Vermont Public Power Supply Authority

Board of Directors Meeting

January 3, 2024
9:30 a.m.
5195 Waterbury-Stowe Road, Waterbury Center, VT 05677

CALL IN NUMBER: 1-347-991-8065
Meeting ID: 474 495 819
Click here to join the meeting

Directors

Vera LaPorte, Barton	John Dasaro, Enosburg	Mike Sullivan, Hardwick
Vacant, Jacksonville	Erik Bailey, Johnson	Thomas Petraska, Ludlow
Jonathan Elwell, Lyndon	Scott Johnstone, Morrisville	Steve Fitzhugh, Northfield
John Morley III, Orleans	Bill Sheets, Swanton	

Agenda

Allotted number of minutes set forth in bold type after each item
"*" items will have written materials but no presentation unless questions are asked

1. Call to Order **(9:30)**
2. Consideration of changes/modifications to agenda **(3) (9:31)**
3. Public Comment **(2) (9:34)**
4. Introduction of BED as Strategic Member **(5) (9:36)**

Action Items

5. Minutes of the 12/06/2023 Regular Board of Directors Meeting **(3) (9:41)**
6. Minutes of the 12/18/23 Special Board Meeting **(3) (9:44)**
7. Monthly Financial Report for period ending 11/30/2023 (Grace) **(5) (9:47)**
8. Creation of Legislative Committee **(10) (9:52)**

Discussion Items

9. Invited Guest (VELCO) (Ken N) **(30) (10:02)**
10. Power Supply Status (Drew) **(10) (10:32)**
11. Legislative Update – RES **(15) (10:42)**
12. Regulatory Update (Sarah) **(20) (10:57)**
13. GM Updates **(15) (11:17)**
14. Board Member Updates **(5) (11:32)**

Executive Session

15. McNeil Generating Plant – District Energy (30) (11:37)

Other

16. Other Business

CC:

Denis Fortin, Barton	Vacant, Ludlow
Abbey Miller, Enosburg	Penny Jones, Morrisville
Vacant, Hardwick	Jeff Schulz, Northfield
Vacant, Jacksonville	Marilyn Prue, Orleans
Vacant, Johnson	Lynn Paradis, Swanton
Erica Welton, Lyndon	

Vermont Public Power Supply Authority

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P.O. Box 126 • 5195 Waterbury-Stowe Rd. • Waterbury Center, VT 05677 • 802.244.7678 • Fax: 802.244.6889

Memorandum

To: VPPSA Board of Directors
From: Ken Nolan, General Manager
Date: December 29, 2023
Subject: Agenda Item #4 – BED Strategic Membership

On December 15th BED and VPPSA entered a Memorandum of Agreement ("MOA") establishing BED as a Strategic Member of VPPSA in accordance with the Board vote in November. A copy of the signed MOA is provided in the packet.

BED also notified VPPSA that its representative to the Board is James Gibbons with the alternate representative being Emily Stebbins-Wheelock.

No further action is required by the Board.

MEMORANDUM OF AGREEMENT BETWEEN BURINGTON ELECTRIC DEPARTMENT AND VERMONT PUBLIC POWER SUPPLY AUTHORITY RE: STRATEGIC MEMBERSHIP

This Memorandum of Agreement ("Agreement") is entered into this 15th day of December 2023, by and between the City of Burlington, Vermont, a Vermont municipal corporation acting by and through its Electric Department ("BED"), and Vermont Public Power Supply Authority ("VPPSA") (each a "Party" and jointly the "Parties").

WITNESSETH:

WHEREAS, VPPSA is a body politic and corporate and a public instrumentality of the State of Vermont exercising public and essential governmental functions on behalf of its members, with duties and powers as set forth in 30 V.S.A Ch. 84; and

WHEREAS, membership in VPPSA is open to all municipalities in the State of Vermont engaged in the manufacture, distribution, purchase or sale of electricity upon such terms and conditions as VPPSA's Board of Directors ("Board") finds appropriate; and

WHEREAS, a Vermont municipality otherwise qualified that also has the in-house capacity to provide services VPPSA does not provide itself, or which services will provide substantial ongoing benefit to VPPSA as a whole, may become a strategic member of VPPSA in accordance with VPPSA's Amended and Restated Bylaws dated June 6, 2018, as the same may be amended from time to time (hereinafter "Bylaws"), and on terms and conditions as the Board finds appropriate; and

