STATE OF VERMONT

BEFORE THE PUBLIC UTILITY COMMISSION

Investigation to update screening values for use by the Energy Efficiency Utilities when they perform cost-effectiveness screening of energy efficiency measures	))))	**Case No. 19-0397-PET**

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

CONSERVATION LAW FOUNDATION

Resource Insight, Inc.

MAY 23, 2019

TABLE OF CONTENTS

TABLE OF EXHIBITS

TESTIMONY SUMMARY

Mr. Chernick's testimony reviews the testimony of Riley Allen on behalf of the DPS, regarding four avoided-cost issues that affect how the electric Energy Efficiency Utilities screen energy-efficiency programs, measures and projects. He recommends that:

- The PUC accept the regional DRIPE values estimated in AESC 2018, unless it decides that economic costs to out-of-state owners of generation and fuel supply are as important as the benefits to New England ratepayers.
- The PUC include avoided T&D costs in energy-efficiency program screening; until the DPS can develop a Vermont-specific value for both transmission and distribution, the EEUs should use the values estimated in AESC 2018.
- The PUC recognize that purchases of energy from generators designated as "renewable" still result in carbon emissions and other environmental externalities and treat the bulk of avoided energy as avoiding externalities. The portion of marginal supply that is treated as emission-free should be limited to the Tier 2 RES, until and unless the utilities commit to other emission-free resources.
- The PUC maintain the use of the 10% risk discount for DSM, pending further analysis.

I. Identification & Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: My name is Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a Bachelor of Science degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and a Master of Science degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, conservation program design, estimation of avoided costs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit CLF-PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over three hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-seven states and six Canadian provinces, and three U.S. federal agencies. This previous testimony has included avoided costs, the valuation of externalities, the benefits of load reductions on the distribution and transmission systems, the effects of load changes on market prices, marginal costs, and related issues.

Q: Have you testified previously in Vermont?

A: Yes. I have testified in approximately 18 Vermont proceedings, from 1985 to 2012. Most of those testimonies were sponsored by the Department of Public Service (DPS), although I have also testified on behalf of Conservation Law Foundation and other parties.

Q: Have you been involved in activities related to avoided costs in New England?

A: Yes. I have been part of the team that developed several versions of the regional avoided costs (called the Avoided Energy Supply Cost study) since 1999, on behalf of the regional utilities, program administrators and other stakeholders, including 2007, 2009, 2011, 2013, and the current 2018 version. I also testified on the avoided costs of Green Mountain Power (GMP) and Central Vermont Public Service, as well as statewide Vermont avoided costs and other analyses of avoided costs for various utilities in Massachusetts.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Conservation Law Foundation.

Q: What is the scope of your testimony?

A: I review the testimony of Riley Allen on behalf of the DPS, regarding four avoided-cost issues that affect how the Energy Efficiency Utilities (Efficiency Vermont and the Burlington Electric Department, collectively the EEUs) screen energy-efficiency programs, measures and projects:

- Demand-reduction induced price effects (DRIPE), the suppression of market prices by energy-efficiency programs.
- Transmission and distribution (T&D) costs avoided by demand reductions.
- Environmental externalities (including carbon emissions) avoided by energy reductions.
- The risk adder for avoided costs.

Q: Does Mr. Allen dispute the basic cost-benefit test that the EEUs apply?

A: No. The EEUs, Mr. Allen, and I all support the use of the societal test. Our interpretations of that test vary.

Q: How does Mr. Allen frame the application of the societal test?

A: Mr. Allen's view of the groups to be included in the societal test varies, with his recommending inclusion of all consumers and producers for DRIPE, all New England ratepayers for T&D, and the globe for environmental externalities. I agree with him on the last of these; Vermont's accounting for environmental externalities should include the adverse effect of Vermont energy consumption on everyone.

For economic costs, I believe Mr. Allen uses the right perspective for T&D. As he says, "Vermont is shoulder to shoulder with neighboring states in solving the common or collective good of reducing GHG emissions for both the benefit of Vermonters and the globe." (Allen Supplemental at 3) As a result, Mr. Allen believes that to "the extent that Vermont's share of PTF costs are reduced, [if] these costs will be shifted to other New England states, [the result will be] no overall societal benefit. Therefore, no benefit should be credited to DSM for reduced PTF costs to Vermont consumers." (Q.CLF:DPS 33) The New England states all have energy-efficiency and renewable programs that produce environmental, T&D and DRIPE benefits for all six states (and in some cases, beyond).

The societal test can use various definitions of the expanse of "society," in terms of geography and other factors. I believe that all the states should include the DRIPE benefits, transmission savings, and avoided capacity from the perspective of the entire region, and not count costs shifted from ratepayers in one state to those in another.

Q: What alternatives do the New England states have in selecting a consistent geographical perspective across categories of economic benefits?

A: There are two common approaches. One would count the costs and benefits to utility customers in all six states, including DRIPE. The other would count only costs and benefits to home-state customers, in this case, Vermont energy consumers. In the latter case, the PUC would accept DRIPE benefits only to the extent that lower market prices reduce bills for Vermont ratepayers, but would include as benefits costs shifted from Vermont ratepayers to those in other states (specifically the reallocation of generation capacity costs due to load reductions that have not yet cleared in the ISO market, as well as embedded transmission costs), which the AESC studies have not treated as benefits.[1]

So far as I am aware, the use of the regional perspective is not in dispute in this proceeding.

Q: How does Mr. Allen describe the objective of his critique of the AESC avoided costs?

A: Mr. Allen explains his intention as follows:

> Let me be clear that that the Department believes strongly in energy efficiency and is not suggesting that Vermont should not invest further in efficiency measures. The Department instead is merely urging caution in investing more on the margin associated with values ascribed to load-driven bulk transmission investment and potential additional value for movement in clearing prices associated with otherwise beneficial energy efficiency programs. (Allen Supplemental Testimony at 1–2)

Q: Are Mr. Allen's recommendations consistent with his stated objectives?

A: Not really, for two reasons. First, while Mr. Allen asserts that his concern with the incorporation of various benefits relates to the effect of those benefits to produce "additional value…associated with otherwise beneficial energy efficiency programs," his concern is misplaced. If an energy-efficiency program, measure or project is cost-effective without consideration of some avoided-cost components, inclusion of those components in the avoided costs will not affect whether the program, measure or project is pursued, or the amount of energy saved. The treatment of the avoided-cost components on which Mr. Allen concentrates is relevant only for programs, measures and

[1] A third possibility would be to extend the geographic scope beyond New England, to the entire country, North America, or the world. I am not aware of any party advocating this broader economic perspective.

projects that are cost-effective including the components, but would be rejected if the value were excluded from screening.

Second, Mr. Allen lumps together all energy-efficiency options, even though the planning considerations differ dramatically between discretionary retrofits and transient opportunities. Discretionary retrofit opportunities include measures that can be implemented over a wide range of time: blowing in attic insulation; replacing inefficient windows, appliances, and equipment that still work but waste energy; adding controls to existing equipment. Transitory opportunities include new construction, building rehabilitation and renovation, addition of new equipment, installation of replacement equipment on failure or obsolescence, measures that are less expensive or more effective if undertaken simultaneously with other measures (e.g., increasing building shell efficiency when HVAC is being replaced, so the HVAC can be downsized; installing a measure when a crew is on site to install other measures), and incremental efficiency levels (e.g., spraying in another couple inches of insulation, installing equipment with a SEER of 18 rather than 16). If the PUC follows Mr. Allen's proposals, reducing avoided costs and resulting in some measures no longer passing the cost-benefit test, EVT can delay discretionary retrofits until the PUC approves higher avoided costs. But many choices cannot be delayed; if screened with artificially reduced avoided costs, the transient opportunities will be lost.

Q: Does Mr. Allen recognize this last problem of long-term lost opportunities?

