IDENTIFYING AND ADDRESSING ELECTRIC GENERATION CONSTRAINTS IN VERMONT

A Report Submitted Pursuant to Act 139 of 2018

Vermont Public Service Department
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Executive Summary

The past few years have seen major growth in the amount of distributed generation built in Vermont. This activity has been the result of significant policy support that built upon the emphasis in the early 2000s of deploying distributed generation, in part, to avoid the need for costly transmission and distribution infrastructure. At the same time the amount of distributed generation was growing across the state, the pace of Vermont's investment in energy efficiency increased as well. As a result of the success of these two policy initiatives, Vermont – like a number of other states – is now experiencing the growing pains associated with successful and rapid deployment of resources. Contrary to prior assumptions, there are now significant areas of the state that are facing the potential for costly transmission and distribution investments *as a result of* the successful deployment of distributed generation and energy efficiency.

In this report, the Public Service Department (PSD or Department) provides an overview of the state's renewable and greenhouse gas (GHG) policies, goals, and requirements; the costs associated with generation constraints; and strategies for encouraging deployment of renewable generation. There are no easy ways to address the issues. There are several options for encouraging deployment of renewable generation; however, there is no silver bullet that will cost-effectively address the issues in all areas. Instead, an increased emphasis on distribution-level planning and grid modernization will be necessary to open up constrained areas. This will take some time, but the constraints are not currently impinging on the ability of the state to meet renewable and GHG goals and requirements.

Generally, the options available for addressing generation constraints include:

- Grouping infrastructure upgrade costs – Developers of renewable generation already have the ability to work together to request a joint study of the infrastructure required to add additional generation in a constrained area and to share the costs associated with that infrastructure.
- Providing locational value for generation, flexible loads, and energy efficiency – The compensation for these resources is not currently differentiated based on the relative value they provide to the system in the location where the resource is installed. Moving forward, the regulatory process should include pricing considerations in valuing these resources: for example, additional generation and energy efficiency has less value to the system in generation constrained areas, while increased flexible loads have greater value to the system in the same areas.
- Controlled load building – Choreographing the timing of flexible loads with production of intermittent generation will minimize the amount of energy that is required to be exported out of a specific area, thereby minimizing the need to curtail generation to avoid overloading the transmission and distribution infrastructure.
- Energy storage – The ability to store excess energy during times of overproduction can help alleviate generation constrained areas; however, there would need to be appropriate economic signals to ensure that this approach is cost-effective.

- Curtailment – Although curtailment represents energy that could have otherwise been produced, and in general should be avoided, there will be circumstances where limited curtailment within a generation constrained area is the most cost-effective solution to maximizing total output of renewable resources in that area.

These options are not mutually exclusive (in fact they are generally complementary) and there is no one-size-fits-all solution that applies to every generation constrained area in the state. There are a number of planning mechanisms contained in statute, including the integrated resource planning conducted by the electric utilities and the long-range transmission planning conducted by Vermont Electric Company, Inc. through the Vermont System Planning Committee. To date, these planning mechanisms have not focused on integration of distributed energy resources such as small-scale generation and flexible loads. However, these planning mechanisms are able to be readily adapted for this purpose and are the appropriate venue for identifying the most cost-effective tools that can be deployed to address specific generation constrained areas.

In addition, the siting process set forth in 30 V.S.A. § 248 should include robust statutory language that makes clear that, in order for the Public Utility Commission to make a determination that a resource in a generation constrained area promotes the good of the state, the resource cannot add to existing constraints and thereby impose uneconomic and unreasonable costs on ratepayers. This could include a statutory rebuttable presumption that a resource in a constrained area should not be granted a certificate of public good unless the project developer provides a reasonable solution to address potential constraints.

Vermont's Renewable and GHG Policies, Goals, and Requirements

Vermont's Statutory Energy Policy

Vermont's overall energy policy, as articulated in statute, is clear that there must be a balance between affordability, reliability, and sustainability. While these objectives do not need to be in conflict, there can be considerable tension among them.

> It is the general policy of the State of Vermont:
>
> (1) To assure, to the greatest extent practicable, that Vermont can meet its energy service needs in a manner that is adequate, reliable, secure, and sustainable; that assures affordability and encourages the State's economic vitality, the efficient use of energy resources, and cost-effective demand-side management; and that is environmentally sound.
>
> (2) To identify and evaluate, on an ongoing basis, resources that will meet Vermont's energy service needs in accordance with the principles of least-cost integrated planning; including efficiency, conservation, and load management alternatives, wise use of renewable resources, and environmentally sound energy supply.
>
> 30 V.S.A. § 202a

Statutory Renewable Energy Goals

Chapter 89 of Title 30 sets forth numerous renewable energy goals (Section 8001), requirements (Renewable Energy Standard – Section 8004 and 8005), and programs (Standard offer – Section 8005a, Net metering – Section 8010).

The renewable energy goals set forth in Section 8001 provide high-level direction for the development and implementation of any renewable program. These can be summarized as: 1) balance costs and benefits; 2) support the development of renewable energy along with its related economic development; 3) provide price stability; 4) develop markets for renewable and energy efficiency projects; 5) promote air and water quality; 6) contribute to reducing climate change and anticipating impacts to the state's economy that might be caused by federal regulation to attain those reductions; 7) support generation which is distributed throughout the Vermont grid; and 8) promote diverse technologies.

In addition, 10 V.S.A. § 580, added in 2007, states that: "[i]t is a goal of the State, by the year 2025, to produce 25 percent of the energy consumed within the State through the use of renewable energy sources, particularly from Vermont's farms and forests." This language was added well before Vermont adopted the Renewable Energy Standard, described below, which utilizes renewable energy certificates. Instead, this statutory goal should be read in the context of the then existing Sustainably Priced Energy Enterprise Development (SPEED) program. The SPEED program required Vermont's distribution utilities (DUs) to enter into long-term, stably priced contracts with developers of renewable energy projects, but also allowed DUs to sell the RECs associated with those projects.[1] The sale of RECs reduced the overall costs of the SPEED program but also prevented the DUs from claiming that the underlying energy was renewable.

Statutory Renewable Energy Requirements

With respect to the pace of adding renewable generation sources within Vermont, the Renewable Energy Standard (RES) adopted in 2015 establishes clear statutory requirements. Act 56 of 2015 requires electric utilities to increase the portion of renewable energy they sell to Vermont customers to 55% in 2017, rising over time to 75% in 2032. This is the RES's Tier 1 requirement and includes renewable resources of any size, vintage, and location within or able to deliver into the New England grid. Tier 2 of the RES requires that an increasing portion (1% in 2017, climbing to 10% in 2032) of electric energy sales come from small (less than 5 MW), new (built after June 30, 2015) electric generators that are connected to *Vermont's* distribution or sub-transmission grid. The Tier 2 requirements are a carve-out of the Tier 1 requirement; in other words, the total Tier 1 and Tier 2 requirement in 2032 is 75% of retail sales.

Tiers 1 and 2 of the RES require utilities to retire Renewable Energy Certificates or Credits (RECs) to satisfy their requirements, as do all five other New England states. One RECs is created when one megawatt-hour (MWh) of electricity is generated from a qualified renewable resource. RECs can either be bundled with or sold separately from the electricity generated by the resource. RECs are registered by generators in the NEPOOL Generator Information System (NEPOOL GIS). The NEPOOL GIS tracks the characteristics of each generator in order to determine which "classes" of which New England states' renewable standards would be met by production associated with the REC.

RECs are fungible products and are routinely sold around the region. For example, a REC produced by a hydro facility in New Hampshire can be used to comply with Tier 1 of the Vermont RES and RECs from a solar project in Vermont can be used to comply with Connecticut renewable requirements. The REC is the renewable component of the generation; unless a utility (or other entity claiming ownership) retires the RECs associated with a generator, it cannot claim that the MWh produced from that generator are renewable.

Under Vermont's RES, utilities can bank RECs (i.e., save them for compliance in future years) for up to three years after the REC was produced. Accordingly, to the extent that a utility has an excess supply of RECs in 2017, it can bank them and use them for compliance in any year until 2020. Consequently, a utility that has an oversupply of Tier 2-eligible resources in 2017 can utilize these banked RECs for future compliance, further extending the time before new Tier 2-eligible resources are needed.

[1] In a 2013 report, the PUC identified 140 MW of SPEED projects built within Vermont (primarily consisting of three wind projects totaling 113 MW) that fulfilled the SPEED requirements. See, Biennial Report to the Vermont General Assembly Pursuant to 30 V.S.A. § 8005b, available at: https://legislature.vermont.gov/assets/Documents/Reports/289540.PDF.

In addition, Tiers 1 and 2 have an Alternative Compliance Payment (ACP) that effectively creates a price cap on the RES requirements. If a utility does not have sufficient RECs at the end of a compliance period, the utility will pay the ACP; the price of purchasing a REC is almost always less than the ACP. By bounding the overall costs of RES, the ACP therefore balances costs with increasing the renewable characteristics of the state's power supply. The ACP for Tier 1 starts at $10 per MWh and rises at the rate of inflation, while the ACP for Tier 2 starts at $60 per MWh, with the same escalation. Any payments of the ACP are required to be deposited into the Clean Energy Development Fund.

Act 56 also created a separate, Tier 3 energy transformation obligation that rises from 2% in 2017 to 12% in 2032. A utility may meet this requirement through additional distributed renewable generation, or through energy transformation projects that result in net reduction of fossil fuel consumption by the utility's customers. Examples of these projects could include building weatherization; air source or geothermal heat pumps; biomass heating systems; and electric vehicles or related charging infrastructure. The Tier 3 requirements are additional to the Tier 1 requirements and include an ACP equal to the Tier 2 ACP.

Greenhouse Gas Reduction Goals

In 2005, the Vermont legislature established goals to reduce greenhouse gas emissions "from within the geographical boundaries of the State and those emissions outside the boundaries of the State that are caused by the use of energy in Vermont" from a 1990 baseline of 8.1 million tons of:[2]

(1) 25 percent by January 1, 2012;
(2) 50 percent by January 1, 2028;
(3) If practicable using reasonable efforts, 75% percent by January 1, 2050

In addition, in 2015, Vermont signed on to the Under2 MOU, committing the state to limit emissions levels to less than 80-95 percent below 1990 levels by 2050.[3] Also in 2015, Vermont joined the conference of New England Governors and Eastern Canadian Premiers in adopting a regional greenhouse gas emissions reduction target of 35-45 percent below 1990 levels by 2030.[4]

The Department of Environmental Conservation's (DEC) most recent annual report on progress toward these goals revealed that the state's emissions in 2015 (the most recent year for which a complete data set is available) were 9.45 million metric tons, meaning emissions have actually increased 16 percent compared to the 1990 baseline.[5] As the report notes, "Overall emissions are still below the peak levels in 2004, but annual emissions levels have generally been increasing since 2011, with an overall slight upward trend from the 1990 baseline."[6]

[2] 10 V.S.A. § 578
[3] https://www.under2coalition.org/
[4] http://www.coneg.org/Data/Sites/1/media/39-1-climate-change.pdf
[5] https://dec.vermont.gov/sites/dec/files/aqc/climate-change/documents/_Vermont_Greenhouse_Gas_Emissions_Inventory_Update_1990-2015.pdf
[6] Ibid, p. 7

