analysis. In the case of large solar PV, there is also concern with reliance on the estimates of

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86. Massachusetts Technology Collaborative (2009). Commonwealth Solar – Information on installers and costs. Available online at: http://www.masstech.org/SOLAR/CSInstallerCostLocationData.xls.

87. In its comments of September 4, 2009, the Department also indicated that it validated its estimates of capital costs using online sources that revealed a complete 500 kW solar PV system could be purchased (uninstalled) for a price of $284/Watt, delivered.

88. ,Power Advisory LLC, Independent Analysis of Prices Required for Vermont's Standard Offer, September 12, 2009, at 10.

89. *Id.*, at 10.

90. The Department's installed costs for 115 kW, 500 kW, and 2.2 MW were $6260, $5960, and $3960, respectively. The Board's Technical Advisor recommended estimates of $6070, $5700, and $5410, respectively.

initial capital costs used by the Department base on only one project proposal.[91] We agree that the adjustments to capital cost estimates proposed by the Board's Technical Advisor are reasonable in light of current cost trends and the limitations on project size in the database that REV's advisor, the Department, and the Board's Technical Advisor relied upon.

The REV analysis assumed a capacity factor of 13 percent. The DPS relied on output estimates provided by applicants for CEDF grants.[92] The Department assumed a factor of 15 percent for the large project categories used in its modeling.[93] Without the benefit for more detailed examination, we are reluctant to adopt either value for our modeling of the larger projects at this juncture. We believe that both estimates appear to fall within the range of reasonable values based on the information provided. The Board's Technical Advisor recommends a value of 14 percent for the largest project size evaluated (2.2 MW), which was assumed to be a ground-mounted project, and 13% for the other project sizes evaluated (500 kW, 150 kW and 15 kW). We conclude that a capacity factor of 14 percent is reasonable and have relied upon it for purposes of our determination.

The Board's Technical Advisor has included the Solar ITC and the Federal ITC in the modeling of solar PV, as described in Section VI.A.(3), above. As noted in the earlier discussions, we conclude that some reliance on the Solar ITC and the Federal ITC are appropriate to include in estimating the initial costs of solar PV.

Based on the modeling, we conclude that the cost of solar PV ranges from $282/MWh for large solar PV projects (over 500 kW) to a high of $335/MWh for projects of 150 kW. The comments from BED and GMP lend further support for these estimates.[94] Given the inherent uncertainties in the factors that drive these costs, we cannot conclude that the statutory default value of $300/MWh does not represent a reasonable approximation of the price based on the

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91. *See*, Reply Comments, Department of Public Service, September 4, 2009. Indeed, despite considerable support in comments for the Department's other calculations, the estimates of cost for the largest solar PV generator did not enjoy similar support. *See*, for example, BED Supplemental comments, August 28, 2009.

92. Department of Public Service, attachment to e-mail communication, dated September 4, 2009.

93. The range of estimates of capacity factor for the Clean Energy Development Fund ranged from a low of 11.6 percent to 16.5 percent, with an average of 14.7 percent.

94. *See*, Supplemental comments of BED, August 28, 2009, and Reply Comments of GMP, September 4, 2009.

statutory criteria of Act 45. Consequently, the interim Standard Offer price should be set at the statutory default of $300/MWh.

Indeed, the significant declines in the costs of panels following events in Spain and the global economic decline suggest that the costs of a future solar PV project will continue to decline in the reasonably near term, potentially below the thresholds that we establish here.[95] The risk here is that the prices established through this process are lagging real world events, with resulting overpayment by consumers and the potential oversubscription of a single category of renewable energy, to the exclusion of others. As such, we believe that some form of backstop in the form of a resource cap, consistent with proposals under consideration by the Standard Contract Subgroup, may be appropriate. We will address this shortly in a separate decision.

(6) Wind

The initial project runs for wind were based on two sets of estimates, one for a 1.5 MW facility and another for a 100 kW wind project. No model runs were made for the 15 kW and below because no information was made available. For the larger project size, initial model run estimates were $126 MWh. The Department of Public Service estimated that cost at $111/MWh.[96] The Department's estimate included CEDF grant funding and the effects of a 7.2% state investment tax credit.