WHEREAS, BED qualifies for strategic membership in VPPSA in that it is a Vermont municipality engaged in the manufacture, distribution, purchase or sale of electricity, and has the in-house capacity to provide services VPPSA does not provide itself, including without limitation energy efficiency services, with such services potentially providing substantial ongoing benefit to VPPSA as a whole; and

WHEREAS, the Board desires to offer BED strategic membership in VPPSA on the terms and conditions set forth in this Agreement, and BED desires to accept same;

NOW THEREFORE, in consideration of the mutual covenants and agreements hereinafter set forth, and other good and valuable consideration the receipt and sufficiency of which is hereby acknowledged, the Parties hereto agree as follows:

1. **Term**: This Agreement shall be effective upon execution and shall continue in effect indefinitely subject to annual appropriation of the Basic Fee into BED's budget. Notwithstanding Article II, Section 3 of the Bylaws. in the event of non-appropriation of the Basic Fee, BED's strategic membership shall terminate on the last day of the fiscal year for which the Basic Fee was appropriated. BED's withdrawal from strategic membership for non-appropriation shall be without penalty. In the event of termination of this Agreement, any rights and obligations arising from commitments made prior to such termination (including, but not limited to, commitments related to financing arrangements by VPPSA on behalf of BED) shall remain in effect pursuant to their terms.

2. **Strategic Membership:** BED's strategic membership in VPPSA shall be governed by Article II, Section 5 of the Bylaws and this Agreement.

3. **Board of Directors:** BED shall have the right to participate in Board meetings through a representative appointed by BED's General Manager. BED also may appoint an alternative representative to participate in meetings in the absence of the primary representative. BED's representative or alternative representative shall not, however, have a seat or a vote on the

Board. The names of BED's representative and alternative representative, and any replacements thereof, shall be reported to VPPSA's Secretary

4. **Fees:** BED shall not be required to pay any fees under Article IV of the Bylaws except for the Basic Fee pursuant to Section 1.a. thereof, which presently is Five Thousand Dollars ($5,000.00) per year. Services performed by BED for VPPSA, or by VPPSA for BED, shall be on a fee for service basis at a rate set by the Board, which presently is One Hundred Dollars ($100.00) per hour. Any proposed change in such fees or other material provisions of this Agreement shall be communicated to BED at least 60 days in advance of the effective date of such change. If BED does not agree to any such change in the fees or material provisions of this Agreement, BED's strategic membership shall terminate without penalty on the date such changes become effective.

5. **Project Participation:** BED will be invited to participate in VPPSA-sponsored projects on such terms and conditions as may be mutually agreed upon by BED and the Board. Potential projects shall include, but not be limited to:

a. **Financing:** BED may access VPPSA-backed financing, including for equity calls by Vermont Transco LLC.

b. **Renewable Energy Standard (RES)**: BED may participate in VPPSA RES projects, including complying with Tier III RES requirements in the aggregate with other VPPSA members.

c. **Efficiency Efforts**: BED and VPPSA will jointly explore mutually beneficial opportunities to improve the cost effectiveness and efficiency of services provided to BED and VPPSA's members' customers.

6. **Staff Sharing:** The Parties shall jointly explore opportunities for collaboration in the following areas:

a. Power Supply: Management of power supply efforts including, but not limited to, long term procurement, daily load and generation bidding, Renewable Energy Credit purchases and sales, including Renewable Energy Standard (RES) Tier I and Tier II compliance, ISO New England stakeholder interactions, and various planning activities.

b. Regulatory/Legislation: Development of policy positions, and joint representation before the Vermont General Assembly, Vermont Public Utility Commission, the Department of Public Service, and possibly the Federal Energy Regulatory Commission.

c. Generation Operations: The Parties will explore whether joint or collaborative operation of their generating assets would be advantageous, including consideration of whether the Parties could provide operational support to the other in a way that maximizes the value of existing staff.

7. **Employee Relations**: Any staff dedicated to joint efforts shall remain employees of their respective organizations subject to their existing personnel policies and collective bargaining agreements. When employees of either BED or VPPSA perform work for the other organization, the employees shall remain members of their respective organizations and collective bargaining units, if any, but will report to the individual(s) in charge of the work being performed.