A: No. When asked "If a new building is built in 2021 with a less efficient shell because some efficiency measures failed due to exclusion of some avoided costs, how long will that building continue to waste energy?", he responded by citing "The weighted average life of energy efficiency programs reported by Efficiency Vermont in their annual report in its most recent plan was 8.5 years." (Q.CLF:DPS 41a) He continues with various digressions about higher efficiency for buildings built in 2030, the fact that energy-efficiency programs "can be throttled up and down," the possibility that Vermont load forecasts will decline, the likelihood that "distributed generation and storage continue to growth with the declined in their costs," and an aside about bulk transmission. (ibid) I do not know why he is so reluctant to admit the obvious: if the EEUs miss transient opportunities, many of those opportunities are lost in the long term.[2]

Q: What are your recommendations?

A: My recommendations are as follows:

- That the PUC accept the regional DRIPE values estimated in AESC 2018, unless it decides that economic costs to out-of-state owners of generation and fuel supply are as important as the benefits to New England ratepayers.
- That the PUC include avoided T&D costs in energy-efficiency program screening; until the DPS can develop a Vermont-specific value for both transmission and distribution, the EEUs should use the values estimated in AESC 2018.
- That the PUC recognize that purchases of energy from generators designated as "renewable" still result in carbon emissions and other

[2] Mr. Allen did concede that "Retroactive adjustments to buildings constructed or modified during that period would likely rank among the least efficient pathways for addressing future challenges." (Q.CLF:DPS 41b) In other words, understatements of avoided costs will degrade efficiency in the long term.

environmental externalities and treat the bulk of avoided energy as avoiding externalities. The portion of marginal supply that is treated as emission-free should be limited to the Tier 2 RES, until and unless the utilities commit to other emission-free resources.

- That the PUC maintain the use of the 10% risk discount for DSM, pending further analysis.
- Finally, if the PUC is sympathetic to Mr. Allen's objective of reducing energy-efficiency efforts, it should distinguish between discretionary retrofit and transitory opportunities, by limiting any restrictions in avoided costs to decisions to undertake discretionary retrofits.

III. Price Suppression

Q: Please explain the significance of DRIPE.

A: For normal market commodities, reduced demand results in lower prices. Typically, the highest-cost supply is no longer competitive in the market, resulting in the market price for all output to fall to the price of the next-highest bidder. This reduction in price benefits all consumers of the commodity (often including the consumers of the products made with that commodity) and reduces the profitability of all the suppliers.

As is true for other analyses on behalf of energy consumers, the AESC analysis estimates the benefit to consumers without regard to the effects on suppliers. Among other factors, AESC 2018 accounts for the fraction of energy and capacity already pledged to ratepayers under fixed-price contracts, including the resources owned by or under contract to the Vermont utilities. Massachusetts, Connecticut and Rhode Island all use the AESC DRIPE values, while Maryland, Delaware and the District of Columbia use separate estimates of price suppression for DSM and other load reductions.[3] DRIPE is also accepted as an effect of additional supplies, especially those with low dispatch prices, such as nuclear and wind, as evidenced in the arguments for retaining existing plants and adding offshore wind, and by the arguments of the incumbent generators against allowing state-subsidized resources to participate in capacity markets.

Q: Does Mr. Allen dispute the reality of the price-suppression effects of energy-efficiency programs?

A: No.

Q: What is the nature of Mr. Allen's opposition to including DRIPE in the avoided costs?

A: At heart, Mr. Allen takes the position that the PUC should include all costs and benefits resulting from load reductions, including the revenues lost by generators selling into the regional energy and capacity market; the companies that drill for gas in Pennsylvania, the Southwest, and elsewhere; the individuals and corporations who own the rights to subsurface minerals; and the states that charge value-based taxes on the extraction of natural gas.

In contrast, the AESC DRIPE values are computed for state regulators whose objective is to reduce costs to their ratepayers, or regional ratepayers, perhaps in addition to reducing other costs (such as global environmental costs due to energy use in the state).

[3] DRIPE is only relevant for restructured markets, so most states would have no reason to consider it.

Q: Where does Mr. Allen take that position?

A: He states this position fairly clearly in his supplemental testimony. For example, he concludes "that the movement of the clearing price in isolation of other factors produces no material benefit for consumers net of the adverse impacts on producers." (Supplemental testimony at 12)

Mr. Allen relies on a study whose "focus seemed to be center[ed] on concerns that adverse impacts to producers might offset the technology benefit (i.e., the first order energy efficiency improvement) ascribed to consumers from appliance standards." (ibid at 13) He quotes that study (Carnall, et al, 2016) as saying:

> To the extent that the benefits from lower energy prices reflect reductions in producing goods and services, they represent an increase in social welfare. However, if they simply reflect reduced compensation to resource owners, lost profits to the producing sectors, or shifts in tax burdens, the reductions are transfers to consumers from the adversely affected sector. (ibid at 14)

In response to discovery, Mr. Allen states his thesis most clearly:

> …I believe that the so-called DRIPE effect, that attempts to ascribe value to consumers over other market agents should not be counted under the societal test. I do not believe Vermont should be trying to somehow divine which market agents are deserving or not of a so-called benefit or cost. If the DRIPE effect is ignored as a benefit, there is no need to follow the stream of lost profits and tax losses that might flow to agents inside or outside of Vermont….
>
> Efficiency Vermont and Burlington Electric Department participate in regional capacity markets that are adversely impacted by the depression in price levels that are associated with the DRIPE. Vermont's reducing in wholesale energy prices also lower prices throughout New England. The lower prices likely impact the profits and profitability of companies that participate in these regional markets. Some taxes that flow to gas-exporting states are also likely associated with associated burdens of maintaining public systems like roads and bridges affecting the same areas. (CLF:DPS 1c)

While I am reluctant to summarize Mr. Allen's expansive discussion of the adverse effects of price suppression on parties other than New England ratepayers, it appears that he believes that the PUC should treat gas producers, gas-exporting states, and merchant generators as being just as "deserving or not of a so-called benefit or cost" as the ratepayers of Vermont and other New England states.

Q: Did Mr. Allen clarify his position in response to discovery?

A: To some extent. For example, he says that "I do not believe Vermont should be trying to somehow divine which market agents are deserving or not of a so-called benefit or cost….Vermont should avoid application of the a so-called societal test, or any test, for that matter with component screening features (like the DRIPE) that are designed or have the practical effect, purely to affect zero sum distributional effect that effectively adversely target one group of market actors or agents to the benefit of another (i.e., producers over consumers or out-of-state interests to the benefit of Vermont)" (Q.CLF:DPS 1c).

Q: Is Mr. Allen's insistence on including the costs and benefits to merchant generators and gas producers on an equal footing with consistent with normal practice?

A: No. Mr. Allen's approach would treat additional payments to Hydro Québec and Koch Industries as being equivalent to the costs to Vermont ratepayers. I doubt that he would take that position in any situation, other than this argument against DRIPE.

Q: Does DRIPE treat in-state and out-of-state generators and other suppliers differently?

A: No. Mr. Allen repeatedly suggests that DRIPE represents some conflict between Vermont and other states, but he is wrong. Any merchant generator is treated the same way, whether it is in Vermont, Massachusetts, New York or Québec. In my preferred approach, all ratepayers in New England are treated equally in the DRIPE computation.

Q: Does Mr. Allen articulate any problems that he thinks would flow from including DRIPE in screening?

A: Mr. Allen claims that including DRIPE "undermines" all of the following:

- "the integrity of energy efficiency programs,"
- "representations of benefit/cost ratios, and"[4]
- "the otherwise sound public policy and environmental responsible behavior of advocates." (CLF:DPS 1c)

Q: Are these assertions correct?

A: These claims are not supported by data or logic and it is difficult to understand what they mean.

[4] Mr. Allen complains that DRIPE would "impact the perceived benefit-to-cost ratios and net benefit calculations" for energy-efficiency programs that would be cost-effective without consideration of DRIPE, even though it would make not difference in screening. (CLF:DPS 3a) He goes on to say "When there is a DRIPE value that is positive, it potentially affects the perceived economic benefits, net benefit calculations, and benefit-cost ratios that are associated with measures and programs. Even when the measures and programs screen in without the DRIPE value, they have the potential to affect the narrative and exaggerate the characterization of benefits that are reasonably tied to those measures and programs.…I believe that the inclusion of a positive value for DRIPE exaggerates claimed benefits and, in the process, the overstates the otherwise positive narrative for EVT and the energy efficiency services that they deliver." (CLF:DPS 3b) He does not explain why he cares about the optics.

