EXHIBIT
#37
DE 16-576

Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014

Public Service Department
October 1, 2014
Revised November 7, 2014

1 Introduction

Act 99 of the 2014 Vermont legislative session directed the Public Service Department (Department) to complete an evaluation of net metering in Vermont and file the resulting report with the Public Service Board. The report is required to include an analysis of each of the items described under 30 V.S.A. §8010(d)(1)-(9), paraphrased here:

- *§8010(d)(1) – Analyze Current Pace of Net Metering deployment Statewide and by Utility*
- *§8010(d)(2) – Recommend future pace of net metering deployment Statewide and by Utility*
- *§8010(d)(3) – "Existence and degree" of cross subsidy between Net Metered customers and Others.*
- *§8010(d)(4) – Effect of net metering on retail electricity provider infrastructure and revenue.*
- *§8010(d)(5) – Benefits to net metering customers of connecting to the distribution system*
- *§8010(d)(6) – Economic and environmental benefits of Net Metering*
- *§8010(d)(7) – Reliability and Supply diversification costs and benefits.*
- *§8010(d)(8) – Ownership and transfer of environmental attributes of energy generated by Net Metered Systems*
- *§8010(d)(9) – Best practices for net metering identified from other states*

This report to the Public Service Board (Board) addresses the legislative request. It builds directly from the report completed by the Department in January 2013 pursuant to Act 125 of the 2012 legislative session, updating assumptions and methodology as appropriate and described herein. Aspects of the methodology and approach that are not significantly changed from the 2013 Report will not be restated in this report. Instead, interested readers can find the 2013 Report on the Department's website at http://publicservice.vermont.gov/topics/renewable_energy/net_metering.

The Department undertook several steps to address the legislative request and evaluate net metering in Vermont. The Department issued a letter to stakeholders describing its proposed approach to the report, to which we received several sets of comments. Many of these comments urged the Department to hold a set of technical working group meetings inviting stakeholders to address each Act 99 criteria. Given time constraints and the Public Service Board process that will follow this report, significant stakeholder interaction and feedback was not solicited for this report. Rather, this report is intended to *start* the dialogue expected to take place via the upcoming Public Service Board process. The Department did hold a meeting for stakeholders to vet the updated structure and assumptions in the spreadsheet cost-benefit model.

Section 2 of this report begins with a brief background describing the changes to net metering contained in Act 99 of 2014, and the current status and pace of net metering deployment in Vermont. Section 3 updates the analysis of the existence and magnitude of any cross subsidy created by the current net metering program that was originally completed pursuant to Act 125 of 2012. Section 4 addresses lessons learned and guiding principles for net metering program design from a review of recent literature discussing these issues. Finally, Section 5 addresses the balance of the Act 99 criteria.

2 Background

A brief history of Vermont's net metering statute can be found in the 2013 Report. This section describes the changes to net metering contained in Act 99 of 2014. It will also update the current status and pace of net metering deployment Statewide and by utility.

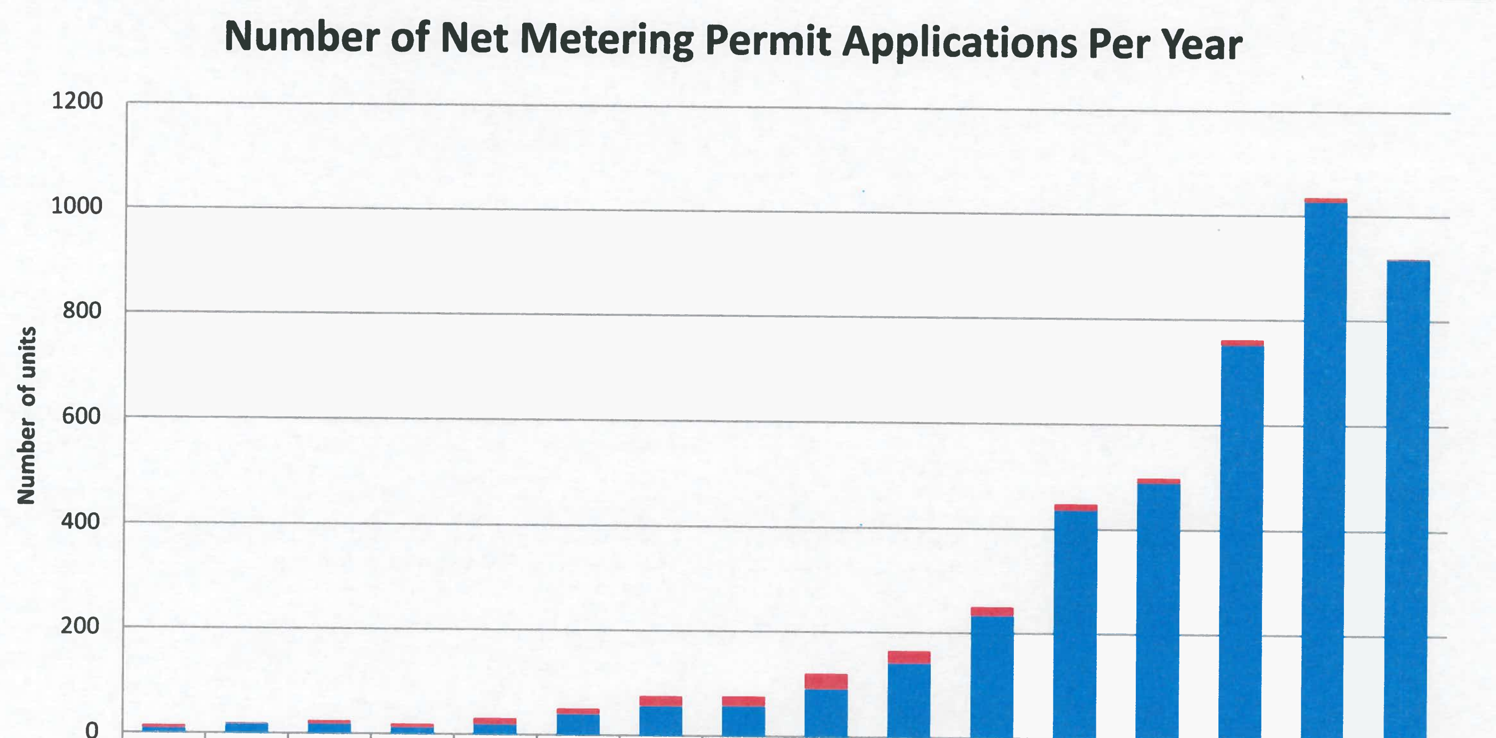
2.1 Act 99 of 2014

Act 99 of 2014 amended Vermont's net metering statute in the following relevant ways:

- Utilities must now allow net metering up to 15% of their peak capacity, changed from 4%.
- For systems over 15 kW the solar credit is now calculated by subtraction from 19 cents, down from 20 cents.
- Following the 10 year period of the solar credit, the systems are to be credited at the blended rate, rather than the highest residential rate. The solar credit is also calculated by reference to the blended rate.
- Net metered customers may now assign the renewable energy attributes of their generation to their utility for retirement on their behalf.
- Approval for various pilots and alternate net metering structures for utilities that have met certain criteria.

2.2 Current pace of net metering deployment statewide and by utility

Net metering has experienced rapid growth over the last seven years as the demand for local renewable energy has grown, costs have decreased, and access to renewables has broadened. As can be seen in Exhibit 1, solar PV has had the most substantial growth of all the renewable technologies. The number of PV systems applying for net metering permits annually has grown by a factor of more than seven since 2008.



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Fuel Cell	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	5	1	6	5	11	10	18	18	28	23	16	12	9	10	7	2
Solar	9	17	18	13	19	39	57	58	92	141	232	435	490	752	1027	917
Methane	0	0	0	0	0	1	0	0	0	1	2	2	0	1	1	0

Exhibit 1. *Number of net metering applications & registrations annually. (Data as of 9/26/14.)*

With the recent rise in number of PV applications, solar now accounts for 93.5% of all net metering capacity. Wind turbines represent less than 3% of all net metered capacity and hydroelectric represents approximately 2.2% (see Exhibit 2). To date, there have been no net metered fuel cells or combined heat and power systems in Vermont.