8. **Miscellaneous**: This Agreement may be modified only by a written amendment signed by the Parties. If any provision of this Agreement shall be found to be invalid, inoperative or unenforceable in law or equity, such finding shall not affect the validity of any other provisions of this Agreement, which shall be construed, reformed and enforced to affect the purposes of this

Agreement to the fullest extent permitted by law. This Agreement shall be governed by and construed under the law of the State of Vermont, without application of principles of conflicts of laws, and constitutes the entire agreement of the Parties with respect to the subject matter hereof, superseding all prior oral and written communications, proposals, negotiations, representations, understandings, courses of dealing, agreements, contracts, and the like between the Parties in such respect.

IN WITNESS WHEREOF, the parties hereto have set their hands the day and year first above written.

BURLINGTON ELECTRIC DEPARTMENT	VERMONT PUBLIC POWER SUPPLY AUTHORITY
______________________________	Kenneth A Nolan
Darren Springer, General Manager	Kenneth A. Nolan, General Manager

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Board of Directors
Meeting Minutes
December 6, 2023

Board of Directors:

X	Vera LaPorte, Barton	X	Jonathan Elwell, Lyndon
X	John Dasaro, Enosburg	X	Scott Johnstone, Morrisville
	Mike Sullivan, Hardwick	X	Stephen Fitzhugh, Northfield
	Vacant, Jacksonville	X	John Morley, Orleans
X	Erik Bailey, Johnson	X	Bill Sheets, Swanton
X	Thomas Petraska, Ludlow		

X indicates attendance in person, P indicates attendance by phone.

Alternate Directors present:

Abbey Miller, Enosburg (P)	Lynn Paradis, Swanton (X)
	Penny Jones, Morrisville (X)

Others present:

Ken Nolan, VPPSA (X)	Sarah Braese, VPPSA (P)	Jackie Pratt, Guest (X)
Grace Sawyer, VPPSA (X)	Heather D'Arcy, VPPSA (X)	Crystal Currier, VPPSA (P)
Drew Clayson, VPPSA (P)	Amanda Simard, VPPSA (P)	Lance Woods, VPPSA (P)
Josh Bancroft, VPPSA (P)	Steve Farman, VPPSA (P)	Apryl McCoy, VPPSA (P)

Numbers in bold type correspond with agenda item numbers:

1. Chairman Fitzhugh called the meeting to order at 9:30 a.m.

2. Chairman Fitzhugh asked if there were requests for changes and or/modifications to the current agenda. There was an addition to the agenda of item 7.a.

3. Chairman Fitzhugh asked if there were public comments and/or individuals who would like to address the Board. There was no public comment.

4. Director Bailey made a motion to accept the minutes of the Board of Directors meeting held on November 1, 2023. The motion was seconded by Director Sheets. Motion approved.

5. Director Johnstone made a motion to accept the minutes of the Special Board of Directors meeting held on November 29, 2023. The motion was seconded by Director Morley. There were two abstentions. Motion approved.

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6. Director Morely made a motion to approve the Monthly Financial report for the period ending October 31, 2023. The motion was seconded by Director Johnstone.

Ms. Sawyer, VPPSA's Controller provided a summary of operational revenue vs expenses for the period ending October 31st, 2023. It was noted that VPPSA's Year-to-date (YTD) Net Income is $2,219,257, which is greater than budget by $220K. Net Power supply and transmission expenses are $34K above budget. Interest income is $102K greater than the budget. Interest expense is below budget by $18K YTD because VPPSA has not had to draw on the LOC. VPPSA's Operational income is $1,408, which is greater than budget by $202K Year to date. Other items of note: The REC purchase contract of $1.1MM was delivered at the end of May. For the budget, we did not anticipate delivery of the full contract at once and had evenly spread the expenses to match the revenue. The project will show a decreasing loss for the remainder of the year as the revenue catches up. McNeil generation is under budget 31.15% for the year resulting in revenue being below budget by $398K. P10 interest income is over budget by $167K YTD and various other operating expenses are below budget by $25K YTD resulting in net income of $518K which is $192K greater than budgeted YTD. The GIS Revenue loss of $5K from Ludlow leaving the project and depreciation expense of $5K results in the project being over budget by $10K YTD.

The motion was approved.