Q: Does Mr. Allen suggest any ways in which Vermont might be harmed by what he perceives to be unfair treatment of natural-gas producers and merchant generators?

A: I believe that Mr. Allen tries to make this point. He warns that counting DRIPE "can engender ill-will between states and groupings of market actors….Vermont has recent experience with application the SPEED program initiatives that were interpreted by neighboring states as being designed for a similar distributional effect." (CLF:DPS 1c)[5]

I believe that he is conflating effects on producers with effects on other states, which makes his comments somewhat difficult to parse out. He opines that "the effects are distributional and arguably designed to benefit Vermonters only as the expense of non-Vermonters" (CLF:DPS 1c), but there are no DRIPE-related conflicts between consumers across states. The energy price reductions that drive the electric energy DRIPE value benefit consumers in all the New England states and to a less extent New York and further afield. The capacity-price and gas-basis reductions benefit consumers in all the New England states, Nova Scotia, New Brunswick and possibly New York. The reductions in gas supply costs benefit consumers throughout North America. In AESC 2018, we estimated the benefits for each state, as well as the benefits to all New England consumers of the price reductions, for regulators who

[5] Mr. Allen is somewhat evasive about the example he invokes here. I believe that he is referring to the practice of some Vermont utilities in declaring that they were purchasing renewable energy for their customers and then selling the renewable energy credits (RECs), effectively double-counting the green characteristics. The complaint was not that the practice was harming other states (which would have benefited from lower REC prices), but that it was undermining development of renewables and thus harming the environment.

consider all those consumers to be acting on their common interests, standing shoulder-to-shoulder (in Mr. Allen's memorable phrase). We could have added additional DRIPE benefits for consumers more broadly, but we did not believe that regulators would want to broaden the range of benefits beyond New England.

DRIPE measures the transfer of benefits to New England ratepayers from electric generators, gas producers, pipeline capacity owners, mineral-rights owners and states that charge price-related extraction taxes. Those groups are acting for their own benefits, not to help consumers in Vermont or New England. For example, owners of generation in New England consistently argue and litigate for rule changes that will increase prices to customers; sometimes owners delist or retire plants to increase market prices for other plants, or they threaten to retire generators to force ISO-NE to give them more favorable pricing (as has been the case recently for Mystic Station). Oklahoma and Pennsylvania do not consider the interests of Vermont in setting their tax policies for gas extraction. The states attempt to maximize benefits to their residents and businesses, while the other players attempt to maximize their own profits. Since those groups are not working in tandem with the PUC or other regulators, there is little risk of engendering ill-will from these groups. If ExxonMobil, BP and other producers, or the gas-producing states, have not been outraged by state energy-efficiency and renewable mandates, they are unlikely to be bent out of shape by a small increment of avoided cost in the valuation of the energy-efficiency programs.[6]

[6] Various states use different approaches and estimates in setting avoided costs; the only interstate dispute that I recall related to avoided costs was North Dakota's attempt to force Minnesota to purchase energy from North Dakota coal plants. States have also sometimes argued over the

Q: How does Mr. Allen argue that producers of natural gas and electricity deserve to be treated equally with Vermont and New England ratepayers in the PUC's review of DSM economics?

A: Interestingly, Mr. Allen claims that he does not believe the position that he takes so clearly and repeatedly. When asked "Is it Mr. Allen's contention that the Vermont PUC should be concerned only with reducing total costs globally and should not value costs to Vermont ratepayers above national and international generation owners, gas producers and marketers?" he responded "No. The Commission should be concerned with the implications to Vermont. Ratepayer and public interest should be a central concern." (Q.CLF:DPS 2)[7] But he then rejects any "economic screaning (sic) test elements that are specifically designed to ascribe value to zero-sum distributional effects." (ibid.) He seems to be saying that the PUC should value Vermont ratepayers above national and international generation owners, gas producers and marketers, but it should not reflect that preference in screening.

When asked about the consequences of his apparent rejection of the concept "that the PUC should value a dollar to a Vermont ratepayer more highly than a dollar to investors and firms from outside the state, region or even country,…" he responds "This is not what I believe." (Q.CLF:DPS 2b)

---

supply plans of multi-state utilities, where the cost expectations and priorities of the states differ and they do not want to be burdened with the costs of other states' decisions. I do not see how those problems would arise in New England

[7] Similarly, he admits that he "know[s] of nothing in Vermont statutes that puts the impacts of out-of-state power plants or related companies as being on equal in importance as Vermont energy consumers." (Q.CLF:DPS 2a)

So apparently he believes a dollar of savings for Vermont is more important than a dollar of earnings to the shareholders of NRG Energy.

Whatever Mr. Allen's actual feelings about the damage of lower market prices to the shareholders of merchant generators, he takes a harder line with GMP shareholders, arguing that an unnecessarily high return on equity is somehow different from unnecessarily high prices for generation services (Q.CLF:DPS 2ci). Again, it is difficult to understand why Mr. Allen applies different standards in these similar situations.

Mr. Allen also suggests that "Some taxes that flow to gas-exporting states are also likely associated with associated burdens of maintaining public systems like roads and bridges affecting the same areas." (Q. CLF:DPS 1(c)) Of course, if Vermont, Massachusetts and the other New England states pay lower prices for electrical energy, capacity and natural gas, their companies will be more profitable and the states will have more money to spend on roads and bridges. It is not clear why Mr. Allen believes that the public interest requires that New England pay for its own infrastructure, as well as that of states that happen to be blessed with frackable natural gas reserves.

When asked whether Vermont stands "shoulder to shoulder with the owners of the Merrimack and Schiller coal plant; the oil plants at Canal, Wyman, Montville and Middleton; or the many gas-fired plants in New England in solving the collective good of reducing GHG emissions," Mr. Allen refused to discuss the degree of common interest and solidarity of those parties with Vermont and New England ratepayers (Q. CLF:DPS 5).[8]

---

[8] This is another situation in which Mr. Allen conflates the welfare to the generators with the welfare of neighboring states. Mr. Allen appears to be more concerned about the welfare of generators in other states than those states are. He does not cite, and I could not find, any situation

Q: Is it surprising that Carnall, et al, found that lower gas prices reduce the profits of electric generators, gas producers, and mineral-rights owners.

A: No. While Mr. Allen seems to think that the relationship between reducing prices for consumers and reducing profits for producers is controversial,[9] it is mathematically obvious. The interesting part of the Carnall, et al paper is that they made some assumptions about taxes, fees, owners' compensation and other inputs, so that they could try to estimate how much of the savings to consumers would fall on each of the supplier groups.[10] In essence, they started with the correct assumption that price reductions help consumers and hurt suppliers and tried to identify which windfalls and economic rents would decline. It is clear that Mr. Allen believes that the PUC should value the profits to all the production interests equally with New England energy consumers.

Q: What does the study that Mr. Allen cites mean by shifting tax burdens?

A: The study is referring to the severance fees and taxes charged by various government entities on the extraction of natural gas.

---

in which other states complained about Massachusetts large DSM programs (let alone much smaller Vermont programs) reducing market prices. Massachusetts has not complained about low market prices shutting down its coal and nuclear plants. Mr. Allen does not specify whether he resents Massachusetts, Connecticut or Rhode Island for pursuing DSM that contributed to the retirement of Vermont Yankee.

[9] For example, he says that producers will be harmed "if, as I assert, and the paper supports, the effects are distributional and arguably designed to benefit Vermonters only at the expense of non-Vermonters" (CLF:DPS 1c). (As I explain above, the redistribution is between consumers and producers, not Vermonters and non-Vermonters.)

[10] Oddly, Carnall, et al, concluded that gas and electric price changes due to the gas appliance efficiency standard they analyzed would save consumers \$1.81 billion, but cost the suppliers \$1.95 billion, even though they assume that suppliers avoid some costs. I have not tried to determine how they reached this counterintuitive conclusion.