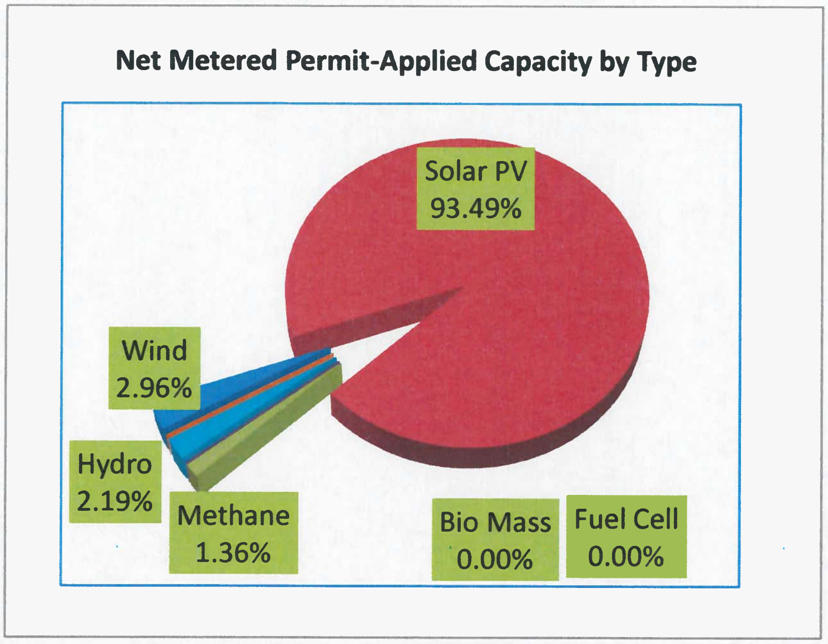
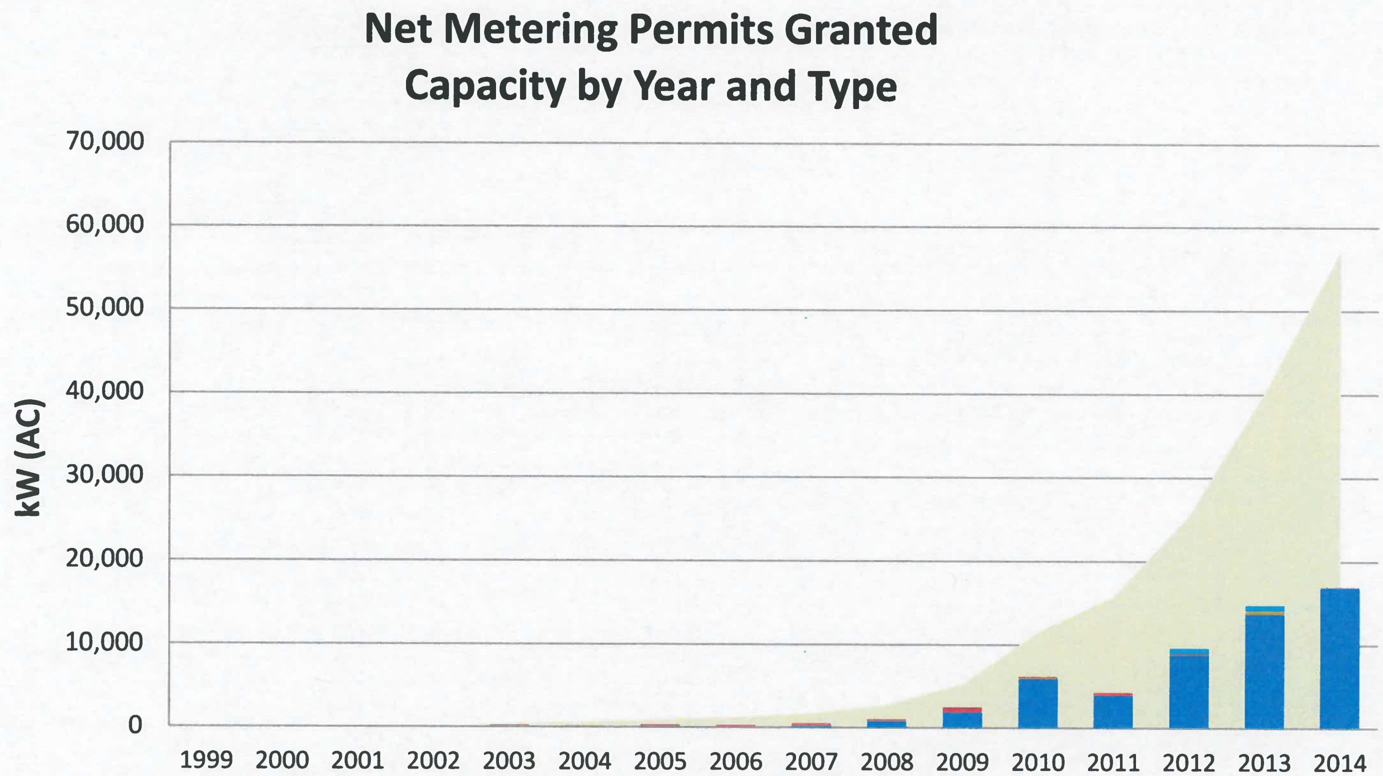


Exhibit 2. *Capacity of net metering permit applications by technology type (as of 9/26/14)*

The exponential increase in the number of PV system installations has driven not only the overall number of net metered systems but also the total growth of permitted net metered system capacity to 57.2 MW (see Exhibit 3). In addition to permitted systems, and additional 6.8 MW of proposed net metered projects have applied for permits but not yet received them, for a total of 64 MW.



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Cumulatve Capacity	50	99	177	224	436	670	980	1,255	1,749	2,798	5,307	11,568	15,828	25,496	40,274	57,188
Hydro	-	-	-	-	-	-	-	-	-	-	18	-	-	716	664	-
Methane	-	-	-	-	-	65	-	-	-	19	39	127	-	49	248	-
Wind	32	10	28	31	98	72	123	102	147	158	482	154	239	66	125	12
Solar	18	39	50	16	114	97	187	174	347	872	1,969	5,981	4,021	8,838	13,741	16,902

Exhibit 3. *Capacity of net metering permits granted by type and cumulative capacity. (Data as of 9/26/14.)*

The capacity histogram (Exhibit 4) shows that 48% of net metering systems that have applied for permits to date are less than 5 kW, 36% are between 5-10 kW and fewer than four percent are larger than 100kW. Notably, a significant number of 500kW applications have been submitted in 2014, potentially indicating a trend towards larger group net metering systems.

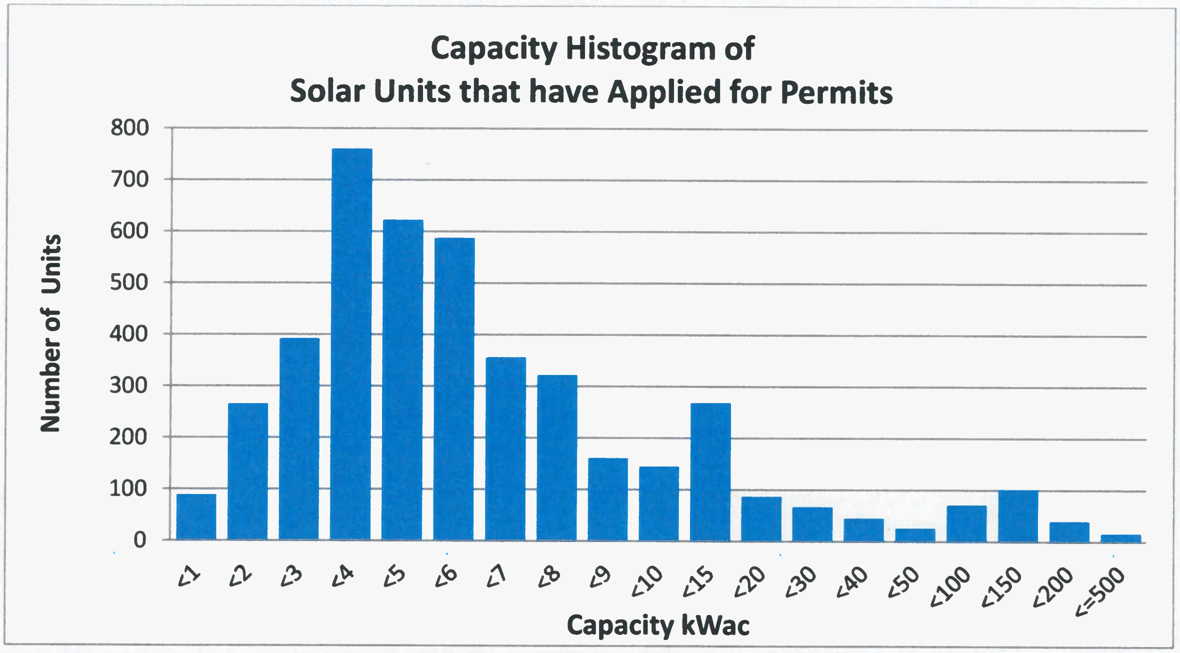


Exhibit 4. *Histogram by Capacity (in kW AC) of all net metered solar PV system permit applications (as of 9/26/14)*

While the growth has been rapid, 63.8 MW of net metered systems represents a small fraction of Vermont's overall electrical portfolio. GMP, VEC, WEC, Hardwick, Jacksonville and Morrisville have all exceeded the previous 4% capacity cap. If all permitted and constructed, net metered systems to date would produce less than 2% of the electric energy Vermont uses each year or approximately 80 GWh per year.

	Solar PV		Wind		Methane		Hydroelectric		Total	Approx.
Utility	**Count**	**Capacity**	**Count**	**Capacity**	**Count**	**Capacity**	**Count**	**Capacity**	**Capacity**	**% of peak**
Barton	8	43	2	19	0	0	0	0	62	2.0%
BED	96	1,836	4	15	1	248	0	0	2,099	3.1%
Enosburg	12	83	0	0	0	0	0	0	83	1.5%
GMP	3,376	50,010	107	1,231	7	489	10	1,399	53,128	6.9%
Hardwick	57	473	9	79	0	0	0	0	552	8.0%
Hyde Park	19	87	1	10	0	0	0	0	97	3.8%
Jacksonville	2	159	3	11	0	0	0	0	170	14.4%
Johnson	6	220	0	0	0	0	0	0	220	7.8%
Ludlow	0	0	0	0	0	0	0	0	0	0.0%
Lyndonville	43	276	2	99	0	0	0	0	374	1.7%
Morrisville	28	493	4	38	0	0	0	0	531	5.8%
Northfield	17	107	0	0	0	0	0	0	107	2.0%
Orleans	1	6	0	0	0	0	0	0	6	0.2%
Stowe	32	276	0	0	1	20	0	0	296	1.6%
Swanton	7	33	0	0	0	0	0	0	33	0.3%
VEC	498	4,174	45	332	1	96	0	0	4,602	5.5%
WEC	214	1,566	7	60	0	0	0	0	1,626	10.2%
TOTAL	**4,416**	**59,842**	**184**	**1,892**	**10**	**853**	**10**	**1,399**	**63,986**	**6.2%**

Exhibit 5. *Number of net metered permit applications and the capacity of those generators (in kW), by utility and type of generation, with the approximate percent of each utility's 2013 peak load.*

3 Existence and degree of cross-subsidy

The Department's Act 125 report described a statewide average analysis of the existence and degree of potential cross-subsidy between those customers participating in net metering and those not participating. This section describes several updates to that analysis and provides summary results by utility. The analysis uses the same logical structure as the Act 125 analysis. The reader is encouraged to review that report for examination of choices to include or exclude certain costs and benefits, the perspective from which the analysis is conducted, which generation to include, etc.

3.1 Costs and benefits

The Department's analysis includes the following costs:

- Lost revenue (due to participants paying smaller electric bills);
- Vermont solar credit, for solar PV systems; and
- Net metering-related administrative costs (engineering, billing, etc.).

The Department's analysis includes the following benefits:

- Avoided energy costs, including avoided costs of line losses and avoided internalized greenhouse gas emission costs;
- Avoided capacity costs, including avoided costs of line losses;
- Avoided regional transmission costs (costs for built or un-built pooled transmission facilities, or PTF, embodied in the ISO-NE Regional Network Service charge and other regional changes allocated in a similar fashion);
- Avoided in-state transmission and distribution costs (avoiding the construction of new non-PTF facilities). New for this report is the separation between transmission and distribution costs, in order to account for differences between utilities;
- Market price suppression in both energy and capacity markets; and
- Potential future regulatory value associated with retention of renewable energy credits in Vermont;

Net costs and benefits were calculated both including and excluding the value of avoided greenhouse gas emissions that are currently not internalized in the cost of energy or the value of renewable energy credits. Ratepayers face a risk that more costs associated with mitigation of greenhouse gases from electricity production will be internalized into energy prices in the future, potentially leading to stranded assets if resource decisions are made without consideration of the value of greenhouse gas emissions mitigation or abatement.