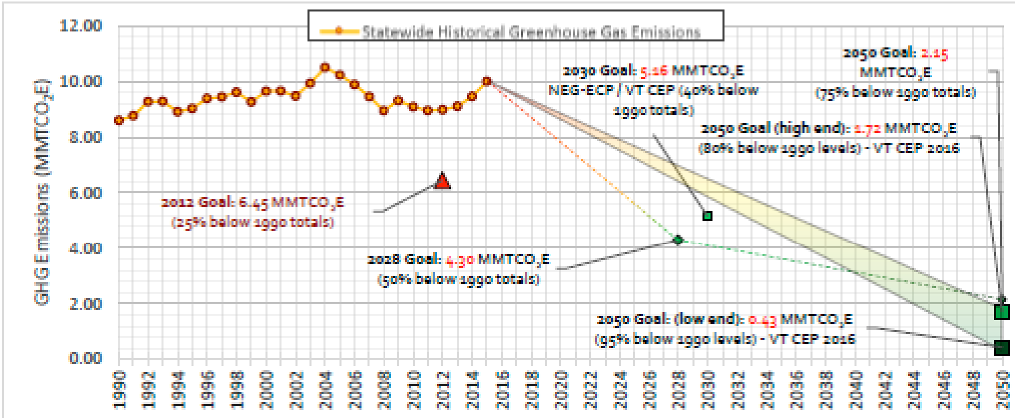
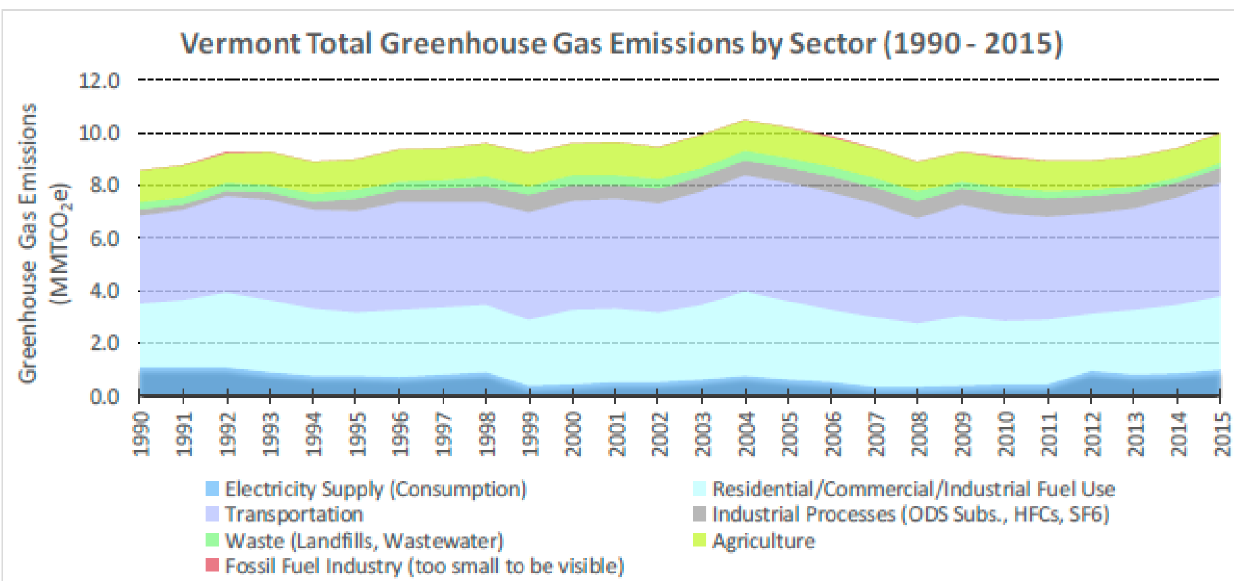


Figure 16. GHG Emissions Trends and Goals for Vermont.

Source: ***Vermont Greenhouse Gas Inventory Update 1990-2015***

While energy is the dominant source of Vermont's greenhouse gas emissions overall, emissions from electricity generation pale in comparison to those from other energy sectors. The DEC report points out that transportation (primarily cars and trucks) accounted for approximately 43% of the state's total emissions, with residential/commercial fuel use and electricity accounting for 24% and 10% of the total, respectively. And while all three sectors show trends in increasing emissions, the report recommends that the Transportation, Residential/Commercial fuel use, and Agriculture sectors "contribute significantly higher percentages and should be areas of focus for state mitigation efforts."



Historic Gross GHG Emissions (Figure 6 from: *Vermont Greenhouse Gas Inventory Update 1990-2015)*

Recognizing the nexus between energy generation and greenhouse gas emissions, Vermont's 2016 Comprehensive Energy Plan, discussed below, sets two supplemental goals for reduction in emissions specifically from Vermont's energy use, both of which are consistent with the plan's other goals for energy use reduction and renewability. The first is a 40 percent reduction below 1990 levels by 2030, and the next is a reduction of 80-95 percent below 1990 levels by 2050.[7]

The RES, described above, requires utilities to meet increasing amounts of their electricity sales with renewable generation. In 2017, 63% of the state's electric power supply was met through renewable energy and an additional 13% through nuclear. Accordingly, 76% of Vermont's electric supply is considered to be carbon free; an increase of 29% since 2016. These numbers are not reflected in the most recent Vermont Greenhouse Gas Inventory, which provides data through 2015.

In addition, Vermont participates in the Regional Greenhouse Gas Initiative (RGGI), a regional CO2 cap and trade program that requires electric generation resources with a nameplate capacity of 25 MW or greater to own credits equal to the CO2 produced by the generator. This policy effectively caps the total amount of CO2 produced within the nine RGGI states.

Meeting electric supply with more renewable generation will lower overall emissions. However, the electric sector in Vermont contributes less GHG emissions than each of the transportation, thermal, and agricultural sectors, and the RES puts the electric sector on a steady path for future reductions. While it is relatively easy to impose mandates on the electric sector, as the costs of the mandates are reflected in electric rates rather than taxes, from a policy perspective the focus of GHG reductions would be best focused on those sectors that are producing the most GHG emissions and that do not currently have long-term mandates to accomplish reductions.

2016 Comprehensive Energy Plan

Vermont Law requires the Department to issue a Comprehensive Energy Plan (CEP) developed at least every six years after stakeholder input. The most recent plan was published in 2016. It is designed to "implement the State energy policy set forth in section 202a."[8] The 2016 CEP establishes a total energy goal of 90% renewable by 2050 for the state. It is important to note that the 90% by 2050 goal is a total energy goal and is not specific to the electric sector. As explained in the Department's *2019 Annual Energy Report*, the majority of the work needed to achieve this goal will be in the thermal and transportation sectors.

The 2016 CEP sets a goal of 67% renewable electric power by 2025,[9] which is roughly the amount required by then under the RES. The 2016 CEP's electric power goals do not establish a percentage that must be met by in-state resources; however, the CEP includes language regarding an expectation as to the percentage: "The distributed projects that these programs [net metering, standard offer, etc.] have facilitated account for 2.5% of Vermont's total electric supply – and that number is expected to rise to 12% or more by 2032 under the RES."[10] This expectation is consistent with other language that makes clear that the 2016 CEP does not supplant the RES or otherwise require more renewable electric generation than is required by statute through 2032:

[7] https://publicservice.vermont.gov/publications-resources/publications/energy_plan/2016_plan, p. 4
[8] 30 V.S.A. § 202b.
[9] CEP at 2.
[10] CEP at 243.

"[p]ower supply questions now revolve around the most cost-effective way to meet the RES requirements, not around how much renewable energy to acquire."[11]

The 2016 CEP makes clear that the electric sector as a whole is moving toward a more distributed future and that distributed generation can have significant benefits. However, the 2016 CEP does not recommend abandoning least-cost principles or pursuing a specific amount of in-state distributed resources.

The electric component of the 2016 CEP – which tracks the RES – is being met with relative ease in contrast to the transformation of the transportation and heating sectors, which is crucial to meeting the 90% by 2050 goal. A significant portion of the transformation of these sectors will be switching from combustion-based to electric vehicles (EVs) and from fossil-fueled boilers and furnaces to cold climate heat pumps (CCHPs). These technologies significantly reduce fossil fuel usage, in large part because the process of combustion is inherently inefficient. According to the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, "EVs convert about 59%–62% of the electrical energy from the grid to power at the wheels. Conventional gasoline vehicles only convert about 17%–21% of the energy stored in gasoline to power at the wheels."[12]

Given that customers are much more likely to switch to electric technologies if the economics favor this decision, the cost of electricity will have a significant impact on the pace of electrification. More progressive rate designs can assist in lowering the cost of charging electric vehicles or heating with cold climate heat pumps; however, the total electric system must still be paid for by ratepayers. And while supplying these additional loads with renewable electricity will be critical to meeting the 90% by 2050 goal and the RES, increased costs associated with enabling more generation to be added to the Vermont grid – such as building out the distribution and transmission system to reduce curtailment in certain areas – will impose costs that must still be borne by all electric users.

Expectations Regarding the Amount of Renewable Generation Located in Vermont

In order to understand the extent to which generation constraints are an issue, it is important to know how much distributed generation is expected to be added to the system. The 2016 CEP and statutes are clear that there is a *requirement* that 10% of load be met through distributed resources, commissioned after June 30, 2015, and connected to the Vermont system. Based on the amount of renewable generation located in Vermont that is not Tier 2 eligible (i.e., installed before June 30, 2015 or is larger than 5 MW), combined with the amount needed to meet the Tier 2 requirement, Vermont will have approximately 1150 MW of installed renewable generation by 2032. This includes 300 MW of existing distributed solar (and one existing 20 MW solar project), an additional 400 MW of new Tier-2 eligible solar, about 200 MW of hydroelectric, 150

[11] 2016 Comprehensive Energy Plan at 277. See also the statement of the PUC on this issue, in Case No. 18-0086-INV, Order of 5/1/18 at 29: "With respect to electric supply, the CEP recognizes that the consideration of future supply should be done in the context of the RES."

[12] *See*, https://www.fueleconomy.gov/feg/evtech.shtml.

MW of wind, 70 MW of biomass, 11 MW of landfill gas, and 5 MW of farm methane resources. This does not include new renewable projects that would be located in Vermont but selling power to utilities outside the state. It is important to note that many of these in-state resources do not presently count toward Vermont's renewable requirements. The majority of the RECs produced by the larger in-state facilities are sold out of state to reduce the overall cost of service for Vermont's utilities, with the exception of a large portion of the RECs from the hydroelectric resources and those solar resources constructed after June 30, 2015 (to the extent that RECs in excess of Tier 2 requirements are not sold).

There are other goals contained in statute that argue for extending beyond this amount. Additionally, there are sound policy reasons to exceed the distributed generation requirements required by the RES. However, only RES includes a mandate[13] that the numbers set forth in statute be met and that includes a consideration of the acceptable cost of meeting that requirement – i.e., through the imposition of Alternative Compliance Payments.[14] When the legislature passed RES, it presumably was conducting the balancing that is inherent when imposing mandatory requirements that incur costs for Vermonters – in this case ensuring that the sustainability of Vermont's power sector was improved, considering the overall costs of the RES, and seeking to obtain economic development benefits.

As the PUC stated in its 2018 net-metering biennial compensation adjustment order, regulation of renewables in Vermont requires "finding the balance between moving toward a carbon-free energy future, as outlined in the 2016 CEP and the RES, and doing so at a reasonable cost to ratepayers."[15] The RES is structured to achieve renewable goals while balancing costs. Due in part to declining economies of scale and a smaller market potential, RECs from Tier 2 resources tend to be significantly more expensive than Tier 1 RECs. The approximate cost of Tier 2 compliance in 2017 was $1.3 million (with an average price of $25 per REC). This is significantly less than if REC prices were at the ACP of $60 per REC, which would represent a Tier 2 cost of $3 million, but is still a meaningful cost for Vermont ratepayers.

In addition, absent changes to the RES requirements, additional in-state generation does not promote Vermont's renewable and GHG goals. To the extent that utilities procure distributed generation resources in excess of RES Tier 2 requirements or build new generation that does not quality for Tier 2, the utilities would be expected to sell the associated excess RECs out of state to offset compliance costs and reduce total costs for customers.[16] This is the natural outcome of the market-based approach selected by the legislature to implement the RES. Procurement goals that are in excess of RES requirements benefit developers of renewable generation and the

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[13] See, *Shlansky v. City of Burlington*, 188 Vt. 470, 481 (2010), citing *In re Mullestein*, 148 Vt. 170, 173-174 (1987). "In general, a statutory time period is not mandatory "unless it *both* expressly requires an agency or public official to act within a particular time period *and* specifies a consequence for failure to comply with the provision." *Id.* at 173–74, 531 A.2d at 892 (quotation omitted).

