From: Linda McGinnis [lindamcginnis0@gmail.com]
Sent: Friday, November 02, 2012 4:03 PM
To: Jan Eastman; Scott Johnstone; Jim Matteau; louisemccarren@gmavt.net; Gaye Symington; Markowitz, Deb; Miller, Elizabeth
CC: Hofmann, Sarah; Margolis, Anne; Grace, Sheila; Coster, Billy; Lee Pelletier; Percival, Penny; Hughes, Michelle
Subject: Follow up to EGSPC meeting of Oct 31, 2012
Attachments: Dennis Liddy_Windaction article 1 submission.pdf; Dennis Liddy_Windaction article 2 submission.pdf; wind coalition statement - final2.pdf; comprehensive energy pla_001.pdf (1).pdf

Dear Commissioners,

Many thanks for your thoughtful participation in the first EGSPC meeting. It was a great start to achieving the important mandate of the Commission. I hope you've had a couple of days to absorb the wealth of information and comments it contained. I wanted to follow up with a couple of additional dates, reading materials, and feedback requests.

First, please note a couple of dates in your calendars:

- **Next EGSPC meeting**: Wednesday, November 14 from 9-12. We are trying to reserve Room 11 again, and will confirm with you as soon as we find out. The purpose of this meeting will be to learn from the siting experiences of other States. We have confirmed the participation of New Hampshire (in person), Connecticut and Maine (via phone). We are considering inviting other states to a future meeting (OR, NY, WA) so as not to crowd the discussion.
- **Proposed Future EGSPC meetings:** Based on our updated doodle polls, it looks like the next three most likely dates for upcoming meetings will be: i) Wed or Thurs Nov 28 or 29 for perspectives from stakeholders; ii) Mon Dec 3 or Thurs Dec 13 for presentations from OR, NY, and WA; and iii) Wed, Dec 19 for a second session on perspectives from stakeholders. We can arrange for you to participate remotely if this is an issue. Please let us know if you have specific concerns with any of these dates or topics.

Second, we'd like to share with you some additional reading material (see attachments):

1. The two articles submitted by audience member Dennis Liddy, which Jan requested be sent to all Commissioners.
2. The original letter from the coalition of 6 environmental groups to Governor Shumlin requesting that a 'high level commission" be established to look at VT siting policies related, in their case, to wind (referenced in your appointment letters)
3. An electronic version of the sections of the Comprehensive Energy Plan that DPS felt would be most relevant to the work (included in hard copy form in your binders from Oct 31)

Third, we would appreciate your feedback on the following:

1. **The total number and topics of the proposed Commission meetings**. Please note that we have proposed adding another informational session to be able to include three additional states, bringing the total number of public meetings to 8 (five informational and three public hearings), prior to deliberations. Let us know if you agree with this, as well as whether 3 public hearings is sufficient.
2. **The possibility of three site visits** covering different energy sources and geographical areas. Your suggestions are most welcome.

Finally, in response to Jim Matteau's question to ANR regarding whether there were other steam generation facilities that have a Multi-Sector General Permit, they sent this response: The answer is yes, Ryegate and McNeil, both have coverage under the Multi-Sector General Permit. Consequently, The Bullet on slide 17, should read "Entergy Nuclear Vermont Yankee, Ryegate Power Station, and the McNeil Generating Station have this permit."

Thank you, and I hope you enjoy your weekend...

Linda

--
Linda McGinnis
Director - Energy Generation Siting Policy Commission

(Cell) 802-324-6993

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- By Topic

PLEASE READ,
SUBMITTED BY
DENNIS LIDDY
WESTFIELD, VERMONT
802-744-2797

The health and safety of those living in proximity to industrial wind turbines are at risk due to a lack of objective, practicable siting standards.

Given the lucrative and enabling energy policies now in place to promote renewable generation across the U.S., local communities are under significant pressure to develop land use regulations aimed at protecting their residents from poorly siting industrial wind plants. Inevitably, such efforts invite difficult technical questions regarding turbine noise, shadow-flicker, decommissioning and a host of others related to building and operating industrial power plants.

The controversy surrounding wind energy development complicates the siting issue making it difficult to know what or who to believe when it comes to standards. A review of existing wind ordinances adopted in other communities is helpful but standards that might work in one area are not necessarily right for another given population densities, terrain, and other environmental considerations.

Working with no standards

Rules and regulations guiding the siting of wind energy projects essentially do not exist as James Luce, chairman of the Washington State Energy Facility Siting Council, made clear in the Council's October 2011 order recommending conditional approval of the Whistling Ridge wind plant.

In the order, Luce wrote:

> The Council is challenged by the fact that it has no rules for siting renewable resources. ...For guidance, we look to our previous decisions, organic statutes and regulations developed primarily for thermal projects. And we use our best judgment to "balance" competing considerations. ...Absent rules, the Council proceeds on a case-by case basis and our decisions inevitable leave room for questioning whether the correct result was reached.

A lack of guidelines does not mean a lack of evidence. But guaranteeing the evidence is taken seriously by review boards is another matter.

Noise models and non-standards

This is certainly the case regarding wind turbine noise. Despite extensive expert testimony that credibly demonstrates the flaws inherent in noise predicting models used by the wind industry, the methods are still utilized.

In two separate proceedings before the Vermont Public Service Board -- Deerfield Wind and Kingdom Community Wind -- Kenneth Kaliski of RSG, Inc. modeled

turbine noise emissions at different points within several thousand feet of the proposed towers. Kaliski relied on the Cadna A software tool used by the wind industry, which is based on the ISO 9613-2 standard for sound prediction.

Kaliski knows the ISO 9613-2 standard was never validated for wind turbine noise but insisted its use was appropriate. He argued that by using another tool, the "CONCAWE algorithm," in conjunction with Cadna A he could more accurately predict turbine sound levels. He calibrated his 'modified' ISO method using sound data from a wind farm in Kansas but admitted on cross that he never calculated a "standard confidence interval" before applying his findings to projects in Vermont. He provided no data supporting how his modeled data in Kansas compared to actual sound data surveyed at the Kansas site, nor did he attempt to explain how the mountainous topography, different ground and atmospheric conditions, and foliage found in Vermont compared to that of Kansas and what adjustments he made (and potential errors introduced) to account for the differences.

In short, Kaliski used modeling software (Cadna A) outside its accepted parameters, applied a second tool previously tested at a site located on flat farm land, threw in undocumented adjustments for the Vermont setting and declared his noise predictions accurate for the Vermont sites because he said so -- with no way for any independent party to validate his work.

The flaws in Kaliski's work were obvious but ignored by the Vermont Public Service Board. Instead, the Board imposed a post-construction noise limit on the projects that was itself, non-standard. Neither wind project is in-service at this time but we have good reason to expect operating noise levels will prove problematic for nearby residents.

Public safety and non-standards

This same 'standard-less' approach appears to have guided the Ohio Power Siting Board when it approved the Buckeye Wind LLC application to construct a wind facility in Champaign County, Ohio. The Board's order was upheld in a 4-3 decision by the Ohio Supreme Court but the two dissenting opinions were appropriately critical.

On the question of public safety, Justice Evelyn Lundberg Stratton cited the risks of blade shear. Buckeye assured the Siting Board that a "shorn blade could fly only 500 feet", 41 feet less than the minimum setback from neighboring properties. But when the Board's

staff asked Buckeye for supporting data, testimony revealed that Buckeye's prediction pertained to a different, smaller turbine, and that "no such calculation existed" for the proposed turbines.

Justice Lundberg Stratton wrote:

> Nevertheless, despite lacking either evidence or sufficient competence in physics even to attempt to calculate the distance a blade could fly, the staff member responsible signed off on Buckeye's proposal. His portion of the investigatory report stated, 'Staff believes that the Applicant has adequately evaluated and described the potential impact from blade shear at the nearest property boundary.' ...even though this appeal represents the final review of the final order of the board, we have no evidence that the project is being built safely away from yards and homes, and we never will. Yet the majority affirms the order.

The Buckeye wind project is not built but the company's flawed testimony on blade shear has already been demonstrated in the field. On April 26, two blades on a Vestas V90 1.8 MW wind turbine sited at a different project in Ohio shattered under high wind conditions catapulting blade debris up to 1,300 feet from the turbine's foundation.

BCCRWE
BROWN COUNTY CITIZENS FOR RESPONSIBLE WIND ENERGY (IN NORTHEAST WISCONSIN)

PLEASE READ.
SUBMITTED BY
DENNIS LIDDY
WESTFIELD, VT
802-744-2797

Health Impact and Setback Guidelines for Wind Siting Council

Health and Wellness

RE: Health Impact and Setback Guidelines for Wind Siting Council

Author: Herbert S. Coussons, MD

Introduction

Thank you for reading and considering my comments. I hope to explain in this document the problems related to noise and health. I have all of the original studies and can give you even more as I have read through many studies from the US, Canada, New Zealand and the whole of Europe that come to the same conclusions. *Large industrial wind turbine developments do not belong in close proximity to locations where people live and work.* I hope to show valid, accepted and reproducible data that put guide lines on siting distances. At 30-40dB measurable objective sleep disturbances are seen. At 40-55dB adverse health effects are seen. Above 55dB is dangerous to public health. Experience has shown industrial wind turbines cause noise that exceeds 40 dB when in close proximity. Noise deteriorates over distance. Allowing for proper distance will mitigate the noise levels both experienced and predicted by independent research and the wind industry. *The safest minimum distance to protect the health and safety is to allow for less than 40dB which correlates to 0.5 miles or 2640 feet. The optimal distance in a rural setting would allow for no more than a 10dB increase in ambient noise which would correlate to just over one mile.*

Background

As Wind Energy projects continue to expand across Wisconsin and as the need for energy independence becomes more urgent, controversy over siting regulations has become a dividing point in communities across the state. The recent applications for projects

in northeast Wisconsin make safe siting guidelines the center of the argument. In local townships such as ours in Wrightstown, Holland, Morrison, and Glenmore, hours of emotionally charged meetings and conflicted town supervisors have lead to only more controversy. A vote of town's members as slanted as 245-18 overwhelmingly does not support the Ledge Wind project. These same conflicts are seen world wide as wind energy projects develop. It is clear that studies are presented both supporting and refuting to notion that wind turbines harm people's health. It is my opinion as a physician that the best evidence support that *building large wind energy turbines in close proximity to humans has a negative impact on the health.*

Medical Facts

Normal sleep is essential for health and well-being. The science of sleep study has established the population averages for the amount of time it takes to fall asleep. The number of awakenings during the night and the number of sleep arousals that are standard. (American Academy of Sleep Medicine 2005.)

Disturbed sleep is defined as problems falling asleep, excessive awakening, excessive sleep arousals, difficulty resuming sleep after awakening, and an overall lack of restorative sleep. Environmental sleep disorder is when outside factors such as noise cause sleep disturbance, insomnia, or results in daytime fatigue. These problems result in deficits of concentration, attention and cognitive performance, reduced vigilance, malaise, depressed mood, and irritability. The effects are seen in all ages and both genders.

Long-term sleep disturbance has great influence on metabolic and hormonal function. C-reactive protein is an inflammatory marker associated with the development of atherosclerotic plaques in the coronary vessels and is associated with increased risks of strokes and heart attacks. CRP as a risk predictor of stokes and heart attacks increases as sleep disturbance increases. (Meier-Ewert et al., 2004)

Leptin is secreted at night and helps to regulate appetite and glucose metabolism. When humans are sleep deprived, weight gain and impaired glucose tolerance is seen.

Cortisol has also been studied as a separate marker of disease related to environmental sleep disturbance. Higher cortisol levels are seen in individuals that are sleep deprived. Higher cortisol levels lead to increased blood pressure and impaired glucose tolerance. In fact the risk of heart attacks is two fold higher in those with insomnia. (Hyyppa and Kronholm, 1989) Many other health hazards can be directly related to sleep disturbance, including decreased immunity and susceptibility to viral illness, and many other consequences related to daytime fatigue such as work injuries, poor school performance and auto accidents. It has been shown that fatigue may impair driving more than alcohol. Work injuries may be increased, and children suffer from behavioral problems and decreased school performance. Children have problems with learning, attention and memory. These are all substantiated medical facts that stand alone as they relate to sleep disturbances. Many causes of sleep disturbance such as shift work, sleep apnea and environmental have been shown to cause the same group of adverse health effects. In summary, the overall health impact is that

death rates increase as sleep decreases (Patel et al., 2004; Tamakoshi and Ohno, 2004) And according to Kripke et al. 1979, reduced sleep may be a greater independent risk factor for death than smoking or hypertension.

Environmental factors

Noise disturbs sleep. Many studies over the last 30 years show there are physical responses to noise as it disturbs sleep. EEG changes, blood pressure and heart rate, body movement and restlessness, and awakening can all be measured in the common sleep study. Environmental factors such as airport noise, road traffic, railway noise, and neighbor noise have all been reported as sources of sleep disturbance. They all follow a similar curve in that as noise levels increase so do complaints of sleep disturbance. At 40 dB less than 5% of individuals show night time sleep disturbance. At 50dB about 6% have sleep disturbance. At 55dB up to 10% have sleep disturbance. At 60dB as high as 15% have sleep disturbance. (European Commission, 2004) The neighbor induced noise is worth a closer look as up to 20% of neighbors are disturbed by voices, water running, toilets, TV, radio and music as well as neighbors pets. This is important in consideration of siting wind turbines because most locations targeted for development are rural (though not sparsely populated in southern Brown County). These areas tend to be quieter at night than urban areas. The people that chose to live there do not have background ambient noise, making any additional noises more noticeable.

Experience is the Best Teacher

Wind Turbine noise is disturbing to those who live close to them. Planners of wind turbine developments need to take into account the noise complaints from existing sites and the real world examples of the noise disturbance caused by wind developments.

Many of these sites have been in place for years and those that are in close proximity to people are rife with complaints, law suits and unhappy landowners. Proper siting away from people will prevent such complaints. (Hanning, 2009) Surveys of residents living in close proximity to industrial wind turbines show high levels of sleep disturbance and annoyance. In Kewaunee County 52% of individuals living within 2400 feet found noise to be problematic. 32% within 4800 feet and 4% greater than 1 mile were disturbed. 67% reported disturbed sleep if they lived within 1200 feet. (Kabes 2001) In Sweeden 2 studies yield similar results with complaints of disturbance rise as the noise levels increased from 32.5 dBA to 40 dBA. (Pederson and Persson 2007) Multiple other surveys from France, New Zealand, Canada, The United Kingdom, the Netherlands, Sweeden and others show similar results. The conclusion that industrial wind turbine noise is disturbing to people that live close to the developments is a fact. We should learn from others mistakes and not subject the people of Wisconsin to repeat the problems seen across the United States and the world. It is clear that proper siting by increasing the distance of the wind turbines from people will prevent the noise complaints. The deterioration of noise over distance is very predictable and several models exist for industrial wind turbines. (UK Department of Transport and Industry 2006; Kamperman and James 2008)

What is the Best Distance?

At least 14 published recommendations follow the same logic. Wind turbines cause noise. Noise disturbs sleep. Sleep disturbance has a bad effect on health. The conclusions of many sound studies show that the noise decreases as the distance from the turbine increases. (Theriault Acoustics, 2009 for Invenergy) Figure 9 "Predicted Noise Level Contours – Area" Shows that the entire Area shaded red will exceed 40dB. To reach an ambient level of less than 35 dB a home must be at least one mile away from the nearest turbine. To the northeast of the Ledge Wind Project that distance exceeds 2 miles. This agrees with the 14 studies tabulated in Dr Hanning's article "Sleep Disturbance and Wind Turbine Noise" (2009) Table 1 on page 33 summarizes these recommendations published between 1994 and 2009 by engineers, scientists, lawyers and physicians. The recommended setbacks vary from >0.62 miles to 1.55 miles with an average of 1.2 miles. At these distances the noise levels will be less than 45 dB. According to the WHO in their 2009 authoritative document on noise and sleep disturbance, *levels between 32 dB and 42 dB will disturb sleep and noise levels of 50dB or higher have been proven to cause health consequences.* The same study uses 21dB as a threshold for rural nighttime sleep.

According to Invenergy, the sample data from the Theriault study, the ambient noise in 8 locations in rural Brown county were measured. The highest noise recorded was an isolated 56 dBA and the predominant level of daytime noise was 32dB. The ambient nighttime noise averaged 25 dBA. According to the WHO standards, between 32 and 42dB or a 10dB level above ambient sound will be disruptive. *If we use Invenergy's sound contour map, then a setback of one mile will be required to safely fall within these standards.*

Best Choice

The council has a decision to make. With the known data on sound and sleep disturbance, with other wind farm failures by close siting, and with the wind industries predictions of sound in the wind farm – *will the council make the best recommendation for the people living in Wisconsin and take steps to be conservative by placing a setback of one mile from where people live, work, and attend school? This is the best choice based on the current data* to ensure the safety of those living within a development by keeping the noise levels less than 40dBA

Or will the council compromise the standards knowing that up to 50% people will experience disrupted sleep and 5% may suffer health effects if ½ mile is used? Or worse *yet if 1250 feet is used, then up to 67% will complain of disturbed sleep and up to 15% will see adverse health effects.*

TABLES

Table 1 From Hanning 2009; Recommendations for setback of residential properties from industrial wind turbines.

Authority	Year	Notes	Rec'd miles	Rec'd Kilometers

Frey and Hadden	2007Scientists. Turbines >2MW	>1.24	>2
Frey and Hadden	2007Scientists. Turbines <2MW	1.24	2
Harry	2007UK Physician	1.5	2.4
Pierpont	2008US Physician	1.5	2.4
Welsh Affairs Select Committee	1994Recommendation for smaller turbines	0.93	1.5
Scottish Executive	2001Visual recommendation included	1.24	2
Adams	2008US Lawyer	1.55	2.5
Bowdler	2007UK Noise engineer	1.24	2
French National Academy of Medicine	2006French physicians	0.93	1.5
The Noise Association	2006UK scientists	1	1.6
Kamperman and James	2008US Noise engineers	>0.62	>1
Kamperman	2008US Noise engineers	>1.24	>2
Bennet	2008NZ scientist	>0.93	>1.5
Acoustic Ecology Institute	2009US Noise engineers	0.93	1.5

Table 3 from World Health Organization 2009; Effects of different levels of night noise on the population's health.

Average night noise level over one year	Health effect observed in the population
Up to 30dB	Although individual sensitivities and circumstanced may differ, it appears that up to thi slevel no substantial biologic effects are observed.

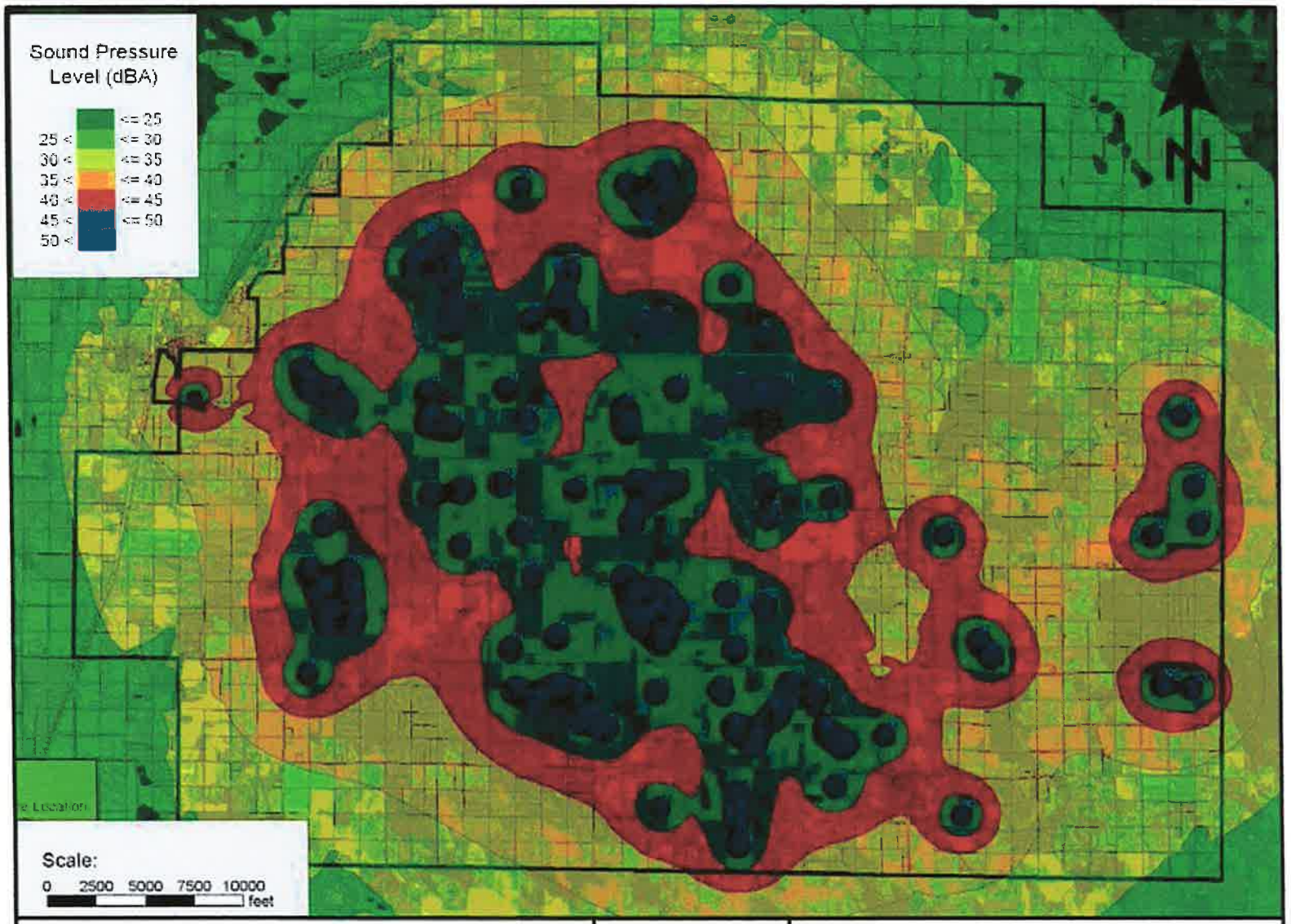
30 to 40 dB	A number of effects on sleep are observed; body movements, awakening, self-reported sleep disturbance, arousals. The intensity of the effect depends on the nature of the source and the number of events. Vulnerable groups (elderly, children and chronically ill) are more susceptible.
40-55 dB	Adverse health effects are observed among an exposed population. Many people have to adapt their lives to cope with the noise at night.
Above 55 dB	The situation is considered increasingly dangerous for public health. Adverse health effects occur frequently, a sizeable portion of the population is highly annoyed and the sleep disturbed. There is evidence that the risk of cardiovascular disease increases.

Table 2 from Theriault 2009 for Invenergy; Summary of ambient noise levels in the Ledge Wind project assessment

Location	Description	0600-0800	1200-1400	1800-2000	2200-2400
1	Blake Rd	26	26	24	19
2	Cooperstown	31	33	34	29
3	Mill Road	34	36	34	27
4	Dickenson Road	29	37	34	31
5	Morrison Road	29	34	29	28
6	Park Road	31	31	28	20
7	Refuge Road	35	36	56	27
8	Mill/Blake Road	31	32	28	23

According to subsequent predictions, the rise in ambient noise will be 15-24 dBA based on 1000 ft setbacks. This exceeds the WHO guidelines for absolute noise levels and relative rise in noise in noise levels. The solution to keep the noise levels within acceptable range is to increase the setback.

<view noise prediction image>



FROM INVENERGY
PROPOSED TURBINE LAYOUT WITH SETBACKS
SEPTEMBER 11, 2009 - REV. 01

Michael Theriault ACOUSTICS

PREDICTED NOISE LEVEL CONTOURS - AREA

LEDGE WIND PROJECT
BROWN COUNTY, WISCONSIN

FIGURE 9 | PROJECT NO. 1790

This Invenergy map supports the setbacks recommended in the chart and my opinions above.

The goal is to have noise that disturbs sleep and impacts health eliminated.

As you can see, all areas shaded red exceed 40 dBA. And all areas shaded Orange will exceed 35dBA. To be outside of the 40 dBA ring, one must live 2500 feet from the nearest turbine. To be outside of the 35 dBA ring one must live over one mile from the nearest turbine. This agrees with the summary in the Hanning paper.

In the chart below consider all of the homes in the areas of 45 to >50 dBA. Then consider the WHO statement on noise from 40-55 dBA *"Adverse health effects are observed among an exposed population. Many people have to adapt their lives to cope with the noise at night."*

<view ambient noise image>

Also consider the schools and businesses located in this area. Clearly the solution to this problem is in PROPER, SAFE siting. That siting guideline should include a minimum distance of ½ to 1 mile based on independent research and data from the wind industry.

"There is no medical doubt that audible noise such as emitted by modem upwind industrial wind turbines sited close to human residences causes significant adverse health effects. These effects are mediated through sleep disturbance, physiological stress and psychological distress. This is settled medical science."

An Analysis of the American/Canadian Wind Energy Association sponsored "Wind Turbine Sound and Health Effects An Expert Panel Review, December 2009." Peer reviewed and published January 2010.

Summary and Conclusion

Sleep is basic and important to human health. When sleep is disturbed, health suffers.

Noise disturbs sleep.

Above 30dB sensitive individuals complain.

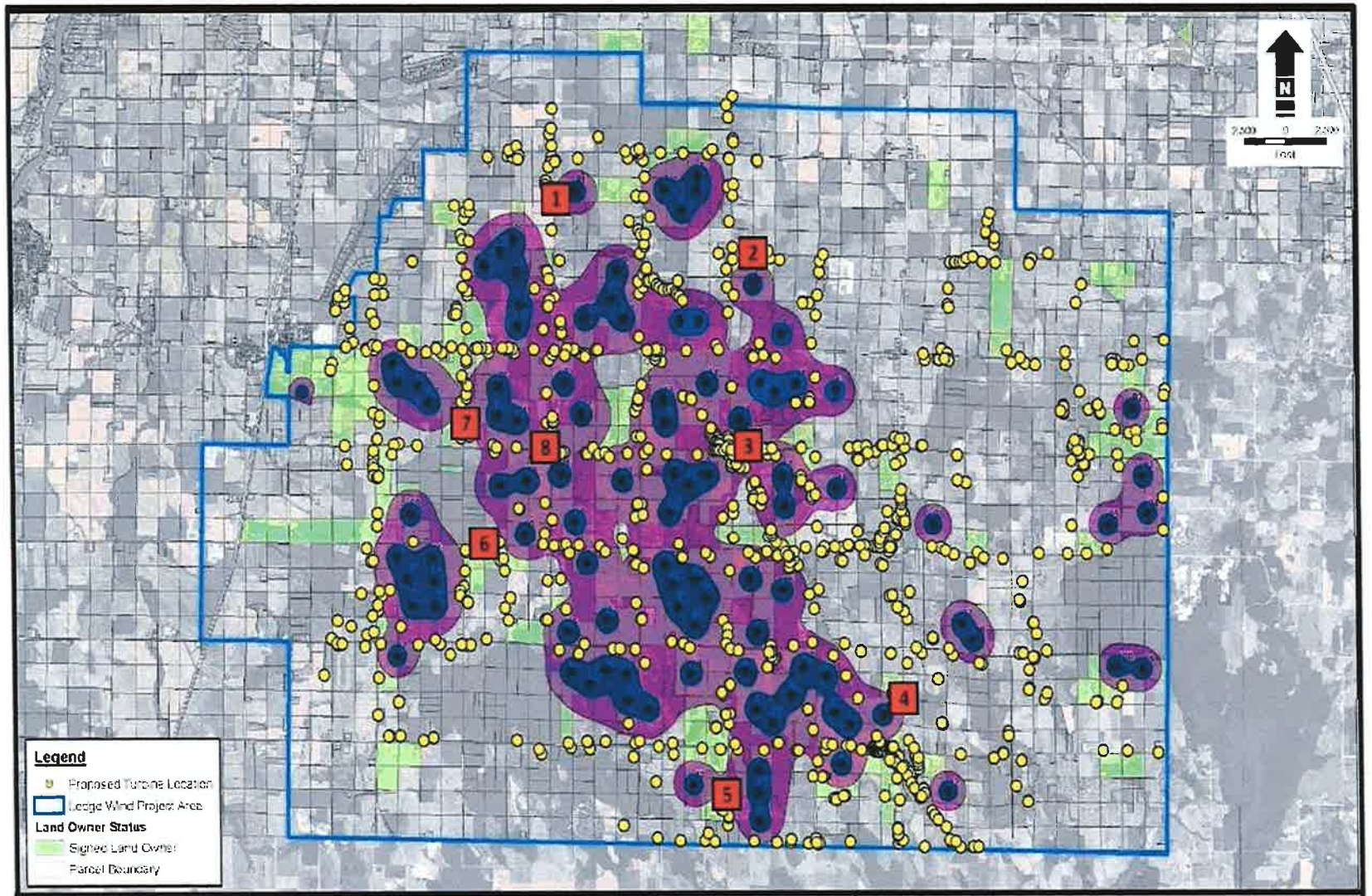
At 30-40dB measurable objective sleep disturbances are seen.

At 40-55dB adverse health effects are seen.

Above 55dB is dangerous to public health.

Experience has shown industrial wind turbines cause noise that exceeds 40 dB when in close proximity.

Noise deteriorates over distance.



Background Graphic Represents Noise Level Predictions From Computer Generated Acoustical Model. Dark Blue Regions Represent Levels Greater than 50 dBA; Light Purple Regions Represent Levels Greater than 45 dBA, up to and including 50 dBA. Yellow Points Represent Residential Structures; Black Points Represent Turbines.

Michael Theriault & Associates

AMBIENT NOISE LEVEL MONITORING LOCATIONS 1 THROUGH 8

LEDGE WIND PROJECT
BROWN COUNTY, WISCONSIN

FIGURE 4 | PROJECT NO. 1790

Allowing for proper distance will mitigate the noise levels both experienced and predicted by independent research and the wind industry.

The safest minimum distance to protect the health and safety is to allow for less than 40dB which correlates to 0.5 miles or 2640 feet.

The optimal distance in a rural setting would allow for no more than a 10dB increase in ambient noise which would correlate to just over one mile.

As a physician and resident of Wisconsin in an area targeted for large industrial wind turbines, I ask the committee to *make the best recommendation for the people living in Wisconsin and take steps to be conservative by placing a setback of one mile from where people live, work, and attend school. This is the best choice based on the current data* to ensure the safety of those living within a development.

Or will the council compromise the standards knowing that at 2640 feet sleep complaints will develop? What percentage of residents is an acceptable compromise when action now by proper siting will prevent these problems?

Respectfully, Herbert S. Coussons, MD

UPCOMING EVENTS

Wrightstown Township Meeting
November 14, 2012 (7:30 PM - 9:
PM)

Wrightstown Township Meeting
December 12, 2012 (7:30 PM - 9:
PM)

Wrightstown Township Meeting
January 09, 2013 (7:30 PM - 9:3C

Wrightstown Township Meeting
February 13, 2013 (7:30 PM - 9:3
PM)

View full calendar

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Contact Information

We'd love to hear your questions, concerns, and stories

Address: PO Box 703, Denmark 54208

Telephone: 920-785-1837

Email: Click here to contact us

September 18, 2012

The Honorable Peter Shumlin
Governor, State of Vermont
109 State Street, Pavilion
Montpelier, VT 05609

Dear Governor Shumlin:

We represent a coalition of Vermonters with a range of opinions and are concerned that debate on wind energy has unnecessarily divided Vermont friends, families and communities.