Costs and benefits are determined from a Vermont ratepayer perspective; transfers from entities which are not Vermont ratepayers to Vermont ratepayers are included; any potential transfers between Vermont ratepayers are not included. Utility-specific analysis attempts to measure costs or benefits that accrue to ratepayers of each utility.

The assumptions used for each of these costs and benefits are described in more detail in Section 3.2 below.

3.2 Modeling assumptions

The spreadsheet model[1] estimates the costs and benefits incurred as a result of any single net metering installation installed in 2015 or a later year. It projects costs and benefits over the 20-year period following installation, allowing examination of the potential changing costs and benefits over that period as well as calculation of a levelized net benefit or cost per kWh over 20 years. The Act 125 report includes a summary of what the spreadsheet model does not attempt to do; this list is still accurate, aside from the new attempt to capture differences between utilities and a revised treatment of the value of renewable attributes.

3.2.1 Utility-specific costs and benefits

In the context of this study, "costs" and "benefits" are measured from the ratepayer standpoint. The utility regulatory structure in Vermont (including GMP's alternative regulation plan, the co-op structure of VEC and WEC, and the municipal structure of the state's other utilities) results in the relevant set of costs and benefits faced by the state's utilities being passed to the state's ratepayers. As a result, the analytical framework treats utility costs as ratepayer costs, and utility benefits as ratepayer benefits.[2]

3.2.1.1 Costs

Net metering reduces utility revenue by enabling a participating customer to provide some of their own electricity (including, at times, spinning their meter backward while exporting energy), which reduces their monthly bill. In order to calculate the size of this reduction due to a modeled net metering installation, the model requires the energy produced per year, along with the expected average customer rate, and any solar credit. The Department collected current rates from each of the state's utilities. We used the residential rate structure, as changes in Act 125 established that nearly all net metered customers will see credit to their bills at the residential rate. Act 99 changed the calculation of credits to use the blended rate (defined as the average rate faced by an average residential customer over all of their usage), rather than the highest residential rate. We used the 2013 average residential consumption of each utility to calculate this blended rate.

Rates were forecast to change in the future using the same methodology employed in the Act 125 report. This methodology incorporates forecasts of energy, capacity, and transmission, and other costs, and accounts for internally consistent avoided energy costs and lost rate revenue.

The Department made no changes to how administrative costs were calculated, and did not vary them by utility.

The Department modeled the costs to non-participating ratepayers due to the current net metering program in each utility territory, including the alternate program in effect for Washington Electric Cooperative members. We understand the purpose of the Board investigation subsequent to this report is to consider alternate net metering program designs; these alternatives would be expected to have different costs.

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[1] Available for download from http://publicservicedept.vermont.gov/topics/renewable_energy/net_metering.

[2] Externalities, such as the externalized portion of the value of greenhouse gas emission reductions, do not follow this pattern.

3.2.1.2 Benefits

3.2.1.2.1 Avoided energy cost

From the perspective of the regional electric grid or a utility purchasing power to meet its load, net metering looks like a load reduction. A utility therefore purchases somewhat less power to meet the needs of their customers. While Vermont utilities purchase much of their energy through long-term contracts, this kind of moment-by-moment change in load is reflected in changes in purchases or sales on the ISO-NE day-ahead or spot markets. The Department assumes that the energy source displaced or avoided by the use of net metering is energy purchased on the ISO-NE real-time spot markets (the difference between day-ahead and spot markets over the course of the year is relatively minor).

The Department calculated a hypothetical 2013-14 avoided energy cost on an hourly basis by multiplying the production of real Vermont generators by the hourly price set in the ISO-NE market. This annual total value was then updated to 2015 and beyond by scaling the annual total price according to a market price forecast. These calculations indicate that fixed solar PV had a weighted average avoided energy price 9% lower than the annual ISO-NE average spot market price, 2-axis tracking solar PV is equal to the annual average spot market price, and small wind is 29% higher. This is a change from the Act 125 report, and is driven primarily by the recent high ISO-NE market prices in the winter.

The Department assumed that the capacity factor for each solar technology is projected capacity factor using the NREL PVWatts tool for a location in Montpelier, using all PVWatts default settings. The assumed capacity factor for wind is the 2013-14 capacity factor of the real Vermont generator used to calculate the correlation. Separating the capacity factor from the price-performance correlation allows the analysis to correct for differences between the typical capacity factors expected over many years for a generic facility and the capacity factors exhibited for a particular generator in only one year.

The Department's market energy price forecast is based on that developed filed by the Department in Docket 8010, related to the setting of avoided costs in the context of Public Service Board Rule 4.100. This is a forecast of Vermont's Locational Marginal Price – for energy measured at the VELCO system border. Energy generated by net metering systems, however, is produced on distribution circuits and often used locally; the difference between the energy avoided at the VELCO border and the energy produced at the net metering system is line losses. The Department updated line loss values consistent with the recent updated analysis completed for the marginal line losses avoided from load reductions associated with energy efficiency in proceeding EEU-2013-07. Across different costing periods, these marginal losses average approximately 11%.

Exhibit 6: *Department assumptions and forecasts of avoided energy, capacity, regional transmission, and in-state transmission and distribution costs, along with assumed self-consistent residential rate forecast, developed for this study. Values are in nominal dollars.*

	Energy ($/MWh)	Capacity ($/kW-month)	Regional transmission (PTF) ($/kW-month)	Vermont Transmission (non-PTF) ($/kW-month)	Vermont Distribution (non-PTF) ($/kW-month)
2015	$67.51	$3.01	$8.17	$3.42	$9.26
2016	$59.04	$3.27	$8.75	$3.46	$9.36
2017	$55.24	$5.41	$9.33	$3.52	$9.53
2018	$47.64	$9.84	$9.93	$3.50	$9.46
2019	$49.31	$11.97	$10.56	$3.57	$9.65
2020	$50.23	$12.18	$11.23	$3.64	$9.84
2021	$54.62	$12.43	$11.95	$3.68	$9.97
2022	$53.71	$12.68	$12.71	$3.73	$10.08
2023	$58.30	$12.95	$13.52	$3.74	$10.12
2024	$59.70	$13.22	$14.39	$3.78	$10.23
2025	$65.27	$13.49	$15.30	$3.84	$10.38
2026	$66.99	$13.77	$16.28	$3.88	$10.49
2027	$72.34	$14.07	$17.32	$3.91	$10.59
2028	$73.12	$14.37	$18.42	$3.95	$10.69
2029	$80.24	$14.64	$19.59	$3.98	$10.78
2030	$81.48	$14.91	$20.84	$4.02	$10.87
2031	$84.42	$15.17	$22.17	$4.05	$10.95
2032	$80.03	$15.45	$23.58	$4.08	$11.03
2033	$85.70	$15.73	$25.09	$4.10	$11.10
2034	$84.57	$16.01	$26.69	$4.13	$11.17
2035	$91.27	$16.30	$28.39	$4.15	$11.24
2036	$91.82	$16.59	$30.20	$4.17	$11.29
2037	$97.62	$16.89	$32.12	$4.19	$11.34
2038	$97.63	$17.20	$34.17	$4.21	$11.39
2039	$107.50	$17.51	$36.35	$4.22	$11.42
2040	$108.13	$17.82	$38.67	$4.23	$11.45

3.2.1.2.2 Avoided capacity cost

From the bulk grid perspective, net metering systems look like a reduction in demand, and therefore reduce the utility's cost for capacity. There are multiple potential methods to measure the effective capacity of generators with respect to different purposes. In determining the peak coincidence factors described in this and the following subsections, the Department examined the timing of the relevant peaks: ISO-NE's peak for capacity costs, Vermont summer peaks for in-state transmission costs, monthly Vermont peaks for RNS costs, and utility-specific peak hours for distribution costs. The ability of variable generators to help avoid ISO-NE capacity costs depends on the level of generation during the summer hours when ISO-NE's region-wide grid demand peaks. The Department calculated coincidence values by averaging the production from generic fixed and tracking solar PV systems as well as an example small wind generator during the months and hours (e.g. July hours ending 5pm or August hours ending 3pm) of the ISO-NE peaks since 2003.

Exhibit 7: *Department assumptions of net-metered generators' performance during peak times used to calculate values of avoided capacity, avoided regional RNS cost, and avoided in-state transmission infrastructure. Each value shows the fraction of the system's rated capacity that is assumed in the calculation of the value of the three avoided costs. For example, in calculating the value of avoided capacity costs due to a fixed solar PV system with a nameplate capacity of 100 kW, the system is assumed to reduce capacity costs by the same amount as a system that can output 52 kW and is always running or perfectly dispatchable.*

	Capacity	RNS	In-state Transmission
Fixed PV	0.520	0.210	0.536
Tracking PV	0.579	0.230	0.551
Wind	0.082	0.121	0.058

The capacity price forecast assumed by the Department, and used by default in the model, is based on that developed for use in Docket 8010 relating to avoided costs and Rule 4.100. The resulting capacity price forecast (in nominal dollars) is shown above in Exhibit 6.

3.2.1.2.3 Avoided regional transmission costs

Regional Network Service (RNS) charges are charged by ISO-NE to each of the region's utilities to pay for the cost of upgrades to the region's bulk transmission infrastructure. These are costs that have already been incurred, or are required to meet reliability standards, and thus cannot be entirely avoided – only their allocation among New England ratepayers can be changed. Avoiding these costs through net metering shifts the costs to ratepayers in other states. RNS charges are allocated to each utility based on its share of the monthly peak load within Vermont. Exhibit 7 shows the values for relevant peak coincidence calculated by considering the production expected from generators of each type during the hours of each month when peaks have occurred since 2003.

The values assigned to this cost are based on the ISO-NE forecast of the next 3 years' worth of RNS charges, and escalated based on historical increases in the Handy-Whitman Index of public utility construction costs. The resulting regional transmission price forecast (in nominal dollars) is shown above in Exhibit 6.

3.2.1.2.4 Avoided in-state transmission and distribution costs

In-state transmission and distribution costs are those costs incurred by the state's distribution utilities or VELCO and which are not subject to regional cost allocation. The values used in this model are derived from those developed by a working group consisting of representatives from the state's distribution, transmission, and efficiency utilities, and the Department in proceeding EEU 2011-02 for the update to the electric energy efficiency cost-effectiveness screening tool.