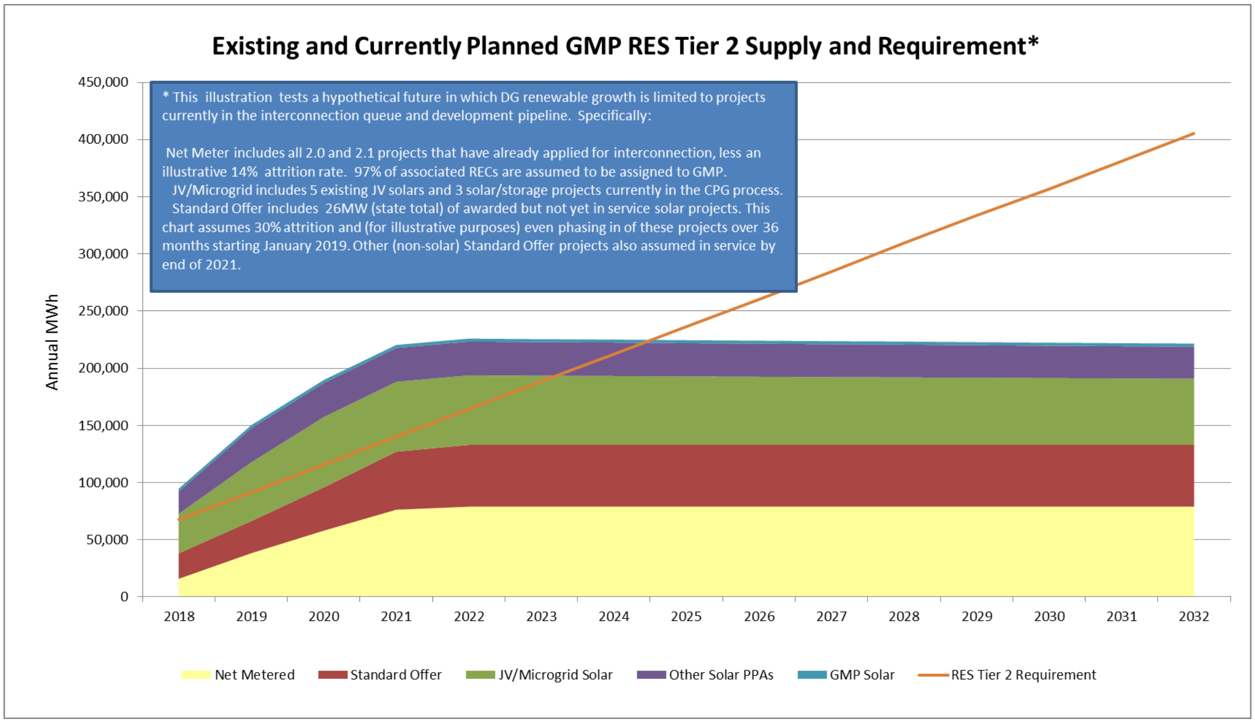
[14] 30 V.S.A. § 8005 requires that any failure to meet the Tier 1 requirements be paid $10/MWh, Tiers 2 and 3 - $60/MWh, with the ACPs escalating over time.

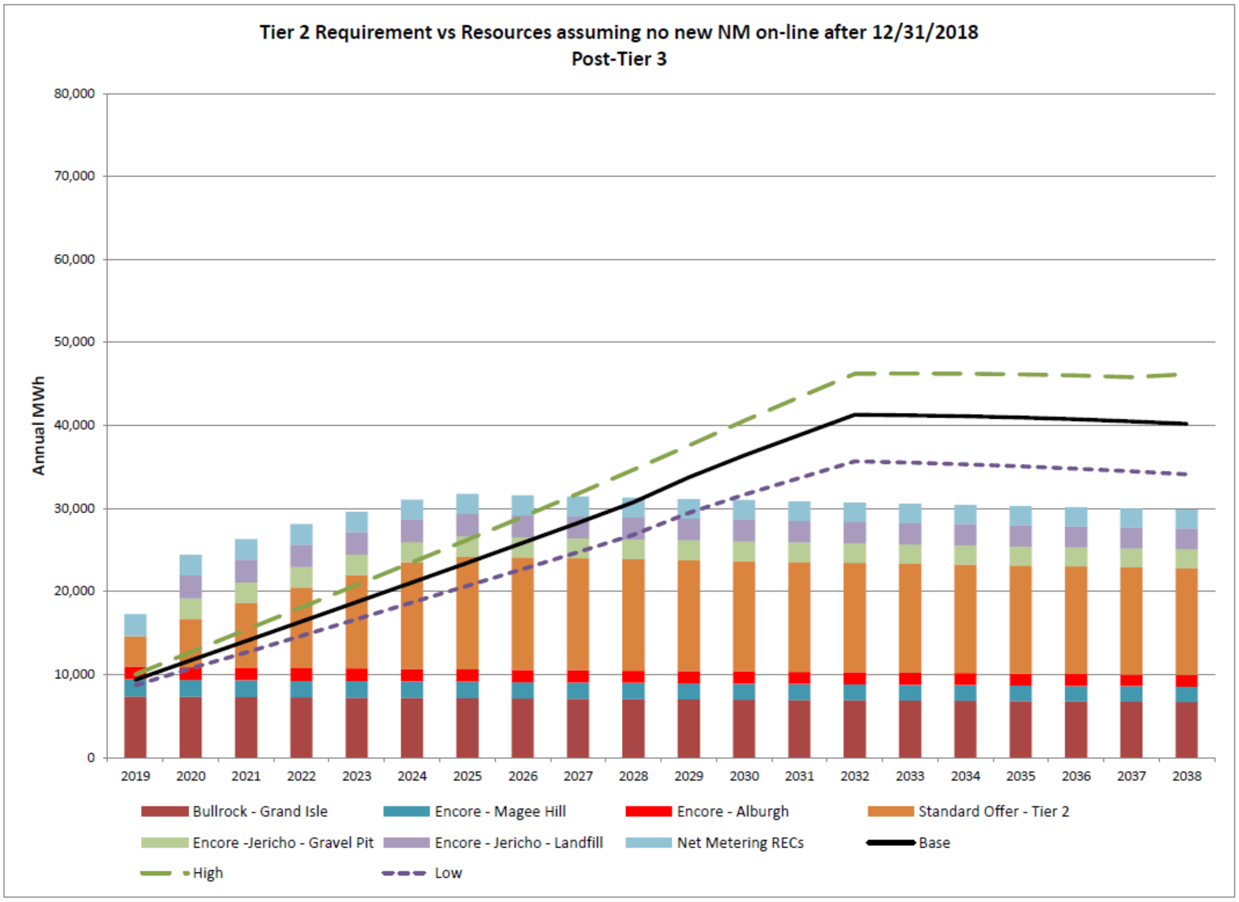
[15] Case No. 18-0086-INV, Order of 5/1/18 at 31.

[16] Pursuant to 30 V.S.A. § 8010(c)(1)(H)(ii) and PUC Rule 5.127(B)(1), RECs associated with net metering resources are required to be retired by the interconnecting utility, provided that the net metering customer provides the RECs to the utility.

associated economic development within the state; however, since the renewable attributes of those resources would not be retired within Vermont, this additional development does not move Vermont any closer to the 2016 CEP's goal of 90% by 2050 or the GHG reduction goals.

Currently, the existence of generation-constrained areas is not negatively impacting the ability of Vermont utilities to meet the Tier 2 requirements. Vermont utilities easily met the RES requirements in 2017 and, in some cases, have procured more resources than necessary to meet the in-state renewable requirements for the next several years. Below are charts from GMP and VEC, the state's two largest utilities, that illustrate the Tier 2 requirements as well as existing and planned Tier 2-eligible resources needed to meet the requirements.





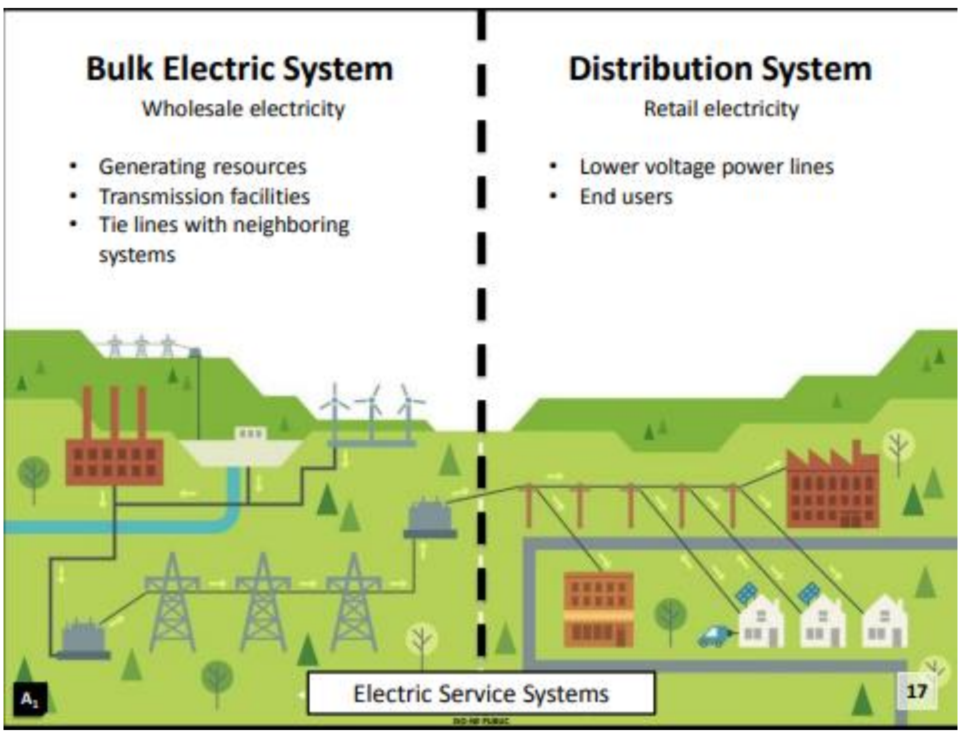
An additional consideration of the extent to which generation to meet Vermont's load is the fact that New England as a region has spent approximately $12 billion on transmission investments in the past 15 years – these investments ensured that reliability standards were met and also had the benefit of reducing congestion. Vermont electric customers have paid approximately 4% of that amount, or $480 million. The Department continues to support efforts to move toward a more distributed grid; however, policymakers must also remember that Vermont electric customers have paid almost half a billion dollars for – in part – the ability to move renewable generation from locations other than Vermont.

Vermont has a significant amount of in-state renewable energy, and Tier 2 of RES will require several hundred more MW to be built. To the extent that policymakers believe that the Tier 2 mandates are insufficient, there should be a clear analysis of the related costs and a weighing against the environmental and economic development benefits associated with developing more in-state renewable resources, along with the imposition of clear statutory requirements.

Electric Generation Constraints within Vermont

Background on the Electric System

In the late 1800s, Vermont's early electric systems were isolated and were built to serve local load from a single generating source (primarily hydroelectric power). Whenever there was insufficient water for generation purposes, electricity simply was not delivered to customers. These discrete systems were eventually tied together physically to better coordinate resources and load, a process that continued until 1971, when the New England Power Pool was created to coordinate dispatch of large-scale generation resources and construction of transmission to move electrons throughout the region. For the last 100 years, the electric system was primarily configured to send flows from large centralized power stations out to load. As an example, a 345 kilovolt (kV) transmission line was fed out of Vermont Yankee to a substation in Windsor where the voltage was stepped down to 46 kV. This 46 kV subtransmission lines carried power out to Chelsea, were the power is further stepped down to 12.47 kV. Further out in remote areas, the 12.47 kV line would be further stepped down to 4.14 kV. At the time the system was designed there was no reason to build it out beyond what was needed to provide the forecasted load, and regulators worked to ensure that the costs incurred by ratepayers are reasonable.



Source: ISO 101: Introduction to ISO New England, available at https://www.iso-ne.com/static-assets/documents/2018/10/2018C-ISO101-student-book-posted.pdf.

In addition, it is important to note that there are two different regulatory systems at play in the energy industry. The Federal Energy Regulatory Commission (FERC) has jurisdiction over interstate transmission of energy and also wholesale sales, such as the sale of power from a generator to a distribution utility. The Vermont Public Utility Commission (PUC) has jurisdiction over siting generation and transmission facilities and also over retail rates – the rates that electric end-use customers pay to the distribution utility. By law, both regulatory structures are focused on ensuring just and reasonable rates for customers.

The regional transmission planning and rules for wholesale sales of electricity are administered by ISO New England (ISO-NE), which administers open and technologically neutral wholesale electricity markets. Under the energy markets approved by FERC, generators compete to supply power by making supply offers at a price per MWh to load, which puts forward demand bids at a price per MWh. ISO-NE selects generation based on least cost and where the supply stack meets the amount of demand, that bid price is considered the marginal price. In a system with no transmission constraints, all generators with bids up to this marginal price would get paid this price for energy. However, such a system does not exist in reality, and ISO-NE has developed *Locational* Marginal Price (LMP) to reflect the fact that system characteristics impact delivery. LMP consists of the marginal price for energy, congestion, and losses.