7. The General Manager provided a brief written overview of the VPPSA Budget process and noted that Per VPPSA's Bylaws the Board needs to approve VPPSA's annual budget in December so that the new budget is in place effective January 1st. The Board received an overview of FY24 major drivers in October, a high-level budget at the November regular meeting, and a detailed budget package for discussion at the November 29th special meeting.

Director Johnstone made a motion to approve VPPSA's FY2024 Operating, Project and Capital budgets as presented. The motion was seconded by Director Bailey.

The motion was approved.

7.a. The General Manager provided an overview of Burlington Electric Departments request to join in the VPPSA financing and the Strategic Partnership discussions with Burlington Electric Department. BED would like to become a Strategic Member of VPPSA and requested this in writing to the Board of Directors. The General Manager also presented the proposed membership agreement. There was a brief discussion around the membership fees and services and the possible future VPPSA borrowing limitations. There was also a brief discussion about Hyde Park and Stowe possibly wanting membership with VPPSA again. Director Morley asked if there would be a press release in regard to the Strategic Partnership and requested Board notification when posted.

Director Johnstone made a motion to approve BED's Strategic Membership Memorandum of Agreement as presented and authorize the General Manager to sign. The motion was seconded by Director Morley.

The motion was approved.

8. The General Manager provided an overview of the Vt Transco equity that is being issued in December to the members valued at $30,000,000 to the Vt Distribution utilities. Several of the members have requested to assign to VPPSA, the member units as offered to them. VPPSA has discussed financing with several lenders and explored multiple financing options for this purchase. VPPSA staff recommends engaging with Burlington Bank who has provided the lowest rates and both short and long-term options.

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Director Bailey made a motion to approve resolution 2023-04 with an amendment to just include the rate not to exceed 7.5%. Director Johnstone seconded the motion. The motion was approved.

9. Director Petraska made a motion to enter Executive Session, under the provisions of 1 V.S.A. §313(a) to discuss the McNeil Generating Plant – District Energy. The motion was seconded by Director Bailey. The motion was approved.

The Board entered Executive Session at 10:23 a.m.

Director Morley made a motion to return to Regular Session, seconded by Director Bailey. The motion was approved.

The Board returned to Regular Session at 11:41 p.m.

Director Johnstone made a motion to schedule a Special Board of Directors Meeting on Monday December 18th @ 2pm, seconded by Director Bailey. The motion was approved.

10. Heather D'Arcy, VPPSA's Power Analyst, provided an overview of the power supply markets, the primary driving factors related to power costs, actual and future energy prices, and the budget vs actual for each member. Ms. D'Arcy presented a detailed review of the Mystic Station costs and what the variances would be absent the Mystic costs and how the unfavorable rate variance for most members is primarily due to the unbudgeted Mystic Station Cost. It is anticipated that this winter the costs will not be as significant as they were in the prior winter. However, ISO-NE has a new fuel program where members will see a charge for an incentive for plants to keep their tanks full. P10 will receive revenue from this program. Ms. D'Arcy also gave an overview of the Renewable Energy Credits. The General Manager notified the Board that VPPSA was going to try and buy as many 2023 Tier III REC's as possible because the cost has dropped even though it is not in the budget. They will be banked for future years. She provided an overview of the forward sales already under contract for 2023-2025.

Lunch break @ 11:56 p.m.
Reconvened @ 12:26 p.m.

11. Sarah Braese, VPPSA's Assistant General Manager, provided a brief Regulatory and Power Services update and a highlight of recent and upcoming regulatory items of importance. Ms. Braese also notified the Board that the PUC has denied the use of a proxy applied to mid- and downstream rebates administered by Efficiency Vermont to benchmark low-income spending. As a result of the PUC Order, VPPSA has been ordered to submit its 2022 RES Compliance and will need to adjust future compliance reporting and filings. In regard to previous discussions with the Department of Public Service (PSD) and release of customers' PII for the purpose of incentive program evaluations, the PSD has rejected VPPSA's proposed "Opt-in" method to authorize disclosure of personal identifying information. The PSD indicated that refusal to share the complete list of Tier 3 participants (beginning with 2024 program year) the PSD intends to exercise its authority under 30 V.S.A. § 206 and raise the issue with the PUC. After discussion, the Board expressed its desire to pursue an explicit PUC Order to disclose customers' PII. Ms. Braese reviewed Case No. 23-3604-PET, VPPSA's petition to implement EV/EVSE Tariff Riders on behalf of its members as well as upcoming dates and filing deadlines including launch of the 2024 VPPSA Rebate Program and new measures.