The Department updated the net metering model to separately consider avoided in-state transmission and distribution costs. Burlington Electric Department's forecasts contained in their Integrated Resource Plan show that even without the effects of energy efficiency, there are no load growth related infrastructure investments planned within the next 20 years. Thus, they are assumed to not have any avoided distribution costs. All other utilities are assumed to have avoided distribution costs consistent with the statewide average cost.

The in-state transmission and distribution upgrades deferred due to load reduction or on-site generation (such as net metering) are driven by reliability concerns. Therefore, rather than average peak coincidence for a net metering technology, the critical value is how much generation the grid can rely on seeing at peak times. Therefore, the Department calculated "reliability" peak coincidence values, separate from the "economic" peak coincidence used in avoided capacity and regional transmission cost calculations. The Department calculated reliability peak coincidence for in-state transmission by calculating the weighted average production from generators of each type during the July afternoon hours when Vermont's summer peak has occurred since 2003. These values are shown in Exhibit 7.

The Department calculated distribution peak coincidence values separately for each of the state's distribution utilities. The methodology is implemented in a spreadsheet tool available for download from the Department's website.[3] The methodology was as follows: First, the Department examined the 2013 hourly loads from each of the state's utilities. Load-growth-related distribution infrastructure needs are driven by the extremes of utility load, so the first step was to identify the 5% of all hours (438 hours over the year) during which the utility had the highest load. These were then collected into month-hour pairs (such as the hour ending 6pm in January of the hour ending 3pm in July). Month-hours with at least 9 high-load hours were then identified for each utility. This filter produced lists of between 13 and 26 month-hour pairs during which avoided load would be most likely to avoid the need for infrastructure investments. The next step was to calculate the average production for each type of generation during these high-load hours, compared with the generator's peak capacity. Exhibit 8 shows the resulting coincidence factors.

Exhibit 8. *Utility-specific distribution peak coincidence factors for each generator type.*

Utility	PV: Fixed	PV: 2-Axis Tracker	Small Wind
VT Average	0.223	0.269	0.124
Barton	0.026	0.065	0.176
BED	0.404	0.484	0.074
Enosburg	0.160	0.201	0.098
GMP	0.219	0.261	0.115
Hardwick	0.009	0.027	0.194
Hyde Park	0.062	0.052	0.205
Jacksonville	0.145	0.229	0.156
Johnson	0.218	0.308	0.140
Ludlow	0.077	0.101	0.147
Lyndonville	0.128	0.196	0.144
Morrisville	0.287	0.310	0.105
Northfield	0.054	0.072	0.165
Orleans	0.262	0.378	0.118
Stowe	0.103	0.151	0.128
Swanton	0.306	0.374	0.113
VEC	0.033	0.083	0.180
WEC	0.000	0.001	0.193

[3] Available for download from http://publicservicedept.vermont.gov/topics/renewable_energy/net_metering.

3.2.1.2.5 Market price suppression

Reductions in load shift the relationship between the supply curve and demand curve for both energy and capacity, resulting in changes in market price. Because net metering looks like load reduction, the Department has approximated the market price suppression effect using analysis based on the 2013 Avoided Energy Supply Cost (AESC) study's calculation of the demand reduction induced price effect ("DRIPE") for Vermont. This is the same (but updated) source as used in the Act 125 report.

3.2.1.2.6 Value associated with renewable energy credits

The model allows for assignment of a value that ratepayers see that is attributable to the environmental attributes of the energy generated by a net metered system. Act 99 allows net metering participants to assign the environmental attributes associated with their generation to the utility for retirement. In addition, future policy design considerations in the coming year's Public Service Board process will likely incorporate discussion of the value and ownership of environmental attributes. For the purposes of this report, the Department has assumed a fixed value of \$30/MWh in nominal terms, with a switch in the spreadsheet to turn this value on and off.

Ownership of Renewable Energy Credits ("RECs") conveys upon the owner the right to claim the use of renewable energy. If a net metered customer retains their RECs, they may claim that the load served by their utility account is in some or whole part renewable. If a customer transfers their RECs to their utility under Act 99 for retirement on their behalf, they may make the same claim. However, if a customer transfers the RECs to a third party, then the customer may no longer make that claim. There is potential future regulatory value in REC retirement to utilities, if Vermont were to adopt a renewable portfolio standard that used RECs as a compliance mechanism. Vermont may only claim environmental benefits of net metering projects (e.g. avoided greenhouse gas emissions) toward state targets if RECs are retained or purchased for retirement in Vermont.

3.2.1.2.7 Climate change

The Department's analysis calculates the costs and benefits of net metering to the state's non-participating ratepayers both with and without the estimated externalized cost of greenhouse gas emissions. It should be noted that these benefits from a marginal net metering installation in Vermont do not flow to Vermonter ratepayers in direct monetary terms. Instead, they reflect both a societal cost that is avoided and the size of potential risk that Vermont ratepayers avoid by reducing greenhouse gas emissions. If these environmental costs were fully internalized, for example into the cost of energy, ratepayers would bear those costs. The Department is assuming a value of \$100 per metric ton of CO_2 emissions reduced (in \$2013); this is the societal value adopted by the Public Service Board for use in energy efficiency screening, and is intended to reflect the marginal cost of abatement. About \$5, rising to approximately \$10, of the \$100/ton is internalized in forecasted energy costs through the Regional Greenhouse Gas Initiative, so the analysis incorporates an additional cost of about \$90-95 (in \$2013) for cases in which costs of environmental externalities are included.

CO_2 emission reductions are calculated by using the 2012 ISO-New England marginal emission rate of 854 lbs/MWh.[4] ISO-NE grid operations and markets almost always result in a gas generator dispatched as the marginal plant, so this value is comparable to the emissions from a natural gas generator. The Department's analysis does not track or account for emissions or abatement of other greenhouse gasses.

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[4] http://www.iso-ne.com/static-assets/documents/genrtion_resrcs/reports/emission/2012_emissions_report_final_v2.pdf

3.3 Results of Cross-Subsidization Analysis

3.3.1 Systems Examined

This report presents the results of the cross-subsidization analysis for 6 systems:

- A 4 kW fixed solar PV system, net metered by a single residence;
- A 4 kW 2-axis tracking solar PV system, net metered by a single residence;
- A 4 kW wind generator, net metered by a single residence;
- A 100 kW fixed solar PV system, net metered by a group;
- A 100 kW 2-axis tracking solar PV system, net metered by a group; and
- A 100 kW wind generator, net metered by a group.

3.3.2 Results for Systems Installed in 2015

The methodology described in section 3.2 allows the model to calculate costs incurred and benefits received from each typical net-metered generator on an annual basis. These values may also be combined into a 20-year levelized value. A levelized value is the constant value per kWh generated that has the same present value as the projected string of costs and/or benefits over the 20-year study period. This section presents graphs of the statewide average annual costs and benefits along with levelized costs, benefits, and net costs (costs minus benefits). The graphs presented below depict the ratepayer perspective.[5] The tables are presented for net benefits for both the ratepayer and a statewide/societal perspective.[6] For each system we separately present the ratepayer-perspective numbers for each utility.

[5] The ratepayer perspective calculation uses the higher discount rate (7.44%) and includes a REC value. RECs were assumed to have a fixed value of $30/MWh, so the reader may adjust for a no-REC-value case by subtracting 3 cents ($0.03) from the benefits values.

[6] The statewide/societal calculation uses a lower discount rate (4.95%), includes avoided externalized GHG costs and does not include a REC value. We have selected a "parochial" version of society which counts avoided RNS costs and Vermont-specific market price suppression; each of these involve transfers between Vermont and other New England states and might not be included in a societal test with a broader perspective.

3.3.2.1 4 kW fixed solar PV system, net metered by a single residence

A 4 kW fixed solar PV system would generate about nearly 5,000 kWh annually with a capacity factor of 14.2%.

Exhibit 9. *Per-kWh costs (red line) and benefits (colored areas) for a 4 kW fixed solar PV system installed in 2015, from a ratepayer perspective.*

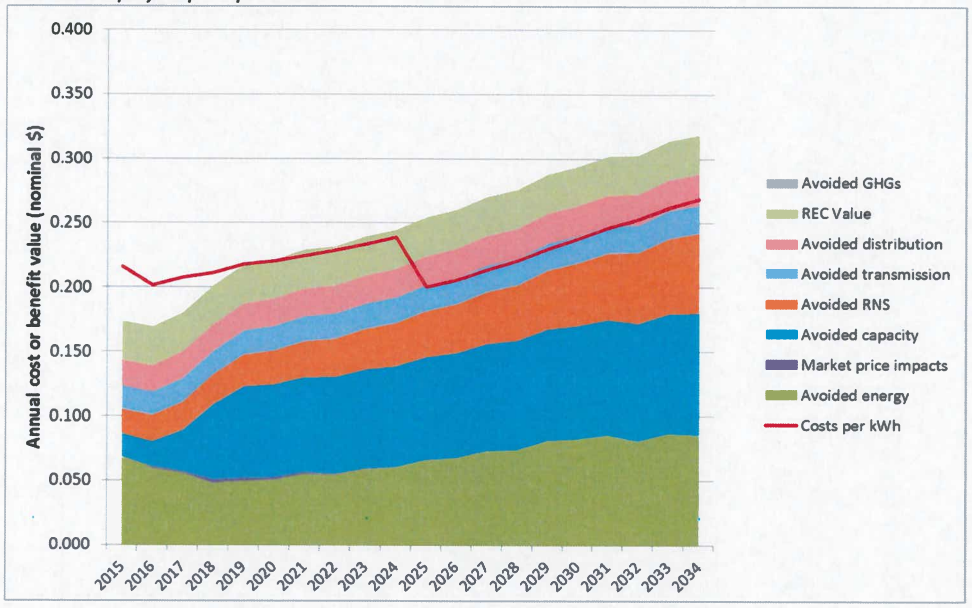

Exhibit 10. *Levelized cost, benefit, and net benefit of a 4 kW fixed solar PV residential system installed in 2015 to other ratepayers or society. Units are $ per kWh generated.*

	Cost	Benefit	Net Benefit
Ratepayer	$0.229	$0.237	$0.009
Statewide/Society	$0.230	$0.256	$0.026

Exhibit 11. *Levelized cost, benefit, and net benefit of a 4 kW fixed solar PV residential system installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated.*

Utility	Cost	Benefit	Net Benefit
Barton	$0.229	$0.217	($0.011)
BED	$0.224	$0.215	($0.010)
Enosburg	$0.229	$0.231	$0.002
GMP	$0.226	$0.237	$0.011
Hardwick	$0.232	$0.216	($0.017)
Hyde Park	$0.232	$0.221	($0.011)
Jacksonville	$0.227	$0.229	$0.003
Johnson	$0.231	$0.237	$0.006
Ludlow	$0.206	$0.223	$0.017
Lyndonville	$0.221	$0.228	$0.006
Morrisville	$0.225	$0.244	$0.019
Northfield	$0.217	$0.220	$0.003
Orleans	$0.212	$0.241	$0.030
Stowe	$0.236	$0.225	($0.011)
Swanton	$0.207	$0.246	$0.039
VEC	$0.233	$0.218	($0.014)
WEC[7]	$0.197	$0.215	$0.017

[7] Due to its unique program, WEC's costs and benefits depend on the fraction of the customer's use that is offset by the net metered system. For this and each other example system, the Department assigned the household a usage comparable to the average residential energy use among WEC members.