In ISO-NE, generators are compensated based on their generation at the "node" where they connect to the electric grid. Each node has an individual Locational Marginal Price (LMP) that is the rate per MWh that generators are paid. The energy component is the price for energy at the "reference point" and is the same for all nodes. If the electric system had no constraints or losses, LMPs would be the same throughout New England. However, constraints and losses do exist and are reflected in the congestion and loss components of the LMP. When generation and load are not located near each other, significant locational price variances can emerge.

Congestion charges send price signals to generators and load (in the wholesale market) based on location such that generation located in undesirable locations will be compensated less. Congestion occurs when there is insufficient transfer capability on the lines to carry the power. When this occurs, ISO-NE must reduce generation in the constrained area, in order to maintain system stability and reliability. To do this, the congestion component is decreased, which lowers the LMP. When LMPs drop below a generator's offer price, or the lowest price it is willing to accept to generate, the generator will not be dispatched, and generation in the region is reduced.

Any electric generator that is larger than 5 MW is required to participate in the ISO-NE wholesale market and be subject to these market rules. The vast majority of distributed generation in Vermont does not participate in the regional wholesale markets and is instead compensated entirely through bilateral contracts between the developer and the utility, net metering rates, or standard offer prices. These projects are considered to be "behind-the-meter" to ISO-NE because they are not reflected in the ISO-NE markets, although they have the effect of reducing the amount of power that utilities need to purchase from the markets. Some larger projects that do participate in the ISO-NE wholesale market also have bilateral contracts with utilities, which can serve to mitigate some of the effect of lower LMPs on the generator while also potentially exacerbating constraints by blunting the economic signal to reduce generation.

Over the past ten years, Vermont's in-state resource generation mix went from a few dozen generators, almost all of which were visible to ISO-NE, to thousands of comparatively smaller generators that are mostly "invisible" and that in the aggregate reduce the amount of load that the utilities must serve through the wholesale market. The majority of these behind-the-meter generators are less than 100 kW and located on the distribution system, which was not designed for two-way flows of electricity. Consequently, the issue of generation constraints is not a result of insufficient investment in infrastructure – given the conditions at the time the system was built – by the state's distribution utilities.

Defining Generation Constraints

In practice, every electrical grid is constrained, as it would be uneconomic and environmentally detrimental to over-build the electric system such that it would not have any constraints. Since 1991, Vermont has had a statutory mandate to ensure that utility planning incorporate least-cost principles in ensuring reliability and sustainability standards, although this least-cost principle has been in effect for a hundred years in accordance with general rate precedent.

The infrastructure that makes up the electric system are assigned ratings that limit the amount of electricity that can flow over or through the components. Maintaining flow of electricity below these ratings prevents overloading and resulting failure of the components.

There are very few states in the country with a greater amount of distributed solar generation compared to the amount of load. Vermont has one of the highest amounts of distributed solar, as a percentage of load, in the country. Hawaii, one of the few states with clearly higher amounts of distributed solar, has higher electricity prices, more sunny days, and a solar capacity factor that is 40% higher than Vermont. In addition, Vermont is one of the most rural states in the country (with respect to the percentage of Vermont's population living outside metropolitan areas). As a result, there tend to be fewer customers per line mile than in other areas, resulting in higher distribution costs per ratepayer and greater likelihood of constrained distribution lines, because the lines that serve these remote customers tend to have limited capacity.

The issue of generation constraints is becoming more pressing as the amount of load decreases in response to aggressive energy efficiency efforts in the state. Generally, load in a given area of the distribution system can be met by generation that is also on that system, provided that the timing of generation matches the timing of load. In hours when load exceeds available generation in a given area, electricity must be imported from adjacent areas. Conversely, to the extent that the amount of generation is greater than the amount of load in a given area, the generation must be exported to an area that can utilize those MWhs. For example, in the town of New Haven, Vermont, 8 MW of distributed solar generation has been built in the past ten years, while the population has stayed relatively stable at 1,727. As a result, the vast majority of the distributed generation is exported out of the area.

Almost all of the distributed generation built within Vermont is solar PV, which has a capacity factor in the range of 14%.[17] However, the RES requirement is based on energy. For example, a 1 MW solar project will produce, on average, 1,226 MWh per year (1 MW * 8760 hours in a year * 14%). A high penetration of solar generation means that while the overall energy

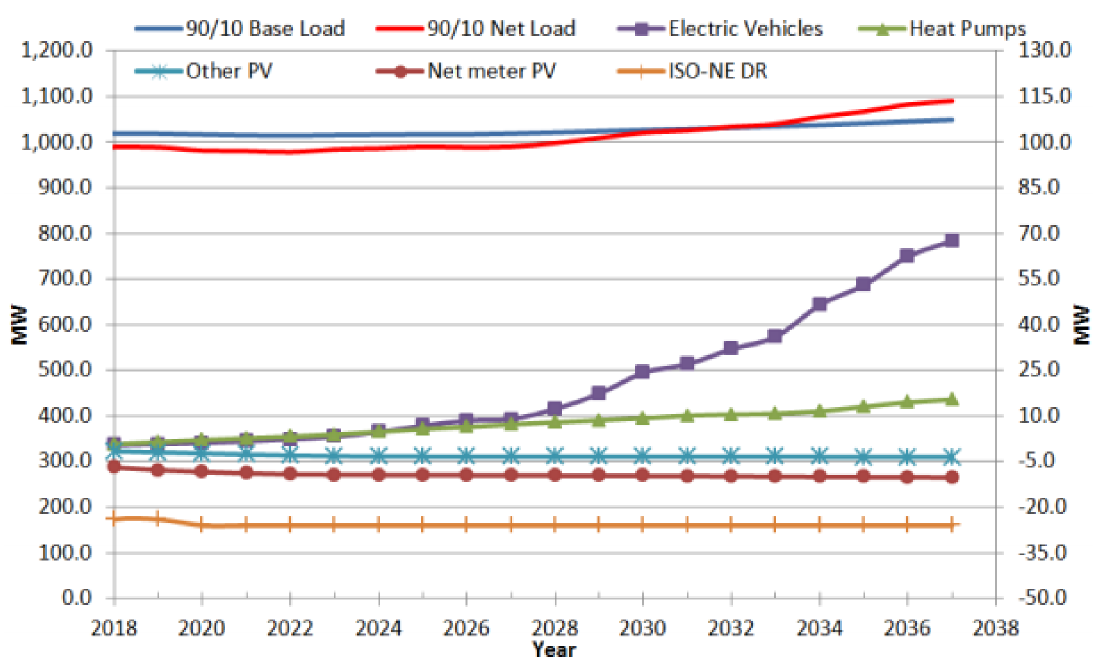
[17] The capacity factor for some plants in northern Vermont is slightly under 12%.

generation is relatively low, but the stress on the system can be significant during a relatively small number of hours per year, when solar production is peaking.

Vermont and New England are moving toward having two functionally different electric systems. In much of the year solar can provide a meaningful contribution toward energy needs and natural gas-fired generation at the regional level keeps wholesale costs relatively low. During the winter time, natural gas is given priority for heating purposes, resulting in increased production from dirty oil-fired units, and solar produces low or negligible amounts. It is increasingly likely that offshore wind, which has a significantly higher capacity factor that on-shore wind or solar, will play a meaningful role in meeting energy needs during winter months.

On a statewide basis, the amount of load has declined over the past ten years due to the successful deployment of energy efficiency and distributed generation. This last decade is the first time in recorded energy regulatory history that load is forecast to be flat to declining. Electrification of the transportation and heating sectors is expected to increase load over time, but most of this growth will only begin to materialize a decade from now.

PROJECTED VERMONT SUMMER PEAK LOAD AND ITS COMPONENT FORECASTS



Source: 2018 Vermont Long-Range Transmission Plan, at 16, available at: https://www.velco.com/assets/documents/2018%20LRTP%20Final%20_asfiled.pdf.

Physical constraints

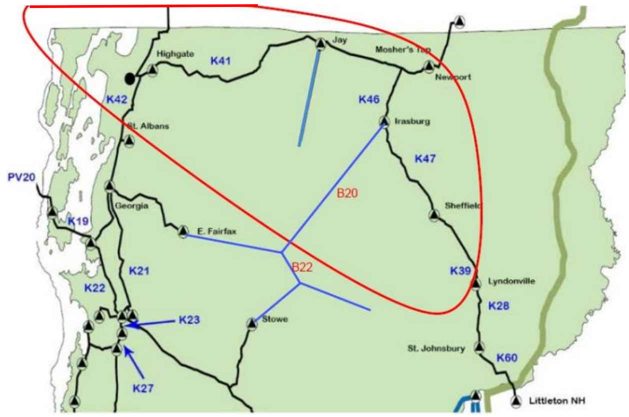
The most straightforward generation constraints exist on the distribution and sub-transmission system. The transformer that steps down voltage from sub-transmission to distribution has a rating that reflects that operation parameters of the transformer; operating over the rating will create accelerated degradation and potential for failure, leading to outages and significant replacement costs. As stated previously, the transformers were installed on the system with the expectation that power would be flowing from centralized generators over the transmission/sub-transmission network to the distribution network and, ultimately, consumers. In reviewing the potential impact of a proposed new generator, the utility will examine whether that generator can safely interconnect without violating the ratings on the equipment. A new customer could interconnect, but would be required to pay for the upgrades necessary to interconnect; in the case of installing a transformer with increased capacity, the costs could be well over $1 million. Technically, the utility is not informing the developer that it cannot interconnect to that particular circuit, but only that the developer, in accordance with long-standing cost allocation principles, must pay for costs necessary to upgrade the system to accommodate the generation.

Generally, the areas currently facing generation constraints on the distribution and sub-transmission systems are located in rural areas with relatively little load. Some of the electric utilities have publicly available maps that depict those areas with limited generation interconnection capacity. Appendix II contains, as an example, GMP's capacity map, as of January 2019.

<u>Economic constraints - SHEI</u>

In addition to the local, distribution, and sub-transmission physical constraints, there is a large portion of northern Vermont that is subject to constraints on the transmission system. Unlike constraints on the distribution and subtransmission system, there is the ability to interconnect new generation (but not necessarily generate) without affecting reliability; however, as a byproduct of ISO-NE rules and markets, the new generation in the area will result in increased congestion and increased curtailment of existing generation with corresponding cost impacts for ratepayers.

The Sheffield Highgate Export Interface (SHEI) is an electric transmission constrained region in northern Vermont that is defined by ISO-NE in order to ensure the reliable operation of the transmission system. Geographically, the region starts at the Vermont/Canada border and extends south into parts of Chittenden, Lamoille, and Essex counties. The borders of SHEI are fluid and can shift with additional load or generation in the region.



The SHEI region is characterized by electric generation that usually exceeds demand, and at times, the capacity of the transmission system cannot safely and reliably transport the energy elsewhere. The area has an average demand of around 35 MW that drops as low as 20 MW at times. The total generating capacity in the area is about 450 MW and includes imports from Hydro-Quebec on the Highgate Converter (225 MW), Kingdom Community Wind (63 MW), Sheffield Wind (40 MW), Sheldon Springs Hydro (26 MW), Highgate Falls (9 MW), Coventry Landfill (8 MW), and several other small renewable generators. It is worth noting that the Sheffield and Kingdom Community wind projects were built in response to the SPEED program, and consequently represent efforts to achieve renewable development requirements in place at the time these resources were built.

When load in the region is lowest, often spring and fall, generation from wind and hydro tends to be the highest, resulting in significant excess generation. However, the capacity of the transmission system limits its ability to transport the power. If the amount of excess generation is greater than the transmission line limits, then the reliability of the transmission system will be compromised and there is the potential for outages in the event of a contingency occurring (such as a tree falling on a line). This dynamic can result in both congestion and curtailments.

Pursuant to FERC requirements, ISO-NE allows proposed generation resources to interconnect to the transmission system pursuant to a Minimum Interconnection Standard. The Minimum Interconnection Standard is focused on ensuring that energy can be delivered into the system. When the system is tested to evaluate the potential impacts of new generation, ISO-NE assumes that generation from the proposed project or other resources can be backed down. In other words, in determining what upgrades are necessary, ISO-NE assumes that any exceedance of a line or transformer rating could be remedied by limiting the amount of generation that is produced in the area. This is consistent with the general regulatory outlook of FERC and ISO-NE, which prioritize the use of technology neutral, competitive markets to dispatch generation.