> Federal, state and local governments are owners of extensive natural gas resources and receive compensation for extraction of these resources. Governments also collect taxes based on the value of the gas produced within their jurisdictions.[11]

In other words, states such as Oklahoma have found that they can augment their state budgets by taxing gas production, increasing the price of gas and thus the cost to consuming states, such as Vermont. I doubt that legislators in those states netted out the increased bills to New Englanders (or Minnesotans, or New Yorkers) when they decided that the taxes were beneficial to their constituents.

Q: Do utility regulators generally include taxes as costs in economic evaluation?

A: Yes. In my experience, the Vermont PUC and its peers include income taxes charged by the Federal government, other states, and even the regulator's own state as costs in evaluating supply alternatives; the same is true for property and sales taxes. In over 40 years of appearances before regulators in about 50 jurisdictions, I do not recall ever seeing a regulator tell a utility to ignore income or property taxes in computing the costs of owning a resource, or to net from the cost of a power purchase the income taxes that the seller will pay on its revenue stream. If the PUC treats the income and property taxes paid by GMP on its out-of-state generators as costs, it should also treat the taxes imposed by other states on merchant generators and gas producers as costs. Mr. Allen's suggestion that energy DRIPE should be reduced by the tax

[11] This quote is from Carnall, et. al., Economic Effect of Efficiency Programs on Energy Consumers and Producers, February 2015, p. 3, https://escholarship.org/uc/item/5mw6m9qc. This appears to the same as the article that Mr. Allen cites from *Energy Efficiency*, but it is not behind a $39.95 paywall.

revenues lost by producing states is inconsistent with normal regulatory practice.

Q: Does the Vermont PUC net other supplier profits out of its assessment of the costs borne by ratepayers?

A: Not that I know of. If the Vermont PUC were to accept Mr. Allen's position that a dollar of additional revenue to a supplier is as desirable as a dollar of reduced costs for consumers, the resulting policies would include:

- The PUC would be indifferent between a utility purchasing solar energy at 8¢/kWh versus 10¢/kWh or 12¢/kWh; the extra payments would simply be a transfer to the solar developers.
- The PUC would not care whether the utilities and EEUs have negotiated the lowest feasible prices with contractors and equipment suppliers, let alone fuel suppliers.
- The PUC would let GMP select its own return on equity, since a dollar of additional payments of GMP's owner or in taxes would be just as good as another dollar in customer pockets.

I understand that the PUC is responsible to set "just and reasonable rates" and to allow the provision of energy services at the lowest life-cycle cost. It cares about ensuring fair prices for ratepayers, even if the suppliers are also Vermont residents and ratepayers. The PUC thus implicitly rejects Mr. Allen's indifference principle on a regular basis when it sets rates and ensures energy is provided at reasonable cost.

Q: Are the parties whose revenues decline due to DRIPE primarily Vermont or New England ratepayers?

A: No. The top ten generators listed in the 2018 CELT report (by capacity for which they are the lead participant) are as follows:

- Calpine
- Consolidated Edison
- Dominion Energy
- Dynegy (now Vistra)
- Exelon
- NextEra
- Genon
- FirstLight Power
- NRG Power
- Emera

Of these companies, only FirstLight can be considered a New England company. And the investors in these companies come from all over the world. Mr. Allen's assertion that counting DRIPE as a cost would pit Vermont against the rest of New England does not hold water.

If the Vermont PUC does not treat as costs the reductions in profits to Vermont contractors from efficient procurement of services, I do not see why it would do so for reduction in profits to these national or continental generation firms.

Q: Do Carnall, et al, demonstrate that the Vermont PUC and other regulators should ignore price reductions that benefit consumers in their jurisdictions?

A: No. They start with the intention of adding together the consumer benefits and the producer losses. The Carnall study roughly demonstrates the obvious, that price benefits to buyers are costs to sellers. Nothing in the study can be read as demonstrating that regulators *should* add together those cash flows. That is an assumption, not a conclusion.

Q: Did AESC 2018 take into account that "Vermont's utilities are owners of power plants associated with lost profits owing to Vermont generation and energy efficiency programs from lower prices in regional markets are also implicated."

A: Again, Mr. Allen's text is hard to follow, but I believe that he means that the Vermont utilities source much of their energy from resources that they own or purchase at fixed prices. AESC 2018 counts that portion of Vermont load to be hedged, and hence not eligible for any DRIPE benefit from lower market prices.[12] We estimated about 63% of Vermont load is hedged on a multi-year basis; if Mr. Allen has a different estimate, I would be happy to review it.

Q: Are you concluding that the perspective taken by Carnall, et al, and by Mr. Allen are factually incorrect?

A: No. They make value judgements that differ from mine, and most judgements by most utility regulators. Mr. Allen argues that the PUC should ignore the benefits that ratepayers derive from lower electric and gas prices, because he believes that the reduced costs to consumers are no more important than the lost profits of Exelon and other generation owners, ExxonMobil and other gas producers, or mineral-rights owners in Texas and other gas-exporting states. I doubt that many Vermont ratepayers would agree with him.

[12] See AESC 2018, Tables 65, 66, 73 and 74, and surrounding text.

Nonetheless, I accept the sincerity of his value judgment about the relative importance of a dollar for New England ratepayers and energy suppliers. This is not a difference of opinions about facts; it is a difference in values.

If the Vermont PUC shares Mr. Allen's concern for the welfare of Dominion, Chesapeake Energy, Louisiana, and mineral owners, it should not include DRIPE in the avoided costs. If the PUC considers a dollar transferred from one of those supplier interests to a New England consumers to be a benefit, it should accept the full regional DRIPE values.

IV. Avoided T&D

Q: What is Mr. Allen's position with respect to avoided T&D costs?

A: Mr. Allen urges the PUC to order the EEUs to ignore any possibility that any Vermont energy-efficiency investment in the foreseeable future will reduce either distribution or transmission costs. I believe that his basis for this position consists of the following:[13]

- Vermont load is lower than 10 or 15 years ago, and ISO-NE forecasts that it will stay lower for several more years, so there will be no load-related distribution or local transmission costs.
- "The strains on the distribution system are not currently load driven, but rather driven by the backflow of energy from distributed generation." (Q.CLF:DPS 23)

[13]He makes these claims in his direct at 12 and in response to Q.CLF:DPS 23. It is often difficult to determine whether a particular statement in Mr. Allen's testimony is intended to refer to distribution costs, local transmission costs, or pool transmission facilities (PTF).

- The ISO does not project any load-related transmission projects in Vermont, and the 2019 Vermont System Planning Committee report identifies only one transmission-constrained area, so there are no avoided transmission costs.
- Vermont loads do not affect transmission requirements outside of Vermont, New Hampshire and Western Massachusetts.

Mr. Allen also suggests that "Vermont energy efficiency will have little impact" on T&D needs because "solar photovoltaic ("PV") is under-accounted for in its contribution to supplies and reducing summer loads." (Allen Supplemental at 10) In response to discovery, he clarifies that the ISO's forecast of New England-wide solar installations has risen over time, rather than that the ISO has been undercounting or under-crediting existing PV. (Q.CLF:DPS 34)

Q: Starting with the last point, can Vermont loads affect projects in the rest of New England?

A: Yes. For example, transmission projects in Maine, New Hampshire and Massachusetts may be needed to maintain reliable service at extreme peak loads as Maine wind and imports from Hydro Québec and Newfoundland through Maine replace fossil generation in New Hampshire and southern New England. If large amounts of load are served from off-shore wind delivered to Massachusetts and Rhode Island, transmission may need to be added in those states (and possibly Connecticut) to ensure that the power is available to Vermont.

I am not arguing that Vermont load contributes to the need for any identified transmission projects, only that Mr. Allen's dismissal of the possibility is too sweeping.

Q: Does Mr. Allen properly cite the 2019 Vermont System Planning Committee report on the need for transmission upgrades?

A: He correctly quotes the VSPC as saying that "the current [Vermont Long-Range Transmission Plan], published in July 2018, identifies no reliability deficiencies, due to declining loads, and increased distributed generation and energy efficiency. Consequently, this report is briefer than in the past, addressing only a single open issue." But Mr. Allen reads too much into this excerpt.