3.3.2.2 4 kW tracking solar PV system, net metered by a single residence

A 4 kW 2-axis tracking solar PV system would generate about 6,600 kWh annually with a capacity factor of 18.8%.

Exhibit 12. *Per-kWh costs (red line) and benefits (colored areas) for a 4 kW 2-axis tracking solar PV system installed in 2015, from a ratepayer perspective.*

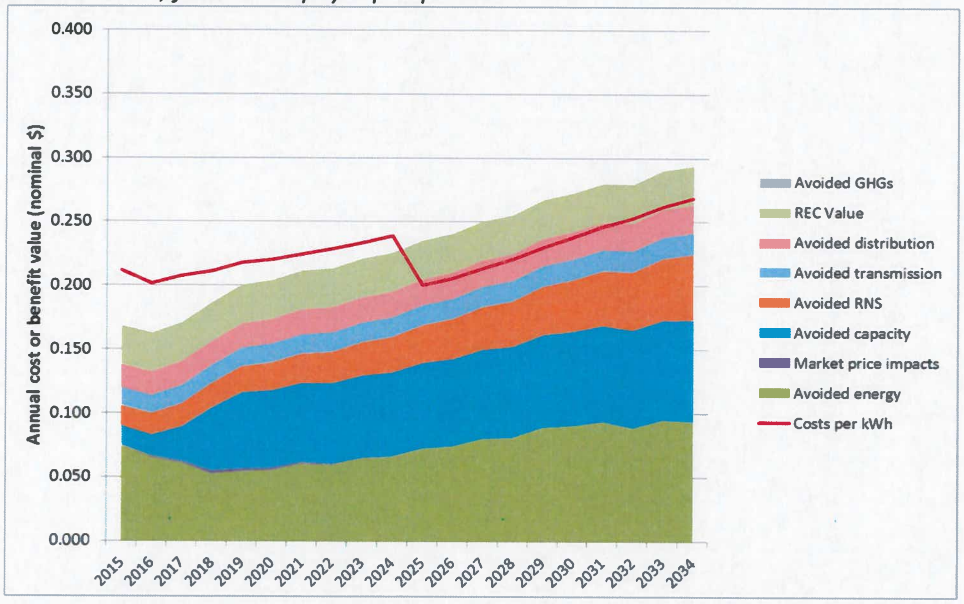

Exhibit 13. *Levelized cost, benefit, and net benefit of a 4 kW 2-axis tracking solar PV residential system installed in 2015 to other ratepayers or society. Units are $ per kWh generated.*

	Cost	Benefit	Net Benefit
Ratepayer	$0.228	$0.221	($0.007)
Statewide/Society	$0.229	$0.238	$0.009

Exhibit 14. *Levelized cost, benefit, and net benefit of a 4 kW 2-axis tracking solar PV residential system installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated.*

Utility	Cost	Benefit	Net Benefit
Barton	$0.228	$0.205	($0.023)
BED	$0.224	$0.200	($0.024)
Enosburg	$0.229	$0.216	($0.013)
GMP	$0.225	$0.220	($0.005)
Hardwick	$0.232	$0.202	($0.030)
Hyde Park	$0.232	$0.204	($0.027)
Jacksonville	$0.227	$0.218	($0.009)
Johnson	$0.231	$0.224	($0.007)
Ludlow	$0.205	$0.208	$0.003
Lyndonville	$0.221	$0.215	($0.006)
Morrisville	$0.225	$0.224	($0.001)
Northfield	$0.217	$0.206	($0.011)
Orleans	$0.211	$0.229	$0.018
Stowe	$0.235	$0.212	($0.023)
Swanton	$0.207	$0.229	$0.022
VEC	$0.232	$0.207	($0.025)
WEC	$0.187	$0.201	$0.014

3.3.2.3 4 kW wind generator, net metered by a single residence

A 4 kW wind generator generates approximately 3,400 kWh per year, with a capacity factor of 9.6%. If such a generator were sited optimally, it could have a higher capacity factor and generate more electricity. However, the per-kWh costs and benefits described here would be unlikely to change significantly.

Exhibit 15. *Per-kWh costs (red line) and benefits (colored areas) for a 4 kW wing generator installed in 2015, from a ratepayer perspective.*

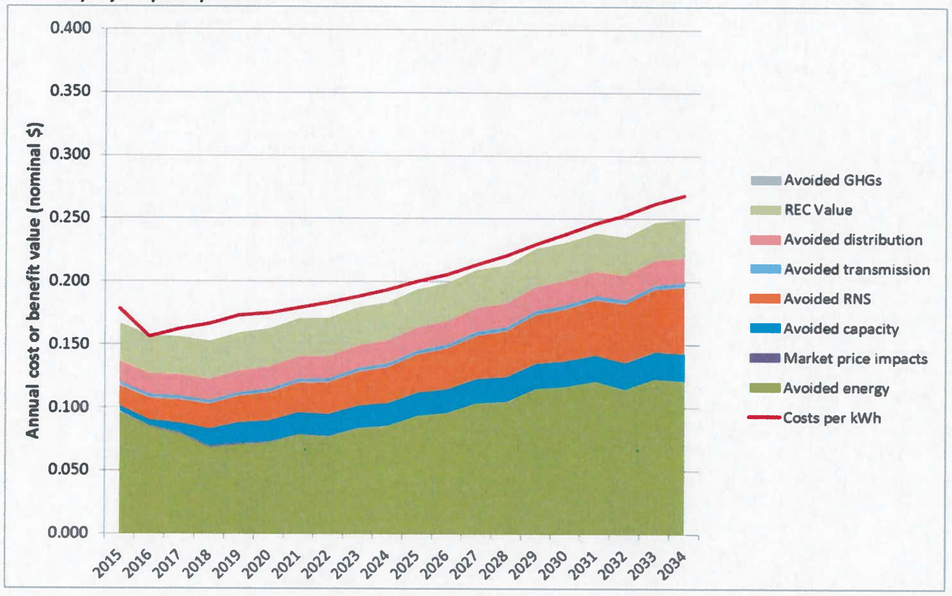

Exhibit 16. *Levelized cost, benefit, and net benefit of a 4kW wind generator installed in 2015 to other ratepayers or society. Units are $ per kWh generated.*

	Cost	Benefit	Net Benefit
Ratepayer	$0.198	$0.188	($0.009)
Statewide/Society	$0.201	$0.204	$0.003

Exhibit 17. *Levelized cost, benefit, and net benefit of a 100kW wind generator installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated.*

Utility	Cost	Benefit	Net Benefit
Barton	$0.197	$0.196	($0.001)
BED	$0.187	$0.170	($0.017)
Enosburg	$0.198	$0.184	($0.014)
GMP	$0.194	$0.187	($0.007)
Hardwick	$0.207	$0.199	($0.008)
Hyde Park	$0.206	$0.200	($0.006)
Jacksonville	$0.193	$0.193	($0.000)
Johnson	$0.203	$0.191	($0.012)
Ludlow	$0.141	$0.192	$0.051
Lyndonville	$0.180	$0.191	$0.012
Morrisville	$0.189	$0.185	($0.004)
Northfield	$0.169	$0.194	$0.025
Orleans	$0.155	$0.187	$0.032
Stowe	$0.215	$0.189	($0.026)
Swanton	$0.144	$0.187	$0.043
VEC	$0.207	$0.197	($0.011)
WEC	$0.219	$0.199	($0.020)

3.3.2.4 100 kW fixed solar PV system, group net metered

A 100 kW fixed solar PV system would generate about 125,000 kWh annually with a capacity factor of 14.2%.

Exhibit 18. *Per-kWh costs (red line) and benefits (colored areas) for a 100kW fixed solar PV system, group net metered, installed in 2015, from a ratepayer perspective.*

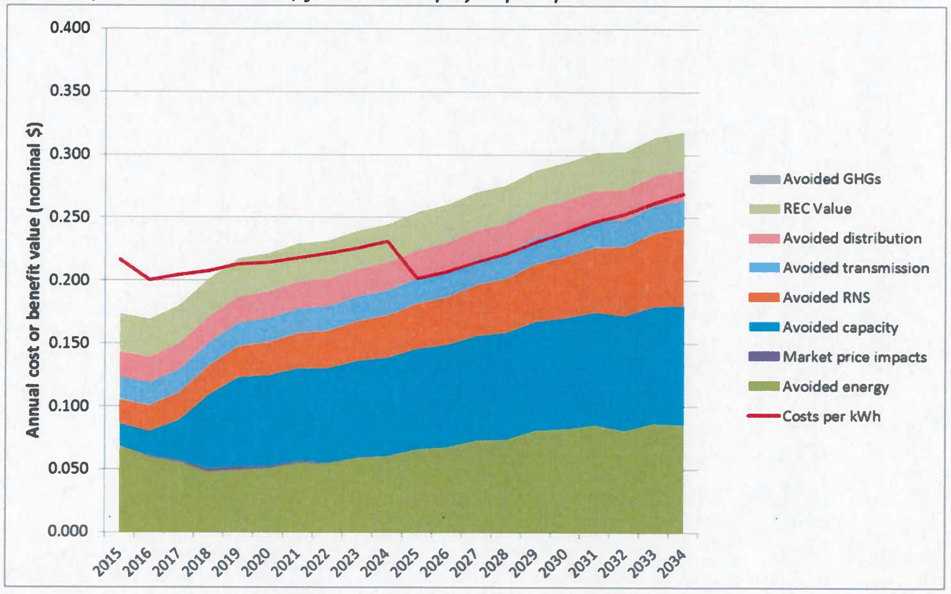

Exhibit 19. *Levelized cost, benefit, and net benefit of a 100kW fixed solar PV system, group net metered, installed in 2015 to other ratepayers or society. Units are $ per kWh generated.*

	Cost	Benefit	Net Benefit
Ratepayer	$0.226	$0.237	$0.011
Statewide/Society	$0.227	$0.256	$0.028

Exhibit 20. *Levelized cost, benefit, and net benefit of a 100kW fixed solar PV system, group net metered, installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated*

Utility	Cost	Benefit	Net Benefit
Barton	$0.226	$0.217	($0.009)
BED	$0.222	$0.215	($0.007)
Enosburg	$0.226	$0.231	$0.005
GMP	$0.223	$0.237	$0.014
Hardwick	$0.230	$0.216	($0.014)
Hyde Park	$0.230	$0.221	($0.008)
Jacksonville	$0.224	$0.229	$0.005
Johnson	$0.228	$0.237	$0.009
Ludlow	$0.203	$0.223	$0.020
Lyndonville	$0.219	$0.228	$0.009
Morrisville	$0.223	$0.244	$0.021
Northfield	$0.215	$0.220	$0.006
Orleans	$0.209	$0.241	$0.032
Stowe	$0.233	$0.225	($0.008)
Swanton	$0.204	$0.246	$0.041
VEC	$0.230	$0.218	($0.012)
WEC	$0.212	$0.215	$0.002

3.3.2.5 100 kW tracking solar PV system, group net metered

A 100 kW 2-axis tracking solar PV system would generate about 165,000 kWh annually with a capacity factor of 18.8%.