The underlying rationale for the Minimum Interconnection Standard is that resources should be allowed to compete to be dispatched. In an area where there are multiple units that all want to run but insufficient transmission to allow this, ISO-NE also determines which units to dispatch based on price – if a unit want to run it must be willing to bid lower than the other units. The lowest price offer that a resource can submit is -$150/MWh; however, since the resource that is dispatched will receive the system-wide marginal price, in most circumstances the actual clearing price that the unit receives will be higher than the floor offer price. Even if the clearing price is low, or even negative, revenues from production tax credits, RECs, and other contractual payments can still provide an overall positive revenue for a renewable resource with zero fuel costs. Ideally, wholesale price signals should be sufficient to incentivize generation resources to decrease production. However, in the SHEI region, almost all of the generation is renewable, with no fuel costs, and therefore the price signal is insufficient.

At times of significant excess generation, in addition to low LMPs resulting from high congestion charges, ISO-NE will also send generation a "Do Not Exceed" signal to generators that caps the amount they can produce.[18] When generation in SHEI receives a "Do Not Exceed" order – or is curtailed – there are both economic and environmental impacts. Almost all curtailable generation in SHEI is renewable and owned or purchased by Vermont utilities to serve Vermont load. Renewable resources have no fuel costs and their generation helps Vermont achieve its renewable goals. When in-state renewable generation is curtailed, it must be replaced with non-renewable system energy. Additionally, when the generation is owned by a utility (rather than purchased), the costs are fixed but LMP revenues are not received and the utility must buy replacement power from the ISO-NE wholesale market to make up the difference. Therefore, curtailments result in both economic and environmental impacts for Vermont.

As described above, generators are compensated with the LMP for each MWh generated and sold into the ISO-NE market at those nodes. The Vermont utility that owns or purchases the energy sees the revenues from the generation reflected in its power supply costs. When LMPs are low, Vermont utilities receive less compensation for that generation. At the same time, utilities must pay the Vermont load zone LMP for their load. When paying for load, lower LMPs result in lower costs. The Vermont load zone LMP is a load-weighted average of all nodes in the state (or zone). However, for SHEI, it is important to note that only about 10% of Vermont's load is located in that region, so the lower LMPs in SHEI have a relatively low impact on the Vermont zone LMP compared to the impact of lower LMPs on the revenue for generation.

Only resources that are subject to ISO-NE market rules are subject to curtailment or DNE dispatch rules. Accordingly, new generation that does not participate in the ISO-NE markets increases congestion within SHEI but does not face the same economic risks as those resources dispatched by ISO-NE. In other words, there is an inequitable distribution of the consequences of adding generation to an area that has more generation than load.

The SHEI boundary is not static, and VELCO's 2018 Long-Range Transmission Plan has analyzed the likelihood that the boundaries of the SHEI area will expand as more resources are added to the Vermont system. This analysis was fully vetted by the Vermont System Planning Committee. It's important to note that the SHEI boundary is not a clear demarcation of which generation facilities will negatively impact the areas, or to what extent. In other words, generation located in some areas within the SHEI boundary will have more impact than in others. The farther south a generator is located (including outside the SHEI boundary) the less the

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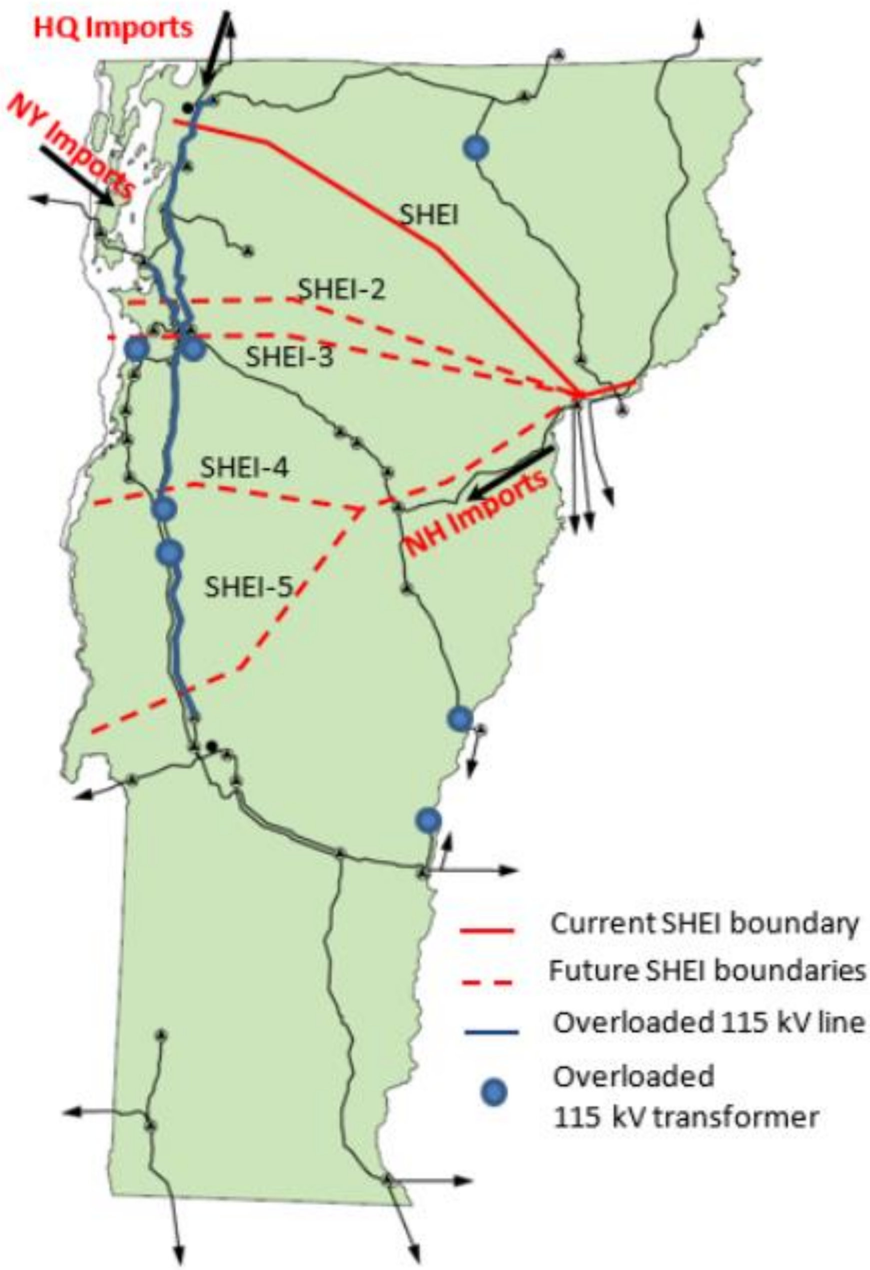
[18] Currently, the only generators that receive DNE signals are KCW, Sheffield Wind, and Sheldon Springs Hydro. External Transactions (or imports from outside New England) such as Highgate, as well as any new solar generation that is built within SHEI, are not subject to DNE dispatch signals.

generator will have a detrimental impact on congestion. As more generation is added within the state, the SHEI boundary will shift toward the south.

LOCATION OF TRANSMISSION CONSTRAINTS AS A RESULT OF HIGH SOLAR PV



Source: 2018 Vermont Long-Range Transmission Plan, at 37, available at: https://www.velco.com/assets/documents/2018%20LRTP%20Final%20_asfiled.pdf.

The Impact of Historic Energy Policy

Since 2005, Vermont statute and policy have assumed that distributed generation provides benefits to the electric system; and in a system where load is growing, that is often the case. The

Vermont System Planning Committee (VSPC) was formed as a result of a PUC Order that determined that a transmission line might have been deferred if there was sufficient planning associated with non-transmission alternatives such as energy efficiency and generation. The VSPC is specifically tasked with examining areas of the state that are experiencing increased load and determining whether non-wires alternatives such as distributed generation or targeted energy efficiency can defer or eliminate the need for additional utility infrastructure. In addition, a statutory mechanism to incentivize distributed resources specifically exempted from the programmatic cap resources that mitigate transmission and distribution constraints.[19]

At a time when load was continuing to grow and there was relatively little distributed generation within Vermont, this assumption was reasonable. However, there have been significant changes to the electric sector since 2005. In 2006, the statutory cap on the Energy Efficiency Utility budget was lifted; with the annual budget increasing from $17.5 million to over $50 million, and a resulting significant decrease in electric usage. In addition, there have been approximately 300 MW of new distributed solar resources added in the past decade.

Given the high penetration of distributed generation in the state, and the flat-to-declining load, the state has evolved to a point where the benefits of a distributed generation project will be highly dependent upon the location, size, type, and other characteristics of project. In other words, distributed generation is not an intrinsic good in and of itself. Generally, distributed generation provides the following benefits: (1) reduction in the need for transmission and distribution upgrades; (2) the production of renewable energy to meet renewable energy goals; (3) reduction in transmission and wholesale energy costs; and (4) reduction in line losses.

Distributed generation continues to provide value; however, as with every other resource, the benefits have to be weighed against costs, and there needs to be a recognition that benefits and costs change over time. In most areas of the state, distributed generation will not provide system benefits, in some areas, additional distributed generation would have negative impacts on the system, and for some very limited areas, new distributed generation may provide system benefits. Advances in technologies may also enable new or enhanced value streams from distributed generation, such as pairing generation with storage and "shaping" the timing of output to match system needs; this is discussed further below.

Costs Associated with Generation Constraints

There are multiple costs associated with generation constraints. These include costs to electric customers, to owners of current renewable generation facilities, and to developers of potential generation projects. Weighing these costs is difficult in part because some of the issues are difficult to measure.

It is important to note that the costs do not include the environmental impacts associated with reduced amounts of renewable generation. Vermont is not an island; for decades it has relied on hydroelectric generation from neighboring states and Canadian provinces to meet load

[19] 30 V.S.A. § 8005a(d)(2).

obligations. Vermont utilities have the ability to contract with new renewable resources in New England, Quebec, or New York. Some of these resources – such as off-shore wind – would likely have greater environmental benefits than in-state resources because the output from such resources would result in greater reductions in oil-fired generation during winter months, given the magnitude and timing of the output from such projects. In addition, as explained above, there is not an immediate need for new in-state generation to meet Tier 2 of RES, and any RECs from in-state DG beyond the Tier 2 requirements would likely be sold and could not be counted toward meeting Vermont's renewable and GHG goals.

The Vermont renewable energy industry involves a sizeable number of jobs,[20] and there are opportunity costs associated with the inability to add new generation resources in constrained areas. To the extent that constraints persist over time, there will be a negative impact on the jobs in the industry. However, as described below, there are measures that solar developers can take to overcome the up-front costs associated with building out constrained areas.

To the extent that generation constraints completely foreclose or materially impinge on the ability of new renewable resources to be built in order to meet Tier 2 of RES, Vermont ratepayers would bear higher costs associated with compliance. If a utility fails to procure sufficient Tier 2 RECs, it must pay the ACP, which started at $60 per MWh and increases over time. Additionally, since RECs are a market mechanism, as supply of Tier 2 eligible RECs is restricted, the price will increase, thereby increasing overall Tier 2 compliance costs.

For existing generation in the SHEI area, the current constraints are causing negative impacts for ratepayers through curtailment of existing, utility-owned generation and congestion that impacts the renewable resources under contract to Vermont utilities. Increasing generation and energy efficiency in the area is exacerbating these impacts. All of the costs described above need to be weighed against the costs of upgrading infrastructure to address the constraints, which can be significant – an upgrade of the existing 115 kV lines could be well over $100 million.

Allocation of Costs Necessary to Address Generation Constrained Areas

For distribution-level constraints, the interconnecting utility does not tell the developer that its project cannot be interconnected, but instead the utility notifies the developer of the costs to upgrade the system such that the resource could interconnect. The interconnection costs in constrained areas often make the projects uneconomic. As an example, a developer of a 500 kW solar project would file an interconnection application with the appropriate utility and would be notified that the upgrades needed would cost $1 million. That project could not be economically developed.