First, Mr. Allen treats the fact that there is a plan to deal with the single open issue suggests that there are no costs that could be avoided by lower load. As described in some detail in the VSPC report (Exhibit CLF-PLC-2, p. 5), the current conditions in the Hinesburg area require addition of a battery energy storage system and a new or upgraded substation to be owned by Vermont Electric Coop and/or GMP. The Hinesburg problems seem to have arisen during the period in which Mr. Allen notes Vermont has experienced very little aggregate load growth, and the report notes that "the potential for future load growth" is driving some of the concerns (ibid).

Second, the Vermont Long-Range Transmission Plan (VLRTP, attached as Exhibit CLF-PLC-3] acknowledges that "Several of the reliability issues identified in the 2015 plan have been resolved as they are pushed beyond the 10-year horizon due to lower load levels based on the most recent load forecast." (VLRTP at 30) So energy-efficiency since 2015 has been effective in reducing T&D expenditures.

Third, while the VSPC report cites to the 2018 VLRTP as identifying only "a single open issue," the VLRTP itself lists six areas with potential reliability issues, where "potential" seems to mean "the distribution utilities may apply different standards." Note that "the timing of potential concerns is determined to be year 2017 if they are severe or 2025 if they are marginal" (VLRTP at 30).

Table 1: Sub-Transmission Potential Reliability Issues[14]

Location	Year Needed	90/10 Load Forecast for Year (MW)	Contingency	Reliability Concern
Ascutney	2017	< 987	Subtransmission	Thermal Low Voltage
Ascutney	2025	992	Transformer Subtransmission	Low Voltage
Ascutney	2025	992	Transformer Subtransmission	Thermal
Blissville	2025	992	Transformer	Low Voltage
Blissville	2030	1023	Transformer	Thermal
Rutland	2017	< 970 Winter	Subtransmission End open	Low voltage
Montpelier	2031	1028	Transmission	Thermal
Montpelier	2017	< 987	Subtransmission End open	Low Voltage
Montpelier	2017	< 970 Winter	Subtransmission End open	Low Voltage
Burlington	2017	< 987	Transformer Subtransmission	Thermal
St. Albans	2017	< 987	Subtransmission End open	Thermal
St. Albans	2025	992	Transformer Transmission	Low voltage

The VLRTP reports that "The St. Albans…concerns will be eliminated by line reconductoring planned for 2018 and capacitor bank additions planned for 2019…. Load growth has been reduced in the St Albans area by geo-

[14] VLRTP at 31.

targeting efforts over several years. Without this geo-targeting effort, the St Albans area load would have been higher, and the required upgrades could have been more extensive." (2018 VLRTP at 31) So again, load growth has required additional investment, and energy-efficiency helped reduce that cost.

Thus, the VSPC report and its underlying source indicate that Vermont still faces load-related transmission or sub-transmission costs in several areas.

Q: Have you reviewed any other summaries of load-related need for T&D investments in Vermont?

A: Yes, the GMP 2018 IRP indicates that load growth is still expected on some parts of the system, which could require such projects as the following:[15]

- On the subtransmission system in northwest Vermont the "current summer peak of 83 MW is forecasted to be 101 MW by 2024." (p. C-3)
- "Rapid growth in the surrounding area overloaded a 12.47-kV circuit from our Essex substation, limiting our ability to serve existing and new loads or to provide feeder backup in the area." (p. C-4)
- "The aged Marshfield substation had numerous problems [including]…a transformer with limited ability to support load growth," which led to a set of additions that will "enable growth on the distribution system." (C-6)
- The Waterbury substation was rebuilt and redesigned due to "significant load growth in the area from several large customers (including the State of Vermont and Vermont Coffee Roasters); and…the need to provide feeder backup because the area's 4.16-kV feeders were approaching capacity." (C-8) The new design "accommodates new loads."

[15] Some of the project descriptions are not sufficiently specific to determine whether load levels contribute to the need.

- A "recent upgrade to the White River Junction substation and its associated distribution system from 4.16 kV to 12.47 kV (for load growth and partially backing up circuits from the Wilder substation) proved inadequate," due in part to "Larger load growth." (C-8)
- GMP is rebuilding the East Barnard to Bethel subtransmission line due to potential overloads. (C-13)
- "Without reconductoring, the existing Florence to West Rutland line could not carry peak demand." (C-13)
- The "Taftsville to Windsor Subtransmission Line…would overload… following certain contingencies." (C-14)
- GMP is reconductoring a segment of the Welden St to East St. Albans line because "an existing overload…exceeded 10% of the line segment's thermal rating." (C-15)
- GMP is planning to start building a new substation in Danby in 2022 to "relieve capacity issues on the Wallingford substation." (C-16)
- "As part of its St. Albans study … VELCO looked at a proposed load increase for the area," leading GMP to plan to add capacitors at East St. Albans. (C-18).
- "There is very limited capacity for the GMP Dover and Wilmington substations, and there is very limited feeder backup capability. In addition, the Hermitage Club at Haystack Mountain in Wilmington has future plans for an expansion requiring 10 MW of additional load. As such, we plan to build a new Haystack substation in Wilmington to accommodate future load growth, …." (C-18)
- An eight-mile, 12.47-kV distribution line originating at the Charlotte substation serves Hinesburg. New development in the area is likely to

increase its 4.6 MW winter peak. This increasing load and distribution line length contribute to potential thermal and voltage limitations…" A. short-term [reconfiguration] solution still exposes the area to a number of long-term reliability and capacity needs: the potential for continued load growth,…" (C-19) "This substation would increase the available capacity to serve existing and new load…" (C-20).[16]

- "The Maple Avenue to Charlestown 46-kV path [faces] potential overloading under first contingencies at existing loads….As such, we plan to reconductor the" line starting in 2021 (C-21).
- The McNeil to Gorge subtransmission line faces "thermal overloads and low voltages" under some contingencies, so GMP plans to reconductor the line starting in 2021 (C-21).
- Underground cables at the North Brattleboro Substation limit the ability of that substation to provide backup capacity, so GMP is planning on reconductoring those lines (C-22).
- "VELCO's 2015 Long-Range Transmission Plan identified the Websterville to VELCO Barre 34.5 kV subtransmission line as potentially overloading under first contingencies at existing loads," so GMP is planning on reconductoring that line starting in 2021 (C-24).
- "Capacity limitations in the area served by the White River Junction and Wilder substations could overload the White River Junction substation and leave little remaining capacity for Wilder to address contingencies." GMP plans to start the replacement of the Wilder transformer starting in 2021.

---

[16] This is the Hinesburg issue discussed in the VSPC report and acknowledged by Mr. Allen.

As energy-system transformation shifts more load from fossil fuels (especially space heating, water heating, and vehicles) to electricity, capacity constraints may appear in more areas. This is especially true if a reduction in avoided costs reduces the EEU efforts by artificially diminishing its cost-effectiveness.

Q: How is it possible that the VLRTP and the GMP IRP show load-related investment requirements, if Vermont loads are not growing?

A: Loads are apparently falling in some parts of Vermont and growing in others. Falling load on a feeder in Brattleboro does not reduce the need for investment to relieve an overloaded circuit in Rutland.

Q: Do these reports consider all the load-related T&D costs?

A: No. In addition to the substation and feeders addressed in the VSPC report, the VLRTP and the GMP IRP, load levels affect the number and sizing of line transformers as new loads are added to existing primary feeders. In addition, load levels affect the aging of transformers and lines (mostly by heat accumulation degrading insulation), so existing equipment will last longer under lower loads.

Q: Is it clear that all of the projects you listed above could be avoided or delayed by reducing load growth or reducing load below existing levels?

A: No. The reports that I cite above are not intended to address that question. Nonetheless, they indicate that Vermont continues to add load-related T&D investments and that load reductions may defer or avoid some investments. Mr. Allen is incorrect in asserting that Vermont has no load-related T&D projects, and that lack of statewide growth implies that no load-related investment could be needed. Mr. Allen relies on sweeping generalizations and selective use of data; the actual projects built in a time of low aggregate load growth, as well as planned projects, are better indicators of the costs that could be deferred or avoided by lower loads.

Q: Mr. Allen says that "ISO-NE …recently concluded that no further needs assessment was needed for Vermont due to its flat to declining loads that are expected to continue into the future" (Allen Supplemental at 9). Is that correct?