Exhibit 21. *Per-kWh costs (red line) and benefits (colored areas) for a 100kW 2-axis tracking solar PV system, group net metered, installed in 2015, from a ratepayer perspective.*

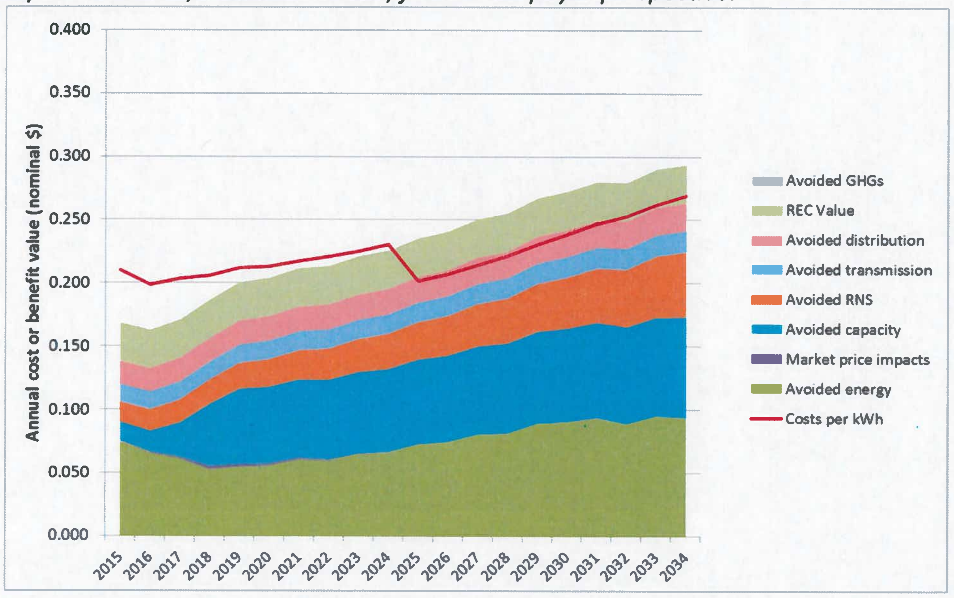

Exhibit 22. *Levelized cost, benefit, and net benefit of a 100kW 2 axis tracking solar PV system, group net metered, installed in 2015 to other ratepayers or society. Units are $ per kWh generated.*

	Cost	Benefit	Net Benefit
Ratepayer	$0.225	$0.221	($0.004)
Statewide/Society	$0.226	$0.238	$0.012

Exhibit 23. *Levelized cost, benefit, and net benefit of a 100kW 2 axis tracking solar PV system, group net metered, installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated.*

Utility	Cost	Benefit	Net Benefit
Barton	$0.225	$0.205	($0.019)
BED	$0.220	$0.200	($0.020)
Enosburg	$0.225	$0.216	($0.009)
GMP	$0.222	$0.220	($0.001)
Hardwick	$0.228	$0.202	($0.026)
Hyde Park	$0.228	$0.204	($0.024)
Jacksonville	$0.223	$0.218	($0.005)
Johnson	$0.227	$0.224	($0.003)
Ludlow	$0.202	$0.208	$0.007
Lyndonville	$0.217	$0.215	($0.002)
Morrisville	$0.221	$0.224	$0.003
Northfield	$0.213	$0.206	($0.007)
Orleans	$0.207	$0.229	$0.022
Stowe	$0.232	$0.212	($0.020)
Swanton	$0.203	$0.229	$0.026
VEC	$0.228	$0.207	($0.022)
WEC	$0.206	$0.201	($0.006)

3.3.2.6 100 kW wind generator, group net metered

A 100 kW wind generator generates approximately 84,000 kWh per year, with a capacity factor of 9.6%. If such a generator were sited optimally, it could have a significantly higher capacity factor and generate more electricity. However, the per-kWh costs and benefits described here would be unlikely to change significantly.

Exhibit 24. *Per-kWh costs (red line) and benefits (colored areas) for a 100kW wind generator, group net metered, installed in 2015, from a ratepayer perspective.*

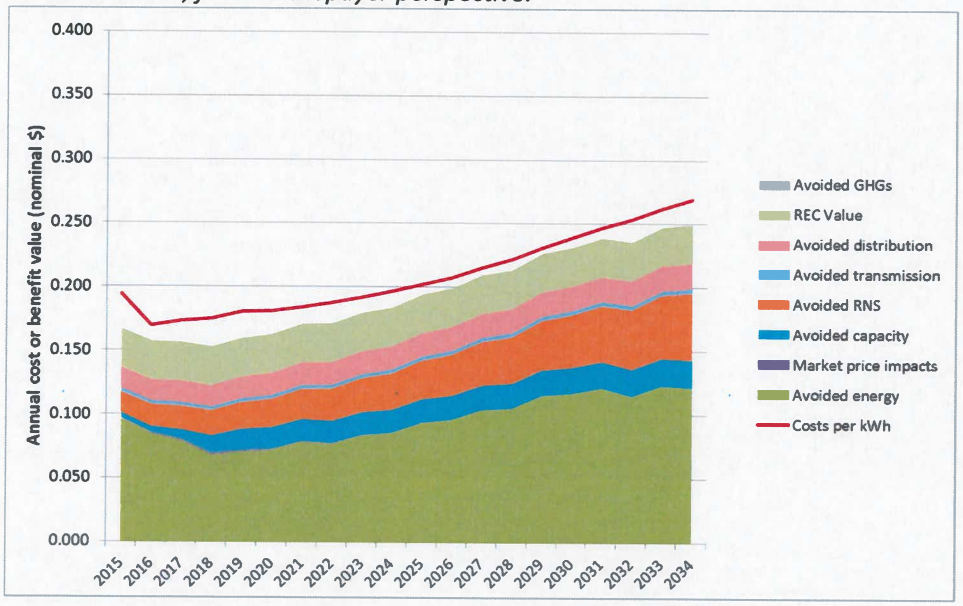

Exhibit 25. *Levelized cost, benefit, and net benefit of a 100kW wind generator, group net metered, installed in 2015 to other ratepayers or society. Units are $ per kWh generated.*

	Cost	Benefit	Net Benefit
Ratepayer	$0.204	$0.188	($0.016)
Statewide/Society	$0.207	$0.204	($0.003)

Exhibit 26. *Levelized cost, benefit, and net benefit of a 100kW wind generator, group net metered, installed in 2015 to other ratepayers, by utility. Refer to Section 3.2 for a description of why these values vary by utility. Units are $ per kWh generated.*

Utility	Cost	Benefit	Net Benefit
Barton	$0.204	$0.196	($0.008)
BED	$0.193	$0.170	($0.024)
Enosburg	$0.205	$0.184	($0.020)
GMP	$0.200	$0.187	($0.013)
Hardwick	$0.213	$0.199	($0.015)
Hyde Park	$0.213	$0.200	($0.012)
Jacksonville	$0.200	$0.193	($0.007)
Johnson	$0.209	$0.191	($0.019)
Ludlow	$0.147	$0.192	$0.044
Lyndonville	$0.186	$0.191	$0.005
Morrisville	$0.195	$0.185	($0.010)
Northfield	$0.175	$0.194	$0.019
Orleans	$0.162	$0.187	$0.026
Stowe	$0.221	$0.189	($0.033)
Swanton	$0.150	$0.187	$0.036
VEC	$0.214	$0.197	($0.017)
WEC	$0.213	$0.199	($0.015)

3.3.3 Concluding Remarks on Cross-Subsidization

The analysis presented in the preceding sections indicates that the aggregate net cost over 20 years to non-participating ratepayers due to net metering under the current policy framework is close to zero, and there may be a net benefit. Analysis of the differences between utilities indicates that winter-peaking utilities, which see fewer benefits from net metered solar PV, will incur a larger share of the net cost than summer peaking utilities or those utilities with lower retail rates. As such, for the post-2016 period, the Department recommends that the Board consider whether or not changes to the current program structure to allow flexibility for the program to vary by utility would better serve the state.

It is appropriate to note that cross-subsidies are common in utility ratemaking. While rates strive to assign costs to those who cause them, this cannot be done exactly. The classic example is the comparison of urban and rural rates – the rural ratepayers have caused the construction of an extensive distribution system, form which the urban customers do not directly benefit, yet all pay equally for distribution network costs. This challenge is a portion of why rural electrification required explicit government action in the early part of the last century. Society as a whole has benefited from universal electrification, and concern about this cross-subsidy has generally faded. While policymakers can strive to minimize cross-subsidization in the net metering context, a precise elimination is unlikely and would hold net metering policies to a higher standard than that achieved by other ratemaking.