12. Ken Nolan, VPPSA's General Manager gave the GM update summarizing the status of various projects including the IT Cyber review, various Federal Grants, Jacksonville Operations, Barton Operations, Pecos Wind, Transmission Joint Ownership, the Legislative RES working group, the AMI project, and the GIS project. As previously noted, VPPSA was not awarded the GRIP grant, nor were most Vermont grant applications. VPPSA is working with our consultant, Meguire Whitney, to assess whether a revised version of our GRIP proposal should be resubmitted. The Sander's Grant is still under

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negotiation and VPPSA is awaiting approval. Overall, Jacksonville has stabilized, and steps are beginning to improve the operations. Significant progress has been made in bringing down past due amounts to VPPSA. VPPSA continues to look at how it can assist Barton with significant needed hydro facility capital improvements. Bill Ellis has reviewed outstanding bond covenants and determined that a purchase or lease by VPPSA is not feasible. Bill has suggested that a more workable approach may be for Barton to hire VPPSA to operate the facility under an "Operating Agreement" that includes provisions for VPPSA to make capital investments in the plant and recoup the funds through the operating fees. VPPSA is beginning discussions with Pecos on potential PPA rates and interconnection issues. This effort will form the basis for VPPSA moving forward with the community wind concept initially discussed with Pecos. The proposal VPPSA has been working on with MMWEC and CMEEC has passed another milestone in state (NESCOE) review. The legislative RES Working Group has been very active. There is still significant debate, and the utilities are trying hard to bring net metering reform into the conversation. It is likely that VPPSA will want to avail itself of the opportunity for a minority report, and then will need to gear up for the legislative session. The AMI project is now up and running. Aclara is in State working on the FCC licenses. The DPS has indicated the intent to submit testimony in the PUC Docket, "mostly supportive" and has proposed a follow up schedule for VPPSA's response. VPPSA continues to work with mPower to convert GIS operations, and with Dave DeSimone to do Member training. P10 Unit 2 had an outage for several weeks because the unit would start and then trip off. The relays that were installed were the wrong size, so they added another set of relays inside the system to resolve the issue. Then ISO-NE would send the signal to start the unit and it would not receive it, however Dave could start when he tested it. Another test run with ISO-NE was done and it started and ran successfully. Unit 1 is working beautifully.

13. Board Member Updates: Most members fared well with the last outages. Director Morley reminded the members to keep up to date with the VT Outage website. Director Morley inquired about members' input around potential disconnection rule changes mandated by the Legislature and being proposed under Case No. 17-4999-INV. A brief discussion ensued around remote disconnects and landlord notices.

14. Other Business: None

Director Johnstone made a motion to adjourn the meeting. The motion was seconded by Chairman Fitzhugh. Motion approved.

The meeting was adjourned at 1:31 p.m.

Respectfully submitted,

Grace Sawyer

Grace Sawyer, Secretary

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Vermont Public Power Supply Authority

Special Board of Directors Meeting Minutes

December 18, 2023

Board of Directors:

P	Vera LaPorte, Barton	P	Jonathan Elwell, Lyndon
P	John Dasaro, Enosburg	P	Scott Johnstone, Morrisville
P	Mike Sullivan, Hardwick	P	Stephen Fitzhugh, Northfield
	Vacant, Jacksonville	P	John Morley, Orleans
P	Erik Bailey, Johnson	P	Bill Sheets, Swanton
P	Thomas Petraska, Ludlow	P	James Gibbons, BED

X indicates attendance in person, P indicates attendance by phone.

Alternate Directors present:

Abbey Miller, Enosburg (P)	Lynn Paradis, Swanton (P)
Penny Jones, Morrisville (P)	

Others present:

Ken Nolan, VPPSA (X)	Grace Sawyer, VPPSA (P)	Drew Clayson, VPPSA (P)
Heather D'Arcy, VPPSA (P)	Steve Farman, VPPSA (P)	Jackie Pratt, Stowe (P)

Numbers in bold type correspond with agenda item numbers:

1. Chairman Fitzhugh called the meeting to order at 2:00 p.m.

2. Chairman Fitzhugh asked if there were requests for changes and or/modifications to the current agenda. There were no changes.