We know that global climate change is a serious and growing threat, with potentially catastrophic environmental consequences, and greatly appreciate your strong national leadership on this issue. The lack of a clear policy in wind facility siting, however, has led to a piecemeal process that creates uncertainty, unnecessary conflict, and may not always be in the best long-term interests of Vermont.

We accept Vermont's responsibility to reduce its reliance on carbon-based fuels. Wind is and will be a part of Vermont's renewable energy portfolio and landscape. However, our support for wind energy is dependent upon appropriate siting, scale, design, and cumulative impact. Wind projects that vary widely in scale and design have already been approved in Vermont, and we need to evaluate and learn from these projects.

Unfortunately, the facts regarding wind energy are in dispute. Vermonters need to better understand the benefits and financial costs associated with utility scale wind energy generation and the potential risks to public health. Also current tax policy, which allots all the financial benefits of large wind sites only to the "receiving" town, and not to other affected towns should be reviewed and evaluated. Unbiased, factual information is urgently needed. While those issues are better considered in an objective manner by appropriate authorities in those fields, we urge that progress on addressing these issues be made concurrently with our proposal below.

Our particular concern is that the process for siting wind power facilities, especially on Vermont's ecologically fragile mountaintops, now lacks both long-term vision and consistency. Mountaintops are where the wind blows most reliably, but such places are also characterized by the state's most sensitive terrain and, many believe them to be a critical part of our aesthetic heritage and identity as a state. Large-scale development of these areas should only occur after careful thought and consideration of all the consequences.

We believe the siting debate over wind energy raises fundamental questions: What is the right process for deciding appropriate sites for wind towers, and what policies can Vermont enact to proactively guide the development of wind energy?

When faced with similarly challenging and divisive issues, Vermont leaders have often established a high level commission to sort out a path forward. In the aftermath of the 1927 flood, Governor Weeks established The Commission on Country Life, which produced a book-length report entitled *Rural Vermont: A Program for the Future*. The "Little Hoover Commission" was led by Deane Davis and produced a plan to reorganize and modernize Vermont's state government. Governor Davis later established the "Gibb Commission" to look at land use issues. We recommend the immediate formation of such a commission to explore issues associated with large-scale wind energy generation. The work of such a commission should:

- Provide a mapped inventory of potential wind energy development locations, in addition to important natural and cultural resources that should be protected from adverse impacts associated with large-scale wind energy development. This inventory should build-off of the resource mapping initiative of the Agency of Natural Resources called for in S.214 (Act 170), enacted this year, and include:
    - conserved lands (including a clear understanding of the purposes for which they were originally conserved, and their current ecological and aesthetic function);
    - sensitive environmental resources, such as rare and endangered natural communities, significant wildlife habitat (large habitat blocks and linkages between large habitat blocks), fragile resources (e.g., headwater streams, wetlands), and other important features; and
    - significant cultural resources (e.g., landscapes of exceptional scenic, historic, recreational or economic value).

- Consider the cumulative impacts of developing multiple sites within a specific region and statewide, including a projected "build-out" (i.e., identification of the maximum number of facilities required to meet the state's renewable energy goals).

- Review the existing policies and standards for evaluating and permitting wind power facilities, including the standards applied by the Public Service Board, especially with regard to mountaintop and ridgetop sites, and explore whether the current process properly considers the cumulative impact of multiple wind generation sites in a region.

- Include an assessment of the environmental impacts of approved wind facilities, and set forth a consistent protocol for monitoring the impacts of future projects and remediating adverse impacts should they occur.

- Provide ample opportunity for public involvement on both the local and regional level.

This process should be fair, independent and broadly representative, and undertaken and completed as soon as possible. Ultimately, it should result in a technical report of all findings and policy recommendations, and a non-technical report written in a manner for general distribution and public education.

We believe this would benefit all Vermonters, the Vermont countryside we value, and our energy future. Greater informed understanding of the pros and cons of large-scale wind projects can bring Vermonters together on this difficult topic.

Sincerely,

Doug Parker
Executive Director
Audubon Vermont

Will Wiquist, III
Executive Director
Green Mountain Club

Robert Klein
Director
Nature Conservancy, Vermont Chapter

Gil Livingston
President
Vermont Land Trust

C. Stark Biddle
Chair
Vermont League of Conservation Voters

Brian Shupe
Executive Director
Vermont Natural Resources Council

CC:

Secretary Deborah Markowitz
Commissioner Elizabeth Miller
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5 Vermont's Electric Supply

Electric generation meets Vermonter's electricity needs by converting a variety of resources (renewable, fossil, and nuclear) into electricity and reliably delivering that power to our homes and businesses. This section describes the state's current electricity supply, the regional transmission network that delivers our power, and the potential for a number of technologies and resources to meet our supply needs in the future. The section concludes with a discussion of tools and recommended policies to improve the state's electric portfolio.

Over the last decade, Vermont ratepayers have used electricity from resources with relatively stable prices and relatively low emissions. Going forward, we will face many challenges if we are to continue to deliver electricity "in a manner that is adequate, reliable, secure and sustainable; that assures affordability and encourages the state's economic vitality…that is environmentally sound."[34] These challenges breed opportunities; indeed, the electric sector has an integral role to play in securing Vermont's energy future by implementing policies that will lead to 90% of our energy consumption coming from renewable sources by mid-century.

The challenges and opportunities ahead are a result of Vermont's present circumstances and the events that led us here. In the late 1990s, Vermont resisted the movement toward industry restructuring and retail choice while the rest of New England and the northeastern U.S. moved toward a more competitive environment that increased exposure to short-term and spot-market prices. Under current market conditions, Vermont appears to have benefited by maintaining a vertically integrated structure; the retail rate for electricity in Vermont is currently the lowest, on average, in New England. Part of this price advantage is related to long-term contracts entered into by Vermont's utilities, which will expire soon. New long-term contracts for power have been made by Vermont's electric distribution utilities, but some of these are indexed to the regional market and thus may, over time, result in prices that are more similar to those of neighboring states. And transmission and distribution infrastructure needs both within Vermont's borders and beyond can significantly affect the cost of electric supply.

To meet these challenges, Vermont utilities can continue to develop zero- and low-emissions sources of power for ratepayers, through deployment of and contracts with in-state resources, contracts with resources out of state, and strategic use of system power. Vermont must ensure that the electric sector plays its part to reduce the state's overall greenhouse gas emissions to sustainable levels, and to ensure affordable, reliable, and secure electric supply into the future. As the regional and in-state supply grows more renewable, and as the transportation fleet moves toward electrification, Vermont will be well-positioned to maintain a clean, regionally competitive power supply.

This section's discussion of electric supply begins by describing the current electric supply portfolio and future supply options, focusing on the aggregate interest of all Vermont ratepayers and the utilities' responsibility to

[34] *30 V.S.A. § 202(a).*

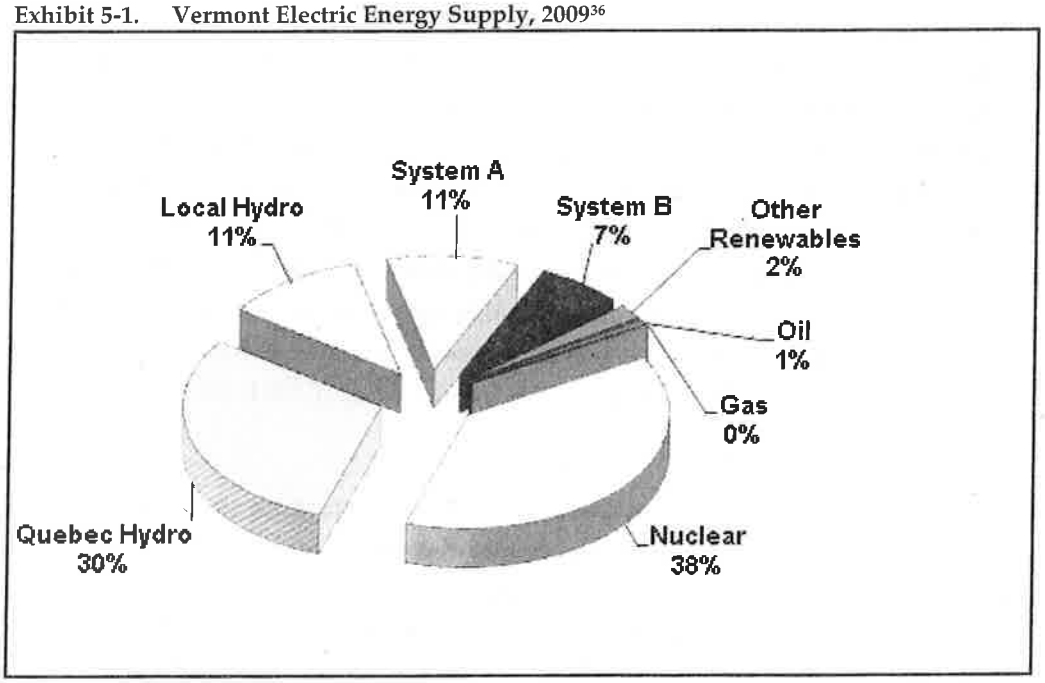
serve the entire electric load of the state of Vermont.[35] Recommendations are provided to facilitate acquisition of appropriate resources to set Vermont on a path to attain the goal of achieving 90% total renewable energy by 2050. We discuss specific policy tools that will help us achieve our goal.

5.1 Current Electric Supply

Historically, the Vermont electric grid has developed to function as an importer of electric energy, and its ties to New England, New York, and the Canadian provinces have served the state well. Nevertheless, Vermont-based resources have supplied a significant portion of the state's electric need.

Although the composition of portfolios for any one utility can vary, the aggregate supply of committed contracts or generation units (as opposed to open market purchases) has provided 85% to 90% of Vermont's energy needs over the last several years, of which 55% to 60% has been from Vermont-based resources. Exhibit 5-1 shows the mix of sources that supplied electric energy to end users in 2009.

Exhibit 5-1. Vermont Electric Energy Supply, 2009[36]



This supply mix is currently dominated by stable long-term commitments focused on two sources—Hydro-Quebec (HQ) and Vermont Yankee, which together have supplied approximately two-thirds of the electricity

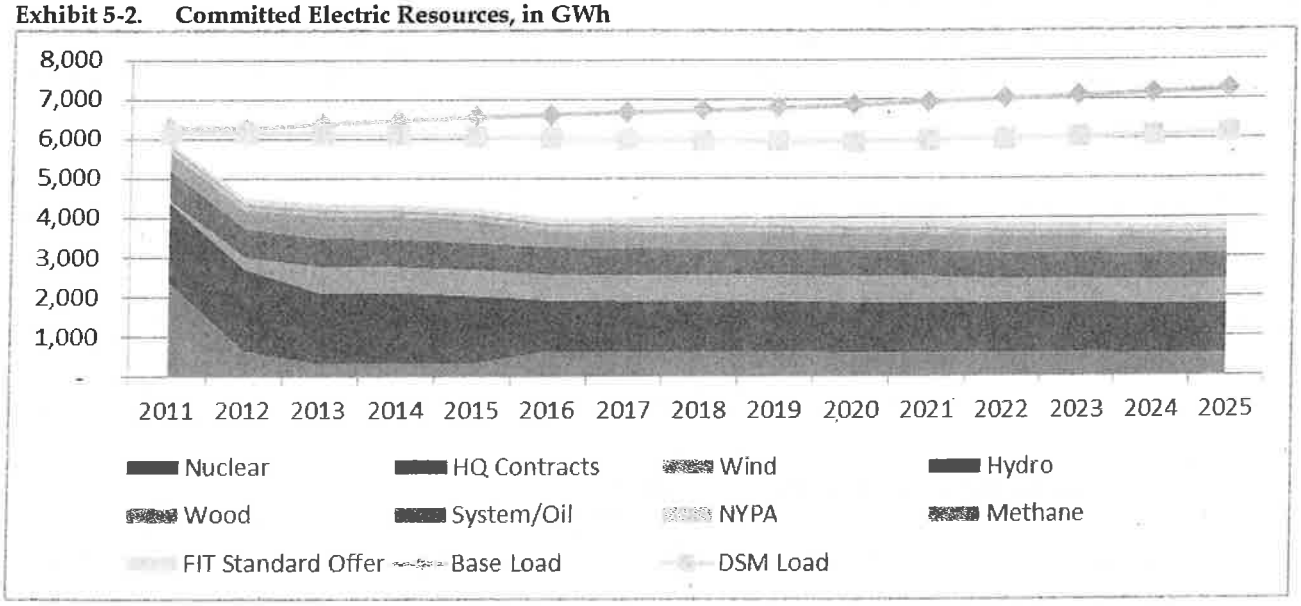
[35] *Forecasts of demand and policies to reduce demand can be found in Section 3. Moreover, although it is discussed in the context of reducing demand earlier in the CEP, efficiency can also be considered a supply resource just like wind, solar, or any other generator, and is the first choice of the state in meeting demand.*

[36] *System A is market purchases of energy by Vermont utilities. System B is energy produced by Vermont renewable facilities where the renewable energy certificates (RECs) have been sold to third parties who now own and claim those environmental attributes.*

used in the state for the last several years. Those two contracts are due to expire in 2016[37] and 2012, respectively. The replacement of these long-term contracts has begun. Recently, a new contract was signed with HQ by a coalition of Vermont utilities for 218 MW of capacity starting in 2016. In addition, as described in more detail in the section on nuclear power, some Vermont utilities have already contracted for power to, in part, replace the power previously provided by the Vermont Yankee contract.

As shown in Exhibit 5-2, even with the new Hydro-Quebec contract and other contracts to replace power previously supplied by Vermont Yankee, a gap between contracted supply and expected demand still exists. There is, however, an excess of supply in our regional market at this time. Vermont remains tied to the regional power pool, so Vermonters will have access to the vast resources inside New England and neighboring areas through the wholesale markets.

Exhibit 5-2. Committed Electric Resources, in GWh



A significant portion of electricity supplied to end users in Vermont is currently from renewable resources. In 2009, in-state hydroelectric power accounted for 11% of supply, and other in-state renewable generation accounted for approximately 2%.[38] Further, power generated from renewable resources in-state with renewable energy certificates sold out of state accounts for another 7% of Vermont's electric supply, for a total of nearly 20%.[39] When the renewable power from Hydro-Quebec, which has been approximately 30% of supply, is counted, nearly 50% of the power supplied for purposes of Vermont end-use consumption is presently from

[37] *The current HQ contract phases out in stages between 2012 and 2020; the majority of the power deliveries end by 2016.*

[38] *The percentage of energy from in-state renewable sources varies from year to year, mainly owing to fluctuations in river levels and the associated water availability for hydro generation. Wood biomass electrical generation also varies from year to year based on market prices for electricity.*

[39] *Vermont utilities own commercial-scale wind and landfill methane projects. Most of the attributes from the landfill methane project were sold into neighboring Vermont markets and therefore cannot be claimed in Vermont as renewable energy.*

renewable sources. While not downplaying the challenges and efforts necessary, we believe this fact shows that a goal of acquiring most of our electric supply from renewable sources is reasonable and attainable.

Vermont utilities should continue to diversify their portfolios with appropriate mixes of renewable energy, through contract procurement and ownership of generating supply via both in-state and out-of-state sources, with a goal of increasing the total renewable generation sources in the state's power mix to at least 75% over the next 20 years. The following sections delineate all the current resources in the electric portfolio, and describe policies and strategies to help achieve greater renewable electricity use in the next 20 years.

Generators can be divided into classes based on their size and how they connect to the grid. The CEP uses three classifications: large-scale centralized, small-scale centralized, and distributed. Large-scale and small-scale centralized generators are tied to the transmission or sub-transmission grids, whereas distributed generation is tied to utilities' distribution circuits. Large-scale is defined as a generator of 200 MW or larger. All three of these classes of generation exist in Vermont.

5.1.1 Large-Scale Production In-State

The infrastructure requirements of large facilities limit their application in Vermont. Currently, the only large-scale generator located in Vermont is the 620 MW Vermont Yankee Nuclear Power Station (Vermont Yankee) in Vernon. Some Vermont utilities contracted for a portion of its power output through March 2012, and the remainder of its power is supplied to neighboring states or the wholesale market.

5.1.2 Small-Scale Centralized Generation In-State

Small-scale centralized generation in Vermont includes hydroelectric, wood biomass, landfill methane, natural gas, and wind generators; these facilities are owned by utilities or by independent power producers (IPPs) that operate under the auspices of the Public Utility Regulatory Policies Act (PURPA).

Utility-owned generators include the McNeil Generating Station (50 MW, wood biomass), Burlington Electric's gas turbine (25 MW), Washington Electric Coop's Coventry Landfill methane plant (6 MW), Searsburg wind facility (6 MW), and a number of small hydroelectric facilities.

5.1.2.1 Independent Power Producers

In addition to utility-owned generators, Vermont has several generators owned by private merchant producers. Recently constructed examples include the Sheffield wind project (40 MW); others, such as the Deerfield wind project and the Georgia Mountain wind project, have received CPGs (certificates of public good) but have not yet been built.

Most of the presently operating, independently owned renewable resources in Vermont were developed in response to the Public Utility Regulatory Policies Act (PURPA). PURPA was passed by the U.S. Congress in 1978 in order to create a framework that allowed renewable projects and cogeneration projects access to the grid

at prescribed market rates. Each state was left to implement PURPA on its own; Vermont's implementation of PURPA was through the Public Service Board's Rule 4.100.

Rule 4.100 allowed renewable generators to access stably priced long-term contracts. Twenty hydro projects and one large wood project entered into contracts under this rule. This rule also set up a central purchasing authority (Vermont Electric Power Producers Inc.) to purchase the output from Qualifying Facilities and allocate the costs and energy among the Vermont utilities. The rates for these contracts were established largely during the 1980s and early 1990s, on the basis of then forecasted future market prices. Those estimates have proven to be relatively high compared to the market prices that have transpired since the late 1990s. Although Rule 4.100 and PURPA were successful in bringing renewable energy and independent power to Vermont and much of the region, this approach to stimulating the market proved to be an expensive one when evaluated retrospectively. PURPA renewable energy projects and their annual output can be found in Exhibit 5-3. As can be seen, many of these projects have contracts ending soon.

Exhibit 5-3. Vermont Electric Power Producers (VEPP Inc.)

Project[40]	Annual Output[41] (kWh)	Capacity[42] (kW)	Contract Ending Date
Barnet	1,814,000	490	Oct. 31, 2016
Comtu	2,367,970	460	Dec. 31, 2018
Dewey's	6,903,800	2,790	Jan. 31, 2016
Dodge	27,000,000	5,000	Dec. 14, 2020
Emerson	700,000	230	Oct. 31, 2015
Killington	295,400	100	May 31, 2016
Martinsville	712,000	250	Jan. 31, 2009
Moretown 8	2,519,000	920	Jan. 31, 2019
Nantana Mill	760,000	220	Mar. 31, 2020
Newbury	1,096,268	270	Oct. 31, 2017
Ottauquechee	5,834,000	2,180	Aug. 31, 2017
Ryegate	173,412,000	20,500	Oct. 31, 2012
Sheldon Springs	70,808,000	26,380	Mar. 31, 2018
Slack Dam	1,950,000	410	Oct. 31, 2017
Winooski 1	29,000,000	7,300	Mar. 31, 2013
Winooski 8	3,500,000	910	Dec. 31, 2015
Woodside	729,000	120	Apr. 30, 2017
Worcester Hydro	400,000	170	Oct. 31, 2016

In addition to the policy tools for renewable generation discussed elsewhere in this section, the following are specific recommendations related to these Qualifying Facilities:

Recommendations

(1) *The state should work to maintain existing Qualifying Facilities provided that the plants can be operated cost-effectively compared to new renewable energy generation.*

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[40] *All the VEPP Inc. projects are hydroelectric plants, except Ryegate, which is a wood-chip combustion plant.*

[41] *"Annual Output" is an estimate (provided by the producers) of average yearly production.*

[42] *"Capacity" listed is maximum capacity. In some months the capacities for some of the hydros decrease because of statistical water flows.*

(2) *Vermont utilities should explore opportunities to purchase former Qualifying Facilities as well as similar new generation projects currently under non-utility development, if such purchases would lower ratepayer costs in comparison to continued merchant ownership.*

5.1.3 Distributed Generation

Generators that connect directly with Vermont's utility distribution grids include net metered systems and those deployed through the SPEED Standard Offer Program. More than 13 MW of net metering systems have received certificates of public good CPGs), and 50 MW of projects have been approved to receive the Standard Offer. Net metered projects are limited to 500 kW or less, and the Standard Offer projects are 2.2 MW or less. Distributed generation reduces the load on transmission systems by meeting load on a distribution circuit with generation on that or a nearby circuit.

5.2 Considerations for New Generation in Vermont

Electric generation in Vermont can be a boon to the state's economy. However, not every generation technology and scale may be appropriate to meet Vermont's needs. Larger projects yield greater generation and may be able to take advantage of economies of scale, but can have greater negative impacts; smaller projects have less individual impact, both positive and negative. Although the scale of smaller projects may be more readily accepted by Vermonters, it is important to ensure that the projects (which are likely to produce relatively modest contributions to Vermont's energy supply) truly reduce rather than just distribute, environmental impacts.

Building and operating electricity generation facilities requires significant investment that generates substantial direct, indirect, and induced economic benefit. A ripple effect of direct benefits results from development, including jobs, potential land-lease payments and increased tax revenues, indirect benefits from businesses that support the facility, and induced benefits from additional spending on goods and services (e.g., restaurants, retail establishments, and child-care providers) in the surrounding area.

Such projects create engineering, legal services, manufacturing, construction, and operation and maintenance jobs. Jobs related to wind projects are concentrated during the construction phase (however, these jobs are short-term and may employ some out-of-state workers). Apart from specific project job creation, Vermont is home to a number of energy companies that employ Vermonters and export expertise and products.

Construction of new large-capacity generators such as combined-cycle natural gas plants, nuclear generators, and coal generators creates significant regulatory and other risks, due in part to large capital expenses necessary to begin construction, environmental impacts of large-scale construction, and the likely need for significant upgrades to transmission facilities to efficiently move the power. Large-capacity combined-cycle gas plants have been the favored technology for most of the new generation built recently in New England—in fact, approximately 40% of New England's power is generated via natural gas combustion. A large natural gas plant built in Vermont would compete with similar plants in New England, but would have no apparent competitive

advantage by being built in Vermont; in addition, siting choices would be limited by the gas transmission infrastructure. Thus, such a plant is unlikely to be proposed here and is not recommended by the CEP.

In contrast to the addition of a large natural gas plant, strategic siting of one or more smaller combined-cycle combustion turbines that are also used for district heating could have multiple benefits—offsetting otherwise needed transmission infrastructure upgrades, reducing reliance on oil for heating, and providing moderately priced energy to parts of Vermont. The potential for combined heat and power using natural gas increases as natural gas service expands in Vermont. This is one of many factors to be incorporated in the evaluation of gas service expansion.

Development of local renewable technologies such as biomass, wind, solar, and hydro will contribute to meeting the goals set by the Vermont Legislature and in the CEP, and be responsive to the wishes of Vermonters as expressed during the broad public engagement processes held for the purposes of revising the CEP. These technologies can be deployed in either a centralized or a distributed manner, depending on the appropriate scale of the resource and the economics of deployment.

Renewable generation technologies deployed on a small scale are presently more expensive than other sources of electricity. However, given the need for zero- and low-emissions energy supply; long-term affordability and price stability helped by the lack of fuel required for most forms of renewable energy; energy security and stability; a diverse resource mix; and the expressed preferences of Vermonters for greater use of renewable resources, these smaller-scale renewable projects offer great potential. See the modeling results discussed above and in Appendix 4—Modeling Study for a discussion of the economic impacts of implementing scenarios associated with significant renewable energy investment, including small-scale distributed generation. Fostering small-scale and distributed renewable energy by increasing regulatory support is an objective of the CEP.

Small renewable electric projects have a number of incentive mechanisms already built into the policy framework in Vermont. Most notable is the SPEED program, which encourages deployment of in-state renewables in both centralized and distributed applications; the SPEED Standard Offer encourages distributed generation in particular. Net metering, the Vermont Small Scale Renewable Energy Program, the Clean Energy Development Fund, Nuclear Electric Insurance Limited (NEIL) program funds, green pricing programs, and tax incentives have all been important in encouraging small-scale renewable energy projects. These programs contribute to the maturation of these technologies, help to foster the renewable energy industry in Vermont, and generate public awareness and acceptance of these technologies. However, the distributed projects that these programs have facilitated still account for less than 3% of Vermont's total electric supply. Specific tools to further facilitate renewable energy supply in both centralized and distributed applications are further discussed below.

The Department of Public Service has created a new staff position for renewable energy project management. This position at the DPS will be responsible for leadership and facilitation of the development of renewable energy projects in the state, promoting collaboration and communication between the DPS, other state agencies

including the Agency of Natural Resources (ANR) and the Agency of Commerce and Community Development (ACCD), and the developers and interested parties, in order to offer permit assistance and to facilitate the resolution of barriers to the development of responsibly implemented renewable energy projects.

5.3 Land Use and In-State Energy Resources

The siting of energy resources requires careful consideration when projects are being proposed and built within Vermont's borders. The state has bold goals in this Comprehensive Energy Plan; however, it will be important to review, research, and understand these energy goals in light of other important state goals and the trade-offs that might be made depending on the priority. The siting of in-state energy resources must happen in a thoughtful manner. The planning processes for siting should be strategic; that is, it should consider the best use of lands and townscapes by comparing the costs and benefits of all potential uses. For example: How does a solar farm near a park on the outskirts of a historic town center impact both the residents' and tourists' views of the landscape, the frequency of visits to the park and the related commercial benefits to the town? How do electric vehicle charging stations impact historic district designation and related funding sources for community development? How does biofuel crop production impact a community's ability to provide ample affordable local food at its weekly farmers' market or grow wood for home heating? How do wind towers—smaller scale or utility scale—affect the environment and viewshed? State statutes supplant local regulatory authority for electric generation siting, vesting authority in the Section 248 process. While this helps clarify and unify the permitting process for statewide energy resources, it causes some to question whether proper consideration of competing interests has been provided. Implementing the goals in this Comprehensive Energy Plan is important to the state, but there must continue to be an effort to balance the choice of renewable electricity built in-state with other public goods. (For a fuller discussion of land use issues, see Section 9—Transportation and Land Use.)

5.4 Electric Resource Planning

All the recommendations discussed in this plan—from reducing energy demand, to facilitating grid interconnection and load management of renewable electricity generation, to encouraging electric vehicle use—affect utility planning. Fortunately, in addition to the many planning mechanisms described throughout the CEP, Vermont has specific tools in place to allow for a transparent and open electric resource planning process as completed by our utilities, through integrated resource plans (IRPs) and distributed utility planning efforts. The state must continue to use these activities to ensure implementation of the CEP and its recommendations, and future updates of the CEP.

5.4.1 Integrated Resource Planning

Each of Vermont's regulated electric utilities and the state's natural gas utility must submit for DPS review and PSB approval an integrated resource plan (IRP), every three years, that documents the utility's long-term planning efforts (30 V.S.A. § 218c). A key component of each IRP is the utility's planned portfolio of supply resources, demand-side management programs, and transmission and distribution improvements that will

enable the company to serve its customers at the lowest life-cycle cost, including environmental and economic costs, over the next 20 years (30 V.S.A. § 218c(a)(1)). IRPs must be responsive to the Vermont Electric Plan incorporated into the CEP. The IRP process is also intended to facilitate information exchange among utilities, regulatory agencies, and the public and culminate in the filing of utility plans that satisfy the standards for the DPS review and PSB approval with a goal of promoting shared understanding, transparent and sound decision making, and effective planning.

The IRP process that exists today is loosely structured, leaving utilities free to interpret the Vermont statute and prior orders related to the IRP process. This has resulted in significant engagement between utilities and the Department of Public Service. The IRP process has positioned utilities to explore the full range of energy options and solutions to the benefit of Vermont ratepayers. That said, the IRP process can be better utilized as a way to shape the state's electrical portfolio and represents a clear opportunity for the state to engage the utilities in a continual process of reaching the supply portfolio goals laid out in the CEP.

Recommendations

(1) *The state should use the IRP process to work together with the electric utilities to increase the amount of local and renewable energy in their supply portfolios while maintaining the principles of long-term least-cost integrated planning under the definition set forth in Section 218c(a)(1).*

(2) *All future IRPs should consider and plan for electric vehicle penetration in Vermont, and the effect that the resulting increased electricity consumption will have on their systems.*

5.4.2 Distributed Utility Planning

Related to but distinct from integrated resource planning is distributed utility planning (DUP), aimed at creating granular strategies to ensure strategic operation of a utility's distribution system. In shorthand, DUP encourages utilities to consider all available technologies to meet customer demand in the most efficient and cost-effective way. DUP accounts for strategic siting and operation of modular electric generation and storage technologies, and targeted demand-side management programs, to supplement central station generation plants and the transmission and distribution (T&D) grid for cost-effective customer benefits. Applicable generation technologies include small-scale internal combustion engine-generator sets, small gas turbine generators and microturbines, energy storage systems, and a number of "clean" generation technologies, including photovoltaics, wind turbines, and fuel cells. The benefits obtained from DUP can include reducing the load on T&D systems, improving local power quality, and reducing T&D system losses. Distributed utility planning also provides potential for significant benefits for utilities and their customers while lowering financial, environmental, and institutional risks. To date, few electric utilities have fully utilized DUP, owing to a number of regulatory and institutional barriers to distributed resource development. These are addressed specifically in many of the resource supply sections above, and include:

- **Dispersed Benefits**. It is unlikely that the full array of benefits of a distributed resource installation will accrue to the owner of that installation. This could lead to a market failure in which societal resources are allocated inefficiently.

- **Cost Recovery Structures.** Traditional cost-of-service ratemaking, which rewards utilities for prudent capital investments, provides little financial incentive for utilities to lower their investments in T&D. Replacing cost-of-service ratemaking with performance-based ratemaking (PBR) has the potential to reward utilities that effectively implement DUP. In principle, PBR rewards utilities for efficient operation and high-quality service, as measured by performance relative to pre-established targets, rather than for capital investments and sales of electricity.

- **Planning Methodologies.** Traditional distribution planning methods and models do not account for the various costs and benefits of distributed resources. The data required for a comprehensive assessment of distributed resources in a given area may be undeveloped.

- **Generation Ownership and Integration**. In order to effectively integrate distributed generation into distribution systems, distribution system planning needs to be closely integrated with generation planning. Such integration is a departure from traditional distribution system planning functions.

Vermont has supported and encouraged the development of DUP. The Department of Public Service views DUP as consistent with Vermont statutes and Public Service Board precedents regarding least-cost integrated resource planning for the state's electric utilities. Further, the DPS regards DUP as consistent with policies promoting the development of sustainable and renewable energy resources in Vermont. The DPS will continue to work with utilities on DUP, including performance-based ratemaking. The DPS has also been active in establishing reliability benchmarking, a prerequisite to the introduction of PBR. Going forward, the DPS plans to enter into a formal collaborative process with Vermont's electric utilities in an effort to build upon, revise, and further specify the best implementation procedures for DUP. This process will seek to develop procedures for reflecting the principles of DUP in integrated resource planning filings by electric utilities.