A: Not really. Mr. Allen's basis for this statement is a letter from Jinlin Zhang of the ISO to the Planning Advisory Committee, cited in footnote 4 to his supplemental testimony and attached as Exhibit CLF-PLC-4. The letter does not mention "flat to declining loads that are expected to continue into the future;" that seems to be Mr. Allen's attempt to explain the ISO's decision to perform a Needs Assessment for New Hampshire without including Vermont. What the letter actually says is:

> Note that solutions to address all VT needs identified in the NH/VT 2023 Needs Assessment were finalized and recorded in the VT System 2023 Solutions Study report (report finalized in November 2014).

The ISO does not address whether any needs assessment might be needed for Vermont for years after 2023. Since the EEUs are likely to be using the 2018 AESC avoided costs (with updates) through 2020, some measures installed using those costs will be only a few years old in 2024, for which the ISO has not yet conducted a needs analysis.

In discovery, Mr. Allen attributes the statement that he originally claimed came from the ISO letter to "VELCO, Hantz Presume," narrows his claim to the "bulk" transmission system (excluding subtransmission), and makes an uncited claim that "According to GMP, the responsible DU, none of these projects are avoidable through energy efficiency reductions to load growth." (Q.CLF:DPS: 37).[17]

Q: For how long does Mr. Allen believe that Vermont loads will not affect transmission investments?

A: Mr. Allen says that "we believe that load-driven bulk transmission investments driven by Vermont loads are highly unlikely during the planning horizon" (Allen Supplemental at 6). By "planning horizon," he says that he means some combination of a weighted average life for energy-efficiency measures of 7 to 14 years, the 10-year horizon of the ISO-NE Regional System Plan, and at least part of the 20-year forecast horizon used by VELCo, but not the 2023 horizon of the Vermont System Solutions Study (Q.CLF:DPS 35).

Q: Has Mr. Allen reviewed actual historical T&D investments in the period since 2006, when he says that Vermont load growth stopped?

A: No. "Neither Mr. Allen nor the Department have performed any …analysis" of "insulation failure, line sag or other forms of deterioration consistent with the effects of repeated overloads" (Q.CLF:DPS 25). "Mr. Allen has not performed any load-related investment analysis" on the Vermont distribution system. (Q.CLF:DPS 24) The DPS does not know the "annual additions and retirements of T&D plant for the Vermont electric utilities" (Q.CLF:DPS 27) and has no data on how heavily loaded the Vermont substations and feeders may be (Q.CLF:DPS 28, 29), or even how many substations peak in the winter

[17] Given the many errors in Mr. Allen's testimony and responses, and the clear statements in the GMP IRP that projects are load-related, this claim is not reliable. It is possible that Mr. Allen is distinguishing between load-related projects and load-growth-related projects; if so, the question remains as to whether falling loads would avoid the investments.

rather than the summer (Q.CLF:DPS 30). Nor does Mr. Allen have any "estimate of the amount of additional T&D investment that would have been required if Efficiency Vermont and BED had not invested in energy-efficiency programs in the period 2008–2018." (Q.CLF:DPS 31)

However, the DPS is aware of load-related subtransmission projects in the period of no net statewide load, if not their costs.

> There have been numerous subtransmission line reconductoring projects undertaken, for example, by GMP within [2008–2018]. Clearly, these were remedies for "local capacity constraints". Various other more ambitious projects were undertaken in this timeframe as well, to remediate local capacity constraints, including the Newfane 115/46 kV interconnection, the Georgia 115/34.5 kV interconnection, the reconfiguration of the Lowell-Jay 46 kV line, and the Florence-West Rutland 46 kV project, which is just nearing completion. (Q.CLF:DPS 26)[18]

Q: What do you recommend regarding a reasonable value for avoided T&D due to Vermont energy-efficiency programs?

A: The AESC 2018 avoided PTF cost may be overstated for Vermont's avoidable PTF costs, as Mr. Allen alleges, but there is no basis for concluding that those costs are zero over the life of the energy-efficiency measures that will be installed in the next few years. AESC 2018 did not include any avoided distribution or sub-transmission costs, or any non-PTF costs. As explained above, Vermont continues to incur those T&D costs due to load.

---

[18] The remainder of the response appears to be intended to clarify the origin of the load-related investments, but fails to provide much clarification. For example, it attributes the need for projects to the configuration of the projects; this may be an attempt to say that reconfiguration of other parts of the system increased load on particular facilities, prompting upgrades. The response also notes that "Historic load growth and system reconfigurations generally have historically contributed to load related challenges on the distribution system historically."

Without conducting extensive additional analyses, I cannot provide a bottom-up avoided T&D results for Vermont. A reasonable approach would be to use the $94/kW-yr value from AESC 2018 as an aggregate value for all T&D costs of Vermont load.

V. Externalities

Q: What is Mr. Allen's position with respect to externalities?

A: Mr. Allen points out that Vermont's renewable energy standard (RES), pursuant to Act 56, requires the utilities to source at least 55% of their energy from renewable resources in 2019, with the requirement rising 4% every three years, starting in 2020, reaching 75% by 2032. He then says:

> Renewable energy systems are deemed to be carbon free and so the renewable energy standard has implications on the available carbon reduction that can be attributed to energy efficiency programs. (Allen Direct at 4)

> Vermont's portfolio choices matter and have a very real and practical effect on its GHG emissions, even while Vermont's loads are part of a regional system. (ibid at 5)

> If EVT delivers 100 GWhs of savings in a given year, that means that the share of the supply portfolio that must be covered with RECs are reduced by 55 GWhs. Simply put, what is on the margin (of avoided GHG emissions) should be adjusted to reflect the nature of the electricity portfolio. At least 55% of our portfolio requirement (i.e., loads in Vermont) must be carbon-free renewable energy or we face a very expensive penalty. (ibid at 7)

Based on these observations, Mr. Allen recommends "that Vermont simply recognize that on a going forward basis, at least a 55% share of the emissions portfolio (increasing to 75% by 2032) is carbon free." (ibid at 4)

Q: How do you interpret this recommendation?

A: I assume that Mr. Allen means that the AESC carbon externality value attributed to energy-efficiency measures in Vermont should be multiplied by 45% in 2019, 41% in 2020 to 2022, 37% in 2023–2025, 33% in 2026–2028, 29% in 2029–2031, and 25% from 2032 onward. He does not dispute the accuracy of the carbon externality value computed in AESC 2018.

Q: Is Mr. Allen correct in his analysis of the externalities avoided by Vermont's energy-efficiency efforts?

A: No. He is correct that, to the extent that energy-efficiency avoids the generation of a clean, zero-externality renewable resource, the avoided externalities should be reduced proportionally. Mr. Allen greatly overstates this effect in two ways:

- The RES requires Vermont utilities to enter into contractual undertakings to claim renewable resources. The energy output that is avoided by reducing Vermont consumption is not determined by those contracts, but by which resources are not built or operated, due to the lower load. Vermont's contracting for many of the renewable resources that Mr. Allen touts would not reduce emissions, compared to purchases of other market power.
- Renewable resources are not all carbon-free, even those that are carbon-free are not all emission-free, and even those that are emission-free are not all externality-free.

A. *Marginal Energy Resources*

Q: How does the actual operation of the regional utility system differ from the accounting for the RES?

A: The RES focuses on whether the Vermont utilities can claim "ownership of sufficient energy produced by renewable energy plants or sufficient tradeable renewable energy credits from plants whose energy is capable of delivery in New England" (30 V.S.A. § 8004(a)). The definition of "renewable" in this context is very broad:

> "Renewable energy" means energy produced using a technology that relies on a resource that is being consumed at a harvest rate at or below its natural regeneration rate. (30 V.S.A. § 8002(17))

The environmental externality value of energy-efficiency depends on the nature of the energy sources that are not operated due to the lower load. Neither electrons nor emissions follow ownership relationships.

Q: What resources are turned down when Vermont energy-efficiency programs reduce load?

A: When Vermont reduces consumption, it does not proportionally reduce the output of each of its entitlements. Whatever solar, wind, small hydro is delivering power on Vermont's account will continue doing so, as will Hydro Quebec deliveries (unless that energy can be shifted to other time periods). For the most part, either Vermont would just pay for less market power, generated by fossil fuels, or some energy from Vermont's renewable entitlements will be dumped onto the ISO-NE market, displacing fossil fuels.