Net benefits from net metering systems, are either positive or negative depending on the details of utility rate structures, benefits from avoided distribution infrastructure, and the inclusion or exclusion of the value of renewable energy and greenhouse gas emission reductions. Notably, wind net metered systems performed much better in the model based on 2013-14 data than it did for the previous Act 125 model. This is largely due to wind's operation more often during the recent high prices for energy in the winter, and the more comprehensive treatment of winter distribution peaks in this report. As such, small wind as modeled performs even better for some utilities whose peak demand is during dark, winter hours. On the other hand, solar PV has much greater coincidence of generation with times of regional and some local peak demand than does wind power. This phenomenon underscores the year-to year, and utility-to-utility, variability associated with the benefits from net metering technology. It will be important to consider this variability in considering program design, but as described further below (see Section 4), designing a program with stability in mind can mitigate single year price and value volatility. Further, structures could be considered that incent technologies to be developed and/or sited in ways that focus on peak benefits – whether they relate to energy and capacity prices or a utility's peak demand.

The Department suggests that there is value in having a common methodology for the quantification of the value of distributed generation (represented in the benefits side of the above calculations). This will allow interested parties to identify areas of agreement and disagreement on the value of DG resources, and potentially reach consensus regarding assumptions. To that end, the Department has made the spreadsheets used to calculate all of the results presented here publicly available. There need not be a direct link between the value provided by DG resources and the amount or form of compensation provided through a net metering program – Vermont's current policy approaches a lack of cross-subsidy while not explicitly linking compensation to benefits. It may be that in order to achieve long-term objectives for DG deployment, compensation needs to be above value provided for particular technologies or particular time-periods – such compensation above value could be delivered through a net metering tariff, or through alternate incentives structures, and may depend on the availability and structure of funding.

4 Lesson learned for net metering identified from other states

While Act 99 requires that the Department address "best practices" from other jurisdictions, our review of the literature and the current state of distributed generation regulation across the country indicates that it is premature to identify "best practices." Instead, this section identifies lessons learned from other jurisdictions and describes "guiding principles" published in recent literature and offered for consideration here.

4.1 Literature review

The 2013 *Freeing the Grid*[8] report from the Interstate Renewable Energy Council and the Vote Solar Initiative provides a good summary of the nation's net metering policies; an independent catalog of the range of existing net metering policies was not completed for this report. Instead, this section of the report will summarize two key reports, one from the National Renewable Energy Laboratory ("NREL", with assistance from the Regulatory Assistance Project, "RAP") and the other from RAP, which provide both overview and detail on regulatory options for addressing high penetrations of distributed generation (particularly solar). Together, they provide a framework for Vermont to evaluate existing and potential tools to expand or modify our net metering program, drawn from lessons learned across the country.

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[8] Barnes, J., Culley, T., Haynes, R., Passera, L., Wiedman, J., and Jackson, R. (2013). Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures. New York, NY and San Francisco, CA. Interstate Renewable Energy Council and The Vote Solar Initiative. Retrieved from http://freeingthegrid.org/wp-content/uploads/2013/11/FTG_2013.pdf.

4.1.1 "Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar"

In their November 2013 technical report, *Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar*,[9] NREL and RAP provide a useful primer on the range of issues – from cost-benefit analyses to business models and ratemaking options – that regulators should consider when undertaking redesign of mechanisms to accommodate increasing penetrations of distributed solar. The authors recommend that regulators borrow methods learned from energy efficiency program design and regulation in order to address increased distributed solar, or even seek to simultaneously address issues related to distributed generation (DG), demand side management, and energy efficiency in order to achieve optimal regulatory and rate-making solutions.

The authors refrain from advocating any particular tool or combination of tools, stress that there is no one-size-fits all solution, and posit that new regulatory tools or combinations of existing tools will emerge as regulators begin to address the increasing pace of distributed solar deployment happening across the U.S. They suggest the optimal solution will make sense at any scale of solar deployment, rendering revisions and exceptions unnecessary; but if that should prove an impossible task, then regulators should at least anticipate high penetration levels and set in motion a transparent, predictable process to design tariffs that will address those levels.

The study discusses ratemaking options, spanning the universe of existing tools employed by regulators to accommodate distributed solar. They are framed in terms of performance, limits and downsides, and relevant utility type (i.e. investor-owned, cooperative, municipal) and include: net metering, fixed charges, stand-by rates, time-based pricing, two-way rates, minimum monthly billing, and creation of a new customer class for photovoltaic customers. Helpful case studies of places where these various tools are being deployed are included (e.g., implementation of a value of solar tariff – a type of two-way rate – in Minnesota). Notably, the report provides a list of "Questions for Framing the Regulatory Discussion." These questions are attached to this report as an appendix in recognition of its wholesale value to the present discussion.

The authors place emphasis throughout the paper on the various avenues by which regulators can influence the actions of utilities and – consequentially – the climate for solar deployment within a state. One option they discuss is for regulators and utilities to consider strategically placed distributed solar in the resource planning process, as one among a suite of potential least cost options to increase system reliability. The Vermont System Planning Committee (VSPC) serves as a venue today for discussions of utility infrastructure planning; the VSPC plays a role in the identification of constrained areas where DG could provide "sufficient benefit" in the context of the Standard Offer program and in the incorporation of DG into load forecasts.

Finally, the authors point to gaps in the knowledge base that need to be addressed in order for regulators to make informed decisions, such as the benefits and costs of distributed solar at high penetration levels, and the changes in cost-of-service figures and utility financials that will inevitably transpire if and when high penetrations of distributed solar are achieved. As noted in section 5.4, Vermont may be reaching these high penetrations of distributed solar sooner rather than later.

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[9] Bird, L., Mclaren, J., Heeter, J., Linvill, C., Shenot, J., Sedano, R., & Migden-Ostrander, J. (2013). Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar (NREL/TP-6A20-60613). Golden, CO: National Renewable Energy Laboratory. Retrieved from http://www.nrel.gov/docs/fy14osti/60613.pdf.

4.1.2 "Designing Distributed Generation Tariffs Well"

In their 2013 paper, *Designing Distributed Generation Tariffs Well*,[10] the Regulatory Assistance Project focuses specifically on the design of tariffs that fairly compensate both customer-sited DG resources as well as utility services to customers. They note the importance of other regulatory tools to accommodate solar and distributed resources, such as those mentioned in the NREL paper discussed above, but focus on a discussion of tariffs and specifically advocate for two-way distribution tariffs, where both generators and utilities are fairly and accurately compensated for the specific services provided.

The authors are quick to acknowledge barriers to enacting perfect tariffs, such as immaturity of hardware and information technologies as well as legacy imperfections built into retail rate design, but stress the importance of improving upon existing compensation mechanisms in a way that moves toward greater fairness and accuracy while setting the stage for an easy transition to more sophisticated mechanisms (i.e. a transactive energy economy, where multiple parties including utilities, distributed generators, and aggregators are fairly and accurately compensated for the services provided) as technologies and markets evolve.

The RAP highlights that keeping tariffs simple and practical – as advocated by Bonbright[11] – is especially important in examining replacements for relatively well understood tools such as net metering. Beyond that, they then consider whether a serious cross-subsidy problem actually exists; and, if so, which tariff and rate design approaches might address the cross-subsidy. Finally, they propose to solve any remaining sources of stakeholder conflict with additional regulatory treatment (e.g. decoupling).

The RAP report examines issues important for consideration by regulators as they evaluate benefits, costs, and net value of DG to various stakeholders (DG adopters, non-adopter ratepayers, utilities, and society more broadly) as part of the tariff design process. This includes a discussion of sources of mutual benefit and sources of conflict among stakeholder value propositions drawn from examples in various states and jurisdictions. The report considers rate design options and alternative ratemaking approaches for fairly reconciling the needs and perspectives of various stakeholders. The options examined (through the lens of Bonbright's "Principles of Public Utility Rates," also discussed in the NREL paper) include: enacting a fixed charge for distribution costs; imposing a demand charge-based distribution charge and time-of-use (TOU) rate; and implementing a bidirectional distribution rate. (A different take on these approaches is illustrated in Exhibit 27 below.) The impacts of these various approaches on

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[10] Linvill, C., Shenot, J., and Lazar, J. (2013). Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition. Montpelier, VT: The Regulatory Assistance Project. Retrieved from http://www.raponline.org/document/download/id/6898.

[11] Bonbright, J.C. (1961). Principles of Public Utility Rates. New York, NY: Utilities Reports, Inc. & Columbia University Press. The principles, as summarized in the RAP paper, include:

- Tariffs should be practical: simple, understandable, acceptable to the public, feasible to apply, and free from controversy as to their interpretation.
- Tariffs should keep the utility viable, effectively yielding the total revenue requirement and resulting in relatively stable cash flow and revenues from year to year.
- Rates should be relatively stable such that customers experience only minimal unexpected changes that are seriously adverse.
- Tariffs should fairly apportion the utility's cost of service among consumers and should not unduly discriminate against any customer or group of customers.
- Tariffs should promote economic efficiency in the use of energy as well as competing products and services while ensuring the level of reliability desired by customers.

representative ratepayer groups – apartment dwellers, typical residences, large residences, and photovoltaic customers – are then examined.

The RAP authors suggest that today's tools – net metering and feed-in tariffs – may achieve simplicity (per Bonbright) but fall short on precision (per a transactive energy economy). However, they offer suggestions for "Getting NEM and FIT Right" in the meantime.

For net metering, these include: recognizing the premium value of renewable resources, which may justify full retail rate value; avoiding fixed monthly customer charges, which tend to penalize apartment dwellers and urban residents; and considering time-of-use arrangements in tariffs to encourage prices that are closer to the value of power consumed.

For feed-in-tariffs, suggestions include: providing stable and long terms (of at least ten years); allowing for different types of resources that offer unique attributes; considering auctions; committing to a stable policy that still allows for reasonable modification of prices and terms; and making sure program caps are not unreasonably restrictive.

Finally, the RAP authors provide 12 specific recommendations for regulators, reproduced here (additional detail on each is provided in the paper's conclusion):

1. Recognize that value is a two way street.
2. Distributed generation should be compensated at levels that reflect all components of relevant value over the long term.
3. Select and implement a valuation methodology.
4. Remember that cross-subsidies may flow to or from DG owners.
5. Don't extrapolate from anomalous situations.
6. Infant-industry subsidies are a long tradition.
7. Remember that interconnection rules and other terms of service matter.
8. Tariffs should be no more complicated than necessary.
9. Support innovative business models and delivery mechanisms for DG.
10. Keep the discussion of incentives separate from rate design.
11. Keep any discussion of the throughput incentive separate.
12. Consider mechanisms for benefitting "have not" consumers.

4.2 Literature review insights

There are a number of options for the future design of net metering in Vermont. Exhibit 27 highlights a range of possible models for the evolution of net metering in different jurisdictions. Reformed net metering programs (those, like Vermont's, that go beyond simple "spin the meter backward" net metering) can be divided into those which retain a single-rate approach, but reform some piece of that rate (e.g. a fixed charge, demand charge, or other solar charge), and those which use more than one rate (such as a solar value rate). As can be seen, program attributes vary by approach.