5.5 Electric Power Planning: Safety and Security

As many recent significant storm events, including Tropical Storm Irene, have reminded us, the state must be prepared for and plan for electric power supply emergencies. Under the State Emergency Operations Plan, the Department of Public Service has the lead role for State Support Function 12 (Energy), which includes electric energy and thermal energy. The causes of widespread power outages in Vermont have historically been severe weather events, such as those involving snow, ice, or wind. If a severe weather event is anticipated, the electric utilities, the telecommunications utilities, and state agencies such as the Department of Public Service and Vermont Emergency Management participate in daily conference calls before the event to discuss the weather forecast, the status of the electric system (i.e., whether any transmission lines or generation units are out of service for maintenance), and available resources, including plans for additional line crews and associated equipment. The communications continue during and after the weather event to discuss the extent of damage

and to coordinate the restoration effort. This helps facilitate a statewide coordinated effort to restore electric service as quickly as possible. The DPS staffs the State Emergency Operations Center in order to ensure that utilities have a means of coordinating directly with key state agencies to assist with outage restoration. In addition, subsection 248(k) and (l) of Title 30 provide an expedited process for utilities to perform work necessary to resolve an emergency.

The DPS also assists in state planning regarding other energy supply disruptions, such as liquid heating and transportation fuels. The DPS is currently completing an Energy Assurance Plan under a DOE grant, which will review and likely augment the state's planning for energy supply disruptions.

Apart from emergency preparedness, 30 V.S.A. § 248, the siting statute for electric transmission and generation projects, requires the Public Service Board to review the impact of a proposed electric transmission or generation project on the public health and safety under criterion (b)(5), and to make a positive finding that there will not be an undue adverse impact on the public health and safety from any proposed facility. The Department of Health has assisted on occasion in such review, and has stated an intention to increase its role in public health review of siting projects.

5.6 Regional Markets, Electric System Reliability, and Transmission Planning

Electric system design and reliability has evolved steadily from the early days when an individual utility was focused on serving an islanded service territory with a discrete set of customers. Then, a generator was often located in the heart of the community, similar to the McNeil Generating Station today in Burlington. With growth came advancements in generation technology that produced large-scale, efficient generators. This evolution caused utilities to build the first high-voltage lines connecting large, remotely located generation with load centers. Often these connections were radial lines. It soon became clear that interconnecting isolated load centers could provide system advantages such as improved reliability as a result of redundant connections, and helped provide load profile smoothing by combining the diverse load characteristics that utilities previously needed to supply individually into a single blended dispatch. The basic model, though larger, was still a self-contained system—"generate for your own load." As we all understand today, this resulted in significant inefficiencies associated with overbuilding generation and underutilizing assets.

In the 1950s, in order to bring St. Lawrence hydropower to Vermont, a single, statewide transmission company—Vermont Electric Company (VELCO)—was formed. Although its ownership structure and purpose have evolved over the years, VELCO remains utility-owned and utility-operated, and continues to manage the statewide transmission system on behalf of all Vermonters subject to the rules of New England's Regional Transmission Operator, ISO-NE, and the Federal Energy Regulatory Commission (FERC).

In the past 15 years, we have seen a dramatic shift in transmission policy and planning, toward a much more regional and federal system. The first major federal order influencing organized markets was FERC Order 888 (1996). It required utilities to offer open access to transmission facilities without undue discrimination to bring more efficient, lower-cost power to electricity consumers. As organized markets emerged, utility mergers

occurred, and open access rules were developed, the promise of competition and introduction of efficiencies became attractive. It soon became clear that all the various market participants would advance their own interests. In New England, the existing power pool was transfigured into a competitive market and the transmission owners adopted a pool-wide funding protocol that supported transmission system expansion with the goal that any generator could serve load anywhere in the New England grid. This was a successful strategy and offered some assurance that the right amount of generation would be built and shared across the grid. Rather than building generation for individual areas, generation was acquired and dispatched centrally over the entire system. Not unexpectedly, it also incentivized the building of generation in remote, low-cost areas that coincidentally required large amounts of new transmission investment to interconnect the supply with the load. In the early days, there was little regard for controlling demand by properly valuing incremental load. Early organized markets only promoted supply competition—one generator versus another.

Order 2000 (issued in 2001) was FERC's Regional Transmission Operator Order. It was the impetus for the creation of an independent system operator (ISO) with delegated authority to reliably operate the electric system by dispatching generation and controlling transmission paths on behalf of all market participants. It spawned ISO-NE and other similar organizations elsewhere in the U.S. This model extracted various efficiencies. FERC recognized the need for independence and the ability to balance the needs of all stakeholder groups. These ISO characteristics became very important. To ensure repeatability, transparency, certainty, and objectivity it also became very important to develop precise market rules and a system of checks and balances. Market rules today are as complex as the IRS code.

In 2001, to support ISO-NE's mission, management chartered a planning advisory committee and a regional system planning process. These have become important system planning tools, implemented by work groups of stakeholders. In Order 890 (2007), FERC highlighted the value of ISO-NE's process, and defined the purpose of these working groups more precisely by requiring coordinated, open, and transparent regional transmission planning processes to address undue discrimination. This was viewed as both the equal rights amendment for non-transmission alternatives (NTAs, see below) and an acknowledgment that interregional planning was needed.

The intense focus on the business aspects of electricity delivery was replaced with reliability concerns in 2005. The impetus for some of the key elements of the Energy Policy Act of 2005 (EPAct 2005) was the Northeast blackout of 2003. EPAct 2005 authorized FERC to enforce reliability standards, which has the effect of requiring transmission infrastructure upgrades to avoid penalties. FERC delegated authority to the North American Electric Reliability Corporation (NERC) to develop mandatory planning, construction, and operating standards. Broad standards affecting the bulk electric system were published and compliance mandated, with fines of up to $1 million per day for continued violations. The long-range impact of these standards is not yet clear. What is known now is that new stringent planning and design criteria are being adopted and must be incorporated retroactively into transmission systems. This trend is likely to have a significant cost impact due to the need for reliability compliance upgrades in the region and Vermont where an aging infrastructure with legacy weaknesses exists.

Recently, FERC issued Order 1000 (2011). This rule advances past requirements by more prescriptively ordering transmission planning at the regional level to consider and evaluate possible transmission alternatives and to produce a regional transmission plan. It also requires the cost of transmission solutions to be allocated fairly to beneficiaries. The "cost causer" and "beneficiary pays" model used to meet this requirement was upheld. The order is expected to shape transmission expansion activities for the foreseeable future in a number of ways:

- Public utility transmission providers are required to participate in a regional transmission planning process that produces a regional transmission plan.
- Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations.
- Public utility transmission providers in each pair of neighboring transmission planning regions (for Vermont, ISO-NE and New York's ISO) must coordinate to determine whether more efficient or cost-effective solutions are available.

The second issue is particularly relevant. Order 1000 requires each public utility transmission provider to establish procedures that identify transmission needs driven by public policy requirements, and evaluate potential solutions to those needs. Public policy requirements are defined as enacted statutes and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level. In addition, Order 1000's provisions are likely to allow and even encourage competition by independent or merchant transmission providers where the incumbent transmission owner is unable to effectively respond to a particular need.

Finally, per the third point above, the topic of interregional planning is addressed by this order. Interregional transmission facilities are those that are located in two or more neighboring transmission planning regions. The order states that each pair of neighboring transmission planning regions must share information regarding the respective needs of each region and potential solutions to those needs, and identify and jointly evaluate interregional transmission facilities that may be more efficient or cost-effective solutions to those regional needs. This is a promising development because it encourages regional transmission organizations to look for solutions that lie outside their footprint and capture efficiencies that may be described as low-hanging fruit. Often, complicated cost allocation schemes and lack of communication between areas limit opportunities to craft mutually beneficial solutions.

Electrically speaking, Vermont occupies an integral position in the New England electric system and enjoys a strategic advantage because it is interconnected with the separate systems in New York and Canada, both of which have power resources and robust transmission. The current regulatory environment has a disposition for competitive market solutions and offers an encouraging outlook for advancing creative transmission solutions related to public policy needs. In this climate, it is plausible to envision successful projects that interconnect renewable resources with load centers in all three regions.

To accomplish such new transmission solutions in a manner that benefits Vermonters requires a good plan and the support of interested stakeholders. We are fortunate to have an established planning organization in

Vermont—the Vermont State Planning Committee (VSPC). Although the prime responsibility for reliability planning of the bulk power grid has shifted to ISO-NE as a result of EPAct 2005 initiatives, Vermont will still control key decisions that affect our transmission system, such as permitting. Nevertheless, board rules and the VSPC will need to adapt based on the mandates from EPAct 2005. For example, planning criteria established by NERC are now mandatory and enforceable, and they largely preempt state review. So, while permitting remains a Vermont PSB role, planning has shifted to the regional level, and penalties are incurred if needed upgrades are not accomplished. Order 1000 requirements and the lessons from the Eastern Interconnection States Planning Council (EISPC) are likely to continue to push transmission planning responsibility away from Vermont. It will be vital for Vermont to effectively participate in these regional and national decision-making processes. A review of VSPC's role and charter is appropriate to ensure it fully reflects the changes that have occurred in transmission planning standards and authority.

As evidence of this change, several independent transmission companies are already advocating for a greater role in the system regionally, describing their belief that allowing independent transmission developers to compete for cost-of-service projects will result in benefits such as new capital investment in a region, more cost-effective transmission projects, and better ways to integrate small renewable generation projects into the grid, by, for example, one radial line lead connecting multiple projects to the larger transmission grid. One merchant generator partnership project with VELCO, the Champlain Wind Link that would connect northern New York to northwestern Vermont in the Burlington area, continues to be considered and may provide both additional transmission capacity and reliability benefits. Evaluating the evolving role of independent, merchant transmission companies must be a part of Vermont's energy planning going forward.

Building transmission should not be the only answer to a reliability issue. Recently issued FERC Order 1000 prescribes a role for public policy considerations that may allow Vermont to advance a position we have long advocated: regionally shared funding of alternative market solutions, or non-transmission alternatives (NTAs), as they have sometimes been called. The current system for regional cost sharing is exclusive to transmission projects even when equivalent lower-cost alternatives are found. NTAs presently are not eligible for regional cost sharing.

The recent Vermont/New Hampshire 10-Year Transmission Needs Assessment provides a practical illustration of how, in some instances, NTAs such as generation and demand-side resources can provide less costly alternatives to solving a reliability problem than building or upgrading transmission. A recent pilot study suggested that either a $220 million transmission upgrade project or a targeted generator project at less than one-third the cost may address an identified reliability issue in northwestern Vermont. Although the study was not meant to be a complete and conclusive reliability analysis, the finding that a particular NTA might avoid a significantly more expensive transmission solution generated significant interest in better understanding the mechanics of how sharing the costs of one solution but not another can create perverse incentives.

Vermont's funding obligation for reliability transmission projects is based on the regional load ratio share, currently at about 4%. This means that Vermont's share of a $220 million project would be less than $10 million, whereas there would be no regional sharing of the costs associated with choosing the NTA, even though the overall cost could be much lower. This conundrum is likely to be repeated throughout New England. This issue

needs to be addressed to ensure that financial signals consider, influence, and optimize both system performance and cost structure in order to avoid unnecessary electric transmission build-out and greater long-term cost for all ratepayers.

Vermont's interest in treating the cost of equivalent solutions equitably is not intended to discount another important concern raised by ISO-NE: that any individual NTA must truly resolve an identified transmission reliability problem. Expansion of solution sets in the planning process would help ensure selection of appropriate alternatives. Vermont supports a robust process and recognizes that any identified reliability issue may require a combination of projects. We object only to an uneven playing field that does not encourage cost-effective choices.

Transmission planning and market advocacy should be done holistically, because in some cases, one project has the potential to spur another project of value. For example, if our interconnection to New York (known as PV20) is upgraded, and imports there become more reliable, there is likely to be value in establishing PV20 as a pricing node for scheduling transactions. The present import configuration combines multiple interconnects and then prices them all at one proxy node. Unfortunately for Vermont, that node is in western Massachusetts and often reflects higher location marginal price than PV20 might because of congestion. After we resolve the operational restrictions at PV20, we could investigate resolving the market barriers that have the potential to allow delivery of lower-cost power to Vermont.

Looking forward, we must improve our place in the regional market and work to strengthen our transmission system here in Vermont.

Recommendations

It is critical that Vermont:

(1) Focus on ensuring that existing regional transmission facilities and interconnections at Highgate, Derby Line, and elsewhere are as robust and reliable as possible.

(2) Focus on electric efficiency and peak load reduction, because it is Vermont's coincident peak load that is used to calculate Vermonters' share of regional transmission reliability projects.

(3) Place greater focus on Vermont's regional participation and advocacy at ISO-NE, FERC, and regional organizations such as the New England State Committee on Electricity. Vermont participation in market rule making and the regional transmission planning structure is key to keeping the state's interests protected as transmission policy continues to evolve toward regional and national control.

(4) Focus on greater connection between in-state energy policy and regional transmission planning advocacy. VSPC should complete its process of revisiting its mandate and effectiveness as even greater

federalization of transmission planning continues to emerge. Vermont must have a say in the development (or reform) of market rules and must position Vermont to respond to developments in the market itself.

(5) *Advocate for and cooperate regionally in transmission projects that will improve inefficiencies in neighboring transmission zones—for example, the existing PV20 transmission line from the Plattsburgh, N.Y., to Sand Bar, Vt., substations. This asset is currently underutilized because reliability criteria limit its operation. Coordination efforts with NY-ISO and NYPA are under way to approve construction in New York to relieve system constraints that presently restrict imports on PV20 into Vermont.*

(6) *Support appropriately sited and planned transmission projects capable of bringing renewable energy from its source to market throughout the region, in order to bolster the economics of renewable electricity for Vermonters and their neighbors.*

(7) *Continue to push for market reforms that will allow Vermont to effectively pursue NTAs wherever feasible.*

(8) *Promote regular communication about energy matters among all Vermont stakeholders, including utilities, regulators, legislators, communities, and the media, to ensure there is an understanding and awareness of the issues and challenges surrounding this vital matter.*

Overall, we must focus our attention on the reliable and strategic use of our transmission system, and we must continue to press for regional market rules that align with our goals. An appropriately sized and utilized transmission system, in conjunction with efficiency programs that reduce demand and effective development of distributed renewable generation, will ensure a reliable and robust electric transmission system.

5.7 The Regional Greenhouse Gas Initiative

Since 2005, Vermont has participated in the Regional Greenhouse Gas Initiative (RGGI), a regional cap and trade effort designed to reduce CO_2 emissions. Each of the 10 states[43] that participate in RGGI is represented by energy and environmental regulators; in the case of Vermont, these representatives are the chair of the Public Service Board and the secretary of the Agency of Natural Resources (or their designees).

[43] *There have been 10 states participating in RGGI: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Jersey, New Hampshire, New York, Rhode Island, and Vermont. However, New Jersey is withdrawing from RGGI at the end of 2011.*

All the RGGI states have implemented statutes or rules that require fossil fuel–fired electric generating units with a capacity of 25 MW or greater to hold enough allowances to cover the CO_2 emitted from the generating unit. Under RGGI, each of the participating states is allocated a certain number of allowances during a three-year compliance period, based on the CO_2 emissions from that state. The states collectively auction the allowances on a quarterly basis, and any entity can purchase allowances. In addition, there is a secondary market in which allowances can be traded. In Vermont, the proceeds from the RGGI auctions are used to fund thermal efficiency programs and also to fund the Property Assessed Clean Energy (PACE) loan loss reserve program.

There are currently two generating units in Vermont that must comply with RGGI requirements, one owned by Green Mountain Power Corporation and the second owned by the city of Burlington (Burlington Electric Department). Each of these units runs only a relatively small number of hours per year, and accordingly, GMP and BED need to purchase only a small number of allowances for the compliance period.

RGGI is the first CO_2 cap and trade program in the U.S., but it is not an unqualified success. Most seriously, the cap is significantly over-allocated, resulting in regional emissions that fall well under the cap. Although the cap is, by design, expected to be slowly lowered over the next five years, allocations could still exceed emissions. Several factors account for this, including the economic recession, which began shortly after RGGI began conducting auctions, and reduced energy use (and therefore reduced emissions from generating units) in the United States. In addition, the decline in natural gas prices resulted in generation units in the Northeast switching from dirtier fuels, such as coal or oil, to natural gas, with a corresponding reduction in CO_2 emissions. Finally, there have been additional significant investments in energy efficiency, in part due to the investment made in utilizing RGGI proceeds.

Additionally, the methodology used to allocate emissions among states could be improved. The methodology starts with the historical CO_2 emissions for each state; the number of allowances for each state, however, was based in part on historical emissions and in part on negotiations involved in developing the program. A methodology that is based solely on historical emissions penalizes states such as Vermont, which has a long history of implementing energy efficiency programs and encouraging utilities to pursue contracts with renewable generation units. The goals outlined in the CEP will exacerbate this problem if RGGI reforms are not accomplished, by further reducing the emissions generated from Vermont's electric usage.

Recommendation

The participating states have announced that they are preparing for a comprehensive review of the RGGI program in 2012. To the extent that the number of allowances allocated to individual states is altered in the future, the methodology should reflect the fact that some states have invested considerable effort in reducing CO_2 emissions independent of the RGGI program. Further, the remaining participating states should actively investigate lowering the cap to effectuate actual decreases in CO_2 emissions.

5.8 Electric Supply Resources

Several resources currently contribute substantial portions of Vermont's electricity supply, and are expected to continue to supply Vermont's electric power needs. These resources include biomass, hydroelectric, solar photovoltaic, wind, natural gas, and nuclear.

5.8.1 Biomass

Biomass from agriculture and forests can play an important role in providing energy for Vermont. Resources such as woody biomass, agricultural crops including grass and residues in the form of solid fuel, liquid biofuels, and biogas—collectively known as bioenergy—are steadily becoming more attractive in the Vermont energy market. Bioenergy is a broad category with individual fuels, feedstocks, and technologies at different stages of R&D, commercialization, and market readiness in the state.

Bioenergy includes:

—Solid biomass from woody plants and agricultural crops, such as corn or grass.

—Liquid biofuels, including biodiesel and ethanol.

—Biogas, such as methane from agricultural digesters, landfills, or wastewater treatment plants.

Certain types of biomass, such as wood, can be used for energy without significant processing; many other organic products are converted to biofuels such as ethanol or biodiesel—liquid forms of biomass energy—before being consumed, or are processed into dried solid biomass pellets (woods and grasses). Other forms of biomass, such as municipal solid waste and manure from livestock, are used to produce biogas at landfills or in methane digesters on farms. These forms of energy have helped to displace a significant amount of fossil fuel consumption in the U.S., and have concurrently addressed disposal problems associated with these wastes.

Vermont's bioenergy options are at different stages of market development, and each will require a different development timeline and investment strategy. All forms of bioenergy, like the other forms of energy production, have pros and cons that must be weighed carefully prior to implementation. The CEP discusses some of the ways that Vermont can expand the use of bioenergy resources while making decisions that are economically, environmentally, and socially responsible.

This section poses strategies and recommendations for appropriately and sustainably mobilizing supply and demand, primarily for wood-fired biomass and biogas resources for electricity generation. There is potential for the greater use of biomass material other than forested wood for electric generation; for example, grass, crops such as corn, and fast-growing trees such as willows can be cultivated as energy crops. Although the CEP recognizes the potential of these non-wood sources, they are not anticipated to contribute significantly to electric production in Vermont in the near term. Therefore, this section focuses primarily on generating electricity from farm methane and woody biomass. This is not meant to discourage development of these other sources; indeed, the DPS believes these sources may mature into significant contributors to our energy mix in future years. The DPS will continue to follow these sources and associated technologies, and will evaluate their potential for Vermont as they develop.

Section 8 – Thermal Energy Sources and Section 9 – Transportation and Land Use address agricultural biomass (e.g., grass pellets) and other biofuel sources, issues, and recommendations for heating and mobility, respectively.

It is important to recognize that at the time of the CEP's release, there are other, concurrent efforts to evaluate the current and future uses of biomass for energy in Vermont. For example, the state's Biomass Energy Development Working Group, discussed below, is scheduled to release its findings at the end of 2011. Further, our understanding of the science of forest carbon exchange is shifting rapidly, as are forest products markets, thus increasing the importance of public and private stakeholders' working together to monitor and evaluate the effect of policies during their implementation.

5.8.1.1 Current Wood-Fired Electricity Generation

Currently, biomass meets about 6% of the electric load in Vermont, including biomass electric facilities, farm methane, and landfill methane.[44] About 14% of the state heating needs are met with biomass fuels, including cordwood.[45]

Vermont currently hosts two wood-fired biomass electric facilities: Burlington's 50 MW McNeil Generating Station, and the Ryegate 20 MW plant. Woody biomass is also used for combined heat and power (CHP) in some businesses, universities, and institutions around the state.

Opening in 1984, the McNeil plant was the first in-state wood-fired generator, providing a market for low-grade wood and creating jobs and economic benefits throughout the state. McNeil does not operate as a baseload facility as envisioned, but rather functions as an intermediate plant at a 50% to 60% capacity factor, owing to a combination of wood supply and bid pricing issues. Although the plant can use oil or natural gas, it runs primarily on wood chips, using 1.45 tons of wood to produce each MWh.[46] The plant burns about 400,000 tons of wood per year.[47] McNeil was also constructed with the idea that it could provide district heating to either the University of Vermont or to Burlington, making use of the energy otherwise lost, but this aspect of the project has not yet been implemented. However, the Burlington Electric Department (BED) and the city of Burlington's Community and Economic Development Office (CEDO) are exploring options to heat downtown homes and businesses with the existing surplus heat from the McNeil Generating Station. A group of local citizens and staff from BED and CEDO formed the Burlington Electric District Energy System (BURDES) and are in the early stages of planning the service.[48]

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[44] *EIA Renewable Electricity Profile,* www.eia.gov/cneaf/solar.renewables/page/state_profiles/vermont.html

[45] *EIA 2009 State Energy Data System.*

[46] *BED 2008 Integrated Resource Plan.*

[47] *Actual consumption reported was approximately 327,000 tons in 2009. Estimated Wood Fuel Usage in the State of Vermont, Vermont Department of Environmental Conservation.*

[48] *For more information, see:* www.burlingtonelectric.com and www.burlingtondistrictenergy.org

The Ryegate wood-fired generation plant came online in 1992 with a capacity of 20 MW. It is the only non-hydroelectric independent power producer that sells through the Vermont purchasing agent.[49] The plant burns about 250,000 tons of wood per year.[50] The facility produced 175.1 million kWh of electricity in 2010, which was sold to Vermont utilities at an average price of about $0.14 per kWh.[51] Because its PURPA contract is set to expire, the plant received attention during the 2011 Vermont legislative session, culminating with Act 47, which required the SPEED facilitator to purchase baseload power from the facility at a price to be set by the Public Service Board.[52]

Out of the 1.5 million tons of wood consumed in Vermont annually for energy, approximately 650,000 green tons of wood are used to generate the 70 MW of electricity at McNeil and Ryegate.[53]

The two power plants fueled with wood in the state have been a valuable part of the forest products economy. Retaining them should be a goal of state policy.

The wood used in Vermont's two power plants has been obtained from Vermont and from surrounding states and provinces. Since 1984, some wood fuel has also been shipped from Vermont to power plants in New Hampshire, Maine, and New York. The amount of wood shipped to out-of-state power plants has fluctuated, and no simple trend has been exhibited. The maximum shipped out of state to date was 76,451 green tons (1998), and the minimum was 68,453 green tons (2003).[54] This illustrates the regional market for wood; as a commodity it is being bought and sold across borders throughout the region.

In addition to the two large biomass power plants, there are several smaller institutional and commercial CHP wood-fired biomass operations. Collectively, these micro CHP facilities add only a few MW of electric capacity to Vermont and consume about 30,000 tons of wood per year.[55]

5.8.1.2 Projected Biomass Wood-Fired Electric Production Potential

The Vermont statutes set forth a statewide goal of 20% of electricity sales from new renewable sources by 2017, and also seek, by the year 2025, to produce 25% of the energy consumed within the state through the use of

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[49] *See VEPP Inc., http://veppi.org/*

[50] *Actual consumption reported was approximately 272,000 tons in 2009.Estimated Wood Fuel Usage in State of Vermont, Agency of Natural Resources, 2009.*

[51] *Vermont Electric Power Producers Schedule C Monthly Billing Information, 2010 (http://veppi.org/monthly-production).*

[52] *30 V.S.A. § 8009.*

[53] *The actual reported combined use was about 599,000 tons in 2009. Estimated Wood Fuel Usage in the State of Vermont, Vermont Department of Environmental Conservation.*

[54] *Vermont Agency of Natural Resources Department of Forests, Parks and Recreation data.*

[55] *Estimated Wood Fuel Usage in State of Vermont, Agency of Natural Resources, 2009*

renewable energy resources, particularly from Vermont's farms and forests (30 V.S.A. § 805(d)(2) and 10 V.S.A. § 580, respectively). Vermont law also stipulates that a goal of this Electric Plan be to assure that by 2028 at least 60 MW of power are generated within the state by CHP facilities powered by renewable fuels or by non-qualifying SPEED resources.[56] This Electric Plan includes evaluation of 60 MW of CHP in the economic model (see Appendix 4—Modeling Study).

The Vermont 25 x '25 Initiative, launched in 2008, determined that bioenergy fuels from our fields and forests have the technical potential to produce about 25% of the total energy consumed in Vermont by 2025, and that we should strive to attain that level.[57] The 25 x '25 Initiative provided specific technically achievable goals for wood energy production, which can be seen just below.

Exhibit 5-4. Wood Energy 25 x '25 Energy Production Goals

Technology	Energy Type	Energy Prod (2008) (in Billions of Btu)	% of Load (2008)	2025 Energy Production (in Billions of Btu)	% of Load (2025)
Chunk Wood	Heat	5,160	3.05%	764,000 green tons (5,800)	3.40%
Wood Pellets	Heat, Electric	327	0.19%	228,000 green tons (1,550)	0.92%
Wood Cips	Electric only	1,200	0.71%	1,000,000 green tons (1,720)	1.02
Wood Chips	Heat only	520	0.31%	126,500 green tons (707)	0.42%
Wood in CHP	Heat, Electric	760	0.45%	547,000 green tons (3,060)	1.81%

Source: Vermont 25 x '25 Initiative Preliminary Findings and Goals, Spring Hill Solutions, January 23, 2008

In 2008, the 25 x '25 Initiative conservatively calculated that wood-fired electric-only plants produced approximately 1,200 billion Btu of energy, equivalent to about 40 MW, which is below the rated capacity for the two existing plants. The goal for 2025 of 1,720 billion Btu would require an additional 520 billion Btu of power from wood-fired electric-only plants, equivalent to another 25–30 MW facility. This new production was estimated to require 300,000 green tons of wood, which, when combined with the estimates for wood used at the McNeil and Ryegate plants, would total about 1 million tons of wood annually for the production of electric energy in 2025.[58]

The CHP base level in 2008 showed 760 billion Btu of CHP (~25 MW) increasing markedly by 2025 to 3,060 billion Btu (~100 MW at 65% system efficiency). Using estimates from the 25 by '25 Initiative, this additional production of 75 MW CHP would require approximately 400,000 green tons of new wood supplies. Combined with existing CHP, total CHP would require about 547,000 green tons in 2025. Adding this to the electric-only

[56] *30 V.S.A. § 202(i).*

[57] *Vermont 25 x '25 Initiative: Preliminary Findings and Goals, Spring Hill Solutions, 2008, Table 1, pp. 4–5, www.vermontagriculture.com/energy/index.html.*

[58] *See Vermont 25 x '25 Preliminary Findings and Goals, p. 12 and Appendix A—Energy Calculation Notes, for information on assumptions in the calculations, January 23, 2008.*

projections would require 1.5 million tons per year for projected power. Other projected wood uses estimated at about 1,118,500 tons of wood would be used for heating purposes, plus 500,000 tons for possible cellulosic ethanol production, bringing total wood use to an estimated 3.1 million tons per year.

The 25 by '25 technical analysis assumed 1.5 million green tons would be available for new harvest in addition to the 1.5 million tons currently used. One million of those new tons were to be dedicated to both electric and thermal energy and the balance used for cellulosic ethanol. Since cellulosic ethanol R&D has not made much progress in the region, the CEP does not assume that wood will be used to produce ethanol. More recent studies indicate that a level of 1.5 million green tons per year for energy production may be high. A study conducted by the Biomass Energy Resource Center set forth a level of harvest of approximately 900,000 green tons per year from Net Available Low-grade Growth (NALG). (See Appendix 6—Forest Management for Bioenergy for details.) This amount of wood would need to service any expanded electrical and thermal demands emerging in the region.

Assuming that the estimated new electric and CHP wood-fired production capacities were to come on line by 2025, such deployment would require an additional 700,000 tons of wood (300,000 tons for new electric plus 400,000 for new CHP). Section 8.3.2 of the CEP (Biomass Availability for Thermal Energy Use) identifies that the state could potentially use all 900,000 green tons NALG for thermal heating. If some or all of the projected electric and CHP facilities are sited, the state would have less wood available to meet potential thermal uses.

These projections show there may be more potential demand for wood for energy than is available in the state. Fulfilling both potential thermal and potential electric demand may require obtaining wood from surrounding states, and they face similar challenges. Moving in the direction of both new electric and CHP with thermal uses continuing at the same time would likely lead to rising prices, could lead to overharvesting, and likely would constitute a missed opportunity for the state to effectively prioritize the most efficient thermal applications that displace the most fossil fuels.

The increased efficiency of thermal-led CHP yields greater energy output with proportionately less harvesting than electric-only production. Assuming regional harvest rates remain below the annual growth rates, and forest management practices continue to support long-term forest health, there may be an opportunity to site small- to medium-sized electric-only woody biomass power facilities while maintaining the state's priority to reduce fossil fuel use by using wood resources for thermal and thermal-led CHP applications that displace fossil fuels. However, any decisions about wood-fired electric or CHP projects must take into account the potential competing demand for woody biomass emerging in the region, as well as prioritized demand for thermal energy production as recommended by the CEP. Since the addition of a new wood-fired electric facility would have a measurable impact on biomass supplies, it is important to understand overall emissions, carbon impacts, and impact on competing uses as a part of overall planning and permitting for any new electric plant.

5.8.1.3 Challenges to Wood-Fired Electrical Generation

The limited efficiency of wood-fired electric generation plants presents a challenge to wood-fueled generation's development. The upper end of efficiency is typically around 25% for electric-only woody biomass plants. In the

context of a large increase in demand for wood and the partially understood limits to sustainable forest production, this level of efficiency, when compared to other uses, is low. In addition, this low efficiency affects the carbon balance of wood combustion as well as the balance of carbon in forest stocks and soils. Even though forest biomass does not represent sequestered carbon in the way oil or coal does, wood combustion does create CO_2 emissions. A more efficient burn would improve that balance.

The past five years have been a time of speculation for wood-fueled power generation. Both new utility-scale and smaller-scale developments have been proposed throughout our wood supply market. Though none have yet been built in Vermont, new facilities such as the 75 MW Burgess Biopower facility in Berlin, N.H., are under construction in the region, meaning that the practical outcome will be increased competition for fuel grade wood in our region.[59]

The CEP recommends a focus on higher-efficiency uses of woody biomass energy given the inherent limits and increasing demands on forests in the region. At the time of the CEP's release, there were two proposed woody biomass electric production facilities in Vermont under consideration that would each yield approximately 30 MW of electricity and use a portion of the thermal energy generated for other purposes. These facilities, or others that may be proposed, could help meet the 60 MW CHP goal set by the Vermont Legislature if they could find a use for the large amounts of thermal energy the plants create. In addition, there may be opportunities for small-scale CHP projects at the community, commercial, and institutional level for wood, grass, or other biofuel sources. For example, one 400 kW wood-fired CHP project is under development at Rutland Plywood Corporation's plant in Rutland.