3. Chairman Fitzhugh asked if there were public comments and/or individuals who would like to address the Board. There was no public comment.

4. The General Manager informed the Board that Burlington Electric Department (BED) had executed its Strategic Membership Memorandum of Agreement and had appointed James Gibbons as BED's representative. Mr. Gibbons is present for this, his first, meeting, so the General Manager suggested that the Board should decide whether BED should attend the Executive session. Chairman Fitzhugh asked board members if they felt Mr. Gibbons should be asked to recuse himself from the executive session due to the nature of BED's ownership interest in the McNeil Plant outside of VPPSA. A brief discussion followed among the directors. Chairman Fitzhugh asked that if any Directors had questions for Mr. Gibbons that they would pose them prior to entering executive session. Director Morley asked if McNeil was considered renewable and Mr. Gibbons indicated that it would be considered renewable, but depending upon the definition of "green" and carbon lifecycle, that was where recent debates have been occurring. The Chairman requested a poll of the directors to determine if they would like Mr. Gibbons to recuse himself. Five Directors voted to make this request and have Mr.

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Gibbons join again after the executive session if there were additional questions. Mr. Gibbons left the meeting.

Director Elwell made a motion to enter Executive Session, under the provisions of 1 V.S.A. §313(a) to discuss the McNeil Generating Plant – District Energy. The motion was seconded by Director Sullivan. The motion was approved.

The Board entered Executive Session at 2:08 p.m.

Director Elwell made a motion to return to Regular Session, seconded by Director Sullivan. The motion was approved.

The Board returned to Regular Session at 2:46 p.m.

Director Elwell made a motion to adjourn the meeting. The motion was seconded by Director Bailey. The motion was approved.

The meeting was adjourned at 2:48 p.m.

Respectfully submitted,

Grace Sawyer

Grace Sawyer, Secretary

Vermont Public Power Supply Authority

Monthly Financial Report

November 30, 2023

(Unaudited)

VPPSA MONTHLY FINANCIAL REPORT
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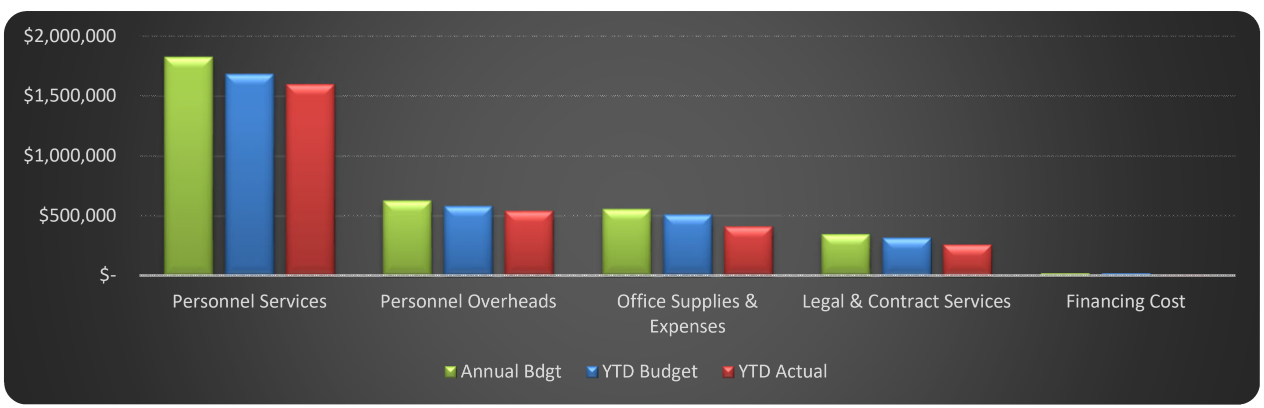
VERMONT PUBLIC POWER SUPPLY AUTHORITY