	CAMP 1	CAMP 2				
	Continue NEM	Reforming the Solar Customer Transaction (NEM reform)				
RATE CONSTRUCT	Single Transaction (Rate) Approach				Two or More Transactions (Rates)	
	Apply NEM	Reform Existing Rates (all customers or solar only)			Solar Rate	Reform All Rates
MODEL	Current Rates	Increased Fixed Charge and/or Minimum Bill	Demand Charge	Stand-by or Solar Charge	Independent Energy Sale and Solar Purchase Rates	Value of Services
ATTRIBUTES	• Currently applicable rates result in an acceptable transaction • Solar penetration does not warrant action	• Add or increase basic service charge ($/month) • Raise min bill requirements ($/month)	• Add or increase customer fee for demand ($/kW/month)	• Charge for stand-by capacity, based on DG system size ($/kW/month or ($/kW/yr)	• Retain existing rates for services provided from utility to cust. • Establish second rate to purchase from customer	• Design rates to reflect itemized services from utility to cust. and from cust. to utility

Exhibit 27. *Summary table of rate structure options for net metering, including options that use one rate and include specific charges and options that use more than one rate. Figure courtesy of Julia Hamm, Solar Electric Power Association.*[12]

In addition to the guiding principles articulated by NREL and RAP, there are other considerations that will affect the success of any redesigned net metering program. For instance, the numerous changes in Vermont net metering statutes over the last decade have highlighted the value of stability in policy and financial programs. This stability allows time for the market to understand and respond to policy goals without the fear of potential swift program changes that might deter innovative solutions. Another consideration should be the value of price certainty for investors; a reasonably predictable credit for generation may allow for more accessible financing of small generation.

It is important to note that the pace of deployment doesn't necessarily only depend on net metering program tariff design. Other, complementary efforts such as tax policy or separate incentive funding mechanisms should be considered in the upcoming process.

The RAP and NREL reports clearly articulate that there is no "best practice" which Vermont can simply emulate; there is no "one size fits all" policy framework that can simply be adopted. Instead, the design of future programs must begin with a critical review of the pertinent issues relevant to Vermont stakeholders to determine feasible options and make informed decisions. While it is unlikely that a perfect tariff could be established that equally addresses concerns of ratepayers and developers (including both home and business owners) installing net metered distributed generation across all of Vermont's utilities, striking the appropriate balance between potentially competing interests will help determine the success of the future of net metering in Vermont.

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[12] Originally presented at the RPS Collaborative Summit, September 23, 2014. Reproduced with permission.

5 Other topics required by Act 99

5.1 Economic and environmental benefits of net metering

The cost and benefit discussion in Section 3 above describes the economic and environmental costs and benefits of net metering that are quantifiable on a per-kWh or per-kW basis. In addition to these costs and benefits, there are impacts which are hander to quantify on that basis. These include the direct employment of Vermonters in the design, permitting, construction, and operation of net metered generators. The Solar Foundation has identified that Vermont has the most solar jobs per capita of any state in the country. These jobs are to some large part a result of the state's aggressive adoption of net metered solar PV generation. In addition, the recent Clean Energy Development Fund *Clean Energy Industry Report*, which surveyed clean energy firms around the state, estimates that over 1,500 Vermonters work in the solar industry in some fashion, the greatest of any renewable energy technology. Maintaining a sustainable economic sector that develops clean energy resources is also a component of the state's recent Comprehensive Economic Development Strategy. The Department did not attempt to quantify these types of benefits in the analysis presented in Section 3; however the spreadsheet model offers the opportunity to add, on a per kWh basis, such values to the benefit of net metered technologies.

The Department considered attempting to quantify the reductions in air pollutants other than carbon dioxide due to net metering, but initial evaluation indicated there is significant uncertainty in the valuation of such emission reductions, and that the values are likely to be comparatively small regardless.[13]

5.2 Reliability and supply diversification costs and benefits

The benefit discussion in Section 3.2 above describes the reliability benefits that can occur due to net metered generators which reduce stress on the transmission and distribution grids during peak hours. At greater levels of deployment on particular circuits, net metered generators could result in "reverse" flows on energy on electric circuits not designed for those flows; equipment upgrades may be required at that point in order to maintain reliability.

Vermont has long valued diversification in its electric energy supply portfolio. For example, extensive dependence on any one fuel, such as oil, coal, nuclear, biomass, or natural gas, can leave ratepayers at risk that increases in the cost of that fuel would result in rate spikes. Vermont utilities have pursued a policy of constructing their portfolios with a substantial fraction made up from contracts for or ownership of different types of generation, and with fixed prices, known price escalation (e.g. with inflation), or prices with "collars" that prevent or dampen spikes. This has served a purpose of maintaining stable rates, leading to predictability for business and household costs. (The downside is that Vermont has not benefitted when one fuel or another falls sharply in price.) Many renewable generators for which there is no direct fuel cost (e.g. solar, wind, and hydroelectric) have economic structures that are fundamentally compatible with this desire for rate stability.

The benefits for rate stability of this sort that flow from net metering programs depend on the structure whereby participating customers are credited by their utility for their generation. Under a feed-in-tariff model or other fixed price arrangement between customer and utility, other ratepayers benefit from

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[13] For example, the ISO-NE marginal emissions rate of NO_x was 0.22 lb/MWh in 2012. A rooftop solar PV system might generate 5 MWh/year, and avoid 1.1 lb. of NO_x emissions. Recent Federal rulemakings value NO_x emission reductions at between $476 and $4,893 per ton, or a maximum of less than $2.50 per pound.

price stability. A retail rate based structure has somewhat more risk, but retail rates are generally relatively smoothly increasing (historically roughly in line with overall inflation in Vermont), due to the many components that comprise a utility's cost of service. The lack of fuel price volatility makes most renewable net metered generators a good fit (in this respect) for Vermont utility portfolios.

5.3 Benefits to net metering customers of connecting to the distribution system

The analysis is Section 3 of this report discusses the costs and benefits of net metering form the utility or non-participating ratepayer point of view. Net metering also has costs and benefits from the standpoint of the participating net metered generator. Access to the electric distribution system, as opposed to being "off grid," allows a net metered customer to avoid the need to deploy energy storage, match supply and demand on-site, or use a diesel or other fuel-based generator. The grid also provides assurance of access to electrical power above that which and off-grid generator may provide. Use of a shared energy generation, transmission, and distribution infrastructure can be a societally least-cost way to meet energy service demand. Net metering customers benefit from the presence of the grid to transmit excess generation to other customers, and to draw upon at times when the net metered generator is not generating enough power to meet the customer's needs. "Virtual" group net metered customers use the distribution, and perhaps even the transmission, systems to connect the power generated by a remote generator to their account (although, as the name implies, this is done through accounting, rather than direct electrical flows).

5.4 The future pace of net metering deployment statewide and by utility

The Department recommends that Vermont ratepayers and utilities take maximum advantage of the current Federal tax incentive structure to build well-sited[14] distributed net metered generators, including solar PV, in the state between now and the end of 2016, when Federal tax treatment for solar PV may change. The design of a future net metering system for the time after 2016, which is the subject of the Public Service Board investigation to follow submission of this report, should be sensitive to the impact of Federal incentive policy. The investigation should also be informed by the amount of distributed solar PV and other generation built in the state and in each utility's service territory by the end of 2016. The Department therefore recommends that the Board take a relatively flexible approach to the setting of any targets for the pace of future deployment.

It is likely that the solar PV industry in Vermont and around the country will see a boom from now until the end of 2016. The economic activity and jobs associated with that boom will boost the clean energy sector in Vermont. Once Federal tax treatment changes, however, the industry will be at risk of a significant drop in activity, with associated economic hardship for particular firms and their employees. If this bust is sharp and deep, it may hamper the industry's ability to rebound, and thus the state's ability to meet long-term renewable energy goals. To that end, stakeholders and the Public Service Board should consider industry impacts when evaluating the impacts of different policy options for the post-2016 period.

At the current pace of permit applications, it is possible that the total permitted net metering may approach 150 MW by the end of 2016. Combined with other distributed generators built under the Standard Offer program or under PPA or utility ownership, this could mean 250 MW or more solar PV permitted in the state. This will have noticeable impacts on the state's load shape, and the load shapes

[14] Encouragement for generators sited on "ideal" locations such as brownfields, landfills, industrial parks, etc. may be an appropriate consideration for the upcoming Public Service Board process.

of each of the state's utilities. In particular, it may push all summer peaks to near or past sunset in the summer.[15] This would have a significant impact on the value delivered by solar PV in terms of avoided in-state transmission and distribution infrastructure, as well as RNS costs. A slower transition throughout New England may impact the ISO-NE peak, shifting it later in the day as well, which will impact the energy and capacity markets. One unknown facing future distributed generation deployment is the level of deployment at which reverse flows and other integration challenges, with associated costs, begin to appear on the grid.[16]

Taking into account the context described in the previous three paragraphs, the Department recommends that the Board and stakeholders strive for a sustained pace of deployment while avoiding market booms or busts. Given the roughly 20-25 year lifetime of most distributed generators, the expectation of continued technological progress and associated falling real prices, and the likely continued development in grid management systems and technologies (including energy storage), renewable energy deployment toward 2050 goals can afford to take a longer-term view. This should be balanced with a need to remain flexible in order to take full advantage of changes in technology, Federal programs and policies, and evolving business models. The Board, and state policymakers in general, should strive for policies that balance the costs and benefits of distributed generation, including net metered generation, remain flexible, and aim for overall targets regarding renewable electricity (such as those established in 30 VSA 8005a) and renewable energy in all sectors.

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[15] Given this shift, it may be worthwhile to consider policies that incent developers to increase focus on peak benefits at some expense of energy generation. An inexact calculation of a west-facing solar PV system in the Department's cost-benefit model indicates that a west-facing fixed solar PV system might produce as much as 15% more value per kWh generated than a south-facing system.

[16] Reliability issues such as maintenance of voltage and frequency events, and potential for accelerated ramping potentially necessary to meet peak demand have been the subject of significant discussion at the ISO-NE Distributed Generation Forecast Working Group. Information is available at http://iso-ne.com/committees/planning/distributed-generation

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Appendix: "Questions for Framing the Regulatory Discussion"

An excerpt from *National Renewable Energy Laboratory's Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar.* Bird et. al. November 2013.