Due to the absence of information, we are unable to conclude that the statutory default of 20 cents/kWh for small wind projects (15 kW and below) does not represent a reasonable approximation of the price based on the factors identified in the statute. As such, our review of the modeling is confined to larger projects (between 15 kW and 2.2 MW).

Northern Power was a significant contributor to the modeling assumptions and discussions of wind projects, especially as it related to the 100 kW size category and in advocating that the Board add further granularity at this stage in the process. As noted in earlier discussion, the Board does not address the issue of granularity in this Order beyond the determinations required by statute. The modeling of the 100 kW size category can help inform

95. The Department's estimate of costs for a larger project equal to $177/MWh based on information for one large CEDF application is further reason for concern.

96. Cost Analysis Subgroup Report and Recommendations, August 28, 2009, at 5 and 6.

the Board in making its determinations for the larger 15 kW to 2.2 MW size category. In general, however, the Board based its determinations on the larger categories of generation resources modeled within a resource or size grouping. For the wind resources, this was the 1.5 MW size generator.

A number of issues need to be addressed in determining costs for smaller wind generators, including the appropriate initial capital costs, interconnection costs, and capacity factors. Considerable uncertainty and differences remained at the conclusion of the subgroup process and these issues will need to be addressed in future price determinations, especially in reviewing prices for smaller capacity resources in the context of the granularity issue.

For larger wind projects we conclude that the assumptions used for modeling are generally reasonable, but believe further adjustments to the input assumptions are warranted in light of the comments received. A 1.5 MW wind generator was used in developing an estimate of costs for the largest generation category. No specific challenges were associated with reliance on this size generator, although the Department of Public Service advocated, more generally, that the largest and most efficient size generation should be relied upon in the modeling.[97] Based on the comments received, however, we conclude that some further adjustments are needed to both the initial and the DPS model runs.

First, we must address issues related to the cost of debt and the term of the loan that may be available to help finance these projects. This topic was addressed in our earlier discussion, but to recap, Northern Power argues that "[s]ince no-one has been able to point to a bank or other financing entity willing to finance 20 years at 7%, this should not be taken as a given in the model."[98] Instead. Northern Power recommends a rate of 10% that it claims "might more realistically represent market costs."[99] The Department counters that the Vermont Economic Development Authority (VEDA) loans of up to seven years are available at variable rates well

97. *See*, Supplemental and Reply comments of the Department of Public Service dated August 28, 2009, and September 4, 2009. The Department, however, relied on the costs for the 1.5 MW generator in its modeling.

98. Northern Power, Supplemental Comments, dated August 28, 2009, at 3.

99. Northern Power, Reply Comments, dated September 4, 2009, at 4. However, it is unclear on what basis the Board should rely on the 10% figure. By its own admission, Northern Power indicates that it is "not a financing entity" and Northern Power recommends only that the rate "[s]hould be checked with lenders." Supplemental comments of August 28, 2009, at 2.

below 7%, and that these financing rates can be coupled with commercial bank rates that are below 7%. The Department further suggests that business mortgages of 6 to 7 percent are available to help complete the loan.[100] Additionally, Vermont utilities have recently secured financing around the 7% interest range.

The Board's Technical Advisor notes that loans on such projects are underpinned by legislation and a Board order approving a contract, would likely have relatively limited regulatory risk, and would not be viewed as unduly risky by lenders. Also, the Technical Advisor notes that there has been considerable improvement in the conditions of the credit markets over the last six months, with continued improvement likely. The Board's Technical Advisor views a rate of 7.5% as reasonable for a longer-term loan. We conclude that this is reasonable for purposes of this Board determination, for the reasons presented by both the Department and the Technical Advisor.