Under long-standing and clear regulatory precedent, the cost associated with upgrading the distribution or subtransmission system to accommodate a new resource is borne by the developer

[20] *See*, Vermont Clean Energy Industry Report 2018. Available at: https://publicservice.vermont.gov/sites/dps/files/documents/Renewable_Energy/CEDF/Reports/VCEIR%202018%20Report%20Final.pdf.

of that resource, not by all ratepayers. This requirement is clearly stated in PUC Rule 5.507(G)(5), which governs interconnection of generation facilities: "Costs of Facilities and Cost Responsibility. Where additional facilities, Interconnection Facilities, or System Upgrades are required to permit the interconnection of a Generation Resource, the Interconnection Requester shall bear the entire cost of such facilities."

Generally, this principle has not applied when transmission and distribution facilities are required to be upgraded as a result of increased load (and there is not a single large user that is causing the increased load).[21] This is due to the fact that new load results in new contributions toward the cost of maintaining the system. In contrast, new generation does not pay for the cost of serving load – the interconnection costs paid by the generator only pay for the costs associated with interconnecting that generator.

In addition, 30 V.S.A. § 218c requires that utilities conduct least-cost planning, which examines the economic costs and benefits of any action and includes the environmental benefits associated with GHG reductions and consistency with renewable goals. Under this statutory requirement, the utilities cannot simply upgrade the system to enable more generation without regard to cost.

Absent a very clear legislative directive that specifically orders the PUC to create a structure where customers subsidize the buildout of infrastructure for the benefit of renewable development, the cost-causer-pays principle should not be altered. Even if the Legislature were to direct such a subsidy, there should be some direction as to how to balance costs – for example, should the PUC authorize a $1-million subsidy in a specific area simply because a developer wants to build one 500 kW group net-metering solar facility in that specific location, and/or are there locations that should be targeted or prioritized for subsidy based on other policy objectives? Addressing constraints within the SHEI area would be considerable as fully addressing all the constraints would involve upgrading the transmission system at the cost of well over $100 million.

Strategies for Encouraging Deployment of Renewable Generation while Minimizing Curtailment

There is no single specific action or policy that can be undertaken to fully address generation constrained areas. The problem arose due to multiple factors and over many years. The solutions will also have to be varied and will take time to successfully implement. However, as noted above, the existing constraints will not impede the ability of Vermont utilities to meet RES requirements for a number of years.

The solutions described below do not constitute an exhaustive list and will require efforts by regulators, developers, and utilities. In addition, VELCO and the utilities have been reviewing potential infrastructure issues to help address constraints in the SHEI area.

[21] However, see Docket 7429, Order of 8/26/08 at 9-10, describing a situation where Mount Snow was required to pay its share of substation upgrade costs.

Grouping Upgrade Costs

The primary impediment to renewable development in generation-constrained areas is that, in many cases, the cost of upgrades is too high for any individual project to be economically viable if that project alone pays the upgrade costs. The individual and competitive nature of resource development makes it difficult to develop a mechanism for resources to share the interconnection costs.

However, Act 174 of 2016, which provides for comprehensive energy planning by municipalities and regional planning commissions, includes a mechanism for developers to identify areas that the municipalities have specifically indicated are preferred for development of energy resources. Developers could work collaboratively to identify such areas and enter into agreements to share the necessary costs of upgrading infrastructure. This mechanism is specifically contemplated in PUC Rule 5.500:

> Grouping of Facilities. An Interconnecting Utility may propose to group facilities required for more than one Interconnection Requester in order to minimize facilities' costs through economies of scale, but any Interconnection Requester may require the installation of facilities required for its own Generation Resource if it is willing to pay the costs of those facilities.[22]

The Department is not aware of this provision having been utilized to date and there are certain programmatic limitations to locating facilities in close proximity that may need to be re-examined. However, it is a mechanism that developers should be pursuing.

Provide Locational Values for Generation, Flexible Loads, and Energy Efficiency

For the most part, the location of constrained areas in Vermont is already known. At the distribution level, many of the utilities have maps available that clearly delineate then constrained areas. For the SHEI area, the general area is well-mapped, and VELCO's 2018 Long-Range Transmission Plan provides a graphic depiction of how the physical boundary of SHEI will increase with additional new generation.

Currently, incentives for renewable generation based on system location and timing of production, for flexible and controlled loads, and for energy efficiency are not dependent on the needs of the system and assume that the value is equal in all areas. This is due in large part to the desire to have a straightforward program that is easier to administer and easier for customers to understand. However, the simplistic nature of the programs also creates confusion between the benefit that such services provide to the customer and the benefit provided to the system. Generally, a net metering system, electric vehicle charger, or more efficient appliance will provide the same value to a utility's customer regardless of where in the utility's service territory that customer is located. However, within a constrained area, a net metering system could impose costs on other ratepayers, an electric vehicle charger that is controlled by the utility will

[22] PUC Rule 5.507(G)(6).

provide greater value to other customers, and a more efficient appliance will have little benefit to (and possibly impose costs upon) other customers. Incentives should reflect the system benefits of a resource, rather than the benefits to individual customers.

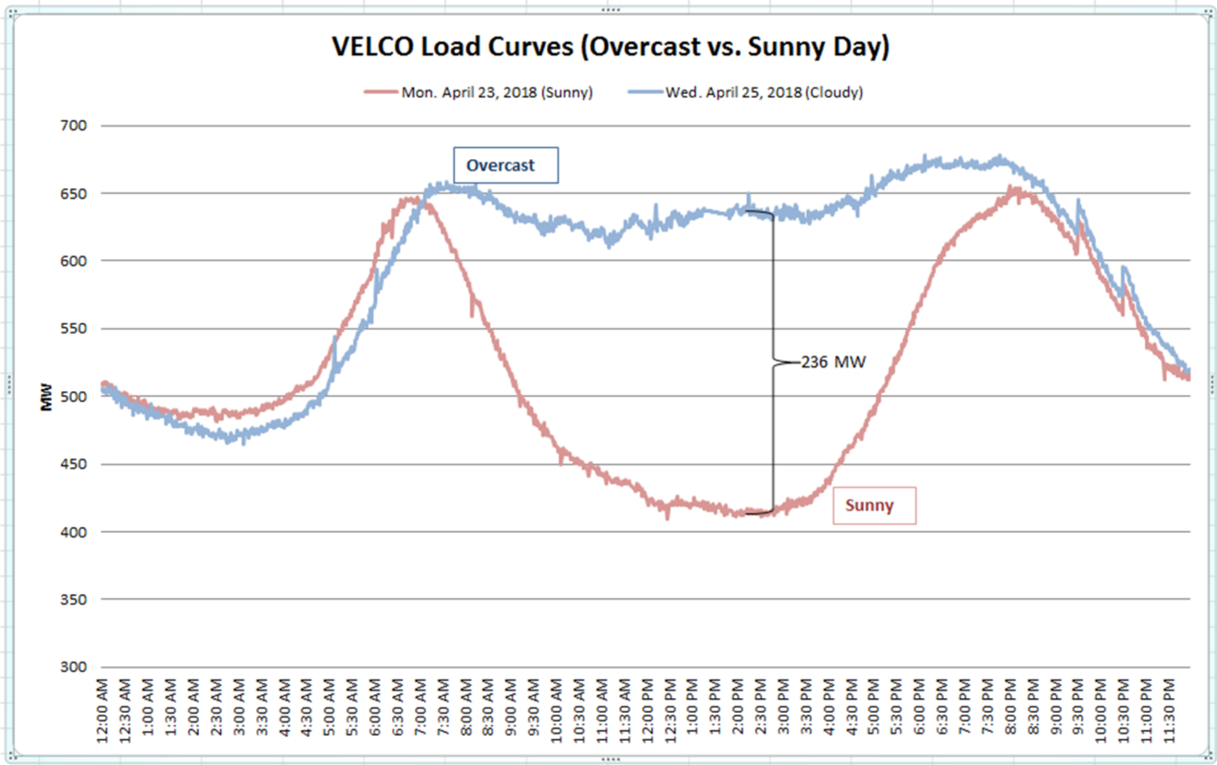
Targeting incentives would increase the complexity of providing programs but is possible. For example, a utility that had a constrained distribution system in one area could work with the municipal energy committees in that area to advertise controlled load devices, with a corresponding increase in incentives for that area. An application for a net-metering system provides the physical address for the system, and the utility should be able to identify and provide notice to the PUC that the system is located within a constrained area. To the extent that the installer of the net-metering system did the necessary due diligence and provided complete information to the customer, the net-metered customer would not be surprised by the decreased incentive and would have factored that into the determination as to whether to proceed with the installation. In addition, in establishing the Energy Efficiency Charge (EEC) which funds energy efficiency programs, the PUC could determine whether it is reasonable to decrease the charge for customers in a constrained area. The money that would have otherwise been collected through the EEC could then be used by the DU to provide targeted electrification efforts in that area.

Load building

Generally, constraints on the electric system tend to be in areas with relatively low loads. To the extent that generation production coincides with load in a given area, the generation is "soaked up" by the load and there is no need to export excess generation outside of the local area. However, it is important that the timing of load and generation coincides. The load curve of the device needs to generally match the supply curve of the majority of generation resources in the constrained area. For example, if a constraint has occurred as a result of too much solar generation, increasing the number of cold climate heat pumps in the area will not have a significant impact on resolving the constraint as cold climate heat pumps use electricity primarily in the winter, when solar generation is minimal.

Tier 3 of RES requires utilities to undertake measures that reduce fossil fuel use, and all of the utilities offer electric vehicle and cold climate heat pump programs. Given that utilities are in the best position to identify upcoming constraints, timing of peak load, and timing of peak supply in the area, Tier 3 can be an effective mechanism to help mitigate generation constrained areas.

One solution to encourage load growth and address overproduction of solar is to structure rates such that the price of electricity is less when there are significant amounts of solar generation on the system. While this model works well when the weather, and corresponding solar output, is generally easy to predict (such as Hawaii and southern California), it is more difficult to do this in Vermont where the weather tends to be more variable. The graph below depicts the amount of solar being produced in Vermont two days apart in spring, when loads are generally low and solar is operating at near its full capacity factor on sunny days – one on a sunny Monday and the other on an overcast Wednesday. As can be seen, the Vermont load, which absent any behind-the-meter solar would be generally the same on both days, is 236 MW (or roughly 40%) lower on the sunny day compared to the overcast day. As the amount of behind-the-meter generation in Vermont increases, time-of use-rates will have increasing difficulty in capturing the variability of intermittent solar production, though storage and time-of-production rates hold promise in managing that variability.



For practical purposes, direct control of flexible electric loads (such as EV charging) by the interconnecting utility is more likely to be a better method of choreographing demand with the output of intermittent generation. This is not a simple process, however, as it relies on active and continuous management of load and generation output and would require that the electric utilities effectively function as balancing entities similar to ISO-NE. Additionally, there needs to be sufficiently robust communications networks to ensure that both generators and end-users are receiving the dispatch signals; reliability concerns would arise if not all parties received the necessary signals and there was an imbalance in load and generation.

Energy Storage

Storage has the potential to alleviate some portion of generation constraints; however, this is dependent on the economics and the ability to charge and discharge the device in a manner that alleviates, rather than exacerbates, the constraints. In addition, the losses associated with round-trip efficiency and the ability of the storage device to perform other tasks need to be taken into account.

Although battery storage costs are declining rapidly, it is not yet clear that the economics of battery storage are at the point where it would be cost-effective for a solar developer to pay the storage provider to offset constraints in all hours of the year. To date, utility-scale battery storage projects that have been proposed in Vermont are economic if a project can reduce a utility's peak loads and thereby reduce regional transmission and capacity costs, while also monetizing other available value streams such as regulation. Since the economics of a battery resource would likely dictate the discharge of the storage resource during the monthly peaks, there would be several hours per month when the storage resource was not able to address over-generation in the area. This could be resolved by curtailing generation during those hours when the storage resource is being used to reduce peaks; however, that would reduce revenues for the developer (or net metering credits for the off-taker) of the generation facility.

Another potential option would be to better link the compensation for the generation output with the value of the energy. As recently as five years ago, the Vermont's monthly peak load coincided with solar production for at least some months of the years. As regional transmission costs are assigned based on the monthly peak load, reducing the peak load reduces costs for all electric customers. However, monthly peak loads are now after dark in almost all months, thereby reducing the relative value of solar production. To the extent that a generator can use storage to put energy onto the grid during peak times, that storage may be able to provide greater value.