Wood fuel has evolved from being essentially a waste product to being a commodity whose price is reflective of its economic value. From 1984 to about 2001, the price paid by power plants for wood fuel was $18 per green ton. From 2001 to present, the price has risen to about $32 per ton. Throughout those two periods, there have been instances of spot pricing, when the price for wood fuel paid by power plants increased to $28 per green ton as a peak during 1984–2001 and $39 during 2001–present. For most of the period 1984–present, the wood-fueled power plants relied on a blend of wood processing residues, wood from forest harvesting, and wood residues from municipal and other sources. In or around 2001, the demand for wood processing residues surpassed supply. Since then, the additional demand for wood fuel has been satisfied by forest harvesting.

The CEP recognizes the challenges inherent with development of new biomass energy options in the state. Facilities proposed for development as electric or CHP projects have the potential to increase the number of jobs in the state and generate a modest addition to the state's baseload power production. Additional baseload production from renewables is required to meet the challenge of the CEP's 90% goal, and biomass electric production at one or more facilities has the potential to contribute to that goal. Such additions would contribute to state and municipal tax revenues while circulating dollars in local economies.

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[59] *Groundbreaking held for N.H. biopower plant, Biomass Power and Thermal.* http://biomassmagazine.com/articles/5846/groundbreaking-held-for-nh-biopower-plant.

At the same time, devotion of forest biomass to electric-only generation increases the short-term carbon debt and has the potential to threaten the long-term health of forest ecosystems should market pressures lead to overcutting and poor forest management practices. Increasing the demand for forest products risks raising the prices for lower-grade firewood—a burden that would fall disproportionately on lower-income Vermonters who rely on firewood to heat their homes. As reflected in the volume of public comments received by the DPS in opposition to electric-only woody biomass power, many people are interested in seeing that forest resources be used as efficiently as possible.

One of the major challenges facing all biomass power is facility siting. Siting challenges include the limited number of properties suitable for industrial development, transportation infrastructure limitations, public infrastructure limitations (water, sewer), and both power and thermal infrastructure limitations for CHP. Particulate matter from biomass combustion typically requires advanced technologies to control emissions. Such pollution control technologies can reduce emissions but add to the cost, which can make biomass less competitive with natural gas plants that do not need such equipment.

The key challenge in developing CHP at the power plant size is locating a host facility that has the ability to use the magnitude of waste heat produced on a continuous basis. People generally do not want power plant–sized facilities located in or near population centers, but this is exactly where such facilities would need to be to make use of the thermal heat if industrial process uses can't be developed. As noted above, the McNeil plant has the potential to add a heating loop because it is near the UVM campus, but to date has not done so. Ryegate, on the other hand—which has the capability of heating approximately 1,300 homes—has no such potential host within a feasible distance.

The Standard Offer Program currently requires biomass plants to meet an efficiency level of 50% to be eligible.[60] With an electric-only plant's efficiency below 30%, the only way to meet the requirement is with a CHP plant, which was the intent of the eligibility requirement. However, with the lack of industrial heat loads in Vermont, this requirement has been very difficult to meet. This suggests the need to revisit the efficiency standards for the Standard Offer Program, with an eye toward whether the present requirements allow for sufficient development of CHP applications.

Adjusting the requirement to allow for thermal-led CHP projects to participate in the Standard Offer Program would benefit the state by providing additional baseload electric capacity, increasing our operational knowledge of CHP plants, decreasing reliance on fossil fuels, and supporting the local economy. Therefore, the DPS recommends that the PSB be charged with setting the efficiency standard for biomass CHP projects in the Standard Offer Program with the goal of meeting the statutory objective of robust deployment of CHP plants.[61]

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[60] *30 V.S.A. § 8005(j).*

[61] *Title 30 § 202(i): "it shall be a goal of the electrical energy plan to assure, by 2028, that at least 60 MW of power are generated within the state by combined heat and power (CHP) facilities powered by renewable fuels or by nonqualifying SPEED resources."*

The efficiency requirement should include a mechanism to incentivize CHP plants with efficiencies of less than 50% that are allowed into the program to increase their efficiencies over time.

Overall, the DPS recommends that Vermont's limited state incentives and financial resources flow first to the most efficient projects that displace the most fossil fuel for the investment. Combined heat and power projects thus remain the priority. However, biomass electric-only power plants that qualify as a renewable resource may be constructed in Vermont if projects are viable financially with only the federal incentives in place. It should be noted that these existing incentives, such as the production tax credit and RPS incentives in other states, favor electric development. The recommendation to prioritize thermal uses of woody biomass means that Vermont will have to be vigilant in its own policy so that federal incentives do not function as the main determinant for energy development in the state.

5.8.1.4 Carbon Implications for Biomass

All fuels release carbon dioxide when burned, yet the emissions balance for biomass energy is a complex issue. Increased harvest of biomass for electricity or thermal energy changes natural carbon dynamics. Carbon is taken in and stored in soils, trees, and other biomass during plant growth, when sunlight is used to convert carbon dioxide into carbohydrates (cellulose and lignin, primarily) and oxygen, which is released into the atmosphere. This process removes carbon from the air and stores it on land, and is referred to as carbon sequestration. Biomass harvesting, transport, processing, and combustion all release carbon, in the form of carbon dioxide, along with other GHG and air pollutants. Thus, biomass energy and forest carbon sequestration form competing demands on the state's forests that land managers must balance.

The complexity of the process of sequestration and emission makes it difficult to quantify true carbon impacts of a given application. Sequestration depends on the area of forest or cropland, tree species and age, type of forest or crop management, past land uses, forest damages, harvesting intensity and frequency, and other factors. Emissions depend on equipment used, efficiency, distance of transport, processing, type of product, and combustion type. On average, Vermont forests store between 77.1 and 84.6 metric tons of carbon per acre in above-ground carbon.[62] Although harvesting biomass for electricity or thermal energy (or any other uses, such as lumber and pulp) may reduce what is naturally sequestered by forests, forests that are cleared for development would emit 30% of stored soil carbon, and much of the above-ground carbon.[63] By keeping forestland productive and preventing land conversion, we can see a positive gain in avoided emissions.

It is generally accepted in international emissions protocols that biomass and biofuels are carbon neutral, meaning that the carbon emitted during combustion is reabsorbed rapidly enough by new growth that the two effectively cancel each other out. This is also described as having net-zero emissions. Yet in practical terms, when taking a life-cycle view, the carbon balance depends upon a variety of factors, as listed above. Preliminary

[62] *Carbon Storage in U.S. Forests, by State, Sub-Region, and Ownership Group (current data as of October 5, 2010).* www.fs.fed.us/rmrs/forest-carbon.

[63] *Lal, R. 2005. Forest Soils and Carbon Sequestration, Forest Ecology and Management, Volume 220, pp. 242–258.*

efforts are under way at the Agency of Natural Resources, which maintains primary responsibilities in the state for emissions accounting, to evaluate life-cycle carbon accounting as it applies to biomass. The EPA is undertaking a similar exercise. It may be possible in the future to determine that "Biofuel A" from "Source X" meets the criteria for carbon neutrality, whereas other biofuels may only partially meet the criteria and still others are deemed to increase the overall amounts of carbon in the atmosphere.

It is recommended that the Agency of Natural Resources continue its efforts to evaluate and use tools that elucidate the relative carbon impacts of all biomass resources used for electricity, thermal uses, and transportation purposes in Vermont. These life-cycle analysis tools can then be used to evaluate levels of carbon neutrality for different forms of bioenergy usage in Vermont under different scenarios.

It is possible through careful and appropriate management that Vermont's forests and fields can provide fuel for energy while continuing to sequester carbon dioxide. The Plenary Group of the Governor's Commission on Climate Change recommended increasing net sequestration in Vermont's forests by 3% by implementing forest management on an additional 1 million to 3 million acres through various forestland incentives programs by 2028 (47,619 to 142,857 acres per year from 2008 to 2028).[64] The Plenary Group also recommended that Vermont could further reduce greenhouse gases by increasing the use of low-value wood by appropriate processing centers and end users to offset fossil fuel use. The goal was to increase production and use of forest biomass energy feedstocks by 30% by 2028. Private ownership of so much of the state's forestland makes these goals contingent on landowner decisions; landowners may be influenced by incentives, market prices, or other factors to sell biomass for one purpose over another. One factor that surely affects long-term sustainability and has direct implications for carbon storage is our ability to keep forests as forests. We must seek ways to ensure a reasonable return to landowners lest conversion to development results in whittling away at our forest and farmland base.

5.8.1.5 Tools to Utilize Woody Biomass for Generating Electricity[65]

- **Financing.** It remains a challenge for forest products and logging operations seeking to augment traditional timber products with chipping operations to gain access to capital. Efforts to expand access to finance would help facilitate a transition to biomass energy.

  The cost of capital for installing new biomass technologies at the institutional and community levels is one of the primary hurdles to shifting schools, campuses, and municipalities from imported heating oil to locally sourced biomass. CEDF grants and loans support the ability of school buildings, community buildings, and other public buildings to convert to biomass heating systems, district heating, and combined heat and power systems.

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[64] *Plenary Group Recommendations to the Governor's Commission on Climate Change, Final Report. October 2007. Pp. 5-8 to 5-9.*

[65] *Woody biomass electricity is a more mature sector than biomass electricity using other feedstocks. As other technologies and supply chains develop, the Department of Public Service will evaluate how the tools described here may be expanded or adapted.*

The use value appraisal program helps landowners maintain land in its productive state. This program remains vital to the working landscape.

- **Policy and Regulatory Actions**. The Vermont Legislative Study Committee on bioenergy established in 2008—the Biomass Energy Development Working Group (also known as BioE)—is in its third year of work and will be making recommendations in late 2011 regarding forest health and increased woody biomass use. Implementation of the CEP should take into account any recommendations of the BioE group, particularly with regard to forest health and sustainability approaches.

  Use of woody biomass includes electric, thermal, and potential transportation uses. Statute provides certain standards for efficiency for wood biomass electric production. Development of economically viable CHP projects remains difficult under the current standards, and efficiency levels should be revisited to explore options for partial thermal usage.

  The Standard Offer Program provides a tool to help advance the use of biomass in the state. This program is limited to qualifying resources with a plant capacity of 2.2 MW or less, and can be used for efficient CHP only.

  Adequate access to forest products to meet the expanding demand for low-grade wood products is essential to supply the necessary raw materials.

- **Outreach and Communications**. Given the debate over whether to harvest forest resources for electricity or thermal uses, outreach programs can help inform citizens about the status of forest health and the amount of harvest that forests can sustain to produce heat and electricity for Vermonters.

  An information clearinghouse and public information capacity through the DPS, ANR, Vermont Agency of Agriculture, Food, and Markets (VAAFM), and partner organizations for current and emerging biomass thermal and CHP technologies would help market participants and consumers remain abreast of rapid changes in this sector.

- **Innovation and Economic Development.** As traditional lumber and logging operations transition toward forest energy, there is a need for additional assistance in helping companies and individuals develop plans and technologies for chipping, storing, and marketing.

  Advances in electric generation technologies and particulate emissions controls also may help woody biomass electric generation viability.

5.8.1.6 Recommendations for Woody Biomass

There is a debate in Vermont over whether it is advisable to convert forest biomass into electricity rather than thermal uses or CHP applications. Vermont will need additional renewable sources of electricity to meet the

renewable energy goals in the CEP, and locally derived biomass including woody biomass for electricity can contribute to that mix. It may also be possible for other agricultural biomass crops such as grass to contribute to the electric mix at some point in the future.

Any biomass fuel and usage scenario requires close attention to the status of Vermont's forest and agricultural resources. Biomass resources are finite in quantity and regenerate at different rates. Great care must be taken to guard against boom-and-bust cycles that could threaten the long-term viability of biomass resources. For more information on this essential aspect of biomass energy as it applies to woody biomass, see Appendix 6—Forest Management for Bioenergy.

At about the time the CEP enters its implementation phase, Vermont's legislative BioE committee should be finalizing its recommendations. Based on the interim report of that committee, we expect the recommendations herein regarding woody biomass to be consistent with the work of that committee; however, any recommendations made in that report should be reviewed and considered in the implementation of the CEP.

Recommendations

The DPS provides the following recommendations for the advancement of biomass electrical generation in Vermont:

(1) *Evaluate and help implement appropriate recommendations of the Vermont BioE Legislative Study Committee, including implementation of harvesting and procurement guidelines to support sustainable woody biomass supply and the long-term health of Vermont's forests and assure the public of harvest sustainability.*

(2) *Ensure that sustainable, monitored forest management practices and efficiency serve as the guiding principles for use of biomass resources, rather than placing specific restrictions on end usage.*

(3) *Support monitoring and study, by ANR, of the amount of woody biomass available and of the associated impacts of biomass harvesting on the forest ecosystem, including the full range of forest species that are adapting to a changing climate, as well as water quality, capacity to moderate floods, soil productivity, and other important forest services.*

(4) *Remove the 50% efficiency requirement from the Standard Offer statute and replace it with a charge to the PSB to set the efficiency standard for biomass CHP projects with the goal of robust deployment of CHP plants that substantially utilize thermal load at least seasonally. The charge to the PSB should also include a mechanism to incentivize those CHP plants with efficiencies of less than 50% that are allowed into the program to increase their efficiencies over time.*

(5) *Consider providing incentives to private landowners, who hold more than 85% of the forested landscape, to encourage harvesting that does not exceed average growth rates. This will help ensure the sustainability of biomass resources.*

(6) *Carry out all wood biomass harvesting for energy under best management practices (BMPs), revised to incorporate considerations of forest health beyond water quality goals.*

(7) *Consider developing a carbon value for land retained as productive land for forest products (and agriculture) and credit for sustainably managed forest resources.*

(8) *Support efforts at the Agency of Natural Resources to build and use effective life-cycle analysis tools to evaluate levels of net carbon emissions or sequestration for different forms of bioenergy usage in Vermont under different harvesting scenarios, and incorporate them into PSB Section 248 criteria once established.*

(9) *Build on the existing forest monitoring capacity at the Agency of Natural Resources to develop a robust forest monitoring program and an adaptive forest management system.*

(10) *Provide additional funding for CEDF (grants and loans) to support the ability of school buildings, community buildings, and other public buildings to convert to biomass heating or combined heat and power systems.*

(11) *Bolster outreach about the environmental and health protection benefits that accompany improved efficiencies with advanced emission control technologies installed on biomass heating and combined heat and power units.*

(12) *Create an information clearinghouse and public information capacity through the DPS, ANR, VAAFM, and other partner organizations for current and emerging biomass thermal and CHP technologies.*

(13) *Investigate renewable heating standards for new and refurbished public buildings that include all renewable heating technologies (biomass, solar, geothermal).*

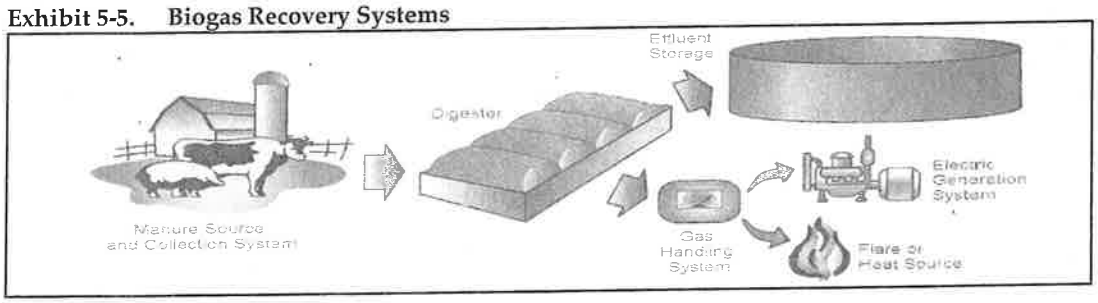
5.8.1.7 Biogas: Farm and Landfill Methane

Farm-Based Methane Digesters. Vermont draws social and economic benefits from its working agricultural sector. Yet dairy farming in Vermont continues to operate under increasing economic stress. The amount of land dedicated to farming in the state has decreased significantly in the past 35

years.[66] Capitalizing on farm energy resources can help improve and diversify the bottom line of Vermont's agricultural enterprises. Benefits extend beyond the farm to the public by providing renewable baseload power to the grid, additional energy security, and a range of environmental benefits, from odor amelioration to greenhouse gas reduction. These private and public benefits are why the DPS, the Vermont Agency of Agriculture, and the USDA have partnered to utilize manure as an energy resource. Through the efforts of these agencies and their partners, farmers are beginning to appreciate manure as an energy resource.

Anaerobic digestion is the degradation of organic matter including manure, brought about through the action of microorganisms in the absence of oxygen. Technologies that use this process yield methane used for energy, while decreasing pollutants and odors resulting from traditional manure management techniques. In addition, the nutrients in the manure become more readily available for plants to uptake, potentially reducing runoff. The resulting product of anaerobic digestion is biogas, composed primarily of carbon dioxide and methane. Biogas can be combusted directly for heat or used to fuel an engine to generate electric power. Exhibit 5-5 shows a simplified diagram of the process. An additional by-product of the process is the remaining undigested solids. This bacteria-reduced material can be used as bedding material for the cows, replacing the need for sawdust, or it can be used as a soil amendment.

Exhibit 5-5. Biogas Recovery Systems



Source: EPA

Anaerobic digestion of manure provides a number of societal benefits. Manure has traditionally been stored in storage lagoons, where it produces methane that escapes into the air; biogas systems capture and harness the methane. The greenhouse gas value of methane in the atmosphere is, over a 100-year time horizon, 21 times that of carbon dioxide, so biogas recovery systems significantly reduce overall greenhouse gas emissions. The systems reduce the odor in the remaining effluent significantly, allowing farms to spread without having to be concerned about odors such as those released when manure stored in a storage pond or lagoon is spread. There are added carbon benefits in that the power produced can offset power produced from higher-carbon sources.

The DPS and Vermont Agency of Agriculture, Food, and Markets (VAAFM) recognized the role of anaerobic digestion. Over the past decade Vermont has taken the lead in helping farmers achieve manure management goals, decreasing their energy requirements and providing a source of additional

[66] *The 2007 Census of Vermont agriculture reports that between 1974 and 2007, the number of acres dedicated to farming dropped from 1.7 million to 1.2 million.*

income. Incentives for farm biogas production facilities are available in Vermont through programs like CVPS's Cow Power, GMP's Greener GMP, the state's Clean Energy Development Fund, the Vermont Economic Development Authority, and the USDA. As of July 2011, there were 12 systems operating in Vermont, with an installed capacity of about 3 MW.

Thanks to the combined efforts of farmers and their partners, Vermont farms have emerged as leaders in the field of small-scale farm methane digester development. Central Vermont Public Service introduced methane digestion for electrical generation to Vermonters through its Cow Power program in 2005, when the Blue Spruce Farm began delivering power to the grid. This innovative green pricing program received grant support from the CVPS Renewable Development Fund, USDA Rural Development, and the Vermont Clean Energy Development Fund. Additional support came from the VAAFM and USDA's Natural Resources Conservation Service.

Exhibit 5-6. Standard Offer Program Methane Generation, July 2010 to June 2011

Production Site	Size (kW)	Production (kWh)
Blue Spruce Farm*	490	1,282,842
Berkshire Cow Power LLC*	600	2,610,767
Chaput Family Farms*	300	1,343,649
Dubois Energy LLC*	335	1,695,443
Gervais Family Farm, Inc.*	200	1,200,449
Green Mountain Dairy*	225	1,622,408
Montagne Farm*	240	461,644
Maxwell's Neighborhood Energy LLC*	200	1,264,386
Westminster Energy Group	200	1,077,913
Total	***2,790***	***12,559,501***

**Participant in CVPS Cow Power program.*
Source: Vermont SPEED Program Monthly Billing Information

In 2009, the advent of the Standard Offer Program within the Sustainably Priced Energy Enterprise Development (SPEED) program created more opportunities for farm methane producers to generate sufficient revenues to become viable.

In June 2009, the Vermont Public Service Board opened Docket 7523 to investigate the development of Standard Offer prices for qualifying renewable generation under the SPEED program. In September, the PSB issued an order that set the rates for farm methane at $0.16/kWh. Subsequently, in January 2010, the PSB opened Docket 7533, in which it reduced that price to a levelized rate of $0.141/kWh. Farmers in the CVPS Cow Power program receive this payment plus an additional $0.04/kWh for farm energy attributes from CVPS as long as enough CVPS customers pay the voluntary Cow Power premium.

As the nation slipped into recession, wholesale energy prices fell, leading to a decrease in revenue for some of the farms that were not initially eligible for the Standard Offer because they had contracted to sell their power at market rates to CVPS. Legislation introduced in 2010 (H. 566) eventually permitted all farms selling farm methane–generated power to a utility to be eligible for the Standard Offer rates, which helped improve the prospects for continued generation. However, some participants in the program continue to endure a degree of economic uncertainty when they do not receive sufficient revenue from the sales of their farm-generated energy attributes. This condition increases the risk for future farms and their backers considering investment in farm methane generation.

Landfill Methane. As refuse decomposes in landfills, methane gas is released, eventually rising to the atmosphere. Large landfills control this flammable gas by collecting it via pipelines buried in the landfill and either flaring it or allowing it to be used for energy. Combustion of methane, a potent greenhouse gas (GHG), is one strategy for reducing the buildup of GHGs in the atmosphere.

Vermont currently has a small number of landfill biogas generation facilities, with operations in Coventry (8 MW), Moretown (3.2 MW), Burlington's Intervale (350 kW), Williston Gas Watt Energy (90 kW), and Brattleboro (300 kW). There is a limited capacity for new landfill biogas generation in the state, mostly from expansion of existing systems or installation of generators on smaller landfills such as Randolph's. Efforts are under way to increase production at the Moretown landfill by installing an additional 1.6 MW generator. Carbon Harvest in Brattleboro is exploring the option of adding a second 250 kW generator at the Brattleboro landfill. Efforts to expand this sector will provide additional GHG reductions. Landfill gas will contribute only a minor portion of power to the state's electricity portfolio in the future. Collectively, landfill methane represents about 12 MW of power operating at about 80% to 90% capacity factor, with the potential to expand this amount to about 13.5 MW.

5.8.1.7.1 Projected Biogas Electric Production

As shown in Exhibit 5-7, the Vermont 25 x '25 Initiative presented specific goals for biogas energy production.

Exhibit 5-7. Agricultural Energy 25 x '25 Energy Production Goals

Technology	Energy Type	2008 Energy Production (in Billions of Btu)	% of Load (2008)	2025 Energy Production (in Billions of Btu)	% of Load (2025)
Manure Digestion	Electric	29	0.02%	444 (15 MW installed capacity)	0.26%

Source: Vermont 25 x '25 Initiative Preliminary Findings and Goals, Spring Hill Solutions, January 23, 2008

As of 2011, Vermont has about 1,000 dairy farms milking a total of about 140,000 cows. These cows are housed in a variety of barn types and are managed in a wide variety of ways. Many farms are facilities at which most of the manure is collected and stored or spread. Some of these farms are pasture-based in the months when grazing is practical and the manure is self-spread. For the 2009 Vermont 25 x '25 Initiative report, the VAAFM

estimated that about one-half of the manure in the state would be available for digestion. VAAFM estimates that this would give a total installed electric generation capacity from manure of 15 MW, producing about 118.3 million kWh of electricity annually by 2025.

The 3 MW of farm methane power currently in production at 12 Vermont farms will be joined by an additional 2.6 MW under development. To meet the goal for 25 x '25, an additional 9 MW of new methane-generated power will be required. The VAAFM estimates for available manure indicate that this goal is attainable. However, given the high costs and long lead times, farmers are going to need predictable power prices and enhancements to net metering, such as renewable energy certificate (REC) ownership to proceed.

In addition to farm and landfill methane sources of biogas, other biogas opportunities may emerge in the future. For example, nascent projects in other states, one with the backing of a Vermont entrepreneur, seek to commercialize extremely high temperature plasma gasification of landfill waste. Should such a technology prove effective, environmentally sound, and otherwise viable, Vermont should revisit the use of landfill waste for direct fuel.

Potential New Sources of Biogas Electricity

Farm Methane Digesters. Currently, about nine new methane digesters in various stages of development in the state are going through the Standard Offer Program, and four farms are expanding their existing digester systems. Collectively, these projects will add about 2.6 MW to the biogas pool should they all come to fruition. Additional potential remains on Vermont farms for manure digesters.

To expand the number of digesters, the state will need additional support for research and development of small-scale digesters such as the 17 kW unit at the Foote Farm. Many pieces of smaller systems are under development, including alternative systems with closed-loop units that have the potential to improve the outcomes from digester projects. Researchers are also exploring connections to hydroponic greenhouses growing vegetables and algae that will use farm resources more efficiently.

Most of the farm systems in Vermont are designed such that they can use more than just manure in their digester. These take in some food wastes, such as whey from cheese making, to enhance the energy output of their system. Farm-based systems that are planning to use separated solids for bedding need to use caution with the materials they use so that they do not have undesirable side effects on the cattle. There are also limits to the types and volume of materials that can be brought in. ANR and VAAFM cooperate with the farms to determine whether the materials proposed are appropriate for land application after digesting, and if the farm has enough storage capacity to get them through the winter, including the new materials. Farms need to derive the majority of the feedstock for a digester from their farm to have the system qualify as an accepted agricultural practice.

Digesters can also be designed to run primarily on materials other than manure. These "mixed-substrate" anaerobic digesters can utilize as inputs various livestock manures, crops harvested or stored as silage, food scraps, and many other food-processing wastes or agricultural waste products. The

biogas yields per ton of crops or food wastes are much higher than those of cow manure (for example, grass silage, corn silage, and food scraps yield approximately eight times as much as cow manure, and waste grease and baking wastes can yield 25 times as much as cow manure). The silage from one acre of crop can run about 1 kW of generation continuously. The 2009 Vermont 25 x '25 Initiative report estimated that Vermont has the potential for about 36 MW of generating capacity from these systems.

The mixed-substrate digesters require cow manure as a source of methane-producing bacteria at startup, but can then theoretically run without additional cow manure. This technology is relatively new to the United States, but is mature in Europe, which has several thousand operating systems with generating capacities ranging from approximately 20 kW to several megawatts.

Vermont has some projects growing algae or other plant materials in a waste stream. The algae can then be harvested for oil or fed into a digester where the plant material can be converted to energy. A goal of the VAAFM is to help develop a system that will take the liquid stream coming from a traditional manure-based digester and grow plants in the waste stream while purifying the wastes so that a farmer would save the energy and time needed to haul liquid manure to the fields. A system that does this could also enhance the energy output by feeding some of the materials grown back into the digester to produce more energy while reducing the energy needed to apply the output products to land and growing other products for new revenue streams.

Mixed-substrate digesters offer a new flexibility because their generating capacity and economic feasibility are not solely dependent upon the number of cows on the farm, but rather on the number of tons of crops or food waste that are available. Thus, a farm that has only a small number of cows (or no cows at all), but owns or has access to cropland, could install a mixed-substrate anaerobic digester.

Other Anaerobic Digesters. Food-processing facilities and municipal waste facilities can also use anaerobic digestion to produce energy. A recent example is provided by a brewery in Vermont that has installed an anaerobic digester to produce combined heat and power and reduce the biological oxygen demand (BOD) load in its waste stream. Essex Junction, Vt., has an anaerobic digester on its municipal waste system that provides heat and 30% to 40% of the power needed for its waste treatment facility. These systems provide environmental benefit from methane destruction and BOD reduction as well as energy from a source that traditionally has been disposed of in a manner that uses energy. The DPS, VAAFM, and ANR need to cooperate on assisting commercial ventures that can use organic wastes or crops that are appropriate for this application. The state also needs to work with municipalities that are remodeling their waste treatment facilities to encourage anaerobic digestion with methane capture as part of their treatment system.

Challenges to Development of Biogas Electric Power

Development Risks for Farm Methane Biogas Projects. Development of new farm methane digesters is a long and costly process. Challenges such as gaining access to the three-phase power needed to support and transmit power from the systems, earning sufficient revenues from the sale of

renewable/farm-based energy attributes, and accessing capital are all difficult barriers that must be overcome. The current cap on the number of MW for renewable projects in the Standard Offer Program, and limitations and uncertainty in the net metering program, also serve as impediments.

New methane digesters can cost millions of dollars and take upward of four years to commission. Farms must provide substantial amounts of their own cash and in many cases increase their debt to capitalize such facilities. Access to grant funding has proven essential to covering costs for such expenses as planning, engineering, and connecting to three-phase power, as has access to low-cost credit from organizations such as CEDF and VEDA. Farms generally have to mortgage their farm to develop a digester because lenders often will not take the digester as collateral.

Another challenge entails rates paid to some farmers and demand for renewable energy by Vermont customers. The CVPS Cow Power program faced a situation in 2009 and again in 2011 wherein the number of farm-produced "renewable" attributes exceeded the demand for these attributes from customers. It is possible that such imbalances may continue in the future, creating the potential to strain the economics for some of the farm methane producers.[67] Farmers in green pricing programs must earn sufficient revenues from the sale of renewable attributes or the Standard Offer Program price to remain viable. If the local demand for renewable attributes drops below the number of attributes produced by farmers, farmers would need to sell those attributes in other markets where they might not receive an equivalent price (e.g., 1 cent per kWh for renewable energy certificates versus 4 cents per kWh). One possible remedy for this situation would be to expand green pricing programs to all Vermont electric customers, thus increasing the overall demand for farm-produced attributes.

Recommendations for Farm Methane and Other Biogas

(1) *Vermont state agencies and electric utilities should continue to support development of biogas recovery systems through incentive programs.*

(2) *The DPS, ANR, and VAAFM should collaborate to identify how to overcome barriers to the development of cost-effective farm methane systems, particularly for smaller-sized digesters for farms with fewer than 200 cows.*

(3) *Investigate mechanisms that encourage development by ensuring a stable, predictable price (such as enhanced net metering and the Standard Offer Program) that farm-based systems could access.*

(4) *Continue support through the Clean Energy Development Fund for effective farm-based renewable energy systems, including methane digesters, and develop other revolving loan funds, both public and private.*

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[67] *See CVPS Renewable Development Fund Progress Report, June 30, 2011.*

(5) *Develop a model farms could use to create group net metered projects.*

(6) *Work with technical experts and system designers and developers to bring down the system size and cost for smaller farms.*

(7) *Create greater statewide consistency with the interconnection process and procedures across all utilities.*

(8) *Enhance DPS review of interconnection plans and costs proposed by utilities to ensure that they are reasonable and do not create an undue burden for developers.*

(9) *Work with Vermont's Congressional delegation for continuation of NRCS and USDA REAP grants for on-farm bio-digesters.*

(10) *Support the research into enhancing anaerobic digester conversion efficiencies, such as the project at UVM that is looking at optimizing a digester to utilize the most efficient methanogenic microorganisms, which have the potential of increasing gas output by 20% with the same amount of manure.*

(11) *The DPS and ANR should work with municipalities that are remodeling their waste treatment facilities to encourage anaerobic digestion with methane capture as part of their treatment system.*

5.8.2 Hydropower

5.8.2.1 Hydroelectricity in Vermont

Prior to the 1920s, Vermont relied on hydro resources almost exclusively for its electricity needs. Many of the projects were small and served the modest local demand for energy. While the state is now less reliant on small hydro sources, in-state hydroelectric power still makes a significant contribution to Vermont's electric load. Hydropower has many benefits. It is renewable, has low emissions of greenhouse gases, and contributes to the stability of the electric grid. Vermont-based hydropower also can support the local economy through jobs and taxation. Thus, Vermont should preserve its use of the local hydropower resources and be open to environmentally sound hydropower development in the state.