OPERATIONAL REVENUE & EXPENSE SUMMARY

2023 YTD ACTUAL VS. BUDGET

Reconciliation Month: **November-2023**

	2023 YTD Budget	2023 YTD Actual	Variance ($)	Variance (%)	2023 Annual Bdgt	YTD Act % of Budget
Revenues:						
McNeil Plant #2	$ 102,488	$ 102,488	$ -	0.0%	$ 109,857	93%
Central Computer #4	$ 51,244	$ 51,244	$ -	0.0%	$ 54,929	93%
Swanton Peaker #10	$ 210,318	$ 210,950	$ 631	0.3%	$ 222,504	95%
Renewable Energy Standards	$ 51,244	$ 51,244	$ -	0.0%	$ 54,929	93%
Net Metering	$ 25,622	$ 25,622	$ -	0.0%	$ 27,464	93%
AMI #7	$ 25,622	$ 25,622	$ -	0.0%	$ 27,464	93%
GIS & Mapping	$ 118,444	$ 77,719	$ (40,725)	-34.4%	$ 125,288	62%
Barton Management #12	$ 72,930	$ 120,700	$ 47,770	65.5%	$ 125,289	96%
Member Revenues	$ 1,715,238	$ 1,717,490	$ 2,253	0.1%	$ 1,833,850	94%
Non-Member Revenues	$ 430,093	$ 367,267	$ (62,826)	-14.6%	$ 566,916	65%
Total Revenues:	$ 2,803,242	$ 2,750,345	$ (52,897)	-1.9%	$ 3,148,490	87%
Billable Expenses:						
Personnel Services	$ 1,685,263	$ 1,598,748	$ (86,515)	-5.1%	$ 1,827,382	87%
Personnel Overheads	$ 582,096	$ 541,331	$ (40,765)	-7.0%	$ 627,732	86%
Office Supplies & Expenses	$ 509,067	$ 410,732	$ (98,335)	-19.3%	$ 555,346	74%
Legal & Contract Services	$ 316,708	$ 261,621	$ (55,087)	-17.4%	$ 345,500	76%
Financing Cost	$ 20,178	$ 1,643	$ (18,535)	-91.9%	$ 20,789	8%
Total Billable Expenses:	$ 3,113,312	$ 2,814,075	$ (299,237)	-9.6%	$ 3,376,749	83%
Net Income(Loss):	$ (310,070)	$ (63,729)	$ 246,341			



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Monthly Financial Report-Variance Analysis
November 30, 2023

	Actual					Budget	Var ($)	Var (%)
Non-Project Ops	Operational	Power Supply	Transco Activities	Other	Total			
Member & Non Revenues	$ 1,991,588	$ 29,478,010	$ -		$ 31,469,598			
Other Revenue Sources	$ 762,843	$ 2,966,491	$ 3,060,183	$ 265,588	$ 7,055,105			
Total Revenues:	$ 2,754,431	$ 32,444,501	$ 3,060,183	$ 265,588	$ 38,524,703	$ 45,570,549	$ (7,045,846)	-15%
Operational Expenses	$ (2,814,075)	$ (32,319,043)	$ -	$ (86,133)	$ (35,219,250)			
Transco Activities	$ (4,087)	$ -	$ (1,273,822)	$ -	$ (1,277,909)			
Other Expenses	$ -	$ -	$ -	$ (99,043)	$ (99,043)			
Total Expenses:	$ (2,818,162)	$ (32,319,043)	$ (1,273,822)	$ (185,176)	$ (36,596,202)	$ (43,734,929)	$ 7,138,727	-16%
Net Cash Flow:	$ (63,730)	$ 125,458	$ 1,786,361	$ 80,412	$ 1,928,501			
Transco Principal (VPPSA)	$ 92,112	$ -	$ -	$ -	$ 92,112			
				$ -	$ -			
Net Income (Loss):	$ 28,382	$ 125,458	$ 1,786,361	$ 80,412	$ 2,020,613	$ 1,835,620	$ 92,881	5%

McNeil	Actual	Budget	Var ($)	Var (%)
Oper Revenues	$ 4,771,723	$ 6,298,609	$ (1,526,886)	-24%
Oper Expenses	$ (4,722,087)	$ (5,785,276)	$ 1,063,189	-18%
Non-Oper Rev/Exp	$ 25,774	$ -	$ 25,774	0%
Financing	$ -	$ -	$ -	0%
Net Income (Loss)	$ 75,410	$ 513,333	$ (437,923)	-85%