The McNeil plant may be turned down if Vermont energy (and hence renewable) requirements fall, since its fuel costs (about $63/MWh) are higher than market energy prices in many hours.[19] But the DPS summary of energy supply by resource type indicates that the Vermont utilities sell all their McNeil RECs in other states, so its usage may also be independent of Vermont load.[20]

Q: Does that relationship change in the longer term?

A: It can. Load reductions mean that Vermont utilities do not need to add as much renewable energy as they would have without the energy-efficiency programs. So the energy-efficiency load reduction can avoid some new renewables. Mr. Allen does not address the issue of the actual generation displaced by Vermont load reductions, but it appears that the DPS and the utilities would prefer to meet the renewable requirements with a minimal amount of new renewables.

Q: What percentage of energy saved by efficiency programs is likely to avoid new renewables?

A: That is difficult to determine with any precision. In principle, as the RES requirements rise, the Vermont utilities could comply by adding 100% new solar and wind to provide the additional renewable energy. The evidence, though, is that the utilities are likely to concentrate on shifting existing resources to the Vermont portfolio and on acquiring low-cost RECs that are not eligible for premium prices in other states.

The distributed generation requirement (1.6% in 2019, rising at 0.3% annually to 10% from 2032 onward) seems to contemplate new renewable resources, which are likely to be mostly solar. For the total renewable requirement, the DPS and the Vermont utilities appear to be leaning toward

---

[19] Joseph C. McNeil Generating Station Special-Purpose Financial Statements, June 30, 2018 and 2017.

[20] http://vt-psd.herokuapp.com/power-supply-by-source-type?

relabeling existing resources without increasing the output of renewable energy or decreasing overall fossil emissions:

- The 2016 Comprehensive Energy Plan states that "it would be a positive step for Vermont utilities to enter into contracts for power from the [eight hydroelectric dams on the Connecticut and Deerfield Rivers, with their nearly 500 MW of renewable power], assuming that acceptable price and quantity terms could be negotiated. The state will also watch for any new opportunity to purchase these hydro facilities if they become available." (2016 CEP at 383)
- The GMP IRP also suggests meeting future Tier I requirements by acquiring 50 MW through "a long-term PPA for the output of one or more existing hydro plants, or a purchase of existing hydro capacity in the region." (p. 8-29)
- As an alternative, GMP suggests purchasing "25 MW of firmed hydroelectric purchases" (ibid), such as from Hydro Québec.
- The GMP 2018 IRP shows it meeting RES requirements through about 2023 with purchased RECs (Figure 8-5).
- Those purchased RECs appear to be associated with existing resources delivered under existing facilities: "to help meet the larger Tier I requirements, we have entered into a multi-year transaction with Hydro-Québec that convey generation attributes from hydroelectric sources imported into New England over the Phase 2 transmission facility." (GMP 2018 IRP, at 5-31 to 5-32)

None of these transactions is likely to reduce overall fossil emissions. Vermont is purchasing RECs from Hydro Québec energy that is being delivered to other utilities and would be delivered, regardless of whether

Vermont utilities purchased the RECs. As GMP notes, “Vermont RES Tier I features a much wider range of renewable resource eligibility than the regional Class 1 markets, so this is presently a relatively large volume, low-priced market.” (2018 GMP IRP at 8-63) Hydro Québec does not need to build additional hydro facilities or increase output for its existing generation to be counted toward satisfying Vermont’s Tier I requirements, and GMP’s purchases do not require them to find incremental renewable resources.

Purchasing Connecticut and Deerfield hydro plants or contracting for their energy output would also not change the dispatch of these plants or avoid any emissions. The same is true for purchases of energy from Canada, unless Hydro Québec or Newfoundland build additional renewable resources to serve that contract, or if Vermont somehow increases the energy transfer capacity from the Canadian resources to markets.

If Vermont load is lower, Hydro Québec is unlikely to spill more water, or defer construction of new plants. Hydro Québec has only one hydro plant under construction (Romaine 4) and has no new production facilities in the study or approval phases (www.hydroquebec.com/projects/), so any future purchases from Hydro Québec are likely to simply take energy that would otherwise have been sold to back down fossil resources in New England, New York and Ontario.[21]

---

[21] Mr. Allen supports this conclusion in response to discovery: “Mr. Allen has no basis for knowing [whether Hydro Québec built additional hydro to meet the most recent Vermont contract]; the Department is not aware of any new hydro facilities built by Hydro-Quebec to satisfy the Vermont contract. According to the CEP, the most recent contract is a 225 MW contract that took effect in 2012. This is contract power I believe could be delivered to Vermont, other New England states, or neighboring provinces….I doubt that any new facilities were built expressly to meet the Vermont contract requirements. HQ is large, but there are many potential

If Vermont conserves less energy and buys more existing renewable energy (or Vermont Tier I RECs), some combination of fossil power plants in New England, New York, Ontario or elsewhere will generate most of the energy output, emitting carbon (and creating other environmental harms).

Q: What is the current mix of Vermont renewables?

A: Table 2 shows the percentage of 2017 renewables, from Mr. Allen's response to Q. CLF:DPS 7, and the Vermont utility-owned hydro as a percent of 2016 energy supply, from the DPS power-supply web page cited in that response (http://vt-psd.herokuapp.com/power-supply-by-source-type.) It appears that both sources show only the renewables for which Vermont has retained the RECs.[22] I converted from percent of renewables to percent of energy supply, and vice versa, assuming that claimed renewable energy was 55% of total energy.

Table 2: Vermont 2017 Renewable Mix

Resource	**% of Renewables**	**% of Energy Supply**
	a	*b*
Hydro-Quebec	50.0%	27.5%
New England Hydropower	48.5%	26.7%
Vermont-owned	19.8%	10.9%
Purchased	28.7%	15.8%
Solar	1.3%	0.7%
Wind	0.2%	0.1%

Notes:
a. from Q. CLF:DPS 7, except the breakdown of New England hydro, which is computed from column *b*.
b. 55% of column *a*, except Vermont-owned hydro from DPS power-supply web page for 2016.

markets for its power in neighboring regions, limited by existing to newly constructed bulk transmission." (Q.CLF:DPS 13).

[22] The 2016 DPS web data shows no wind or solar RECs being retained.

The purchases of Hydro Québec and New England hydropower simply represent the transfer of the financial costs and benefits of existing energy resources, without any change in system emission rates. The same would be true for some of the Vermont-owned hydro, such as GMP's purchase of a dozen small hydro units from Enel (Green Mountain Power 2018 IRP, Table 5-3).[23]

Q: Is it possible that at least some of the marginal sources of RECs for Vermont would actually be new renewables?

A: Yes. GMP suggests that it might participate in a multi-state procurement of off-shore wind (2016 GMP IRP at 5-33 and 5-34), although that source would almost certainly be more expensive than GMP's identified alternatives, such as relabeling existing hydro resources.

More realistically, the Tier II RES requires new small renewables connected to the Vermont distribution system. Most of that is likely to be solar, with limited environmental effects. Of an energy reduction in 2019–2038 due to an energy-efficiency installation in early 2019, the avoided Tier II energy would be perhaps 7% of the avoided energy. The other 93% of avoided energy would be mostly just reductions of the marginal market resources, with carbon emissions as estimated in AESC 2018.

B. Environmental Effects of Renewable Resources

Q: What is your reaction to Mr. Allen's statement that "Renewable energy systems are deemed to be carbon free"?

[23] One of those units, amounting to 3% of the Enel capacity, was built since the New England states started setting up their renewable standards; if GMP retains the renewable attributes, that would force some other New England party to purchase a small amount of energy or RECs from new renewables. The rest are too old to count toward the primary renewable standards.

A: I do not know who Mr. Allen believes does this deeming. But not all renewable energy systems are carbon-free.

Q: Please describe Mr. Allen's analysis of the environmental effects of renewable generation.