Vermont today has 68 FERC-licensed hydropower generation facilities, with an estimated installed capacity of more than 150 MW. In-state hydropower generated in 2009 equaled about 8% of the electricity consumed in Vermont. In addition, there are eight facilities on the Connecticut and Deerfield river systems with a total capacity about 500 MW—however, none of that power is presently contracted for delivery to Vermont utilities.

Hydro project descriptions and documents relating to the development of small hydro in Vermont may be found at the Vermont Renewable Energy Atlas website.[68]

Exhibit 5-8. Vermont Hydroelectric Projects

Plant Owner	Capacity (MW)
CVPS	57
VEPP[69]	48
GMP	24
All Other	28
Total	*157*

A portion of current capacity was added in the 1980s under the Public Utility Regulatory Policies Act (PURPA) in 1978. Spurred by the energy crises of the 1970s, PURPA provided economic incentives for the development of small hydro projects. Under PURPA, 41 new hydro facilities were constructed in the state.

In the late 1980s and early 1990s, the elimination of economic incentives and other factors resulted in a sharp drop in development, and no new projects were proposed for almost 20 years. Further, six facilities developed in the 1980s were decommissioned because of equipment failures and for other reasons. The PURPA initiatives were successful in adding considerable new renewable power to the Vermont mix (about 6%), but at a higher price relative to the wholesale market.

Spurred by new energy concerns, in 2007, the Vermont General Assembly requested a study of the available hydroelectric potential and associated permitting requirements.[70] ANR's conclusions and recommendations have been updated and incorporated into the sections below. Current state policy supports the development of environmentally sound in-state hydroelectric projects. This policy achieves the objectives of helping Vermonters meet their long-term energy needs, shifting Vermont's energy supply to increased renewable resources while also protecting the health of Vermont's waters. In-state hydro is the least expensive power currently being generated by the utilities. CVPS's costs are less than 3 cents per kWh and GMP's are less than 4 cents. Nevertheless, very few new hydro projects have moved forward in the state.

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[68] www.vtenergyatlas.com or www.vsjf.org.

[69] *Vermont Electric Power Producers, Inc.*

[70] *2007's H.520 (Act relating to Vermont energy efficiency and affordability) required ANR to study issues relative to development and permitting of small hydro projects. Although it was ultimately vetoed, the governor directed ANR to develop the report "The Development of Small Hydroelectric Projects in Vermont: A Report to the Vermont General Assembly, January 9, 2008." The report can be viewed at www.vtenergyatlas-info.com/hydro. Click on "Reports and Links."*

5.8.2.1.1 Undeveloped In-State Capacity

Obtaining an accurate estimate of how much undeveloped hydro capacity exists in Vermont and how much of that capacity can be developed in an environmentally benign way is challenging. Opinions differ on the amount of available hydropower in Vermont. Depending on assumptions used, reports vary from 25 MW at 44 sites (estimated by the ANR in 2008) to 434 MW at 1,291 sites (estimated in a DOE study in 2006).[71] A 2007 study for the DPS identified more than 90 MW developable at 300 of the existing 1,200 dams.[72] The ANR is currently working on an updated assessment of the undeveloped in-state hydro capacity.

Under any assessment, it is clear that the best hydropower sites have already been developed. There are very few undeveloped sites that could support capacity greater than 1 MW, and a relatively low number in the 500 kW to 1 MW range. There are many potential smaller community and residential sites sized at less than 200 kW.

Incentives such as net metering, group net metering, and the Standard Offer Program are necessary to facilitate the development of the smaller sites. The ANR has recently approved sites with generation capability as low as 15 kW and 50 kW.

Because there are few undeveloped sites that are candidates for new hydroelectric plants, an effective way to increase capacity is to improve efficiency and output at existing hydroelectric facilities through three types of activities: installing more efficient turbines, installing small turbines at the dams that utilize bypass flows, and installing new turbines that can operate efficiently over a wider range of flows. These upgrades are often possible without changing the current operating requirements, i.e., power production can be increased without additional environmental impacts.

In addition, existing municipal water supply and wastewater treatment pipelines could capture the energy in these systems by installing hydro turbines to the pipelines without otherwise altering the regular operation of the system. Such in-pipe hydroelectric systems have minimal environmental impact. The town of Bennington has developed such a project, and another project is under development by the city of Barre. These projects generate electricity from the excess pressure in the municipalities' water supply systems.

5.8.2.1.2 Regulatory Process

Unlike other types of local renewable energy development, hydroelectric projects are regulated by the Federal Energy Regulatory Commission (FERC).[73] New projects may also require a permit from the U.S. Army Corps of Engineers. These federal permits trigger state review delegated under the federal Clean Water Act.

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[71] *Hall et al., 2006, U.S. Department of Energy.*

[72] *See www.vtenergyatlas-info.com/hydro.*

[73] *Hydropower in municipal water or wastewater systems may request an exemption from FERC licensing.*

FERC has a well-defined permitting process, but it can take two to seven years to complete. The long timeline is largely due to the need to gather the information necessary for the regulatory agencies to make informed permitting decisions and provide for public participation in the process. Hydropower projects involve the use of public waters, a public trust resource, so there is considerable public interest in these developments. Further, care is taken because the terms of the permits are at least 30 years. One class of permits has no expiration date; those projects may operate indefinitely without further review.

Some European countries have regulatory regimes that seem to facilitate hydro development, and some states have worked to streamline their permitting process. Vermont continues to receive public comment that the federal and state hydro permitting process is difficult and lacks clarity. The more that ANR and FERC can coordinate, integrate, and make explicit their procedures, the better it will be for those attempting to develop hydropower resources in the state. FERC recently initiated a process to help simplify the permitting of small hydro.[74] ANR has committed to review its process as well.

Low-impact projects can negotiate the permitting process in a matter of months (from application to issuance of the permit), provided the necessary pre-application work is completed. The key steps developers should take to receive timely permitting decisions are (1) involve regulatory agencies and other stakeholders early in the feasibility phase of the project, (2) engage a licensed professional engineer with hydropower experience to assist with project design and permitting, and (3) complete the necessary studies and include complete information in permit applications. The ANR states that as experience with small hydro projects grows, permitting will continue to gain efficiency.

5.8.2.1.3 Environmental Impact

According to the ANR, the hydro resource is already heavily developed in Vermont, and the resulting impacts on the state's waterways have not been inconsequential. These environmental impacts include intermittent manipulation of flows and water levels, a possible increase in flood hazards resulting from the disruption of natural river processes, some loss of riverine aquatic habitat, and barriers to movement of fish and other aquatic life. For these reasons, construction of new dams is unlikely to be permissible under the anti-degradation policy in the Vermont Water Quality Standards and is not supported by ANR. Of the operating facilities, about 60 have been certified by ANR as complying with the Clean Water Act. ANR has plans to use existing regulatory tools to bring the remaining 20 sites into compliance over time.

However, the environmental impact of a project is not necessarily related to its size, so smaller hydroelectric projects (often called "micro-hydro," "mini-hydro," or "community hydro") are not necessarily low-impact. ANR's 2008 Report "The Development of Small Hydroelectric Projects in Vermont"[75] identified the following criteria as likely to meet a low impact standard:

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[74] www.ferc.gov/industries/hydropower/gen-info/licensing/small-low-impact.asp.

[75] www.anr.state.vt.us/dec//waterq/rivers/docs/rv_smallhydroreport.pdf.

- No new dam or other barrier to aquatic organism movement and sediment transport.
- Run-of-river operation.
- Bypass flows necessary to protect aquatic habitat, provide for aquatic organism passage, and support aesthetics.
- Fish passage where appropriate.
- No change in the elevation of an existing impoundment or in water level management.
- No degradation of water quality, particularly with respect to dissolved oxygen, temperature, and turbidity.
- No change in the upstream or downstream flood profile or fluvial erosion hazard.

The ANR has stated that more work is needed to define projects that are truly low-impact, regardless of size, and has committed to this project.

5.8.2.1.4 Hydro-Quebec and Other Out-of-State Hydro Resources

In addition to the approximately 10% of its power coming from in-state hydro, Vermont currently receives a significant portion of its electricity from out-of-state hydro, principally from Hydro-Quebec (HQ). HQ power is stably priced, immune to escalating fossil fuel prices and retrofit costs, and does not contribute to the air quality problems of our region.[76] Further, since the power is supplied from many generators, its reliability is based on HQ's total system reliability, rather than the performance of a single dam or plant. The Vermont Legislature has recognized this resource as renewable.

Vermont has a long-standing contractual relationship with Hydro-Quebec. In 1990, a group of eight Vermont utilities (the Vermont Joint Owners, or VJO) entered into a 30-year agreement to purchase baseload power from HQ and to make it available at wholesale prices to other Vermont utilities. Under this HQ/VJO contract, power purchases increased from 51 MW in 1994 to approximately 310 MW today. This is a take-or-pay contract (i.e., regardless of whether the Vermont utilities need the contracted power, they still pay for it, although they may resell excess HQ power in wholesale markets. Currently, the average cost of HQ/VJO power is 7.0 cents per kWh, which was 16% above the cost of market alternatives in 2010). The HQ/VJO contract phases out beginning in 2012, with a large portion of its deliveries terminating between 2012 and 2015 and the last schedule expiring by 2020. The HQ/VJO contract currently supplies roughly one-third of Vermont's power requirements.

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[76] *All power purchased from HQ is system power and not tied to any single unit. Of the HQ power in 2010, 97.8% is from hydro. Hydro-Quebec, Sustainability Report 2010, www.hydroquebec.com/publications/en/enviro_performance/pdf/rdd_2010_en.pdf*

In 2010, 20 Vermont utilities signed a 26-year power contract with HQUS (the power marketing arm of HQ) to purchase 218 MW to 225 MW of electricity from January 2012 through 2038. Under this new contract, the contracting utilities also purchased an equivalent quantity of environmental attributes corresponding to the energy from the HQ power system mix composed of at least 90% hydroelectricity. However, the environmental attributes reflecting the HQ power system mix are not currently traded within New England and do not currently qualify for any New England REC program, because only Vermont currently recognizes this resource as renewable.

The new HQUS power purchase agreement's (PPA's) starting price is $58.07 per MWh for the first year of the contract.[77] After that, the price is derived by a formula that remains the same over the contract term. The formula is based on regional electricity prices, and the movement in general of price levels observed across the U.S. economy subject to a damping feature that limits the change from the prior year's price. Contract price adjustments are made annually. The contract is thus stably priced in a way that mitigates market price fluctuations. The annual adjustments are expected to keep the contract price closely associated with market prices during periods of moderate volatility while significantly limiting Vermont's exposure to price spikes or sustained high price periods. In general, this type of protection can be obtained only from resources (like renewable energy) that are not directly exposed to high fossil-fuel input costs. The price of power under the HQ PPA is expected to be either competitive with, or favorable to, forecast market prices over its term and lower than the price of currently available power sources with similar characteristics, and the arrangement offers other favorable characteristics (low air emissions, relative price stability, renewable fuel, freedom from relying on a single generator, and potential for power system benefits).

Vermont will buy this new HQ energy via an internal bilateral transaction (IBT). An IBT significantly reduces performance risk to the utilities and their ratepayers compared to the HQ-VJO contract or to other non-firm power. The IBT mechanism also assures Vermont that the HQUS power deliveries will provide protection from lack of diversity associated with the HQ-VJO contract.

Under the HQUS contract, the initial amount of energy provided is equal to the current transfer capability at the Highgate interconnection, which is 218 MW. If Highgate's transfer capability is increased to 225 MW during the term of the HQUS contract, then delivered energy will likewise increase. Although the contract amount is tied to the size of the Highgate interconnection, Vermont can and does receive power through other interconnections, and the HQUS contract does not require delivery of power at Highgate.

HQ currently has approximately 41,000 MW to 42,000 MW of generating capacity. Approximately 97% to 98% of HQ's power system portfolio is produced by hydroelectric facilities. According to HQ's most recent strategic plan, HQ has a surplus of approximately 10 terawatt hours (approximately 5%) and is expected to add another 10 terawatt hours (an additional 5%) of hydroelectric supply by 2014. In other words, HQ has additional supply available for export.

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[77] *The following language has been obtained from the docket for the current HQ contract. The docket order can be viewed at psb.vermont.gov/docketsandprojects/order/2010. Look for order #7670 dated 9-15-10.*

In addition to HQ, other Canadian hydro resources may be available to Vermont and the region in the future. Newfoundland and Labrador have started a new major hydro project, the Lower Churchill Development (includes Gull Island and Muskrat Falls project sites). This project is to be on line by 2015. When completed, this facility should add another 2,264 MW to the electric grid. Newfoundland and Labrador are investigating means to transmit excess power to New England and neighboring markets, and have indicated that further hydro development for export is in their long-term plans. Other hydro resources exist in neighboring provinces. Canadian exports of hydro power are expected to continue to be available to Vermont and the region; indeed, the available amounts will increase markedly in the coming decades.

- **New York Hydro.** Since the late 1950s, Vermont has obtained hydro power from the New York Power Authority (NYPA) and its predecessor, the Power Authority of the State of New York (PASNY). This power is very inexpensive thanks to historical federal subsidies for hydro dam construction. Until July 1985, Vermont received 150 MW of 0.2 cents per kWh energy from the St. Lawrence and Niagara hydro projects. As fuel prices soared in the 1970s, other states purchased low-cost NYPA power, reducing Vermont's share. NYPA directed Vermont's St. Lawrence project entitlement to drop from 68 MW in 1985 to 1 MW by 1994. Vermont's Niagara power entitlement has also been reduced (11.2 MW in 2004). Even at the reduced level, the price continues to make this energy attractive to Vermont. The power is purchased for Vermont municipal utilities.

- **Connecticut and Deerfield River Dams.** Some Vermonters feel that in 2003, Vermont lost an opportunity to gain ownership of and access to the eight hydroelectric dams on the Connecticut and Deerfield Rivers with their nearly 500 MW of renewable power, when the prior owner suffered financial distress and sold the dams. The final cost of the purchase to the new owner, TransCanada—$500 million—would have added significant increased risk to Vermont's finances and, given market electric prices between 2003 and 2011, would not have been offset by savings in retail sales. Since many Vermonters value this local renewable resource, which provides some tax revenue and jobs to the state, it would be a positive step for Vermont utilities to enter into contracts for power from the eight dams, if acceptable price and quantity terms could be negotiated. The state will also watch for any new opportunity to purchase these hydro facilities if they become available.

Recommendations for Hydro

(1) *Maintain the existing Vermont-based hydro projects in the Vermont energy portfolio, and ensure all hydro projects conform with Vermont Water Quality Standards.*

(2) *Continue to work with FERC and the Army Corps of Engineers to integrate the federal and state permitting processes to avoid delays and duplication while maintaining a high standard of environmental protection for hydro siting.*

(3) *Simplify permitting for installation for run of river projects at existing dams. Continue to provide initial project reviews for proposals in the feasibility study phase to identify environmental issues that will need to be addressed during the permitting process.*

(4) *Encourage increased hydropower production at existing sites and projects that add hydropower to existing water supply and wastewater treatment systems.*

(5) *Investigate the possible use and potential environmental impacts of pumped storage hydro to see if it should be a part of Vermont's energy mix.*

(6) *Investigate the removal of existing dams that are not appropriate candidates for hydropower after first determining their hydroelectric potential and environmental circumstances.*[78]

(7) *ANR should investigate developing an explicit "low-impact" standard for hydro power.*

(8) *The DPS and ANR should produce a guide for those interested in developing small hydroelectric projects to help with understanding the economic and environmental issues, the regulatory system, and the importance of initial project reviews.*

(9) *Vermont utilities should investigate securing additional stable long-term hydropower supply potentially available from Canadian provinces and from hydro projects adjacent to Vermont.*

(10) *Because many hydro stations in Vermont are historic, the DPS and hydro developers should partner with the Vermont Division for Historic Preservation to streamline required historic project reviews and potentially help developers qualify for federal historic tax credits for rehabilitation work on hydro station buildings.*

5.8.3 Solar: Photovoltaic Electric

Photovoltaic (PV) electricity is created by sunlight hitting specially constructed substrates.[79] Contrary to public perception formed by Vermont's long winters, sunlight is Vermont's most abundant renewable energy resource. For illustrative purposes only, consider that Vermont's solar resource could generate 100% of the state's annual

[78] *Because dams serve multiple purposes, the Legislature has required that dams meeting certain criteria cannot be removed unless their hydroelectric potential is determined.*

[79] *Silicon is the most common material used, but other materials are being developed and deployed.*

electricity consumption (5.5 billion kWh) with a solar array of 23 square miles (~0.25% of the state's total land area) using today's PV technology.[80]

Vermont has recently seen a tremendous growth in the amount of PV deployed across the state, as shown in Exhibit 5-9. Long considered an inconsequential niche player in the electrical sector, PV is now becoming a serious and meaningful contributor to the state's electrical needs and is an important part of Vermont's renewable energy industry.

One reason for the dramatic increase in the use of PV is that the technology has been advancing, bringing the cost steadily downward. The cost to install 1 kW of PV in Vermont has dropped approximately 40% in the last six years.[81]

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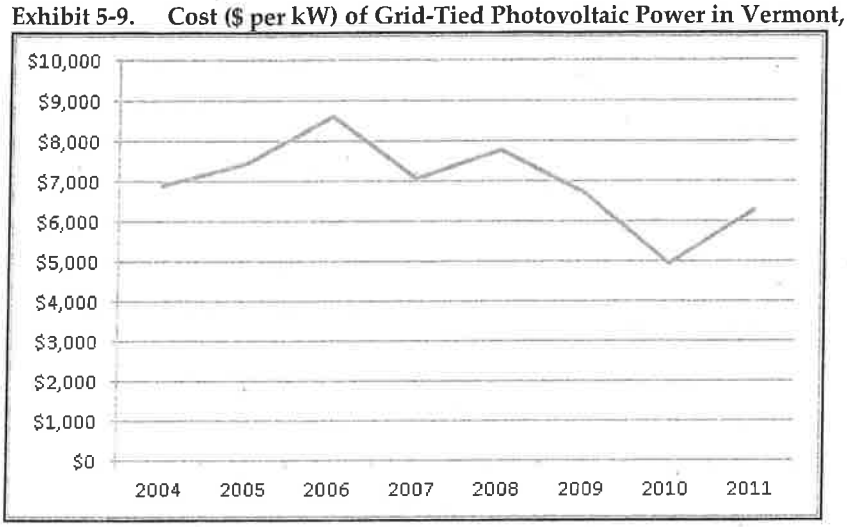
[80] *Solar thermal electric technology uses the thermal energy of sunlight to create steam to generate electricity. At this time Vermont does not have any solar thermal electricity plants in operation or planned, nor are any of the utilities purchasing this type of power from outside Vermont. Solar thermal is not a technology the CEP expects to produce any meaningful amount of electricity in Vermont. However, it is important to differentiate solar thermal energy from solar thermal electric production. Solar thermal energy used for heating is recommended as an important energy source for Vermont and warrants the increased focus of energy policy initiatives. Solar thermal energy is discussed further in Section 8, Thermal Energy Sources.*

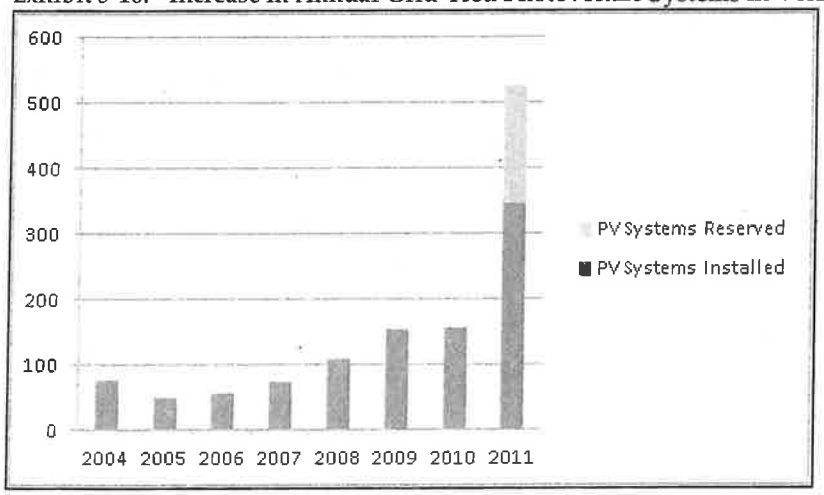
[81] *Vermont Small-Scale Renewable Energy Incentive Program data, 2004–11.*

Exhibit 5-9. Cost ($ per kW) of Grid-Tied Photovoltaic Power in Vermont, 2004–11



Source: Vermont Small Scale Renewable Energy Program, through June 2011

Exhibit 5-10. Increase in Annual Grid-Tied Photovoltaic Systems in Vermont



Source: Vermont Small Scale Renewable Energy Program

Although Vermont's total installed PV capacity is small compared to that of larger states, Vermont is already one of the top 10 states for PV on a per capita basis. This is impressive given Vermont's small size, lower incentive levels, and lower solar resource compared to other states.

Exhibit 5-11. Top 10 PV Capacity per Capita[82]

State	Cumulative 2010 PV Installations (WDC /person)
1. Nevada	38.8
2. Hawaii	32.9
3. New Jersey	29.6
4. California	27.4
5. Colorado	24.1
6. New Mexico	21
7. Arizona	17.2
8. District of Columbia	7.4
9. Connecticut	6.9
10. Vermont	***6.4***

A potential drawback of PV power is that when compared to the current market price forecast for electricity, the price of PV remains high. However, PV power has several advantages that make it a power source that the state should continue to support. PV is largely a peak electric load–following resource, meaning that during peak summer loads, the PV systems are at their highest production, resulting in peak shaving and grid reliability benefits. In addition, PV power is generated without noise, requires low levels of maintenance, emits no pollution, and is extremely distributable.

The Vermont Small Scale Renewable Energy Program (also called the renewable energy rebate program) has helped bring down the capital costs necessary to install PV and has been very popular and successful.

Exhibit 5-12.[83] Vermont Small Scale Renewable Energy Program Solar PV Metrics

Metric	Value
Total Number of Systems Installed	892
Total Cost of Installed Systems	$27,593,675
Incentives/Rebates Paid for Installed Systems	$5,204,802
Total Installed Capacity (kW)	3,674
Estimated Annual kWh/yr production	4,213,659

[82] *DPS data combined with data from the Interstate Renewable Energy Council's 2011 Report on 2010 PV installed capacity.*

[83] *Vermont Small Scale Renewable Energy Program Data from January 2004 through August 2011.*

In addition to offering the rebate program, Vermont has supplied incentives to larger PV projects through the Clean Energy Development Fund[84] grant and loan program as well as through business solar tax credits. This state's investment in the development of PV has paid off in several ways over the last 10 years by producing:

- Exceptional growth of PV installations.
- The leveraging of tens of millions of private dollars invested in local real property.
- The growth and increased maturity of Vermont's PV industry.
- An increased number of jobs in the PV sector.
- An increased amount of locally produced renewable electricity.

Further discussion of PV is broken down into three categories: (1) residential, (2) community and commercial, and (3) utility systems.

5.8.3.1 Residential PV

Residential PV is defined here as systems under 10 kW of rated capacity and installed at a home. Such home-based systems are commonly installed on south-facing roofs, but are increasingly being deployed on the ground with pole-mounted systems, including those that actively track the sun. PV's ability to be easily installed on many homes makes it a popular choice for Vermonters who want to produce their own renewable electricity and participate in creating the clean energy future for which Vermont is striving. Given this, the state should work to ensure that Vermonters have access to the grid for interconnecting PV and that buildings are constructed to allow Vermonters to make the investment in a solar system.

The CEP also encourages community and commercial net metered projects, but the presence of more community and commercial projects should not prohibit homeowners from installing PV systems. Currently, the net meter law caps installations at 4% of a utility's total load. Although system reliability is paramount, the CEP recommends exempting residential installed PV systems of up to 10 kW from the 4% cap, subject to utility infrastructure needs, so that homeowners continue to have the ability to install small systems.

Recommendations for Increasing the Deployment of Residential PV

(1) Update the permitting process for net metering to a web-based electronic procedure.

[84] *The future of the Clean Energy Development Fund and funding decision methodology is further discussed below.*

(2) *Facilitate the statewide collection of aerial photographs or LiDAR images through interagency cooperation and add them to the Vermont Renewable Energy Atlas to allow for better remote site assessments.*

(3) *Extend the 10-day registration-type permitting for net metered systems from 5 kW to 10 kW.*

(4) *Investigate the possibility of utilities' offering customers the option of making PV loan payments on their electric bills.*

(5) *Work with the state and towns to address property tax uncertainty regarding residential systems.*

(6) *Continue providing rebates for PV systems with the goal of reducing the incentive amounts as prices of PV power come down and the market matures.*

(7) *Exclude all residential PV systems up to 10 kW from the calculation of each utility's 4% net metering cap, subject to utility infrastructure needs, effectively allowing an unlimited amount of these very small home-based systems.*

(8) *Establish new solar-ready building standards for new residences.*

5.8.3.2 Community and Commercial PV

Community and commercial PV systems can range from a small net metered system installed on a business to systems of up to 500 kW.[85] Recent changes to Vermont's first-in-the-nation group net metering law make it much easier for entire communities or just a few neighbors to group together to take advantage of PV electricity's benefits. Group net metering is also being used by companies that have multiple locations to meet their power needs with renewable energy by installing one large system at the best location, instead of putting in several smaller installations at different locations.

Like homeowners, businesses are increasingly installing PV systems. Almost all the current commercial PV installations are net metered, under the prior net metered cap of 250 kW. The largest net metered PV system presently is the 200 kW system located at IVEK Corporation's offices in Springfield, Vt.

Due to net metering certificate of public good (CPG) rules, most commercial systems are designed for a capacity of less than 150 kW. This is because projects above 150 kW have a more complex and lengthy permitting and interconnection approval process with the PSB and the interconnecting utility. The 150 kW threshold for more extensive review may no longer be the best capacity point for PV systems. We recommend that the DPS,

[85] *Act 47 of 2011 increased the net metering cap to 500 kW (30 V.S.A. § 219a).*

utilities, and stakeholders collaboratively investigate the best capacity level at which a PV system needs a more thorough review for both the interconnection and CPG approval processes.

We anticipate that as communities develop the best organization for net metered groups, the state will see a rapid increase in the deployment of larger group net metered PV systems in the 150 kW to 500 kW range.

Recommendations for Community and Commercial PV

(1) *The DPS, utilities, and stakeholders should collaboratively investigate the best capacity level at which a PV system needs a more thorough review for both the interconnection and CPG approval processes, determining whether the current 150 kW capacity trigger is the appropriate level, and if it is not, suggesting what a more appropriate level would be.*

(2) *Based upon the Department of Taxes/DPS study currently under way, the Vermont Legislature should establish a state property tax formula for commercial-sized PV systems over a certain kW size.*

(3) *The state should work to install PV systems on state buildings, either directly or with PV developers under leasing or other such financial arrangements, and should continue to find creative cost-saving uses of PV systems for remote power needs, such as in state parks, telecommunication sites, and roadway signage.*

(4) *Establish "solar ready" construction standards for commercial and public buildings. All new state buildings should be designed and built as solar ready if a PV system is not installed during construction.*

5.8.3.3 Utility-Scale PV Systems

Utility-scale systems are those above 500 kW in size. In 2010, Vermont commissioned its first PV system above the net metering size. Vermont now has two utility-scale projects operating and others under active development. The Ferrisburgh Solar Farm is a 1 MW plant, and the Chittenden County Solar Partners project in South Burlington is a 2.2 MW plant that uses Vermont-built trackers. A third utility-scale project is being developed in Pownal, Vt. Construction on this 2.2 MW project is planned to begin in 2012.

Without the financial assistance provided by the state and federal government, it is unlikely that these utility-scale systems would have been built. The Standard Offer Program provided fixed long-term contracts for the power. In addition, the Vermont Business Solar Tax Credit made the economics for these projects favorable enough for the developers to take on the capital risks in bringing these projects on line.

With the economies of scale, utility-scale systems are the most cost-effective way to install PV. However, these large systems require large open spaces with good southern exposure. Thus, concerns about land use and aesthetic impacts of such large systems should be addressed.

Recommendations for Utility-Scale PV

(1) *Investigate the need for changes to Vermont's PV interconnection standards for utility-scale systems.*

(2) *Based upon the Department of Tax/DPS study currently under way, the Vermont Legislature should establish a state property tax formula for utility-scale sized PV systems.*

(3) *The State should ensure, through the Section 248 process, that there is not an undue loss of access to prime agriculture land due to utility-scale PV systems.*

5.8.4 Wind Energy

Wind power generation grew by 15% in 2010, providing 26% of all new electric generating capacity in the U.S.[86] Wind projects across the country now supply enough electricity to provide power for approximately 10 million homes.[87]

In Vermont, 1.2% of electric power is currently sourced from wind energy, all of it generated in-state at the Searsburg and Sheffield wind facilities, and at other small systems across the state. Total installed wind power capacity available for Vermont use is 28.85 MW; this would produce approximately 74.8 GWh annually. Significant growth is expected. As shown in Exhibit 5-13 below, a number of utility-scale projects are currently proposed or under construction in Vermont. If all of these projects become operational, the combined capacity will be 161.6MW. The power contracted for delivery in Vermont, including a New Hampshire project under construction, will total 192.8 MW. This potential equates to approximately 9.2% of Vermont's 2009 total electric portfolio.

Wind power is considered a complement to solar in a renewable portfolio. When solar power is low or unavailable, during cloudy days or at night, the wind is often more potent. For example, during Vermont's winter, when sunlight is diminished, average wind speeds measure at their annual high. Wind power is intermittent in nature, like other renewable sources of power; thus, resource planning for effective grid integration is required.

Vermont could continue to add wind power to its portfolio in several ways—wind purchased from out-of-state wind projects, in-state wind projects, and small-scale net metered installations that serve homes, businesses, and

[86] *2010 AWEA U.S. Wind Industry Annual Market Report.*

[87] *Ibid.*

communities.88 Regardless of Vermont's own wind power development, it is clear from the projects in development regionally that wind energy will be a growing source of electric supply in the regional markets.

Exhibit 5-13. Wind Projects in Vermont's Electric Portfolio

Scale	Project	Developer	Location	Turbines	Turbine Capacity	Project Capacity	Status
Utility Scale, In VT	Searsburg	Green Mountain Power	Searsburg	11	.55 MW	6 MW	Operating
	Deerfield	Iberdrola	Searsburg & Readsboro	15	2 MW	30 MW	Permitting
	Georgia Mountain Community Wind Project	Georgia Mountain Community Wind, LLC	Milton and Georgia	5	1.5–2.5 MW	7.5-11 MW	Permitting
	Kingdom Community Wind	Green Mountain Power	Lowell	21	3.0 MW	63 MW	Under Construction
	First Wind Sheffield	First Wind LLC	Sheffield	16	2.5 MW	40 MW	Operating
Utility Scale, Out of State						**Capacity Sold to VT**	
	Granite Reliable Power Windpark	Nobel Environmental Power	Coos County, NH			65MW	Under Construction
Small Community				**# Sites**	**Avg kW**		
	Net-Metered[89]	Various	Various	158	10 kW	1.6 MW	Installed
	Standard Offer	Various	Various	6	1,675 kW	10.1 MW	Proposed

5.8.4.1 In-State Wind Power

Vermont's mountain ridges provide considerable technical potential for the development of wind resources. The achievable potential is much less; sites are eliminated as various factors are considered, including environmental matters, visual issues, ownership patterns, access to transmission, and other factors. Improved technology, changes in facility costs, and changes in energy prices also influence the viability and achievable potential of sites.