The issue of the term of the loan only received focused attention late in the process.[101] The issue is challenging because time and process for soliciting the involvement of the financial community was limited, and because the debt term is likely a function of both the specifics of the standard contract, previously undefined, and the crisis in the financial community in the last 12 months. The capital markets, however, appear to be moving in a positive direction.[102] The Board's Technical Advisor informs us that while the term of debt of recent project filings have ranges up to 7 to 8 years, the debt repayment schedule is typically amortized over a longer period (except for farm methane projects). The Technical Advisor's debt financing model reflects financing assumptions that assume continued improvement in credit market conditions by the time projects need to secure financing. As such, the Technical Advisor relied on 18-year

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100. Reply Comments of the Department of Public Service, dated September 4, 2009. In the Subgroup Report and Recommendations, the Department notes that available commercial loan rates (for mortgages ranging from $500k to $1.5 M) had rates between 6.5 and 6.75 percent (for a 7-year loan).

101. REV and Northern Power included the issue of debt term as a concern in their Supplemental Comments of August 28, 2009. Northern Power also distributed an e-mail communication to the Subgroup on August 27, 2009, raising this as a concern. The Department included the debt term as an issue earlier by expanding the term across most categories of resources to 20 years (25 years for solar PV and 15 for landfill methane). The initial runs included debt terms of 7 years for farms, 10 years for landfill methane, and 18 years for all other technology categories. *See*, Subgroup Report and Recommendations, August 28, 2009, pages 18 through 24.

102. Power Advisory LLC, Independent Analysis of Prices Required for Vermont's Standard Offer, September 12, 2009.

financing for modeling hydroelectric, wind, and solar PV, and 10-year financing for farm methane. We conclude that these debt terms appear reasonable in light of concerns raised and the forward-looking nature of these price determinations.

Third, Northern Power has challenged reliance on the Clean Energy Development Fund as used in the DPS modeling.[103] For the larger wind projects being modeled (1.5 MW), this appears to have only a small impact on prices, with both estimates reasonably close to the statutory default.[104] As noted in our earlier discussion of the issue, we recognized that the CEDF does not represent an unlimited pool of funds for grants and loans, and have therefore attempted to apply appropriate judgment in applying it to individual resource categories. This issue was further clarified by the Clean Energy Development Board in its September 9, 2009, letter to Chairman Volz.[105] The Technical Advisor has not included the CEDF funds in the modeling of the larger wind and hydroelectric projects based on relative need. We conclude that the Technical Advisor has made an appropriate judgment on the inclusion of CEDF grants in the modeling. As a result, reliance on CEDF funds does not factor into the costs that we estimate for the wind and the hydroelectric projects.

In the end, the Board's Technical Advisor estimated the costs for a 1.5 MW wind project at $119/MWh.[106] Together with other estimates of price based on modeling a 1.5 MW wind generator, we cannot conclude that the statutory default price of 12.5 cents per kWh ($125/MWh) does not represent a reasonable approximation of the cost of eligible wind (15 kW to 2.2 MW) in light of the inherent uncertainties in these estimates.

As compared with the larger projects, there was considerable variability in the estimates of costs for a smaller wind facility of 100 kW. Both the initial model runs and the DPS model

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103. *See* Supplemental and Reply comments of Northern Power, dated August 28, 2009, and September 4, 2009.

104. We acknowledge, however, that it could have a substantial impact on smaller projects like the 100 kW wind projects advanced by Northern Power. The difference in modeled cost between the Department's model and the Initial Model Runs was almost 10 cents/kWh, due in large part to the inclusion of the CEDF grants.

105. Letter to Chairman Volz from Anne Margolis, Director, CEDF, dated September 9, 2009. "Between June 2007 to April 2009, the CEDF received 131 grant applications requesting $17.6 million in funding. We were able to make awards to 74 of those projects for a total awarded amount of $9.6 million. We have allocated $2.5 million per semi-annual grant round for FY 2010-FY 2011 ($10 million total), including the current grant round, for which we have received 51 applications requesting $5.3 million."