A: To be brief, his analysis can be summarized as an admission that he does not know much about the environmental effects of renewables, but that only carbon emissions matter and that he is comfortable with modeling these resource as having no environmental effects. When asked for "any information available to Mr. Allen regarding the environmental effects" for various renewables, he responded:

> All of these [resources] meet the standards of renewable energy in Vermont. Mr. Allen is not presented as an expert on the environmental characteristics of these different technologies. Compared with fossil fuel stack emissions, Mr. Allen believes these to be sources of near zero emissions. Mr. Allen believes that common practice for modeling purposes, is to assume that these are all non-emitting resources. Mr. Allen's recommendation is that the carbon footprint of the Vermont portfolio reflect an adjustment for carbon content that Vermont associates with renewable energy share of the Vermont portfolio. Mr. Allen believes that the adjustments proposed represent a more reasonable approximation of carbon value than ignoring the RES requirements. The approximation seems conservative (likely overstating carbon in the Vermont mix) given the ambitions and actual holdings of renewable and non-carbon emissions sources that are part of the Vermont mix current and planned. (Q.CLF:DPS 20)

Q: Is Mr. Allen correct that he is conservatively overstating the carbon that would be avoided by DSM by assuming that every resource entitlement eligible to be counted as a renewable in Vermont results in no carbon emissions and no other environmental effects?

A: No. His approach understates avoided carbon emissions and ignores all other environmental effects.

Q: Please provide some examples of the emissions of carbon from renewable energy systems that qualify for Vermont RES Tier I and II.

A: New large hydro systems require clearing of land for reservoirs, resulting in the release of much of the carbon that was stored in vegetation on that land. The biomass left behind or washed into the reservoir may decay aerobically to form CO_2, or worse, decay anaerobically to form methane, a more potent greenhouse gas.[24] As described above, Vermont purchases from large hydro are likely to be mostly from existing resources, resulting in no change in hydro construction or operation. If Vermont increases its energy use and meets its RES requirement with existing hydro, some fossil unit will generate the extra energy, regardless of Vermont's transactions with the hydro owners.

Plants fired by woody biomass burn the wood, releasing carbon that otherwise would have been sequestered in trees for decades, or (in the case of waste materials from logging, utility tree trimming, and other activities) gradually decayed over months or years. Depending on what materials are burned, where they originated, and what would otherwise have happened to them, woody biomass plants can increase atmospheric carbon for some period of time and increase the cumulative global-warming forcing permanently.[25]

---

[24] Construction of hydro facilities also requires large amounts of concrete, whose manufacture releases considerable carbon. The life-cycle environmental assessment of generation resources and energy-efficiency equipment is complicated.

[25] Mr. Allen's responses to Q.CLF:DPS 18 and 19 indicate that he has no idea whether the carbon emission of burning wood would be offset by regrowth or avoided decomposition. Yet he claims that "existing woody-biomass facilities…are generally considered to be carbon neutral,

Even once the atmospheric carbon concentration reaches the level that would have occurred had the biomass not been burned, whatever additional heat the Earth has absorbed due to the incremental CO_2 remains.

Q: Are carbon emissions the only environmental effect of generation facilities?

A: No. The construction and operation of most generation resources have non-carbon environmental effects, such as:

- Wind: Land clearing and habitat fragmentation for access roads.
- Biomass: Heating of cooling water, destruction of habitat, emissions of NOx and particulates.
- Hydro: interference with migration of fish and other organisms, injury and death for aquatic organisms, change in erosion and deposition of sediments, mobilization of mercury and other toxins, disruption of habitat.
- Solar photovoltaics: increased total insolation absorption, alteration of land use.

So even where Vermont's procurement of renewable resources and RECs actually results in the addition of renewables, the environmental externalities are not zero. The environmental costs may be less than the marginal environmental costs of operating the regional electric system, but there are environmental costs that can be avoided by reducing the renewable resources built to comply with the RES.

---

especially when combined with sustainable harvesting practices." (Q.CLF:DPS 16) My review of the literature indicates that this may be true for cumulative carbon only in the very long term; it would never be true for cumulative climate forcing, unless burning the wood somehow results in a substantial increase in the eventual storage of carbon.

C. Externality Summary and Conclusions

Q: How do your observations relate to Mr. Allen's hypotheticals regarding state renewable policy in New England, in his Direct testimony at 5–6?

A: In Mr. Allen's first hypothetical, in which "each of the six New England states adopted a 100% renewable energy standard," he repeats his mistake of assuming that any resource designated as renewable is carbon-free, concluding that the region would have "carbon-free marginal emissions and average system emissions." (Direct at 6) So long as the RESs allow biomass and existing resources to qualify as renewables, additional energy consumption would increase emissions from the biomass plants and from plants in the other markets that would otherwise have used the existing renewables (e.g., New York and Ontario, for Hydro Québec plants). In contrast, reducing New England energy use would reduce emissions.

In his second hypothetical, Mr. Allen imagines a world in which all the other New England states had 100% renewable requirements and Vermont had some renewables and some fossil generation. Mr. Allen posits that a 15% reduction in load from the other states (which would be larger than Vermont's entire load) would not reduce Vermont's emissions. Of course, if the other states acquired the renewables and then started to reduce load, the excess energy from the renewables would back out most or all of Vermont's fossil resources. And if the other states' marginal renewables include biomass, purchases from Hydro Québec that would otherwise have reduced emissions in New York and Ontario, and existing New England hydro that would otherwise have eliminated Vermont's fossil generation, reducing load in those states would reduce total emission.

While it is possible to imagine a world in which the marginal carbon emission rate is the effective emission rate of biomass plants, and reducing energy use in Vermont does not back down any fossil plant, it is far from likely within the life of most energy-efficiency measures undertaken in the next few years.

Q: How do you recommend that the PUC reflect avoided externalities in the screening of energy-efficiency options?

A: Since most of the Tier II resources are likely to have modest, but not zero, externalities, and most of the other marginal Tier I resources are likely to be financial transactions with the same externalities as the regional system margin, I recommend that the PUC use the AESC carbon emissions (which reflect only a portion of externalities), discounted by the percentage of Vermont supply required to be from Tier II resources in each year.

VI. Risk Adder

Q: What is Mr. Allen's point with respect to the use of the risk adder that the Commission adopted in PSB 5270?

A: Mr. Allen points out that the Vermont utilities no longer need to purchase specific physical generation resources with long lead times (he suggests a 7-year lead time, although Millstone 3 took about 12 years and Seabrook about 14 years), and there is now a liquid market for wholesale energy and capacity. He does not propose a specific adjustment to the existing 10% risk discount, equivalent to an 11.1% adder to avoided costs.

Q: Did Mr. Allen discuss all the risk components that DSM avoids that market energy purchases do not?

A: No. The risk-reducing benefits of DSM include the absence of the following:

- Fuel costs and hence fuel-price-related volatility. This risk includes the volatility associated with constraints on the gas delivery system.
- Other cost variations during the delivery period for the resource. Once the DSM is installed, the cost is fixed.
- Outage risks. The energy delivered by a unit-contingent contract may drop to zero with operating problems with the generator or the connecting transmission. If a Vermont utility actually owns the resource, it can pay full price for the resource and get no energy or capacity benefits. Depending on the contract. For short-term market purchases, market prices may rise significantly in the event of the outage of major plants (such as Millstone).
- Non-diversifiable sales risk. A utility will generally attempt to hedge its supply with enough energy resources to cover its expected load at fixed prices (or at least prices fixed some months in advance of need). If load is higher than expected, especially due to regional factor such as extreme weather, the utility will be scrambling for additional energy in a tight supply market. If load is low, the utility will have excess energy entitlements to sell into a weak market at a loss.[26] Since DSM programs generally reduce extreme loads by more than average loads, they reduce these costs.

These risks of reliance on generation, and the resulting benefit of DSM, have not been eliminated by changes in the generation markets since 1990.

[26] My experience in overseeing the procurement of standard service resources for the Connecticut utilities suggests that the suppliers add about 7–10% to their bids to cover these risks.

Q: What do you recommend the PUC do with respect to the risk adder for DSM?

A: The 10% discount seems reasonable, although further analysis might support a higher or lower value. I see no need to change the adder in the absence of additional investigation.

Q: Does this conclude your testimony?

A: Yes.