In 2002–03, the Department of Public Service participated in a U.S. Department of Energy study[90] that estimated Vermont's theoretical wind power potential to be approximately 6,000 MW. The study considered the strength

[88] *In Vermont, wind facilities rated at no more than 100 kW are considered small scale. Those rated up to 500 kW can be net metered. Larger facilities are classified as commercial or large scale.*

[89] *This includes grid-connected installations only. The DPS does not presently have a means of tracking off-grid small wind turbines.*

of the wind resource and proximity to the existing electric transmission and distribution (T&D) system, as well as using several criteria to exclude environmentally sensitive and other non-compatible land use areas. A 2010 study by the National Renewable Energy Laboratory (NREL) arrived at similar conclusions when plants with 30% gross capacity factor were considered.[91] In 2006, the Green Mountain National Forest updated its Forest Plan.[92] The plan identified over 160,000 acres on which wind development is allowed and approximately 20,000 acres on which wind development actually may be suitable, including the Deerfield Wind Project location.

Many sites identified in the studies above with high wind potential are owned by the state or federal government. In 2004, Vermont's Agency of Natural Resources explored wind power potential on state-owned lands and concluded that large-scale wind project development on state lands is incompatible with the Agency of Natural Resource's mission of land stewardship.[93] The policy did acknowledge that small-scale projects that are compatible with existing management plans could be allowed. The Agency recently did allow a 100 kW turbine to be installed on state forest land leased to the Burke ski area.

Completed in 1997, Green Mountain Power's Searsburg wind farm was the first utility-scale wind power facility in the Eastern United States. The Searsburg project was selected by the U.S. Department of Energy (DOE) and the Electric Power Research Institute (EPRI) for participation in the Utility Wind Turbine Verification Program, with a goal, in part, of verifying the performance of wind turbines in cold climates. Ten-plus years of wind measurements indicate the average wind speeds along the ridge are 15 to 17 mph. Annually, 11 Searsburg 550 kW turbines produce about 12,000 MWh; this is enough to power about 1,700 homes.

Since Searsburg's development, turbine capacity for inland sites has grown from approximately 500 kW to 3 MW; turbines are also now taller, with larger capacities. Continuing technical improvements have increased turbine capacity and reliability, and reduced the costs of production.

As shown in Exhibit 5-13 above, several new Vermont wind projects are in various stages of development. The First Wind project in Sheffield came on line in October 2011, with a rated capacity of 40 MW. The Lowell project is under construction now, and will add 63 MW of capacity once completed. The Deerfield project rated at 30 MW is not yet under construction, but has contracted with CVPS to sell 66% of its output for the first nine years. A portion of the electricity from Sheffield and Deerfield will be sold out-of-state during the expected life of the projects.

A map and listing of all the wind turbines installed in Vermont, including small-scale wind, can be found in the Vermont Renewable Energy Atlas, www.vtenergyatlas.com.

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[90] *Wind and Biomass Integration Scenarios in Vermont Summary of the First Phase Research: Wind Energy Resource Analysis, March 2002,* www.perihq.com/documents/wind-biomass_integration_scenarios_in_VT.pdf.

[91] www.windpoweringamerica.gov/wind_resource_maps.asp?stateab=vt&print.

[92] www.fs.fed.us/r9/forests/greenmountain/htm/greenmountain/links/projects/forestplan.htm.

[93] *See* www.vtfpr.org/wind/index.html.

As of October 2011, 158 small wind installations have been permitted for net metering. These systems total a combined capacity of 1.6 MW. Under the Standard Offer Program, there are six proposed projects with a total capacity of 10 MW. The DPS does not presently have a means to track off-grid small wind turbines.

Small-scale wind facilities are most often represented by a single turbine, which can range from less than 1 kW to 100 kW for a small commercial turbine. A number of factors affect the success of a small wind project. In order to harness the best wind spectrum, turbine siting is absolutely critical within the microclimate of the landscape. Turbines must be positioned so they extend as high as possible above obstacles. Technical expertise to maintain the system is also essential to securing years of optimum performance.

5.8.4.2 Out-of-State Wind Power

Wind generation projects are being built across the Northeast and in bordering provinces in Canada. Vermont utilities will be purchasing wind power from some of these resources into the future. In November 2010, ISO-NE completed the New England Wind Integration Study[94] acknowledging that public policy initiatives to increase renewable sources of energy and reduce carbon and other emissions are driving the development of large-scale wind generation. These include state renewable portfolio standards, emissions reductions of sulfur dioxide (SO_2) and nitrogen oxide (NOx), and regional carbon dioxide (CO_2) efforts such as the Regional Greenhouse Gas Initiative.

Below is a brief description of wind development goals and some wind projects in progress in our region:

- In Coos County, N.H., the Granite Reliable Wind project is under development. The facility's owner, Nobel Environmental Power, has contracted with CVPS and GMP to purchase 65 MW of the 99 MW project, for a period of 20 years starting April 1, 2012.
- According to Maine's 2009 Comprehensive Energy Plan, Maine is poised to develop 2,000 MW of land-based wind by 2015 and nearly 3,000 MW of on-shore and offshore wind by 2020. Maine views its offshore wind resource as an important export.
- The Massachusetts Clean Energy and Climate Plan for 2020 includes a goal of 2,000 MW installed wind power in state by 2020, much of which is to be supplied from offshore facilities. The Cape Wind project may be the first significant offshore wind project in the U.S. if built; its capacity will be 468 MW.
- In 2001, the New York State Energy Resource and Development Authority (NYSERDA) reported that 41.5 MW of wind energy was in operation in New York and that 425 MW of new wind energy was proposed. By 2011, installed wind power capacity in New York was more than 1,300 MW.[95]

[94] www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/nov162010/newis_iso_summary.pdf.

[95] www.windpoweringamerica.gov/wind_installed_capacity.asp.

- Hydro-Quebec's (HQ) on-line wind generation capacity currently is 547.5 MW, with 211.5 MW under construction and 1,873 MW planned to be installed by 2015.[96]

It is clear that, regardless of Vermont's own utility-scale wind production, wind energy will be a growing resource in the regional market.

5.8.4.3 Balancing the Benefits and Challenges of Wind Power Development

Like other large electric generation technologies, wind generation has impacts and trade-offs that require careful evaluation and decision making. These trade-offs are discussed in detail below.

5.8.4.3.1 Relative Cost and Price Stability

New wind generation is the least expensive form of new renewable energy electric generation to build in Vermont today. That said, the high permitting and construction costs have a major impact on the total electricity costs of wind power in Vermont. Once a system is installed, however, operating costs are relatively low. This leads to stable pricing over the projected 20-year life of a typical installation. For new facilities, the Energy Information Administration's Annual Energy Outlook 2011 projected that by 2016 the total cost of electric generation will be 10 cents per kWh for inland wind, compared to 7 cents per kWh for combined cycle natural gas, and 24 cents per kWh for offshore wind.[97]

5.8.4.3.2 Reduced Emissions

The generation of wind power itself produces no emissions; wind generation in New England is estimated to save 828 lb of CO_2 per MWh generated. Thus, all wind projects now installed in Vermont reduce approximately 106.7 million lb in CO_2 emissions annually. If all proposed wind projects sited in Vermont are included, CO_2 annual emissions saved will be approximately 376.8 million lb per year.[98] Under present laws, Vermont wind projects may sell electricity and renewable energy certificates out-of-state, allowing the out-of-state buyer to gain the emissions credits and other environmental credits. If all proposed wind projects contracted to sell in Vermont are included, annual CO_2 emissions saved will be approximately 459.8 million lb.

5.8.4.3.3 Aesthetics

The beauty of Vermont's natural scenic landscape cannot be overstated. Thus, the permitting process for all energy facilities includes a review of the aesthetic impact of the proposed project. For wind power projects, the

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[96] www.hydroquebec.com/distribution/en/marchequebecois/parc_eoliens.html.

[97] *Energy Information Association's Annual Energy Outlook 2011,* www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf.

[98] *These calculations present the full production capacity of all projects sited in Vermont, and include CO2 emissions for power and RECs sold out of state. These calculations used 15% capacity factor for net metered and 20% capacity factor for Standard Offer.*

aesthetic question is often more pronounced and controversial than it is for other generation projects. Wind power aesthetic concerns arise from the visual impacts of both the turbines and hazard lighting, from near and far perspectives, during the day and the night.

In order to start construction, wind turbines must be granted a certificate of public good (CPG) from the PSB. To assess the aesthetic impact, the PSB judges whether the structures will create "undue adverse impacts on the scenic and natural beauty of the area." The PSB reviews state and local standards, as well as testimony from experts, elected and governmental officials, and citizens. The DPS has engaged aesthetic experts for the permitting process to provide testimony on the aesthetic impact of proposed wind power projects. Simulated pictures and drawings of the proposed project are presented from different viewpoints, near and far. Many factors are considered. Ultimately, the PSB must find that the societal benefits of a project outweigh the adverse aesthetic impacts in order to grant a CPG.

To guide a more systematic review of aesthetic impacts for small-scale systems, the PSB has developed a scoring system. Its brochure, "Siting a Wind Turbine on Your Property," offers advice to those planning a wind site.[99] Larger projects present different concerns and challenges. For example, given Vermont's narrow ridgelines, should projects within view of the Long Trail, or of a historic downtown, or of a popular mountaintop, from a given distance categorically fail the aesthetics review? Should the answer depend on the cost of the power and other economic benefits? Though these questions will never receive uniform answers from all Vermonters, to help bring more uniformity to the aesthetic review process for utility-scale projects, the DPS is investigating either expanding its in-house staff expertise or creating longer-term contractual relationships with aesthetics review experts.

5.8.4.3.4 Environment

The windiest areas in Vermont are most often on the higher-elevation ridgelines that can host sensitive habitats for plants and wildlife, and are the source of the state's most pristine headwaters. In previously roadless areas, permanent road access is built to service the wind facility. The Wilderness Society cites a number of potential environmental harms caused by wind facilities: bird and bat injuries, habitat disruption and fragmentation, erosion, pollution from facility maintenance, turbine noise, and visual flicker.[100] These environmental disturbances can impact wildlife and people in the vicinity of a wind facility. All of the impacts are carefully assessed during the CPG process.

To aid siting of all types of energy projects, including wind power, ANR is engaging in a natural resource identification and mapping project for renewable energy development. That process is expected to be completed by the end of 2012.

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[99] http://psb.vermont.gov/sites/psb/files/forms/PSB_Wind.PDF.

[100] *Ann Ingerson, July 2011, Renewable Energy in the Northern Forest, the Wilderness Society.*

5.8.4.3.5 Measured Production Capacity

The electrical output of a wind turbine is based on its technical capacity and the wind resource at the installed site—the average wind speed. Each wind project presents an estimated production capacity during the permitting process. Actual production is monitored continually once a project is operational. It takes a number of years to collect accurate output data once a site is operational.

There is often concern and confusion regarding wind power's capacity factor, which is a measurement of the projected or actual kWh production output versus the maximum output of a facility if it ran at its full rated capacity 100% of the time. Green Mountain Power (GMP) has rated the lifetime average capacity factor for Searsburg at 23.4%. In 2010, GMP measured Searsburg's most productive year due to above-average wind speeds, which resulted in a capacity factor of 30.6%. The Renewable Energy Research Laboratory at the University of Massachusetts rates the capacity factor for wind power at 20% to 40%.[101]

If the production capacity of a project is found to be below the estimated projected capacity presented during the permit process, the societal benefits anticipated for the project may not be realized. This issue is addressed during the CPG permitting process. The PSB has required reporting of power produced and has set minimum production requirements for a project that if not met would trigger PSB review of a project's CPG. As more projects with CPGs come on line, there will better data on the actual power production of wind turbines in Vermont's distinct environment, which can be used to evaluate the estimated production presented by any new proposed projects.

5.8.4.3.6 Wind Variability

The variability of wind generation and the complexities of accurate forecasting present challenges to the reliable operation and planning of the regional power system. ISO New England commissioned a comprehensive study of this issue, in response to the growth of commercial wind power in New England and neighboring electric systems. The results of this study, known as the "New England Wind Integration Study" and published in December 2010, analyzed wind penetrations of 2.5%, 9%, 14%, 20%, and 24%.[102] The study found that New England's regional electric generation system, which is dominated by natural gas–fired generators, is very flexible and compatible with wind generation. Natural gas generators are able to quickly ramp production up or down, in sync with variable production sources, such as wind and other renewables.

Other key findings of the ISO-NE study:

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[101] *Renewable Energy Research Laboratory, University of Massachusetts at Amherst, Wind Power: Capacity Factor, Intermittency,and What Happens When the Wind Doesn't Blow?* www.umass.edu/windenergy/publications/published/communityWindFactSheets/RERL_Fact_Sheet_2a_Capacity_Factor.pdf.

[102] http://iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_es.pdf.

- Wind could meet up to 24% of the region's electricity needs in 2020 under certain assumptions for load growth, conservation, and infrastructure forecasting improvements. This corresponds to 12,000 MW of installed nameplate capacity. Locational marginal prices were reduced by $5 to $11 per MWh in models for 20% wind penetration.
- Wind generation will displace fossil fuel generation, primarily natural gas–fired plants, which currently provide about 50% of New England's power.
- The region needs a flexible wind system, such as that afforded by its fleet of natural gas generators. Current generation resources are adequate even at 20% wind penetration.
- Regulation and operating reserve requirements will increase with wind penetration levels because of the inaccuracies inherent in predicting short-term wind power differentials. Day-ahead and hourly wind forecasting should be performed to optimize analysis of day-ahead and intra-day system reserves.
- ISO-NE should continue to research improvements to the calculation of wind production capacity values as it gains experience with wind energy.

Some studies report that as wind power supplies an increasing percentage of the ISO-NE grid, the wind's intermittency will have a greater impact on reliability. A 2005 study by Gregor Giebel cites various research papers, and concludes that as the penetration of wind power rises to 30% of an electric grid's load, the capacity credit of wind resources may be only 10% to 15%.103 Currently wind power is less than 0.5% of the ISO-NE grid,104 but there is a focus among system planners to optimize resources in light of growing energy production from intermittent renewables.

The issues of optimization need to be considered in the context of the entire ISO-NE power pool. Wind integration has been extensively modeled by ISO-NE. ISO-NE is implementing new technology (intelligent software complemented with distributed measurements of supply and demand, including advanced meters) and practices to efficiently manage the power system's variable renewable resources. For example, ISO-NE's 2012 system plan and budget calls for greater wind forecasting resources, to help balance loads through more precise just-ahead forecasting of wind speeds.

The National Renewable Energy Laboratory states, "with increased experience in integrating wind generation and balancing various sources of electric power over a large power control area, utility grid operators have learned how to reduce variability and limit reserve additions to modest requirements when wind generation is

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[103] *Gregor Giebel, Risø National Laboratory, Wind Power Has a Capacity Credit: A Catalogue of 50+ Supporting Studies, GGiebel-CapCredLit_WindEngEJournal_2005_right_links[1].pdf.*

[104] *ISO New England, 2010 Annual Markets Report, www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2010/amr10_final_060311.pdf.*

brought online."105 ISO-NE's December 2010 "New England Wind Integration Study" agrees.[106] ISO-NE does not portray the capacity backup requirement of wind or other variable resources as a major cost or impediment to an efficiently integrated system in New England. Instead, it is discussed as a technical adjustment that is diminishing in consequence as the power pool adapts.

5.8.4.3.7 Permitting Issues

In Vermont, the primary permit for all electric generation projects is a certificate of public good (CPG) issued by the Vermont Public Service Board (PSB) under 30 V.S.A.§ 248 of Vermont's statutes. After considering statutory criteria and weighing the overall costs and benefits of the proposed project, the PSB must find the project promotes the general good of the state.

Among the criteria, the PSB considers local ordinances and town and regional plans, and whether such plans specifically address renewable energy siting.[107] Statutory parties[108] include the Department of Public Service, "representing the public interest," and the Agency of Natural Resources (ANR), whose "mission is to protect and improve the health of Vermont's people and ecosystems and promote the sustainable use of Vermont's natural resources." The Vermont Division for Historic Preservation has developed a protocol for evaluating impacts of wind, transmission, and cell tower installations on historic resources, in order to foster predictability in project permitting. (See www.historicvermont.org/programs/evaluatingcelltowers.pdf.)

The permitting process includes approval of binding plans for transportation, blasting, post-construction monitoring of sound and wildlife impacts, and decommissioning. The PSB considers on-site mitigation; purchase and development of alternative sites; and impact fees for recreational, scenic, natural, and cultural resources deemed unduly affected. Mitigation, alternative sites, and fees need be in place only until the facility is fully decommissioned and the environment repaired, unless there are clearly specified permanent disturbances.

Many interveners in wind project matters have voiced concern that the PSB process makes it too expensive for them to effectively participate. Others have faulted a lack of process for resolution of objections apart from full-scale litigation. Meanwhile, wind developers ask for relief from higher costs and permitting times in Vermont, which exceed those of neighboring states.

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[105] *D. Jacobson and C. High, National Renewable Energy Laboratory, February 2008, Wind Energy and Air Emission Reduction Benefits: A Primer, Subcontract Report NREL/SR-500-42616.*

[106] http://iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_es.pdf

[107] *A number of municipalities and regional commissions have voiced disagreement with the designation under Act 250 and Title 30 of "public power generating plant" for small-scale turbines.*

[108] http://psb.vermont.gov/statutesrulesandguidelines/guidelines/GuidetoFiling248Petition

In 2004, the Vermont Commission on Wind Energy and Regulatory Policy provided recommendations[109] on whether 30 V.S.A. § 248 provided appropriate review of "commercial"[110] wind generation projects. The Commission identified Section 248 as "the appropriate vehicle for siting commercial wind generation projects." It made recommendations that included increasing public involvement and encouraging developers to collaborate early with stakeholders; these recommendations have been subsequently implemented by the PSB. Recommendations included as part of this section address the Commission's recommendation of appointing an ombudsperson.

Recommendations

As we weigh the benefits and drawbacks of wind generation, we conclude that wind power should continue to be an important renewable resource for Vermont's diverse electricity portfolio going forward. To improve wind project permitting and siting and to address some of the concerns that have been raised regarding these projects, we recommend the following:

(1) Vermont utilities should continue to monitor opportunities to purchase cost-effective in-state and out-of-state wind generation to add to their sources of energy supply.

(2) Vermont should continue to facilitate development of in-state wind projects in order to achieve the state's renewable energy goals, with particular focus on community and small-scale projects. For utility-scale projects, development should be permitted if there are significant economic and societal benefits to Vermonters, and all other CPG criteria are fulfilled.

(3) ANR should complete its natural resource inventory and mapping project to identify resources that may affect siting for the build-out of renewable energy projects, including utility-scale wind generation.

(4) The DPS, the ANR, and the PSB should consider developing generic siting guidelines for developers of wind projects, to aid permit process uniformity and provide guidance on aesthetics and other common issues. Regarding consistency among siting renewable resources, refer to Section 5.10.6 Regulatory System—Recommended Improvements.

(5) Site decommissioning plans for utility-scale wind projects should continue to cover criteria for deconstruction and remediation upon permanent retirement of each turbine, where appropriate, as well as the entire site.

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[109] http://publicservice.vermont.gov/energy/ee_files/wind/WindCommissionFinalReport-12-15-04.pdf

[110] *Commercial was defined as "larger than net metered projects, which are generally 150 kW or less."*

(6) *Hazard lighting for turbines should use radar-activated lighting wherever possible.*

(7) *For wind siting, and all other Section 248 siting proceedings; the DPS and the PSB should develop a mediation program to be used to resolve disputes among parties. Mandatory mediation at points in the process should be considered. For additional comments on this recommendation, refer to Section 5.10.6 Regulatory System—Recommended Improvements.*

5.8.5 Natural Gas

In 1995, less than 10% of the regional energy mix was natural gas. Currently, roughly 40% of the energy sold on the wholesale market is from natural gas. Ninety-eight percent of the region's capacity additions since 1999 have come in the form of high-efficiency natural gas combined-cycle generation facilities. Natural gas now sets the market price of wholesale electricity in most hours.

Reduced demand combined with shale gas discovery and extraction has driven recent natural gas prices lower, and decoupled the natural gas price from the rising price of oil. Shale gas refers to natural gas that is trapped within shale formations. Shales are fine-grained sedimentary rocks that can be rich sources of petroleum and natural gas. Over the past decade, the combination of horizontal drilling and hydraulic fracturing has allowed access to large volumes of shale gas that were previously uneconomical to produce. The production of natural gas from shale formations has rejuvenated the natural gas industry in the United States. Dramatic increases in the quantity of technically recoverable shale gas resources, coupled with decreases in the expected costs of finding, developing, and producing gas from those resources, is leading to lower projections of avoided costs for natural gas and gas-fired electric energy.[111]

The environmental effects of shale gas may lead to reduced exploration and extraction, adding costs and calling into question projected low prices. An area of uncertainty for shale gas "is the potential impact of changes in the future regulation of shale gas development; in particular changes in the future regulation of hydraulic fracturing. Concerns have been raised regarding the need for additional regulation of hydraulic fracturing in order to minimize its environmental impacts on groundwater, surface water, and air emissions and the potential impact of such changes in regulation on shale gas production quantities and cost."[112] Nevertheless, shale gas is having a present and significant effect on prices in the regional energy markets, and is projected to continue to do so.

Extraction technique aside, natural gas is not as environmentally friendly or as stably priced as renewable energy, but it is currently less expensive. It is also a far cleaner resource than coal or other fossil fuels, when properly extracted and distributed. However, exposure to supply disruptions, price volatility, the region's heavy dependence on a single fuel source, and greenhouse gas emissions associated with the fuel are all reasons for caution.

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[111] *U.S. Energy Information Administration.*

[112] *Avoided Energy Supply Costs in New England: 2011 Report, July 21, 2011.*

5.8.5.1 Natural Gas Electric Generation

Natural gas is a secondary fuel source for the wood-fired McNeil generator in Burlington, and Vermont depends on a certain amount of natural gas generation from out of state. However, there are currently no electric facilities that burn natural gas as a primary fuel in Vermont. Vermont should consider allowing the construction of small or midsized natural gas electric generation plants, strategically located to enhance system reliability and help defer transmission system upgrades, or used as an anchor load to leverage expansion of the Vermont Gas Systems network to communities that are currently without natural gas. (See Section 8—Thermal Energy Sources regarding expansion of the natural gas system in Vermont.)

Increasing our use of renewable energy and decreasing our dependence on fossil fuels are important goals for Vermonters. Nevertheless, fossil fuel power plants are still a strategic component of the region's electric supply mix because of their ability to produce a certain quantity of electricity at a specifically designated time, and natural gas presents the best environmental and economic choice among fossil fuels used for that purpose. As we increase the amount of intermittent renewable energy in our portfolio, it will be important to ensure that we can meet Vermont's energy demand with resources that can guarantee delivery of electricity during periods of peak demand and low output from intermittent renewable energy. Since the Vermont Gas System peak is currently in the winter and the Vermont electric system peak is increasingly during the summer, there are excellent opportunities for additional peaking electric generation using natural gas. Natural gas has the potential to reliably provide electricity, producing fewer point-of-combustion emissions and minimal local air pollution or long-term pollution problems. Natural gas electric generation emits nitrogen oxides and carbon monoxide in amounts per unit of energy used that are similar to those of oil-fired plants. However, natural gas CO_2 and particulate emissions are considerably lower than those from other fossil fuel-powered plants, and natural gas plants present no long-term by-product waste concerns. Because of their lower capital costs and emissions profile, natural gas plants are ideal for adding more peaking generation capacity or small baseload capacity.

The decision regarding whether to permit natural gas-fired electric generation in Vermont must take into consideration that there is already a heavy dependence on natural gas generation in New England. Approximately 40% of both energy and capacity in the region currently comes from natural gas generators. Although Vermont's electric portfolio currently has only a moderate exposure to natural gas price volatility, increasing Vermont's dependence on variably priced electricity such as natural gas would expose Vermonters to additional energy price volatility. Therefore, it is important to size and locate any such plant to provide system reliability enhancements or other benefits, such as leveraging natural gas expansion as an available heating fuel.

Recommendations

(1) *Considering permitting strategically located natural gas electric generation closer to electric loads, constrained areas, or in locations that leverage natural gas thermal expansion or combine thermal energy and electric generation.*

(2) *The DPS, PSB, and VGS should continue to evaluate and take advantage of cost-effective opportunities to extend the natural gas service territory and/or site additional natural gas pipelines within Vermont's borders.*

5.8.6 Nuclear

Currently, five nuclear power plants operate within the New England grid, with a total capacity of 4,629 MW, supplying roughly 20% of the energy for the New England grid. Opinions gathered during the CEP public comment process and prior deliberative process indicated that Vermonters have polarized views regarding nuclear power and the role, if any, it should play in Vermont's energy future. Those opposed to nuclear power cite its safety risks and the lack of an adequate system for long-term disposal of nuclear waste. Those supporting nuclear power cite its low carbon profile at generation and ability to supply inexpensive baseload power to the grid. Whatever the future of Vermont Yankee—Vermont's sole large-scale electric generator, which first operated in 1972—a significant amount of nuclear power will continue to supply baseload energy to the New England grid and will be used by Vermont utilities as well as those of other New England states for years to come.

The Vermont Yankee Nuclear Power Station (VY or Vermont Yankee) presently supplies approximately one-third of the state's electricity needs, through sales to four of Vermont's utilities.[113] CVPS also owns 1.7% of the Millstone 3 unit located in Connecticut. This is a 1,155 MW plant first operational in 1986 that has received an extended operating license through 2045. Historically, Millstone has supplied about 5% of CVPS's power requirements.

Vermont Yankee is located in Vernon and is currently owned by Entergy Nuclear Vermont Yankee LLC, a subsidiary of Entergy Nuclear Operations, Inc., an independent owner/operator of nuclear facilities. Power is currently supplied to Vermont utilities through a purchase power agreement (PPA) executed when the plant was sold to Entergy in 2002. Entergy is the second-largest nuclear plant operator in the U.S., owning 10 nuclear plants, five in the South and five in the Northeast.[114] Prior to 2002, VY was owned by Vermont Yankee Nuclear Power Corporation (VYNPC), which was owned, in turn, by eight New England utilities. Vermont utilities owned 55% of VYNPC and received 55% of the output of the VY station.

In 2003, Entergy petitioned the PSB for an increase to the output, known as a power up-rate, at the VY plant of about 20%, from 510 MW to approximately 620 MW. In March 2004, the PSB conditionally granted that request, subject to an independent engineering assessment of the facility. The Nuclear Regulatory Commission (NRC) approved the power up-rate in 2005. As a result, the plant was able to increase power by approximately 120 MW. This additional power is owned by Entergy and sold into the New England market. As part of the proceeding before the PSB, Entergy agreed to a revenue-sharing provision related to its sales of up-rate power,

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[113] *This accounts for approximately 46% of the plant's total output. The other 54% is sold under contract to other states' utilities, or sold into the New England market.*

[114] *The other plants in Entergy's Northeast fleet are Pilgrim (Massachusetts), Indian Point Units 2 & 3 (New York), and James A. Fitzpatrick Nuclear Plant (New York).*

and this being the case the DPS agreed that the power up-rate proposal represented an economic benefit to the state of Vermont. Funds received from Entergy for operations through March 21, 2012,115 are used to support renewable energy development in the state through the Clean Energy Development Fund.

5.8.6.1 Future of Vermont Yankee

Starting in 1998, the NRC began granting 20-year operating license renewals to nuclear plants. A plant must obtain an NRC license renewal before running beyond its current license. In 2007, Entergy submitted its application to the NRC for a license renewal beyond the original March 2012 date. Entergy received that license renewal in March 2011. Entergy submitted a separate application to the Vermont PSB on March 3, 2008, to obtain a new certificate of public good (CPG) because the original CPG is set to expire in March 2012. The PSB opened a docket for this purpose. As a condition of its purchase, Entergy is prohibited from operating the plant beyond March 21, 2012, without obtaining a renewed CPG. Additionally, the Vermont General Assembly must approve the continued operation of the plant beyond its current CPG. The Public Service Board "may not issue a final order or a Certificate of Public Good until the general assembly determines that operation will promote the general welfare and grants approval for that operation," according to 30 V.S.A. § 248(e)(2). In February 2010, the Vermont Senate did not approve a bill that would have allowed the PSB to issue a final order in the CPG case. The Vermont House of Representatives did not take up the bill in that session.

Entergy has made several additional commitments regarding purchased power transactions should the plant receive permission to run past March 2012. These were the result of terms and conditions negotiated in the agreements made at the time of the sale of the plant in 2002. Entergy's commitments do not obligate the company to sell any power from the Vermont Yankee plant to Vermont utilities should it continue to run past March 2012, though a revenue-sharing agreement for sales beyond that date remains in place. Entergy has not reached agreement regarding power purchases with any Vermont utility beyond its CPG expiration date of March 2012 and, at this point, the Vermont utilities that receive VY power have planned to move beyond reliance on VY by purchasing market power hedges and investing in renewable projects and other long-term contracts to cover their exposure. For example, GMP entered into a long-term contract to obtain power from the Seabrook Station in New Hampshire, with a portion available to other Vermont utilities on similar terms and conditions, and CVPS entered into contracts to cover its near-term power needs presently supplied by Vermont Yankee. GMP and CVPS have also contracted for 99 MW of wind power from Granite Reliable.

In April 2011, after Entergy was unable to secure either a buyer for its facility or a long-term power contract and was unable to secure a Vermont legislative vote in favor of the CPG process, Entergy sued the state in federal court, claiming that Vermont's post-2002 legislative enactments and the CPG process itself are preempted by federal law. That suit is pending at the time of the CEP's publication. Should the plant prevail in its suit or otherwise continue the CPG process, many other matters, including decommissioning, water discharge, and other oversight issues, would have to be addressed in the state process.

[115] *There is one payment in March 2013 that will cover the January 2012–March 21, 2012, time period.*

The CEP will not take a position on whether VY should continue to operate; that is the role of state laws and processes and is the subject of the pending lawsuit. Instead, this document focuses on Vermont's energy future to prepare the state regardless of whether the plant ceases operation on schedule in March 2012. This being the case, the CEP recommends that Vermont utilities diversify their resource mix toward renewable energy and alternative low-carbon baseload resources.