In addition, storage devices have to be actively managed in order to provide value. At the most basic level, this means charging the battery when there is excess generation and discharging when generation is not being produced. However, the charging regime also needs to account for other values (such as reducing peak loads) that may be necessary in order to make the project cost effective.

Finally, while battery storage has been the most visible technology, there other types of storage, including pumped hydro, flywheels, compressed air, and ice. These storage types tend to be specific to a site and/or an end-use customer. By far the most prevalent type of storage in New England, in terms of installed capacity, is pumped hydroelectric storage. However, modern water quality standards would make it extremely difficult for this type of resource to be built today, at least in conventional form.

Curtailment

Although curtailment is considered to be a negative that should be avoided – because it represents a "wasted" resource – it is a reality in most if not all places with high penetration of renewables. In 2016, 4.4 percent of wind power was curtailed in Germany.[23] And in the mainland U.S., regional curtailments have generally hovered around 4%, though they spiked to 17% in Texas in 2009, when a large amount of wind was added to the system ahead of planned transmission.[24] In March 2018 alone, the California ISO curtailed almost 95,000 MWh of electricity – enough to power 30 million homes for one hour.[25]

[23] https://www.sciencedirect.com/science/article/pii/S1364032118300091
[24] https://pdfs.semanticscholar.org/0af3/9008296cbc2f0e21700f4b6d66f65cfd5ee5.pdf
[25] http://www.caiso.com/informed/Pages/ManagingOversupply.aspx

Grid experts generally recognize that, in areas with high penetration of renewables, some amount of curtailment will be necessary. The National Renewable Energy Laboratory (NREL), for example, estimated in its *Renewable Electricity Futures Study* that an estimated 8-10% of wind, solar, and hydropower generation will be curtailed in an 80% (renewable electricity) by 2050 future.[26] At low levels in particular, curtailment may provide a cost-effective source of flexibility.[27] For example, in an area with a high penetration of solar, it may be that new solar will only negatively impact the system during a relatively small number of hours per year. In that case, the affected utility could curtail operation during that limited timeframe either by curtailing all units or – to share the pain equitably – rotating which units are curtailed. At higher levels, however, it becomes important to compare the costs and benefits of curtailment (including an analysis of who incurs them) with other potential mitigation steps or solutions.

In Vermont, curtailment is currently only practiced at the transmission level, in the SHEI region, and only affects generators that are in ISO-NE markets and receive DNE signals. As more generation is added in the SHEI region, there are outsized impacts on production (and therefore revenue, ratepayers, contribution to state goals, etc.) on the few units that are "visible" to – and there for curtailable by – ISO-NE.

Grid operators and other stakeholders in areas with high penetration of renewables are exploring ways to mitigate curtailment, including storage (not yet cost-effective or even technologically feasible yet at scales and durations required), new contractual mechanisms to share curtailment risk between generators and counterparties and that are based on capacity rather than production,[28] and demand-side solutions including time-of-use rates and managed EV charging.[29]

At the distribution level, emerging technologies such as smart inverters can help to some extent – when optimized – to stabilize the system at higher penetrations.[30] Utilities are also exploring mechanisms to share grid upgrade costs among systems when generation exceeds substation ratings, along with options such as storage, demand response, and curtailment. Hawaii has modified its customer generation programs to encourage self-supply and "off-generation-peak" exports, and thus storage, mitigating the oversupply of solar generation during midday hours.

System Planning Requirements

All of the strategies discussed above require significant efforts from the distribution utilities and represent work that cannot be completed overnight. In particular, choreographing load and intermittent generation requires significant effort and expense. In addition, the appropriate solutions may vary depending on the nature of the constraints in a particular location.

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[26] https://www.nrel.gov/docs/fy12osti/52409-1.pdf
[27] https://www.nrel.gov/docs/fy14osti/61721.pdf, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/Beyond33PercentRenewables_GridIntegrationPolicy_Final.pdf
[28] https://cleantechnica.com/2019/01/07/rooftop-solar-curtailment-to-ease-with-refocused-hawaii-energy-contracts/
[29] http://iopscience.iop.org/article/10.1088/1748-9326/aabe97/meta
[30] https://spectrum.ieee.org/energy/renewables/can-smarter-solar-inverters-save-the-grid

Pursuant to 30 V.S.A. § 218c, the utilities are required to develop Integrated Resources Plans (IRP) that address how the utility will meet the public's need for energy services. Historically, the IRPs have focused on the power supply needs of the utilities; however, this was primarily a function of the fact that there was not significant amounts of development at the distribution level. The development and regulatory review of IRPs should be flexible enough to meet the needs of customers and recognize changes to the system. GMP's most recently filed IRP is undergoing PUC review and VEC is developing an IRP. The IRP process will be a useful mechanism for analyzing potential solutions.

At the transmission level, VELCO works with the VSPC to develop a Long-Range Transmission Plan every three years. The original intent of the VSPC and the LRTP was to identify load-constrained areas with the objective of evaluating non-transmission alternatives that could address reliability concerns. Due to the amount of energy efficiency and distributed generation deployed in Vermont, there have not been any load-constrained areas identified in the state in the past few years. Given this reality, the 2018 LRTP evaluated the impact of new in-state generation on the transmission system. Going forward, the VSPC may be a useful mechanism to identify generation-constrained areas (including at the distribution level) and allow for public discussion of potential mechanisms to address constraints in those areas.

Creating a Statutory Rebuttable Presumption Against Uneconomic Development in Constrained Areas

It would be helpful to have a mechanism for making clear that developers of projects within constrained areas have an obligation to at least not add to the constraints. One potential path is to create a statutory rebuttable presumption that deploying generation in constrained areas does not promote the public good. This would not provide an absolute bar from any projects, but would make clear that the project developer must provide a reasonable solution to ensure that the resource does not impose uneconomic and unreasonable costs on ratepayers. For example, the developer could install battery storage with a proposed solar generator, and provide the utility with the ability to charge and discharge the battery; similarly, a new resource could agree to a certain number of hours of curtailment. Under this scenario, language would be added to 30 V.S.A. § 248 that makes clear that a generation resource proposed for siting in a constrained area has the burden of mitigating its impact before it will be permitted for construction in the area.

Conclusion

The existence of generation constrained areas in Vermont will present challenges with the development of in-state renewable resources; however, it does not represent a crisis and is not currently impeding the progress toward meeting renewable requirements and goals. The potential solutions for addressing generation constrained areas are complex and lend themselves to nuanced implementation rather than simplistic approaches. There are currently venues, such as the IRP reviews before the PUC, that allow for engagement and dialogue on the design and implementation of appropriate solutions.

Appendix 1 – Study Requirements

Section 13 of Act 139 provides:

(d) The Department shall submit a written report to assist the General Assembly, renewable energy developers, and electric utilities to plan for the deployment of renewable electric generation in a manner that is consistent with the goals, requirements, and programs related to renewable energy set forth or established in 30 V.S.A. chapter 89, the statutory goals for greenhouse gas reduction at 10 V.S.A. § 578, and the goals and recommendations of the 2016 Comprehensive Energy Plan.

(1) On each of the following, the report shall include analysis and recommendations that are consistent with those goals, requirements, and programs:

(A) How to manage demands on the State's electric transmission and distribution system that relate to or affect the deployment of renewable electric generation. The Department shall identify and review areas of the State, such as the SHEI area, in which generation that is interconnected to the electric transmission and distribution system faces constraints due to system capacity and conditions, including the relationship of interconnected generation to existing load (the identified constrained areas).

(B) How to encourage the deployment of all types of renewable electric generation while minimizing curtailment of such generation.

(C) How to facilitate meeting the distributed renewable generation and energy transformation requirements of the Renewable Energy Standard at 30 V.S.A. §§ 8004–8005 in light of the identified constrained areas.

(D) Whether, until resolution of the constraints in the identified constrained areas, to allocate among all electric distribution utilities in the State the incremental costs to utilities caused by siting in those areas renewable electric generation that was or is encouraged by or used to meet a current or former program under 30 V.S.A. chapter 89 or that is designed or proposed to achieve a goal or recommendation of the 2016 Comprehensive Energy Plan and, if so, to propose a method for such allocation.

(E) The role of energy storage in the deployment of renewable electric generation.

(F) Recommended methods to guide where renewable electric generation should be located in the State.

(G) Recommended methods to guide the location in the State of end users that consume significant amounts of electric energy.

(H) Other relevant issues as determined by the Department.

(2) Prior to submitting this report, the Department shall provide an opportunity for written submission of relevant comments and information by the public and shall conduct one or more

meetings at which the public may provide comments and information. The Department shall provide prior notice of the opportunity to submit comments and information and of each meeting to each Vermont electric transmission and distribution utility, Renewable Energy Vermont, each holder of a certificate of public good for an electric generation facility within the SHEI area with a capacity greater than 500 kilowatts, each entity appointed to deliver energy efficiency programs and measures under 30 V.S.A. § 209(d), and any other person who requests such notice or whom the Department may determine to notify.

(3) With respect to the recommendations in the report, the Department shall identify those recommendations that require passage of enabling legislation and those recommendations that may be carried out under existing law. The report shall propose a timetable for implementation of the recommendations that may be carried out under existing law.

Appendix 2 – Glossary of Technical Terms

(Note: Items in blue text are defined elsewhere in this glossary.)

248 application process - The 248 application process is a regulatory process based on the Vermont law known as Section 248 (30 V.S.A. 248). It is administered by the Vermont PUC to consider proposed projects by utilities serving Vermont, and to determine whether they are in the public interest. Successful applicants are granted a CPG (Certificate of Public Good) which is essentially a license to build and operate the proposed project. The 248 process permits interested parties that qualify by statute and by procedure, to have a say in the hearing process and to influence the decision by the PUC to issue a CPG, a conditional CPG or a notice of denial.

ANR (Agency of Natural Resources) - ANR is Vermont state's agency in charge of protecting air, water, and soil quality, as well as wildlife.

Breaker - See the definition of *circuit breaker* below.

Capacitor - A capacitor is a device located in a substation that supports voltage within a local area. It has no moving parts and is relatively inexpensive. Capacitors are often added to transmission and distribution systems to keep the voltage acceptably high as electric demand grows over time. Over-reliance on this strategy may lead to a system that has high enough voltage, but with poor stability, meaning that its voltage is too easily changed by the daily cycle of demand ramping up and down. This forces utility personnel to constantly re-adjust which capacitors are on and which are off and makes the system vulnerable to a blackout.

Capacity or capability - Capacity is the maximum demand that an electrical component or system can carry without overheating.

Circuit breaker - A circuit breaker is a large switch that turns utility equipment on or off. It may be operated manually in order to safely perform preventative maintenance on equipment, or it may operate automatically to turn off equipment that is malfunctioning (see also the definition of *fault* below).

Conductor - The conductor is the part of a transmission line that actually carries the electricity, in other words, the wire itself. The wire or conductor is just one part of a transmission line; other parts include the poles and the insulators from which the conductor is hung. A conductor must have enough capacity to carry the highest demand that it will experience, or it could overheat and fail.

Contingency - A contingency is an unplanned outage of a critical system component such as a transmission line, transformer, or generator. The time prior to the contingency is referred to as *pre-contingency* and the time after it has begun is referred to as *post-contingency*. See also

N-0 or **N-1** or **N-1-1**

Controlled blackout - A controlled blackout is simply the same thing as a rolling blackout.

CPG (Certificate of Public Good) - A CPG is a document that may be granted by the Vermont PUC at the conclusion of a Section 248 application process. It is essentially a license to build a proposed project that has been applied for (such as a new transmission line or substation) and signifies the PUC's conclusion that the project is in the best interests of the public.

Demand - Demand is the amount of electricity being used at any given moment by a single customer, or by a group of customers. The *total* demand on a given system is the sum of all individual demands on that system occurring at the same moment. The *peak* demand is the highest total demand occurring within a given span of time, usually a season or a year. The peak demand that a transmission or distribution system must carry sets the minimum requirement for its capacity (see also the definition for *energy*).

Demand factor - Demand factor is the *average* demand of a customer or system, divided by the *highest* (i.e. *peak*) demand of that same customer or system. The peak demand determines how much infrastructure is needed; the demand factor determines how fully that infrastructure is being utilized over time.