106. Power Advisory LLC, Independent Analysis of Prices Required for Vermont's Standard Offer, September 12, 2009.

runs suggest that the costs are considerably above the statutory default price. Where the statutory default price is $125/MWh, the initial model runs and the DPS model runs resulted in $269/MWh and $171/MWh, respectively. The Board's Technical Advisor also established a price of $215/MWh. There appears to be a basis for concluding that the costs of generation for a 100 kW system are well above the statutory default. However, there is considerable uncertainty around the estimates. And indeed, at this juncture, we have yet to conclude that 100 kW is an appropriate capacity threshold for setting a different pricing level for wind projects. Those determinations are premature, and will be reviewed in conjunction with the price determinations that are due January 15, 2010.

VII. Conclusion

With the exception of the price of farm methane resources, which is increased, we find the default prices established by statute are a reasonable approximation of the price that would be paid for renewable resources when applying the criteria established by the Act. In addition, we determine "the average residential rate per kWh charged by all of the state's retail electricity providers weighted in accordance with each such provider's share of the state's electric load" which is the statutory interim price for hydroelectric resources, biomass resources, and wind resources over 15 kW.

VIII. Order

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

1. Based on the foregoing discussion, we conclude that the interim price levels that apply under the standard offer program to qualifying Sustainably Priced Energy Enterprise Development (SPEED) resources are as follows:

   (a) for landfill methane projects, 12 cents/kWh;
   (b) for farm methane projects, 16 cents/kWh;
   (c) for wind projects (15 kW or less) , 20 cents/kWh;
   (d) for wind projects (over 15 kW), 12.5 cents/kWh;
   (e) for solar PV projects, 30 cents/kWh;
   (f) for hydroelectric projects, 12.5 cents/kWh;
   (g) for biomass projects, 12.5 cents/kWh.

2. This Docket shall be closed.

Dated` at Montpelier, Vermont, this __15th__ day of __September__, 2009.

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

OFFICE OF THE CLERK

FILED: September 15, 2009

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

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

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

Attachment A – Cost Analysis Subgroup Participants

The following individuals (along with their affiliation) participated at the meetings or via phone on at least one of the seven meetings held by the Cost Analysis Subgroup.

Aldrich, Jon – International Business Machines Corporation

Allen, Riley – Vermont Public Service Board

Basa, William - Northern Power Systems

Becker, John – Vermont Department of Public Service

Beinecke, Ben - Northern Power Systems

Callendrello, Tony - BayCorp Holdings/Great Bay Hydro Corporation

Dalton, John - Power Advisory LLC

Foley, Sean – Vermont Department of Public Service

Hosie, Ron - Longview Infrastructure LLC

Jones, Ken – Vermont Department of Taxes

Krolewski, Mary Jo – Vermont Public Service Board

Kvedar, Tony – Green Mountain Power Corporation

Laber, Gregg - Green Mountain Electric Supply

Lamont, Dave – Vermont Department of Public Service

McManus, David - Delta Energy Group

Mutty, Christopher - Encore Redevelopment

Perchlik, Andrew - Renewable Energy Vermont

Raker, Mike- Agricultural Energy Consultants, LLC

Rickerson, Wilson – Meister Consultant's Group

Scruton, Dan – Vermont Agency of Agriculture, Food and Markets

Swanson, Sam - Multiple organizations

Attachment B – Email Distribution List Members:

Abendroth, Harry R. - VEC
Ackerman, Collin - Encore Redevelopment
Aldrich, Jon - IBM
Arms, Dave
Askew, John - LN Consulting, Inc.
Barg, Lori l
Basa, William - Northern Power
Becker, John - DPS
Behn, Nils - Alteris Renewables
Beinecke, Ben - Northern Power Systems
Bentley, Bruce - CVPS
Berliner, Eric - IBM
Bingham, William - Jones Lang LaSalle
William.Bingham
Bissex, Karl A. - KAB Enterprises
Bowen, Martin - CVPS
Brown, Aaron - CLF
Budreski, Jon - Alteris Renewables
Cadwell, Leslie A. - VELCO
Callendrello, Tony - BayCorp Holdings
Callnan, Brian - VPPSA
Cameron, Dort - PES
Castonguay, Josh - GMP
Choquette, Luc - Green Mtn Elec Supply
Cole, Chris - GMP
Comey, Paul - Green Mtn Coffee
Dalton, John - Power Advisory LLC
Danner, John P. - Northern Power Systems
D'Antonio, Ben - RAP
Davidson, Sean - NextEra Energy Resources
DeVarney, Ed - Gas-Watt Energy
DeVinny, Joan - Reunion Power
Dier, Hilton - Renewable Energy
Dostis, Robert - GMP
Doyle, Janet - IBM
Driscoll, William - AIV
Dunkiel, Brian S., Esq. - Renewable Energy Vermont
Eaton, Chris - PES
Ellis, William F., Esq. - BED
Ely, David
Emero, Thomas D.-New England Alternative Energy
Fitch, Eric - Purpose Energy
Foley, Sean - DPS
Forward, Jeff-Richmond Energy Associates f
Garner, Jeffrey A. - Pizzagalli Const.
Gifford, Jason - Sustainable Energy Advantage
Griffin, Bob - GMP
Hand, Jamie - Hand Energy Services
Hartwell, Bob - VT State Senator
Hipp, Walter - GMP hipp_
Hosie, Ron - Longview Infrastructure LLC
Huessy, Hans G., Esq.
Hughes, Michelle - Northern Power Systems
Hull, Ellen - CVPS
Irwin, Josh - EAPC Wind Energy Services

Johnson, Gregory - Greatwood Engineering Mgmt.
Jones, Ken - VT Tax Dept.
Kieny, Craig - VEC
Kimball, Mike
King, Harriet A., Esq.
Knowles, Bob - Renewable Energy Massachusetts
Kondos, John - Solar Source
Kopperl, Brian - Renewable Energy Massachusetts
Kvedar, Tony - GMP
Laber, Gregg - Green Mtn Elec Supply
Lamonia, Chris - Northern Power Systems
Lamont, Dave - DPS
Levine, Sandra E., Esq. - CLF
Lorraine, Don - GMP
Mayland, Kirt - Penn Energy Trust
McCabe, Michael - Oak Leaf Energy Partners
McMahon, Laurie - VELCO
McManus, David - Delta Energy Group
McPadden, Dennis
Merriam, Jim - groSolar
Miracle, Stephen - Miracle Energy Systems
Mirando, Tony
Molinari, Guy - Northern Power Systems
Moore, James - VPIRG
Morris, Mary - GMP
Mott, Lawrence H.- New Generation Partners
Mullett, David, Esq. - VPPSA
Mutty, Christopher - Encore Redevelopment
Nagle, George - DPS
Necrason, Adam - Sirotkin & Necrason plc
Nolan, Ken - BED
Orost, Katie L. - VEC
Patt, Avram - WEC
Perchlik, Andrew - Renewable Energy Vermont
Peress, Jonathan - DRM
Perry, Kevin - VEC
Pierce, Morris
Porter, James H., Esq. - DPS
Porter, Tom - VEDA
Powell, Bill - WEC
Pratt, Randy - VEC
Punderson, Ebenezer, Esq. - Deppman & Foley, PC
Raker, Mike- Agricultural Energy Consultants, LLC
Raubvogel, Andrew N., Esq. - Renewable Energy Vermont
Richards, Patty - VPPSA
Rickerson, Wilson
Riedo, Katie - Tecta Solar
Rubin, Mathew - East Haven Windfarm
Saudek, Richard H. - Esq.
Schwartz, Joel - Town of St. Johnsbury
Schwiebert, Edward V., Esq. - OMYA
Sciarrotta, S. Mark
Scruton, Dan - AGR
Scudder, Harvey - NECSIS
Seddon, Leigh - Alteris Renewables
Shields, Kirk - CVPS
Shulman, Sam - Dechert LLP

Silver, Morris L., Esq. - CVPS
Singer, Leonard H., Esq. - IBM
Smith, Doug - GMP
Spencer, John - VEPP Inc.
Starr, Scott - groSolar
Stevens, Eric - Vermont Made Energy
Storrow, Charles, Esq. - GMP
Storrow, Chas - KSE
Stover, James - Northern Power Systems
Swanson, Sam - VTIPL
Tofel, Brett - Reknew Energy Systems
Tofel, Steve - ReKnew Energy Systems t
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