Recommendations

(1) *Vermont electric utilities should continue to manage portfolio risk and explore strategies for source diversification to reduce the exposure to ratepayers from unit-contingent contracts.*

(2) *Vermont utilities should continue planning for alternatives to power from the VY facility, including through owned-generation projects, through system power contracts, and through merchant power obtained through negotiations or solicitations.*

(3) *Vermont utilities and agents that are party to the negotiations of major contracts, including out-of-state nuclear, should help ensure that the smaller municipal and cooperative utilities gain access to those resource contracts on similar terms and conditions.*

(4) *The state should continue to advocate for effective oversight of all safety aspects of the plant by the U.S. Nuclear Regulatory Commission.*

(5) *The state should continue to advocate for an appropriate and effective federal solution to the problem of spent nuclear fuel stored on site.*

(6) *The state should provide oversight of decommissioning funding and activities as permitted by law.*

(7) *The state should ensure that Entergy funding of environmental monitoring and emergency preparedness is sustained after March 21, 2012, regardless of whether Vermont Yankee operates or enters into decommissioning activities.*

5.9 Energy Storage

As Vermont expands its reliance on intermittent renewable energy, concerns about the effects on the grid increase. The New England grid has sufficient capability to handle the types and levels of renewable energy envisioned in the CEP in the short term. More specifically, it is expected that Vermont has the transmission resources to handle the level of renewable energy called for during the next five years. Increased efficiency investments will facilitate the ability of the current infrastructure to handle even higher levels for longer.

However, as Vermont's integration of renewable and other in-state electricity projects increases, certain interconnection and grid operation issues will need to be addressed. This must be considered for both smaller

systems installed in stressed distribution areas and large utility-scale renewable energy projects interconnected with the transmission system. These issues can be dealt with in numerous ways, including upgrades to the distribution and transmission infrastructure. Another solution that has promise in Vermont is the use of power storage technology. Power storage can smooth out the intermittent generation of renewable energy, can help meet peak demand, and can assist with optimization of the grid and power harmonics.

In South Burlington, the Dynapower Corporation is developing a power storage demonstration project that has promise to help integrate renewable energy into the grid. The project consists of a 1 MWh battery-based energy storage component, a highly efficient 1.5 MW bidirectional inverter, wind and solar renewable generation, and the associated controls to manage the system and communicate with the utility. This project will demonstrate the increased dispatch and utilizations of intermittent renewable energy sources that can be achieved with the addition of energy storage and advanced power electronics.

In addition, Dynapower's project demonstrates that systems of this size and complexity can be designed, manufactured, and commissioned almost entirely in the state of Vermont—providing the type of clean energy economic development envisioned by this CEP.

Power storage systems can benefit the utilization of the local grid by:

- Substantially reducing the demands placed on the grid by a large manufacturing facility through optimizing the use of renewable energy produced on site.
- Providing load leveling capability, reducing demand fluctuations.
- Demonstrating alternatives to infrastructure-based grid enhancement.
- Providing reserve energy to the local community during unexpected peak demands.

5.10 Tools to Create Desired Electric Portfolio

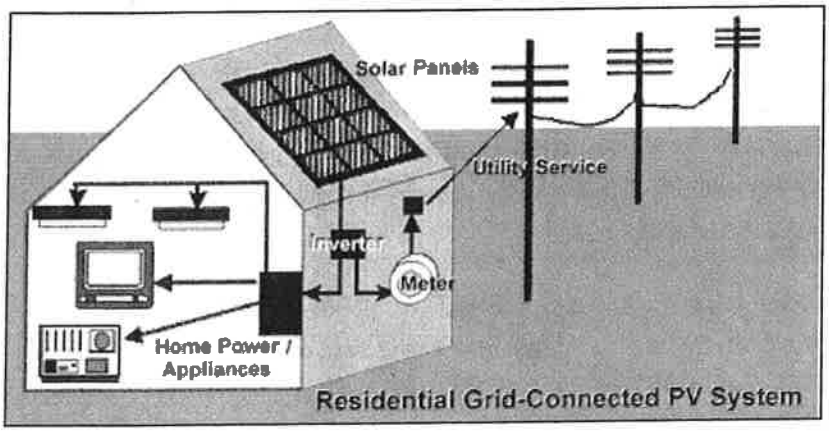
Vermont is blessed with renewable energy resources, access to electricity from a wide array of in-state and regional sources, and connection to three different power grids all larger than Vermont's in-state system. However, policy support is required if the state wishes to ensure that the electric sector portfolio facilitates the overall CEP goal of having 90% of total energy met by renewable sources by 2050.[116]

Broadly, the CEP recommends that utilities secure renewable power generation of all sizes, from small residential systems to large utility systems. The policy tools discussed here can be seen as directed to facilitate three different sizes of generation projects: residential, community, and utility-scale. Some of the policy tools needed to encourage each are discussed below.

[116] *Electric efficiency, the most cost-effective supply resource, is discussed in Section 4.*

5.10.1 Net Metering

The 1998 Vermont legislative session enacted a net metering law (30 V.S.A. § 219a), requiring electric utilities to permit customers to generate their own power using small-scale renewable energy systems. The excess power generated by these systems can be fed back to the utility, basically running the electric meters backward and providing the customer with a credit on his or her monthly electric bill.



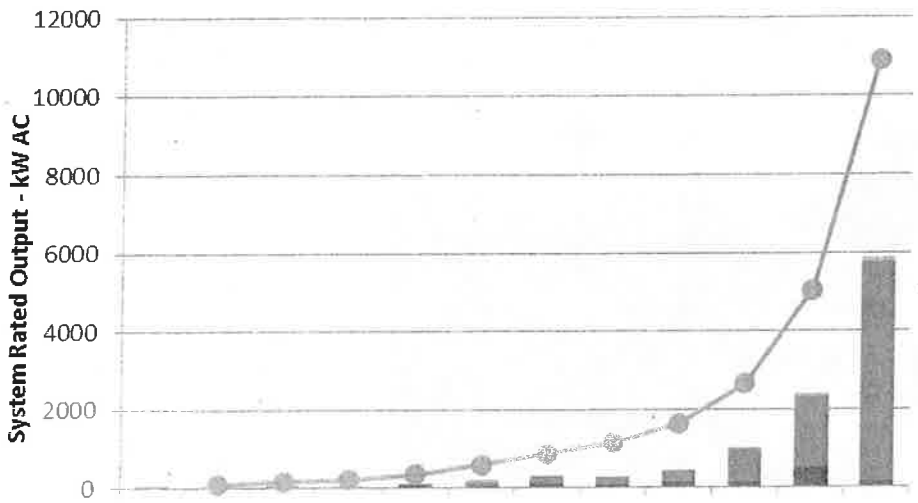
Thus, net metering provides customers with the ability to offset their use of utility-supplied power with power generated on the customer side of the meter produced from a customer-owned renewable source. Combined heat and power systems of less than 20 kW that use fossil fuels are also allowed, but none have been installed. The sources of distributed power that can be net metered have some potential to affect the need for transmission and distribution investment to the benefit of all ratepayers.

Amendments to the net metering law in 1999, 2002, 2008, 2010, and 2011 allowed the installation of a greater amount of overall net metered system capacity, qualified larger individual systems for net metered treatment, and lifted the original restriction of group net metering to on-farm only, opening group net metering to all customers.

Most recently, in 2011, the Vermont General Assembly expanded the permissible size limit per installation to 500 kW, simplified the administration for net metering groups, allowed a registration process for small residential systems, increased the overall net metering capacity cap per utility to 4% of 1996 utility system peak or previous year's peak (whichever is higher), and created a solar adder for all PV net metered systems that had the effect of increasing the value of net metering to 20 cents per kWh for customers who install net metered PV systems statewide.

Exhibit 5-14 shows that Vermont's legislative action, along with increased awareness and the availability of incentives, has led to a dramatic increase in permitted net metered capacity since 1999, particularly for solar systems. In 2006, there were only 329 permitted net-metered systems in Vermont, with an installed capacity of 1,177 kW. By the beginning of 2011, the numbers had climbed to 1,319 installed systems with an installed capacity of 10,923 kW.

Exhibit 5-14. Approved Net Metering kW Capacity by Year and Technology (with Cumulative Total)



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Hydro	0	0	0	0	0	0	0	0	0	0	15	0
Fuel Cell	0	0	0	0	0	0	0	0	0	0	0	0
Methane	0	0	0	0	0	65	0	0	0	19	39	103
Solar PV	23	39	54	16	40	93	187	171	319	859	1842	5611
Wind	32	10	28	31	96	71	119	102	143	144	501	151
Cumulative Total		104	186	233	369	598	904	1177	1639	2661	5058	10923

Source: DPS and PSB

Over the next 20 years, given the present increase of net metered systems and the growth that may be achieved through additional regulatory improvements, the CEP estimates that Vermont will achieve at least 30 MW of additional net metered capacity.

Electric companies are required to make net metering available to any customer system on a first-come, first-served basis until the cumulative output capacity of net metering systems equals a specified limit. This limit on cumulative output capacity was set initially in 2001 at 1% of 1996 or current calendar year "peak demand," whichever is greater.117 As noted above, the Vermont General Assembly raised the cap to 4% in 2011. This cap is intended to ensure that electric rates are not unreasonably affected by the net metering option.

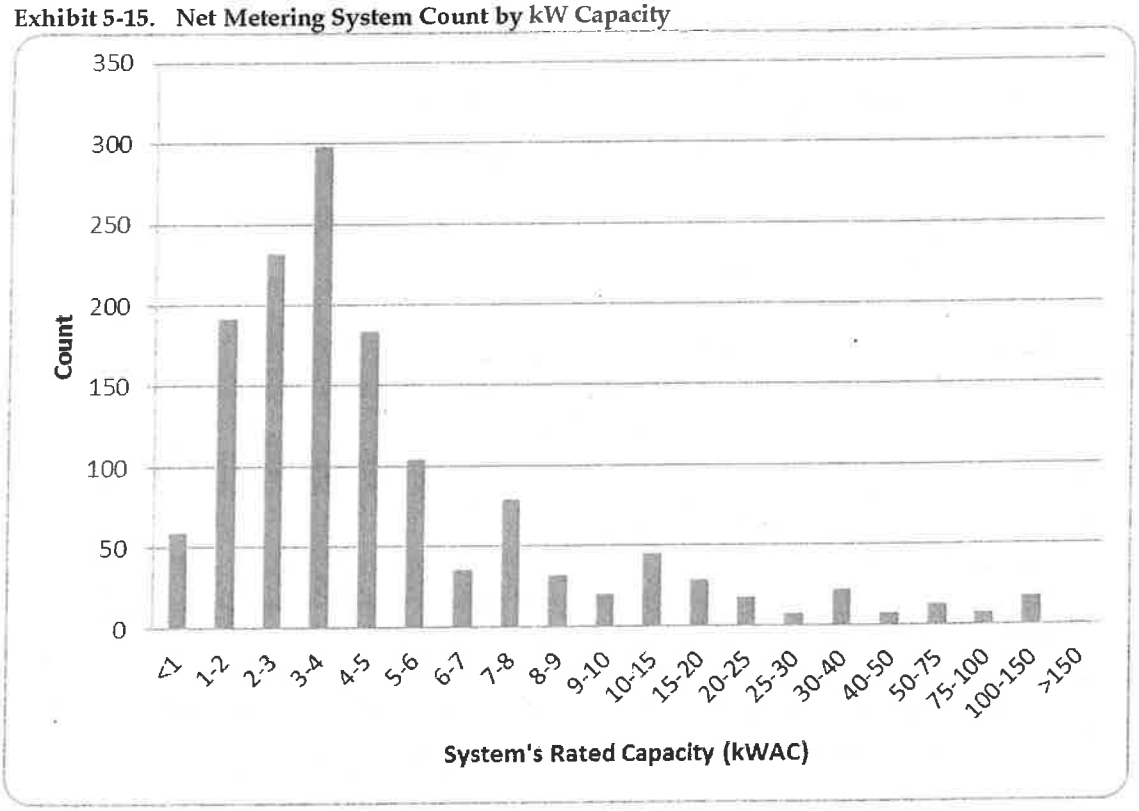
Net metering, as indicated by the data above, has been an increasingly effective tool to promote residential and small commercial renewable energy systems. Net metering started as a way for homeowners to invest in renewable energy generation equipment on their own roof. As interest has grown among both customers and

[117] *"Peak demand" means the highest monthly peak reported in either the electric company's FERC Form 1 or the electric company's Electric Annual Report to the Vermont Department of Public Service for the year.*

the utilities, and experience has shown no adverse impacts to system reliability, the state has raised the cap continually to maintain access to net metering for all customers.

The opportunity to create one's own power and have a simple interconnection with the grid should be widely available to all residential customers. Thus, instead of increasing the cap each time a utility approaches the required percentage, there should be no percentage cap per utility for systems less than 5 kW. This policy would ensure that a residential customer's access to the grid for small systems would not be precluded by larger group net metered or commercial systems using all the available net metering capacity. While the average net metered system has expanded annually, Exhibit 5-15 shows that the bulk of net metering systems permitted to date have been at the 5 kW size and below; about 90% of these net metered systems are solar PV. Approximately 20% of approved net metering capacity is represented by systems of less than 5 kW. Utility infrastructure capacity for interconnection should be the only near-term limitation on the number of small residential systems that can be installed. As net metering expands, the DPS will examine its impact on utility costs and rates in order to develop future recommendations regarding appropriate cost sharing.

Exhibit 5-15. Net Metering System Count by kW Capacity



A simple and transparent permitting process is as important as a simple and guaranteed interconnection process for net metered systems. Recently, as the number of permitted net metered systems has increased, the DPS has received an increased number of comments about the time it takes to get a CPG approved. Currently no data is available on the time it actually takes to grant a CPG, or what causes delays—whether it is the applicant or the regulatory process. To this end, the PSB and DPS should create and maintain a database of net metered CPG applications that includes a record of the time needed for a CPG to be issued once a completed

application is received, and should investigate further use of registration for net metered systems, as well as online applications.

Additionally, net metering permitting and interconnection requirements that may no longer be needed, such as proof of insurance and lockable disconnects for some smaller systems, should be investigated and eliminated if no longer necessary.

Recommendations for Net Metering

(1) *Exclude residential systems under 5 kW from the utilities' percentage system cap calculations, subject only to utility infrastructure needs.*

(2) *Investigate elimination of the net metering permit requirement of proof of insurance for non-inverter-based systems under 50 kW and inverter-based systems under the cap (500 kW).*

(3) *Update the net metering permit application process to include an electronic online form/paperless process option, and investigate extending the 10-day registration process to other systems.*

(4) *Encourage small-scale efficient combined heat and power natural gas units in areas served by natural gas. Study deployment issues for these units.*

(5) *Revise interconnection procedures and standards, in particular the present optional requirement that a separate lockable disconnect be installed for inverter-based systems below a certain kW size.*

(6) *Maintain a publicly available database of all net metering permit applications and issuances.*

5.10.2 Interconnection Standards

Among the regulatory barriers identified by proponents of distributed resources are those associated with uncertain costs and requirements regarding interconnections to the grid. The Vermont General Assembly has responded to the concern by requiring the Vermont Public Service Board to establish simplified interconnection rules for small systems (<150 kW), and clear standards and a timeframe for responding to interconnection requests of larger systems.

These rules created by the PSB for systems below 150 kW have worked well to ensure safe and timely interconnections of more than 1,300 net metered systems. The interconnection rule developed for larger systems (>150 kW, Rule 5.500) are similar to rules for interconnection governed by FERC and ISO-NE. These rules are fundamentally designed to ensure timely response to a generator requesting interconnection and to filter or distill material projects requiring significant analysis and review of distribution and transmission system impacts. Where additional facilities are required to ensure the integrity of the system, the requester is required

to pay for the costs. The requester is also required to pay the costs associated with any system impact or facility studies required.

Despite the significant progress already made in establishing fair and efficient interconnection standards and response times, developers of projects of more than 150 kW remain concerned about potentially stranded investments, time delays, and the appropriate pricing of backup and interconnection service. Vermont has made solid progress and had success in developing simple interconnection standards for net metered systems of up to 150 kW. The DPS and PSB should investigate extending that successful model to larger systems.

In addition to the interconnection requirements set by the PSB and the utilities, commercial projects need to obtain a permit from a state electrical inspector. As PV systems become more common and more systems are installed, there could be delays in getting a state electrical inspection. At times, the concerns raised by developers about the time delays for inspections have been caused by mistakes and miscommunications made by the developers. Regardless, there is currently a lack of verifiable information about how long it actually takes for projects to be inspected. For this reason, the Department of Public Safety should consider tracking the time it takes for an inspection to occur, and should work toward offering an electronic/paperless online application to help simplify the process.

Recommendations

(1) *The utilities and regulators should continue to ensure that interconnection arrangements, business response timetables, and relevant tariffs are fair and nondiscriminatory.*

(2) *The Department of Public Service should monitor utility activity and performance as they relate to interconnection and should request that utilities file annual interconnection reports on the time and costs associated with interconnection applications received.*

(3) *The Department of Public Safety should investigate maintaining a database of commercial PV system inspections that includes a record of the time it takes for an inspection to take place once a proper request has been made by the customer.*

(4) *The Department of Public Safety should investigate offering an electronic/paperless online application process to help in streamlining the state electrical inspection process for commercial systems.*

(5) *Vermont utilities, the DPS, and stakeholders should work collaboratively to establish improvements to the PSB's interconnection 5.500 rule, including investigation of the size of projects subject to simplified interconnection.*

5.10.3 SPEED and Renewable Electricity Portfolio Standard

The Sustainably Priced Energy Enterprise Development (SPEED) program was established by the Vermont General Assembly through Act 61 in 2005 to promote the development of renewable energy by encouraging Vermont utilities to engage in long-term contracts for power from renewable sources. The SPEED program is often confused with the establishment of specific requirements for renewable energy acquisition, which have been established through a renewable portfolio standard (RPS) in 29 states, including all New England states except Vermont.

Vermont has not enforced a mandatory RPS on retail electric sales made in the state. Although a renewable portfolio standard was established by the Vermont Legislature in the 2005 SPEED program, the implementation was delayed until at least 2013, with the stipulation that the RPS would come into effect only if new renewable energy additions to the state's portfolio were below the amount of new load growth over that time. By delaying the implementation of an RPS, the state allowed utilities to increase the amount of renewable energy in their portfolios without the regulatory requirements and potential costs of an RPS.

The 2005 law does not require utilities to acquire any renewable energy certificates (RECs) connected to the new renewable energy generation that they count toward meeting Vermont's legislative requirement. Thus, the utilities are allowed to separate the electricity from the attributes of the renewable energy, so that the RECs may be sold in out-of-state markets. Although this can reduce the cost to ratepayers for new renewable energy, it means that Vermont utilities that do not retain the RECs from renewable energy projects they use in their portfolio are no longer eligible to claim the power as "renewable energy" in advertising to consumers. The selling of the RECs to utilities in other states has allowed Vermont utilities to lower the rate impact of adding new renewable energy generation; however, it has also led to concerns that the renewable energy attributes are being counted twice, once by Vermont utilities to meet the requirement to avoid the implementation of an RPS and once by the utilities that purchase the RECs to meet RPS requirements in their home states.

In 2005, when the SPEED law was created, it was thought that load growth in Vermont would continue at the rate of approximately 1% per year. Thus, it was assumed that approximately 6% of new renewable energy would be needed by January 2012 to avoid RPS implementation. In later years, it became clear that the state's load was not growing as fast as projected—and would in fact likely decrease, in part owing to the state's aggressive energy efficiency programs. In 2008, the Vermont Legislature therefore revised the minimum renewable goal so that at least 5% of new renewable energy had to be added to the statewide total electric portfolio (or at least have a CPG issued) by July 2012 to avoid having the RPS come into effect. At the same time, the Vermont Legislature set a state goal of increasing new renewable and combined heat and power (CHP) resources to meet a total of 20% of the state's electricity retail sales by 2017.[118]

[118] *The CHP resources for this voluntary goal could be fossil fuel based but had to meet minimum standards for efficiency and use of the thermal energy produced.*

The 5% minimum requirement was met in 2011, and the utilities are on pace to meet more than 13% of retail sales with SPEED resources by 2013.[119] To a large degree, the utilities have treated the "20% by 2017" goal as if it were a requirement. In this regard, policies promoting a significant increase in the percentage of energy generated by renewable technologies in the state's portfolio without an RPS have been successful.

Nonetheless, there continues to be an interest in adopting an RPS in Vermont in order to promote higher increases of renewable energy and to eliminate the "double counting" of the renewable energy attributes. The Vermont PSB has issued a legislatively required study on whether Vermont should adopt a mandatory RPS.[120] The PSB's study and recommendations set forth the successes to date, along with the problems, of current renewable energy policies and concludes with the recommendation that an RPS could be efficiently and affordably designed and should be adopted in Vermont. The DPS concurs with the Public Service Board's conclusion.

An RPS can help advance state and regional objectives for fuel source diversity, meet environmental objectives, and satisfy demands for sustainable energy sources. Because market mechanisms are put in play through such an instrument, an RPS is viewed as an effective and efficient mechanism for promoting development of renewable energy regionally at a commercial scale. Many states have used an RPS to achieve specific state goals, such as promoting particular technologies and specifically promoting new renewable development. In the DPS's view, given the progress Vermont's utilities collectively have already made regarding renewable energy acquisition, changes to the state's current renewable energy requirements should include the following goals:

(1) Encourage maintenance of the renewable portfolio progress our utilities have made to date.

(2) Allow greater progress at cost-effective prices by permitting additional large-scale renewable power contracts, including those for existing renewable resources not currently in the Vermont portfolio, to count toward meeting renewable energy requirements.

(3) Encourage development of distributed generation, reducing demands on the transmission system.

(4) Allow new projects (and associated technologies) to compete on a level playing field.

(5) Enable long-term planning and commitments to renewable resources through policy stability.

(6) Enhance regional cost-effectiveness through compatibility between Vermont's policies and those of other New England states.

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[119] *http://vermontspeed.com/project-status/ reports existing or planned deployment of about 760 GWh of SPEED resources. 2013 Vermont electric demand is unknown, but 760 GWh is 13.8% of the state's 2009 retail electric sales of 5,494 GWh.*

[120] *Study on Renewable Electricity Requirements Prepared by the Vermont Public Service Board Pursuant to Section 13a of Public Act 159, October 3, 2011.*

(7) Allow adequate time prior to enforcement of compliance, and through the rate of increase of renewable requirements, for utilities and their customers to adjust cost-effectively.

The DPS recommends that the Vermont Legislature consider adopting a streamlined RPS for Vermont, with an aggressive total renewable electricity goal of 75% within 20 years. Such an RPS appears both achievable and responsible, so long as the RPS is designed to account for total renewable generation—existing and new (as defined by 2005 SPEED terms), small (including net metering), and large. This RPS would maximize cost-effectiveness and utility flexibility while ensuring greater certainty and higher penetration of total renewable electricity in our energy portfolio. In its report, the PSB recommends one such RPS, and the modeling done for the CEP examined another possible implementation.

In designing an RPS, a great number of details require careful consideration, including: the creation (or not) of classes of resources, with requirements for each class, to shape the final portfolio; the rate at which renewable requirements increase; the need to treat utilities equitably, respecting differences in size and current renewable portfolios; consistency with other milestones and policy goals (such as the legislated goal of 20% renewable electricity by 2017); the need to encourage retention of existing resources while not driving up costs; and the method of enforcement for utilities that do not meet the goal. The DPS looks forward to working with stakeholders and the Vermont Legislature to consider and analyze these and other details.

Looking beyond electricity, an RPS should also be designed to integrate well into any future Total Energy Standard to encourage cost-effective adoption of renewables across the entire energy portfolio.

In addition, in order to encourage targeted distributed renewable generation and other new renewable projects, the DPS recommends that any adopted RPS be coupled with programs such as net metering expansion and deployment of a clean energy contract program built upon the Standard Offer Program's success. This will ensure that local renewable electricity projects are robustly deployed. Recommendations on the Standard Offer Program are set forth below.

Finally, on the basis of comments received during the CEP preparation process, we believe there is strong interest in community-scale projects and a desire to create a program to help communities host or own clean energy projects. The DPS and the Agency of Commerce and Community Development should work with local communities to investigate whether voluntary participation in an RPS-like program that would set targets for local community project development—creating local "green energy zones" wherein communities share the benefits and the costs of project development—would help facilitate the construction of community-scale renewable energy projects that include local ownership. Group net metering offers one model, but further investigation regarding the right size and ownership model for community investment is needed.

5.10.4 The Standard Offer Program and Clean Energy Contracts

The structure of the original SPEED program limited the price paid for renewable energy in the program to an amount equal to the projected market price. This did not provide any incentive for renewable energy project

developers to offer their projects in Vermont, because they already could obtain the market price without participating in the SPEED program.

Therefore, in 2009, the Vermont Legislature modified the SPEED program to include a pilot Standard Offer Program for small-scale renewable projects. The Standard Offer, sometimes referred to as a feed-in-tariff, provided to developers of small qualifying renewable generation projects a fixed price for power under long-term standard contracts. In order to ensure rapid development of the qualifying renewable technologies, the Vermont Legislature mandated that the rates paid reflect the actual costs of the various renewable technologies. The program was directed at certain renewable technologies and at projects of 2.2 MW in size or smaller. A 50 MW total cap was also set on the program.

Included in the legislation was an initial set of rates that were applicable to the first round of projects, with a direction that the PSB develop amended rates to go into effect in January 2010. After a brief but intense stakeholder process, the PSB issued a set of rates on January 15, 2010. A comparison of the 2009 statutory rates (which will be paid to those projects selected in the initial Standard Offer round) and the January 2010 rates is shown in Exhibit 5-16:

Exhibit 5-16. SPEED Standard Offer Rates, 2009 Original vs. 2010 Amended[121]

	($/kWh)	
Renewable Energy Technology	**Set in Statute**	**As Amended by PSB**
Landfill Methane Projects	$0.12	$0.09
Farm Methane Projects	$0.16	$0.141
Wind Projects (small)	$0.20	$0.214
Wind Projects (large)	$0.125	$0.118
Solar PV Projects	$0.30	$0.24
Hydroelectric Projects	$0.13	$0.12
Biomass Projects	$0.125	$0.13

To ensure all renewable energy technologies had access to the 50 MW allocated to the program, a sub-cap was set by the PSB at 12.5 MW for any single technology. Interest in the program was strong, and the 50 MW cap was reached almost immediately after the program launched. The PSB set up a queue for those projects that were not awarded a contract.

There are currently 15 Standard Offer projects operating with a combined capacity of 7.58 MW, and 43 projects with Standard Offer contracts in various stages of development representing 42.37 MW of capacity.[122] Projects

[121] *Public Service Board Order in Docket 7533. These are levelized rates that are equivalent to the rate schedule published in the PSB's order, which provides an increasing schedule of rates for some technologies.*

do not cause rate impacts until built; thus, the costs associated with purchasing Standard Offer power occur slowly over time as projects come on line.

Although there may be a few opportunities for projects that are already in the queue to obtain a Standard Offer contract as other projects do not more forward, the initial pilot program is fully subscribed and not available for new projects. A next-generation clean energy contract program is required if Vermont is to provide further support for small distributed-generation projects that provide renewable energy and local jobs to Vermonters. We have an opportunity to learn from the Standard Offer Program and to design a new program thoughtfully, to encourage development while limiting impacts on ratepayer cost.

In order to provide a stable market for small and community-sized projects and to promote the benefits of in-state distributed generation, a clean energy contract program should be created to build upon the lessons from the Standard Offer Program, to provide at least another 50 MW of deployed small-scale distributed generation for Vermont within 10 years. The design of the new program is critical; the goals should be (1) regulatory and contractual certainty for developers; (2) a fair and transparent process for contract awards; (3) legally appropriate pricing mechanisms, taking into account FERC rules and legal precedents; and (4) pricing that achieves the lowest cost for ratepayers needed to support successful deployment of these projects. Other issues, such as the precise size of eligible projects, whether there should be a total offer cap or an annual allotment the location of such projects, and the existence of sub-caps for technology participation, also must be considered. The PSB's RPS report includes a similar recommendation as a method to meet their RPS requirement that 10% of each utility's power be sourced from in-state renewable distributed generation resources[120].

These are complex issues that ought to include stakeholder input. The DPS believes any process should include market mechanisms for pricing and should allow for project deployment over time. The DPS recommends establishing a modified auction mechanism for the new clean energy contract program, similar to the PSB auction recommendation included in the RPS report. The DPS also recommends that the state consider implementing an annual clean energy contract allocation for distributed generation projects, starting in January 2013. The benefit of a regularly scheduled auction, if properly designed, would be prices more reflective of the market. An auction could be sectioned by technology so projects of the same technology would bid against each other, not other technologies. Price bonuses or penalties could be included to encourage projects at particular constrained locations, projects of particular load shape characteristics, projects of particular efficiency levels, projects with particularly robust economic development or job creation potential, etc. Any such value adjustments could be set in advance to promote transparency. Mechanisms to prevent "race to the bottom" bidding should be employed to ensure successful project development. Such an auction mechanism has advantages over the price-setting procedure now in place for the Standard Offer Program. Significantly, the price would be determined in part by the market. This ameliorates the risk of setting the price too high or too low. If the price is set too low, projects will not be developed. If the price is too high, developers could receive an unnecessary profit at ratepayer expense.

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[122] *SPEED Facilitator, www.vermontspeed.com.*

Furthermore, the state should investigate whether the current efficiency requirement for biomass CHP projects to participate in the Standard Offer Program is set at the appropriate level. The current requirement of 50% efficiency may be too high to meet state objectives of robust CHP deployment,[123] because some projects could use up to 100% of the thermal load during the heating season but be unable to meet the annual efficiency standard. Because of their ability to offset fossil heating fuels while producing renewable electricity, projects that can utilize heat while operating at the plant's designed capacity during the heating season should be eligible for the Standard Offer, even if their annual efficiency drops below 50%. This recommendation should be considered after release of the BioE report later this year.

Recommendations for SPEED, RPS, and Standard Offer Program

(1) *The Vermont Legislature should consider adopting an RPS with a target of 75% renewable electricity within 20 years. The DPS recommends that any RPS be designed to encourage maintenance of the existing renewable portfolio, while requiring that significant additional renewable energy be added to the Vermont portfolio over the next 20 years.*

(2) *Vermont regulators and legislators should also foster distributed generation, which brings local renewable energy, jobs, and other benefits to the state. To that end, the state should foster a stable and predictable regulatory environment for encouraging contracts and investments in small-scale distributed renewable energy.*

(3) *The existing Standard Offer Program should transition, after the stakeholder process, to a new clean energy contract program designed to include an auction mechanism for price setting and other improvements upon the original program design.*

(4) *In establishing a clean contract program, the current cap of 2.2 MW should be evaluated to determine whether it should be increased or should be set at a different level for different technologies.*

(5) *The current Standard Offer efficiency requirement for biomass CHP plants should be reevaluated after release of the BioE study.*

5.10.5 Finance and Funding

Financial incentives for clean energy development in the state have been thin compared to those of other states in the Northeast, and the present state budget and economy are not expected to change this situation dramatically in the near term. Programs such as the Standard Offer help, by creating stable, long-term business

[123] *Title 30 § 202(i) states: "it shall be a goal of the electrical energy plan to assure, by 2028, that at least 60 MW of power are generated within the state by combined heat and power (CHP) facilities powered by renewable fuels or by nonqualifying SPEED resources."*

opportunities for developers, but they involve ratepayer cost. Despite its limited funds, the state can and should continue to investigate and facilitate means of financing and funding renewable energy projects. A number of innovative private ownership arrangements and financing options are emerging; one role that the state can play, regardless of its own funding capabilities, is to bring together those that participate in the renewable energy market, including developers, financiers, and investors, to encourage greater innovation.