DG (Distributed Generation) - Distributed generators are relatively small, dispersed electric generators that are intended to serve local electrical demand. They have come into greater use in recent years to satisfy gradual growth in demand, without the need to periodically build expensive, obtrusive, transmission lines. They may be owned and operated by the local utility or by individual customers. Typically, they are driven by gasoline or diesel engines, or by renewable power sources such as solar, wind, and running water. Depending on their size, they may be connected to a transmission system or to a distribution system.

Dispatch - Dispatch is the act of deliberately turning on or turning off system resources that are needed in varying amounts over time, such as generators and capacitors. Such resources are said to be "dispatchable". Some resources such as wind generators or solar generators are subject to the daily quirks of weather and sun and are therefore referred to as "non-dispatchable" or "intermittent".

Distribution - Distribution lines and distribution substations operate at lower voltage than the transmission systems that feed them. They carry relatively small amounts of electricity to local customers. Distribution lines use shorter poles, have shorter wire spans between poles, and are usually found alongside streets and roads, or buried beneath them. Typical distribution voltages include 12.5 kV and 4 kV.

DSM (Demand Side Management) - Demand side management, like DG (distributed generation), is intended to satisfy local growth in electrical demand without the need to build new transmission lines. However, it differs from DG in that it strives to *reduce the demand itself* rather than to *increase the supply*. DSM usually falls into one of three categories:

1. **Conservation** measures such as replacing standard light bulbs with high-efficiency light bulbs, or adding extra insulation to buildings.
2. **Special utility rates and contracts** that encourage customers to conserve energy and/or to move their electrical use to those hours when overall electrical demand tends to be low, in order to avoid overburdening the transmission system that supplies that demand. An example of this is an *interruptible rate* that provides the customer with a discount in exchange for the utility's right to interrupt the associated demand when system reliability or economic considerations necessitate it.
3. **Load control** systems, also known as **demand response** systems, that disable non-essential customer appliances (e.g. hot water heaters) during high-demand hours.

DUP (Distributed Utility Planning) - Planning method that seeks to find the lowest cost of providing reliable energy delivery through traditional means such as transmission, as well as newer approaches such as DG and DSM. Often, these strategies are used in combination.

Efficiency Vermont - Efficiency Vermont is Vermont's energy efficiency utility and administers programs under contract with the PUC that conserve energy by utilizing it more efficiently (see also the definition of *DSM* above).

Energy - Energy is the ability to do work. Energy comes in many forms (electrical, chemical, thermal, mechanical, etc). It is measurable in common units, regardless of which form it is in. The *rate* at which energy is made, used, transformed, or transferred is called power or demand. Energy is expensive to produce and therefore should not be wasted. See also storage.

Fault - A fault is the failure of a line, transformer, or other electrical component. Once such a component has failed (due to overheating, short-circuiting, physical breakage, or other trauma) it is automatically taken out of operation by a circuit breaker that quickly turns the component off. Once it has been "tripped off" it no longer poses a threat to human safety, but its loss may present a difficult burden to the remaining system (see also the definition of *redundant* below).

Generation or Generator - A generator is a device that converts mechanical power from an engine, a water wheel, a windmill, or other source, into electrical power. Generators have internal parts that spin as they make electricity, similar to an electric motor.

Hydro - Hydro is electric generation driven by running water such as streams or rivers, often with a dam to help control the generator's dispatch.

Inverter – An electronic device that converts DC power (such as from a solar panel, wind turbine, or battery storage system) to the AC power that is used by most utility equipment and appliances. The rapid growth in the use of solar, wind, and energy storage batteries means that inverters of all sizes and description are becoming ubiquitous on utility systems. They are dependable but intricate and have significant operational effects on system reliability that must be carefully managed.

Island or Islanding - An *island* in utility parlance, means an area of the electrical system that is electrically cut off from the main system by switches or by disabled equipment, but that is able to serve its own demand by means of generation located within its own boundaries. Islands are sometimes referred to as a microgrids. Creating an island requires that its generation have special controls to match that generation's output to the island's ever-changing demand and requires that there be enough generation to satisfy the island's total demand. *Islanding* is the process of disconnecting from the main system and re-establishing service using these specialized generators.

ISO New England Inc. - ISO New England Inc. is responsible for the coordinated planning, PTF funding, and operation of the New England transmission system, as well as reliability oversight of generators and other electrical facilities. ISO-NE is also responsible for the administration of New England's wholesale electricity markets (in which utilities make bids or exercise contracts for other companies' generation to meet their own customers' demand).

kV (kilovolt) - A kilovolt is a thousand volts. Volts and kilovolts are measures of voltage. As an example, the "Southern Loop" subtransmission line that runs from Bennington to Brattleboro operates at 46 kV or 46,000 volts.

Load - Load is simply the same thing as demand.

Load Duration Curve - A load duration curve is a mathematically-based graph depicting the magnitude of load (i.e. demand) over a long period of time, usually one year. The graph does not show the constant up and down movements of daily or weekly demand cycles. Instead, it is a continuous function that transitions smoothly from peak demand to minimum demand over the given duration. This is because the individual data points, adjacent to one another along the curve, are *sequential in their demand value but are* *not* *sequential in their time value*. The flatter the slope of the curve in a given vicinity, the longer the duration of the associated demand value. The demand near the middle of the load duration curve is commonly referred to as "shoulder load" because of its resemblance to a human shoulder.

Load factor - Load factor is simply the same thing as demand factor.

Losses - Losses are wasted electrical energy. All components and systems that carry electricity waste a small amount of its energy. This wasted energy is given off as heat to the surrounding air. Losses cost money but can be minimized by sound engineering practices.

Microgrid - See Island.

MW (Megawatt) - A megawatt is a million watts. Watts and megawatts are measures of demand. To put this in perspective, the peak demand for the state of Vermont is approximately 1,000 Mw or 1,000,000,000 watts.

N-0 or **N-1** or **N-1-1 -** The term N minus zero (or one, or one minus one) refers to the failure of important equipment. Although these terms sound complex, they are actually quite simple. "N" is the total number of components that the system relies on to operate properly. Only rarely does anyone try to calculate its actual value; it is simply a generic term to describe all the components of a given system. The number subtracted from N is the number of components that may fail in a given scenario, although more information is needed to denote just what component or components are assumed to have failed. Therefore, N-0 means that no components have failed and the system is in a normal condition. N-1 means that only one component has failed. N-1-1 means that two components have failed in a way that overlaps in time, which is generally worse than having only one fail (see also the definition of *contingency* above).

Network - A network line is one that can carry power in either direction, similar to a two-way street. Most transmission lines are network lines, while most distribution lines are not (see also the definition of *radial* below).

Peaking Generation - Peaking generation is generation that is designed to run only a limited number of hours per year, during periods of high demand.

Power - Power is simply the same thing as demand.

PSD (Public Service Department) - The PSD is Vermont state's public advocate in legal proceedings and other forums that involve utility regulation, statutes, consumer complaints, and related issues. DPS staff often specialize in specific areas such as engineering, economics, or law. The acronym "DPS" is occasionally misused to refer to the Public Service Department but really refers to the *Department of Public Safety*.

PTF (Pool Transmission Facility) - The precise definition of a pool transmission facility is beyond the scope of this document but, generally speaking, it is any transmission facility operating at 69 kV or higher that is networked (not radial). PTF falls under the authority of ISO New England. The construction of new PTF facilities is funded by the ISO on a pro-rata basis among its member utilities. Vermont's responsibility for such costs is about 5% of the total.

PUC (Public Utilities Commission) - The PUC is Vermont state's quasi-judicial authority in legal proceedings that involve utility regulation, statues, and related issues. It consists of 3 principal commissioners (appointed by Vermont's governor) and supporting staff. It may be though of as a "court" for hearing disputes among parties who have an interest in utility matters. The PSD represents the *public interest* in such proceedings.

Radial - A radial line is one that can carry power in only one direction, similar to a one-way street. Most distribution lines are radial lines, while most transmission lines are not (see also the definition of *network* above).

Redundant - Facilities that have backups or alternate ways of operating are said to be redundant, that is, their function can be sufficiently provided even after they suffer a breakdown or failure. The more crucial a component or system, the greater the need for it to be redundant.

Renewable power source - A renewable power source is any power source that does not rely on a *finite* resource to keep it running, such as coal, oil, or natural gas, which will eventually run out. Renewable power sources include solar collection systems, wind mills, and hydro generators, because sunlight, wind, and running water will never run out. Generators than burn *replaceable* fuels also qualify as renewable power sources. Examples include bio-diesel generators that run on crop-derived fuels, and wood-burning generators.

Rolling blackout – A rolling blackout is the deliberate cessation of electric service to a limited number of customers during conditions of dire system problems. These blackouts are targeted at different groups of customers, first one and then the next, and continuing this way in a cyclical pattern in order to "spread the pain" as evenly and fairly as possible until the problem is fixed. A rolling blackout may also be referred to as a controlled blackout.

ROW (Right-of-Way) - A right of way is the long but narrow strip of property on which a transmission line is built. It may be owned by the associated utility or it may owned privately, with the utility exercising its state-mandated right to use this private property for the public good.

Storage - Also known as energy storage, this growing class of systems stores energy when it is abundant (e.g. when the sun is shining at midday) and releases it back into the grid when energy is scarce (e.g. high demand in early evening when the sun is fading, and people are preparing dinner). Storage is typically based on DC batteries but may also utilize other technologies such as fuel cells or compressed air.

Substation - A substation is a fenced-in area where several transmission and/or distribution lines come together and are connected by various other equipment for purposes of switching, metering, or manipulating voltage. Often, they contain transformers.

Subtransmission - Subtransmission systems are very similar to transmission systems (see also the definition of *transmission* below) and differ only in that they operate at somewhat lower voltage and carry smaller amounts of power. Typical subtransmission voltages include 46 kV and 34.5 kV.

Synchronous Condenser - A synchronous condenser is a device located in a substation, that supports voltage on electric transmission or distribution systems, much like a capacitor. But unlike a capacitor, a synchronous condenser has moving parts, that is, it spins like a motor, and its outward appearance is very similar to that of a large motor. Synchronous condensers tend to be more effective than capacitors but also more expensive. They run for very long periods of time and produce a humming sound, but do not burn fuel and therefore do not release emissions into the atmosphere.

Thermal - This term is related to the terms capacity or capability. Thermal refers to heat or temperature, which are of concern when electrical equipment is carrying a high demand. Electrical components that exceed their capacity or capability are said to be "thermally overloaded", meaning that they are carrying too much demand, are growing too hot, and could fail as a result. A "thermal limit" or "thermal rating" is the highest amount of demand that an electrical component or system can safely carry without overheating.

Transformer - Transformers are the "on-ramps" and "off-ramps" of the "transmission highway". Specifically, a transformer is a device located in a substation that connects high-voltage equipment to low-voltage equipment and allows power to flow from one to the other. Different voltages are used because higher voltages are better for *moving* electricity over a distance, but lower voltages are better for *using* electricity in machinery and appliances. Transformers (and the substations in which they reside) are commonly described by the two (or more) voltages that they connect, such as "115/46 kV", signifying a connection between 115 kV and 46 kV equipment.

Transmission - Transmission lines and transmission substations operate at high voltage and carry large amounts of electricity from centralized generation plants to low voltage distribution lines and substations that supply small towns and localities. A few transmission lines or even one may be capable of supplying an entire region or metro area. Transmission lines use very tall poles or towers, have long wire spans between poles, and usually traverse fairly straight paths across large distances. They do not tend to follow roads. Typical transmission voltages include 345 kV, 230 kV 115 kV, and 69 kV.

VELCO (Vermont Electric Power Company) - VELCO is a transmission company wholly owned by Vermont's distribution companies, and responsible for the planning, construction, and operation of Vermont's transmission system and its supporting systems such as fiber optics networks.

Voltage - Voltage in an electric transmission or distribution system is much like water pressure in a system of pipes. If the pressure is too low, the pipes cannot carry enough water to satisfy the needs of those connected to them. If the voltage is too low, the electric system cannot carry enough electricity to satisfy the needs of those connected to it.

VSPC - Vermont System Planning Group. This committee meets periodically to discuss and coordinate planning issues in Vermont. Stakeholders include VELCO, the distribution utilities (like GMP), business and industry representatives, and advocates for public interests. The VSPC website can provide more detail about this crucial organization.