In addition, the state can direct its limited resources in ways that leverage the dollars available. For example, Qualified Energy Conservation Bonds (QECBs) can be used to support both efficiency and renewable energy. QECBs are a taxable tax credit bond; the state has received an allocation of $6,445,000. The government issuer, or private activity borrower, of the QECB financing is eligible for a subsidy or rebate on the interest paid to the bondholders. QECBs may be issued by a state, or through conduit agencies, to finance qualified energy conservation projects. A minimum of 70% of a state's allocation must be used for government purposes, and the remainder may be used to finance private activity projects. However, in addition to public facilities, the funding of "green community programs" may also qualify for use of public QECB financing, as determined by the IRS. Examples of qualified projects include energy efficiency capital expenditures in public buildings, green communities, renewable energy production, efficiency/energy reduction measures for mass transit, and other uses.

The state of Vermont uses a prudent and conservative approach to financing that takes into consideration an annual review of the size and affordability of the state net tax-supported debt. A recommendation of the amount of debt that prudently may be authorized for the next fiscal year is submitted to the Vermont Legislature by the Capital Debt Affordability Advisory Committee (CDAAC). QECBs can be used in conjunction with a state borrowing to reduce the cost of borrowing for a qualified project within, for instance, the state's annual capital appropriation, or can be issued through a conduit, outside the state's net-tax supported debt calculation. To the extent that the former model is applicable, it is recommended that the debt be incorporated into the CDAAC annual calculation. If it is issued through a conduit or authority and the bonds are repaid from non-tax sources, there is no requirement for the state's full faith and credit. If utilized for loan loss reserve or direct loan funds, the QECBs will support broader progress than otherwise would occur. Financial products offered by the Vermont Economic Development Authority (VEDA) similarly leverage state dollars. The DPS is working to partner with VEDA to deploy Vermont's QECBs and expects to offer the QECBs in 2012.

Recommendations

(1) *The DPS should host, along with the Agency of Commerce and Community Development and the Vermont Climate Cabinet, a renewable energy financing summit to bring together those that participate in the renewable energy market, including developers, financiers, and investors, to encourage greater innovation in financing.*

(2) *Vermont should deploy its allotment of QECBs, so long as it does not burden the state's general indebtedness, to promote efficiency savings and renewable energy projects.*

(3) *DPS should explore application of financing tools such as PACE and on-bill financing to small-scale renewable generation. These tools are discussed in greater detail in Section 7.2.1.*

5.10.5.1 Clean Energy Development Fund

Currently, the primary financial tool the state has to promote clean electric generation is the Clean Energy Development Fund (CEDF). In 2005, the Vermont General Assembly established the CEDF through Act 74. The purpose of the fund is to promote the development and deployment of cost-effective and environmentally sustainable electric and thermal energy resources for the long-term benefit of Vermont consumers.[124] Since its creation, the CEDF has played a critical role in the development of distributed renewable energy projects across the state. The state should strive to continue the financial programs of the CEDF as part of a comprehensive strategy to support new residential and community-scale renewable energy projects.

Act 74 specified that the CEDF be funded with payments by Entergy Vermont Yankee, arising out of two memorandums of understanding (MOUs), and by any other monies that may be appropriated to or deposited into the fund. The two MOUs the state signed with Entergy Vermont Yankee were the results of negotiations involving the storage of spent nuclear waste in dry casks on-site and the increase of Vermont Yankee's electric generating capacity. Exhibit 5-17 below shows the total amount of funds the CEDF has received from Entergy and from other sources through fiscal year 2011.

Exhibit 5-17. Vermont Clean Energy Development Fund: Statement of Revenues from Inception

Revenues	Total Received 2006–FY 2011
Entergy Initial Payment	$200,000
Entergy Dry Cask Storage Payments	$14,375,000
Entergy Up-Rate Payments	$13,443,690
Interest Income	$510,574
Loan Interest Income	$77,206
Loan Application Fees	$10,830
Total Revenues	***$ 28,617,300***

Source: CEDF

Initially, the CEDF was a program of the DPS, with a Vermont legislative advisory committee and an appointed investment committee. In 2009, the Vermont Legislature moved responsibility for the CEDF to an independent Clean Energy Development Board. Although the funding and programmatic design decisions of the CEDF were the responsibility of the appointed board, the CEDF was still supported administratively by the DPS.

[124] *10 V.S.A. § 6523 (c).*

Exhibit 5-20. Vermont Small Scale Renewable Energy Program Project Installations from 2003 through late October 2011

Wind	Number Installed	117
	Total Cost of Installed Systems	$6,554,354
	Incentives Paid for Installed Systems	$1,245,695
	Total Installed Capacity (W)	460,890
	Estimated Annual kWh per Year	641,430
Solar PV	Number Installed	1,019
	Total Cost of Installed Systems	$32,527,863
	Incentives Paid for Installed Systems	$5,885,917
	Total Installed Capacity (W)	4,490,656
	Estimated Annual kWh per Year	5,203,764
Solar Hot Water	Number Installed	930
	Total Cost of Installed Systems	$10,991,461
	Incentives Paid for Installed Systems	$1,758,276
	Total Installed Capacity (kBtu/day)	87,671
Total	Number Installed	2,066
	Total Cost of Installed Systems	$47,073,678
	Incentives Paid for Installed Systems	$8,889,888
	Total Dollars Leveraged	$38,183,790

Source: Vermont Small Scale Renewable Energy Program, 2011

A recent economic review of the CEDF by Kavet, Rockler & Associates determined that the CEDF had leveraged the $28 million in state expenditures nearly four-to-one, creating $110 million in total project expenditures since its inception.[126]

5.10.5.1.2 Future of the CEDF

The 2010 CEDF board outlined four principal objectives to guide the activities of the fund:

- Maximize clean energy generation and energy savings.
- Accelerate economic development.
- Build the knowledge base and clean energy infrastructure.
- Leverage public and private funding.

[126] http://publicservice.vermont.gov/energy/ee_files/cedf/Memo%20-20Clean%20Energy%20Development%20Fund%20Summary.pdf

The new CEDF board will revisit these objectives as part of the strategic planning process and will make recommendations regarding deployment of returning loan funds and regarding future funding sources. The DPS and CEDF board will complete a strategic plan that will include suggestions for new funding of the CEDF programs as well as program design for existing programs. In the event that no further funding sources are available, the CEDF will likely continue to operate its revolving loan fund and the Vermont Small Scale Renewable Energy Program. The revolving loan program totals approximately $7 million. The CEDF has $2.7 million earmarked for the Vermont Small Scale Renewable Energy Program and will begin to use those funds to keep the program operational as the current federal funding for it is depleted.

Given the current funding constraints, the CEDF is looking to wean the technologies that are maturing within local markets from the need for CEDF incentives. The CEDF should focus on those technologies that need the most market assistance while providing the greatest progress toward the CEDF's four principal objectives. For example, photovoltaic power has received considerable financial incentives (approximately 50% of all CEDF funds through 2010 have gone to support PV). Although PV warrants continued CEDF attention, there are other worthy technologies that have not received any CEDF support to date. The CEDF board will include consideration of this issue in the next CEDF strategic plan.

Two important guiding concepts for the CEDF's work will likely be performance and efficiency. As a result, certain program designs might be established, such as the following:

- The Vermont Small Scale Renewable Energy Program could be coupled with efficiency retrofits completed so that a project that has made efficiency gains would be rewarded with an increased rebate amount. This would help prevent the CEDF from encouraging new generation that could be achieved through efficiency at the same location at a much lower cost.
- Any technology receiving a CEDF incentive should be able to offer third-party verification of the system's rated capacity and performance.
- Incentives should be market-based and leveraged where possible.

In addition to grant and loan programs to renewable energy projects, the DPS and CEDF have supported education efforts through the School Energy Management Program (SEMP), the Municipal Technical Assistance Program (MTAP), and the Vermont Energy Education Program (VEEP). These programs provide much-needed public and technical education and outreach. The DPS strongly recommends that the DPS/CEDF continue to support these efforts.

Recommendations

(1) *The CEDF strategic plan should address a sustainable funding model for CEDF. The CEDF's funding priorities should focus on technologies that do not already have a mature market presence, and should be weighted to maximize performance and efficiency of dollars spent.*

(2) *The CEDF is a fund that serves many populations. The website for the CEDF should be made more useful and informative, clearly setting forth available funding and programs. It also should make available all the final reports of CEDF-funded projects.*

(3) *The CEDF should continue to support educational efforts to promote renewable energy technology.*

5.10.6 Regulatory System Improvements

Many of the recommendations discussed throughout this section will aid in simplifying or improving regulatory processes. There are other overarching regulatory improvements that could be made to increase the efficiency of the energy generation permit process, reducing overall costs and supporting the state's goals.

Recommendations

(1) *The state should make improvements to the permitting and regulatory process governing electric generation siting. Specifically, right now nearly all projects, regardless of size, undergo the same regulatory scrutiny—whether the project is a five-turbine wind installation, a 20-turbine wind installation, a modest solar tracker, or the expansion of a substation footprint and internal configuration. (The only exceptions are projects that qualify under Section 248(j) of Title 30 as being of "limited size and scope" and not raising a "significant issue.") The DPS, the stakeholders, and the PSB should develop legislation to create a revised regulatory process for projects that do not qualify for the Section 248(j) process but are nevertheless small enough to justify a less-intensive process than complete Section 248 review. This new process should be written to apply particularly to community-scaled and owned projects designed to support local load.*

(2) *Given the potential benefits of renewable energy and the allowance of other types of development (such as telecommunication towers) permitted on public lands, ANR should consider revising and clarifying its December 2004 written policy on renewable energy projects sited on state lands, specifically with regard to net metered and small-scale projects.*[127]

(3) *The state should consider creation of an even more streamlined net metering process for all net metering applications. Consideration should be given to an automated process in which applicants file electronically and are advised in a short timeframe regarding the completeness of the application. In the absence of comments expressing concerns by interested parties, net metering applications should*

[127] *Vermont ANR, "Wind Energy and Other Renewable Energy Development on ANR Lands," December 2004, www.vtfpr.org/lands/documents/windpower.pdf.*

receive shorter review time by PSB and DPS if an interconnection has been previously approved by the utility or meets the criteria of a standard interconnection protocol.

(4) *The DPS has been asked by the Vermont Legislature to consider "intervenor funding," requiring project applicants to pay for the legal and other costs of those who may intervene to oppose a project at the PSB. The DPS is concerned that intervenor funding will increase the intensity and duration of litigation without assisting in resolution of disputes between developers and those who may oppose the project. Rather, DPS recommends developing other mechanisms to address the concern that intervenors lack an effective voice in the Section 248 permitting process. Regional planning commissions and town energy committees should be encouraged to develop and approve specific energy siting policies that the PSB can consider in the Section 248 process. Moreover, the DPS and the PSB should develop a mediation program to be used to resolve or narrow disputes among parties. Mediation has successfully been integrated into Vermont civil proceedings and should provide an avenue for dispute resolution in Section 248 proceedings if used at points in the process where parties are committed to finding solutions, rather than elevating litigation, and if it is integrated within the process in a manner that does not add significant time and complexity to the process. Applicant funding of mediation should be considered.*

(5) *As briefly discussed above in the Transmission Planning section, modifications need to be made to the memorandum of understanding in the transmission planning docket (Docket 7081) that will increase consistency between the Vermont transmission planning process and the regional planning process. Modifications are necessary to reflect the reality that ISO-NE has taken on the principal regional transmission planning role as delegated to it by FERC.*

5.10.7 Toward a Total Energy Standard

The Vermont Comprehensive Energy Plan is designed to encompass all forms of energy generation and consumption, in recognition of the fact that all energy is interconnected. If we plan and set goals separately by energy sector, we run the risk of taking a step toward one goal while taking two steps away from another. The state's approach to energy planning must be comprehensive in its approach and goals.

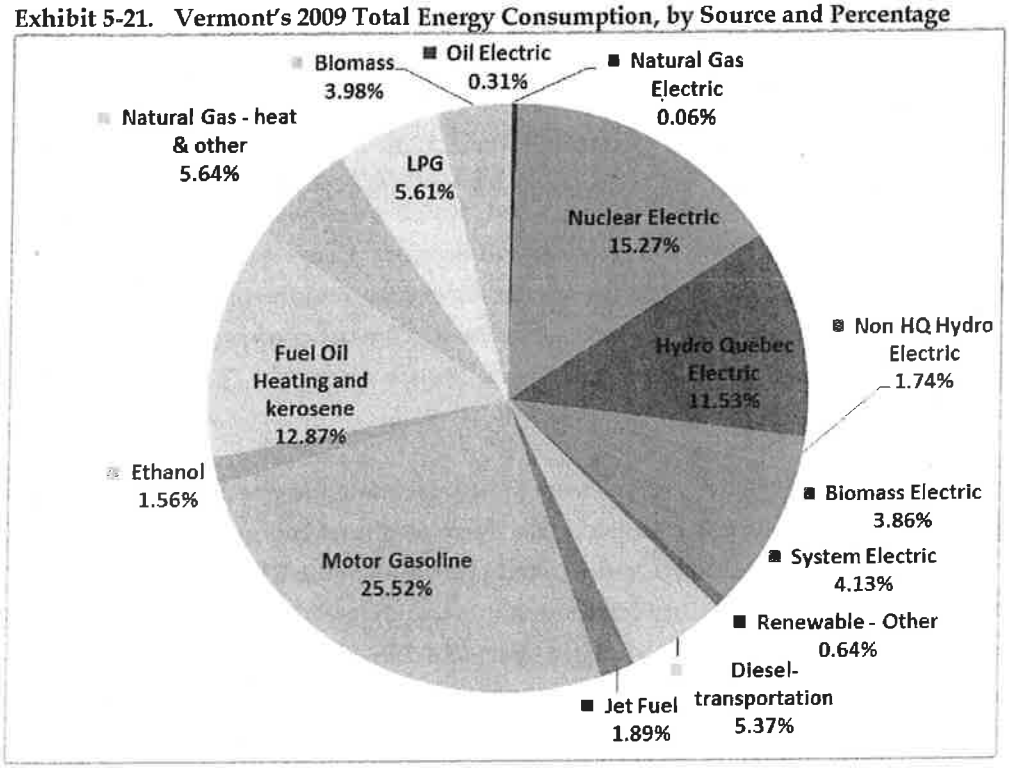
Thus, the state should develop holistic goals for total energy use. The RPS and SPEED goals discussed above help promote renewable electricity generation, but they do nothing to address increased renewable energy for transportation and heating. In fact, to the extent that such policies target *only* electricity, they risk charging electric ratepayers for progress on renewable electric goals rather than targeting progress—and cost—where it might most be needed. In the 21st century, with an awareness of the effects of climate change and a growing desire for energy security and economic independence, we need regulatory policies and funding mechanisms that encourage a more efficient, cleaner energy portfolio in all sectors, not simply regulated electricity.

To this end, the DPS recommends that the state investigate creation of an interagency and stakeholder working group to develop a proposal for a Total Energy Standard (TES) by the end of 2013. A TES would work with and complement any RPS or new SPEED program the Vermont Legislature may implement, but would apply to Vermont's total energy usage. Essential to the creation of a TES would be adoption of a common measurement unit for all energy. Most of the world measures energy in watts per hour, which is easily scalable—kWh/MWh/GWh/TWh—and that would seem to be the most logical unit to adopt. However, the U.S. Energy Information Agency (EIA) uses British thermal units, Btu, as the common measure, and the EIA is the source of much of our energy consumption data. Thus, until Vermont can collect its own energy consumption data for all sectors or until the EIA changes units, there is a compelling reason to use Btu for a Vermont TES if one is adopted.

The DPS has conducted a preliminary analysis of total energy usage to help facilitate the discussion of a TES. Using a compilation of EIA and DPS data, the DPS has calculated that Vermont's total energy use was approximately 154 trillion Btu in 2009.[128] Of that total (and as described elsewhere in the CEP), 23% (35.7 trillion Btu) came from renewable energy sources. The state could build upon this total renewable energy progress by establishing five- and 20-year goals for increasing this percentage as part of a TES. The TES goals could be met by a combination of reduced demand, through efficiency and conservation, and through new renewable energy usage by sector. Exhibit 5-21 shows Vermont's 2009 total energy usage with all energy converted to Btu.

[128] *Designing the accounting rules for conversion of diverse energy types to a single metric would be one of the tasks of the TES study recommended below. For example, EIA standards convert non-thermal electric generation to a common Btu metric using the average heat rate of fossil fuel generators. Given the small fraction of Vermont electricity generated using fossil fuel combustion, this may not be the rule best suited for Vermont. This plan uses the EIA rule for consistency with other reports, pending recommendations from a TES study.*

Exhibit 5-21. Vermont's 2009 Total Energy Consumption, by Source and Percentage



In order to encourage progress, a compliance payment similar to that employed in RPS structures could be used. If such a payment were both small and targeted, it would help achieve the TES goals and ramp down as progress is achieved. For example, the payment could fund training and financing programs for fuel dealers who might wish to offer energy efficiency contractor services, in order to redirect their business as fossil fuel usage declines over time. Or it could provide incentives for expanding transit routes or for farm production of renewable heating fuels.

As an example only, if a compliance fee were set at $0.0002/kWh (two one-hundredths of a cent per kWh),[129] such a fee applied to heating oil would be approximately eight-tenths of a penny per gallon of fuel ($0.008 per gallon). Using the total renewable energy calculations set forth above, a compliance payment of $0.0002 per kWh for non-renewable energy could generate approximately $6 million per year for renewable energy programs in all sectors. Such funding could be allocated by sector to ensure that progress is made in proportion to the funds raised, thereby helping most those sectors with the least renewable energy. There are, without doubt, many policy issues both large and small that must be considered if Vermont chooses to investigate adoption of a total renewable energy standard applicable to all fuels and energy uses. The DPS offers this recommendation to help move Vermont from comprehensive energy planning to comprehensive implementation.

[129] *Although the TES would be based on Btu, any compliance payment would likely be set as a kWh charge. All energy sources could be converted to a comparable Btu value for the TES and then converted to kWh for the compliance payment. Non-renewable electricity would be converted to Btu using its heat rate, and then converted back to kWh.*

Recommendation

The Vermont Climate Cabinet and/or the Vermont Legislature should create a study committee for a Total Energy Standard program, targeting legislative consideration of any plan developed in 2013.

Exhibit 9-36. Plan Implementation Monitoring and Measurement

Objective	Data Source to Monitor	Frequency/Interval
25% of all vehicles registered in Vermont will be powered by renewable sources by 2030.	DMV Registration Records	5 years
Improve the combined average fuel economy of the Vermont vehicle fleet to meet the national average fuel economy set by the federal CAFE standards, or improve it by 5%, whichever is greater, by 2025.	DMV Registration Records	5 years
Increase the number of medium- and heavy-duty vehicles powered by biodiesel or CNG by up to 10% by 2030.	DMV Registration Records	5 years
Slow VMT annual growth rate to 1.5% (half of the national average) for that portion controlled by the state.	VTrans Highway Research Section	5 years
VMT per capita will not increase from a 2011 base year.	VTrans Highway Research Section	5 years
Reduce share of SOV commute trips by 20% by 2030.	American Community Survey (U.S. Census)	5 years
Increase public transit ridership by 110%, to 8.7 million annual trips by 2030.	VTrans Public Transit Section and Chittenden County Transportation Authority	5 years
Double the bicycle and pedestrian share of commute trips to 15.6% by 2030.	American Community Survey (U.S. Census)	5 years
Double the carpooling to work share to 21.4% of commute trips by 2030.	American Community Survey (U.S. Census)	5 years
Quadruple passenger rail trips to 400,000 Vermont-based trips by 2030.	Amtrak	5 years
Double the amount of rail freight tonnage in the state from 2011 levels by 2030.	Freight Analysis Framework	5 years
Triple the number of state Park-and-Ride spaces to 3,426 by 2030.	VTrans Local Transportation Facilities Section	2 years

Source: Vermont Agency of Transportation

9.7 Land Use

The state's development rules and patterns have a major influence on the amount of energy used in Vermont, both in our buildings and in transporting people and goods from place to place. When people live far from the places that they work, shop, bank, etc., more energy is required. Land use is also impacted by the energy

generation siting choices that we make for Vermont. In planning for our energy future, therefore, it is critical that we include a vision for sustainable development in our communities. To be successful, we must balance transportation and energy needs with the impact on our economy and on our natural resources and environment to build strong, healthy communities that last. For a sustainable future, we should look to the past: to our traditional development pattern of downtowns and villages surrounded by a working landscape. If residential growth can be better tied to developed community centers, we can limit the impact on our natural resources and achieve integrated and holistic energy strategies through land use choices.

9.7.1 Compact Centers

The state has a long-standing goal of encouraging concentrated mixed-use development in and around community cores, while protecting natural resources and working landscapes outside those areas. This traditional land use pattern supports a variety of public interests, including reduced development pressures on agricultural, productive forest, and natural resource lands; increased housing options; continued use of our historic resources; a strong Vermont brand; economic efficiency; and active community centers.

This land use pattern also reduces the demand for energy to move people from their homes to work, shopping, school, or social gatherings. Within an area of compact development:

- More people can walk to their destination.
- More opportunities exist for biking and other alternative modes of transportation.
- More effective transit systems are possible, both within communities and between communities, because successful transit systems depend on having a large and concentrated ridership base in core community areas.
- Commuters have a relatively common origin and common destinations, increasing carpooling opportunities.

Although the state has been subject to significant development pressures over the past decades, it has not experienced the same degree of sprawl and disconnected rural development as have other states around the country. Vermont's downtowns and villages remain largely intact, and public interest in and support for "smart growth" has been increasing. In fact, although it is widely seen as a rural state, much of Vermont's population resides or works in its core communities—the 23 municipalities that host one of Vermont's designated downtowns account for more than 30% of the state's population.

That said, we have not been unscathed by increased development pressures. The 2010 Census reported that three-quarters of those 23 communities grew at a slower pace than the state average, indicating that growth continues at a higher rate of development outside our core areas. There are multiple potential reasons for this, but the result has been continued development outside our core areas in a low-density, automobile-dependent fashion. It has created strip development and large lot subdivisions which in turn require more vehicle miles

traveled to meet basic needs, and ultimately, higher energy costs for the transportation sector—a trend we must reverse.

9.7.2 Framework to Reduce Transportation Energy Use Through Compact Land Use Patterns

Our current statutory framework includes a variety of state and local directives and programs that collectively support a compact development pattern. The state offers programs to designate smart growth areas, and directs state funding for capital improvements. Municipalities have been vested with the primary land use regulatory authority, as well as controlling investments in capital infrastructure projects. In order to reduce the energy expenditures for transportation, it will be important to fully use the following tools to support smart growth:

- Vermont's Municipal and Regional Planning and Development Act (24 V.S.A. Chapter 117) includes specific land use goals and required plan elements. Most relevant is the goal to "plan development so as to maintain the historic settlement pattern of compact village and urban centers separated by rural countryside." The act enables municipalities to adopt zoning, subdivision, and other tools to regulate development. The Act also created the Municipal Planning Grant (MPG) program, which currently grants $400,000 to support municipal plans, bylaws, infrastructure planning, and related activities. Municipalities must continue to focus on meeting this goal, and MPG funding must be used to support a more compact development pattern, supporting our community centers.

- The Municipal and Regional Planning and Development Act provides for the creation of regional planning commissions, and requires the development of regional plans—including a land use element and an energy element. It also enables these commissions to undertake a wide variety of other activities—including participation in Act 250, transportation planning, support of municipal land use planning and regulations, and a wide variety of other planning activities. These regional commissions currently receive substantial state funding, and it is important for these funded activities, including training of municipal officials, to continue to support a compact development pattern.

- Municipal capital budgets (24 V.S.A. § 4430) provide for sewer, water, road, parking, pedestrian/bike facilities and other municipal improvements. The kind of compact development pattern anticipated in statute is not possible without investments in such improvements. It should be noted that these improvements can also be used to promote sprawl and strip development, so it is vital to maintain investment focus on supporting well-planned, dense-growth areas proximate to the community core.

- Act 250 (10 V.S.A. Chapter 151) is a statewide permitting process that protects a wide variety of natural resources—water, soils, habitat, aesthetics—and ensures that public infrastructure, such as transportation, water, and wastewater systems, is adequate to serve proposed development. Development proposals must demonstrate that energy will be used efficiently, and that the

development will not place an unreasonable burden on utilities. In addition, applications must be in compliance with municipal and regional plans, which would include provisions in those plans that relate to energy.

- The Downtown Development Act (24 V.S.A. Chapter 76A) was created to revitalize the state's downtowns and village centers. Subsequent changes to the Act created programs to support new development in growth centers and neighborhoods. The designation processes for all these programs ensures that the designated areas provide for compact, mixed-use development. The Act provides dedicated support of these areas—including transportation grants, rehabilitation tax credits, Tax Increment Financing districts, modified Act 250 thresholds—and directs a number of state funding programs to give priority to these areas. These programs could be strengthened and better integrated, providing a more comprehensive foundation for the state's smart growth strategies.

- Complete Streets legislation (19 V.S.A. § 10b and 19 V.S.A. § 309d) was passed in 2011 to ensure that Vermont's roads are safe for all uses, requiring transportation planning to take into account the needs of motorists, bicyclists, public transportation users, and pedestrians of all ages and abilities. Implementation of this new law is now beginning to help focus state investments on our community core areas.

- State infrastructure expenditures are enormously influential in supporting growth. Other states are increasingly focusing state investments to support compact, smart growth areas, and it is critical for Vermont investment policy to do a better job of directing such funding to community centers. These investments also make financial sense, serving more users in a smaller area while supporting a development pattern that minimizes single occupancy vehicle dependence.

9.7.3 Framework for Land Use Planning and Energy

The narrative above has primarily addressed the connections between transportation and land use. However, the connection between land use and energy policy extends more broadly to include the planning and permitting of energy facilities and energy savings.

- The Municipal and Regional Planning and Development Act includes specific responsibilities and limitations related to energy. Both municipal plans (24 V.S.A. § 4382) and regional plans (24 V.S.A. § 4348a) are required to have energy elements, that "may include an analysis of energy resources, needs, scarcities, costs and problems within the [region or municipality], a statement of policy on the conservation of energy and the development of renewable energy resources, and a statement of policy on patterns and densities of land use and control devices likely to result in conservation of energy." This energy planning is done as part of a comprehensive planning process that includes transportation, natural resources, infrastructure, housing, land use, and other matters, with the goal of balancing the competing interests. These plans are implemented, using various regulatory and

non-regulatory tools, by the municipality, by local energy committees, and via ongoing work at each of the regional commissions. They also form the policy basis for municipal participation in the state's Section 248 regulatory process for permitting energy facilities, if they contain clear standards.

- Statute provides for the appointment of a municipal energy coordinator, and hundreds of communities have also created energy committees, providing significant capacity to support local energy conservation and energy generation initiatives.
- All energy projects connected to the grid are regulated by the Public Service Board through the Section 248 process, including small net-metered generators such as solar panels and small wind turbines. Act 250 and municipal jurisdiction for these projects is superseded by Section 248 review. As a result, consideration of the impacts of regulated projects on agricultural soils and flood-prone areas—which are normally considered in local and Act 250 reviews—are not a factor in the Section 248 process.
- Finally, municipalities do retain the authority to regulate energy-generating installations that are not connected to the grid, to the extent that they have adopted specific standards. And they are enabled to protect access to renewal energy resources such as solar and wind through the subdivision and site plan review.

9.7.4 Recommendations for Land Use

In order to ensure further progress in meeting our compact development and smart land use goals, and reducing energy needs, the following recommendations are made.

(1) Goal: Ensure state programs recognize and encourage compact development patterns, which over the long term will reduce transportation-related energy use.

(1a) **Strategy:** Strengthen and streamline the state "designation" programs to ensure consistency, efficiency, and improved function to encourage new growth in and around our centers.

Measure:

- Completed program review and proposed improvements, amendments, and revisions by July 31, 2012.
- 2020 Census shows above average growth in designated areas.
- Increased participation in designation programs:
  - ☐ Downtowns—maintain current number of designations.
  - ☐ Villages—increase designations by 15% in five years.

- ☐ Growth centers—after statute revised, increase by 30% in five years.
- ☐ Neighborhoods—after statute revised, increase by 50% in five years.

(1b) **Strategy:** Review state agency programs and funding sources that are linked, or could be linked, to state designation programs—including wastewater, water supply, transportation, Municipal Planning Grants, and other infrastructure programs—to better support growth in smart growth locations rather than outside designated areas.

Measure:

- As part of strategy (1a) above, funding criteria are reviewed and revised by December 2012 to give priorities to projects within designated areas.

(1c) **Strategy:** Review and develop recommendations on how the state's permitting programs—including Act 250 and ANR programs—support or impede development within designated areas and other smart growth locations.

Measure:

- Statutory changes are considered that would incorporate smart growth principles (24 V.S.A. § 2791(13)) into the Act 250 and Section 248 processes.

(1d) **Strategy:** Develop training and implement Complete Streets legislation in partnership with Department of Economic, Housing and Community Development, VTrans, AARP-VT, Vermont League of Cities and Towns, Vermont chapter of the American Institute of Architects, and others.

Measure:

- At least three workshops are held in 2011–12 to explain the requirements to the varied interests.
- VTrans and municipal projects report compliance by March 2012.

(1e) **Strategy:** Ensure that transit investments focus both on areas with development density necessary to support them, and on key corridors that link commuters to their jobs.

Measure: A model is developed that assesses different land use scenarios and their impact on transportation and energy use.

(2) Goal: Increase awareness and strengthen local and regional land use planning for smart growth.

(2a) **Strategy:** Strengthen emphasis on smart growth through education programs for municipal officials. This particularly includes a focus on stronger policies in municipal plans, more aggressive implementation of those policies in municipal bylaws, and stronger use of other tools like capital improvement plans to direct and support growth in appropriate places.

Measure:

- The Vermont Department of Economic, Housing, and Community Development conducts at least three statewide workshops each year on policies and tools that support compact development.
- The DPS continues to work with regional planning commissions to deliver training on smart growth.
- The DPS continues to work with other partners, such as VTrans, ANR, the Vermont Department of Health, Vermont League of Cities and Towns, and Vermont Natural Resources Council to develop stronger municipal capacity to support compact development.

(2b) **Strategy:** Work with RPCs to strengthen emphasis on well-designed and appropriately scaled development through regional planning activities, and in their work with municipalities.

Measure:

- Revised municipal consultation process is adopted.
- Annual consultations between RPCs and municipalities are completed.
- Revised confirmation process is consistently applied statewide by each RPC.
- Town plans meet the statutory goal of compact settlement pattern surrounded by working lands.
- No loss in the number of confirmed communities over the next five years.

(3) Goal: Coordinate energy and land use planning.

(3a) **Strategy:** RPCs will review regional plans for consistency with state's Comprehensive Energy Plan.

Measure:

- Each region has reviewed the CEP for consistency with its regional plan by July 2012, and has developed recommendations for changes to both the state and regional plans.

(3b) **Strategy:** The DPS and regional planning commissions will provide data and other support to local energy committees to increase their knowledge of the individual, business, and municipal tools available to decrease energy use through community development, behavior change, and transportation options. Because energy conservation is highly dependent on individual actions, having the local capacity to reach out to individuals becomes critical.

Measure:

- Increased training opportunities for local energy committees.
- Increased number of local energy committees involved with municipal planning.
- Increased number of local energy committees involved with marketing/promotion of mobility options.

(3c) **Strategy:** Because the Section 248 review of energy projects preempts Act 250 and municipal regulations, a number of issues normally considered in permitting processes—such as impacts on agricultural soils—are exempt from review. These permitting processes should be better coordinated, ensuring that all competing interests can be balanced in the permitting process.

Measure: The permitting process for energy projects is amended as necessary to ensure that siting under Section 248 reviews all the appropriate criteria that would be used under Act 250.