Sander's Grant	Actual	Budget	Var ($)	Var (%)
Oper Revenues	$ 231,094	$ 1,135,373	$ (904,279)	-80%
Oper Expenses	$ -	$ (1,144,465)	$ 1,144,465	0%
Non-Oper Rev/Exp	$ -	$ -	$ -	0%
Financing	$ -	$ -	$ -	0%
Net Income (Loss)	$ 231,094	$ (9,092)	$ 240,186	-2642%

Central Computer	Actual	Budget	Var ($)	Var (%)
Oper Revenues	$ 152,014	$ 140,663	$ 11,350	8%
Oper Expenses	$ (159,990)	$ (140,663)	$ (19,327)	14%
Non-Oper Rev/Exp	$ -	$ -	$ -	0%
Financing	$ -	$ -	$ -	0%
Net Income (Loss)	$ (7,976)	$ -	$ (7,976)	0.00%

RES	Actual	Budget	Var ($)	Var (%)
Oper Revenues	$ 1,396,295	$ 1,397,295	$ (1,000)	0%
Oper Expenses	$ (1,601,864)	$ (1,397,295)	$ (204,569)	15%
Non-Oper Rev/Exp	$ 65,601	$ -	$ 65,601	0%
Financing	$ -	$ -	$ -	0%
Net Income (Loss)	$ (139,968)	$ -	$ (139,968)	0%

Project 10	Actual	Budget	Var ($)	Var (%)
Oper Revenues	$ 3,064,890	$ 3,064,888	$ 2	0%
Oper Expenses	$ (2,217,771)	$ (2,281,854)	$ 64,082	-3%
Non-Oper Rev/Exp	$ 193,427	$ 11,000	$ 182,427	1658%
Financing	$ (430,988)	$ (431,750)	$ 762	0%
Net Income (Loss)	$ 609,558	$ 362,284	$ 247,274	68%

Net Metering	Actual	Budget	Var ($)	Var (%)
Oper Revenues	$ 26,310	$ 26,309	$ 1	0%
Oper Expenses	$ (25,622)	$ (26,309)	$ 687	-3%
Non-Oper Rev/Exp	$ -	$ -	$ -	0%
Financing	$ -	$ -	$ -	0%
Net Income (Loss)	$ 688	$ -	$ 688	0%

AMI	Actual	Budget	Var ($)	Var (%)
Oper Revenues	$ 27,844	$ 3,553,379	$ (3,525,535)	-99%
Oper Expenses	$ (42,592)	$ (3,553,379)	$ 3,510,787	-99%
Non-Oper Rev/Exp	$ 1,026	$ -	$ 1,026	0%
Financing	$ (132,260)	$ -	$ (132,260)	0%
Net Income (Loss)	$ (145,983)	$ (0)	$ (145,982)	0%

GIS	Actual	Budget	Var ($)	Var (%)
Oper Revenues	$ 215,718	$ 224,256	$ (8,538)	-4%
Oper Expenses	$ (225,789)	$ (228,494)	$ 2,705	-1%
Non-Oper Rev/Exp	$ -	$ -	$ -	0%
Financing	$ -	$ -	$ -	0%
Net Income (Loss)	$ (10,071)	$ (4,238)	$ (5,833)	138%

Budget to Actual Variance Narrative - November 2023

Summary: VPPSA's Year-to-date (YTD) Net Income is $2,020,613, which is greater than budget by $93K. Net Power supply and transmission expenses are $112K below budget. Interest income is $111K greater than the budget. Interest expense is below budget by $18K YTD because VPPSA did not have to draw on the LOC until December. VPPSA's Operational loss is $63,729, which is less than budget by $246K Year-to-date.

Detail of key factors with a 5% or greater change ($5,000 de minimis):

1. McNeil: Generation was underbudget YTD by 11,695,450 or 26.94% resulting in revenue being below budget by $438K Year-to-date.

2. Central Computer: This project is over budget by $7,976 due to the depreciation expense for assets of which the full cost was collected up front.

3. Project 10: Interest income is over budget by $182K YTD, Fuel is underbudget by $29K and various other operating expenses are below budget by $36K YTD resulting in net income of $610K which is $247K greater than budgeted YTD.

4. Renewable Energy Standards: The REC purchase contract of $1.1 million was delivered at the end of May. For the budget, we did not anticipate delivery of the full contract at once and had evenly spread the expense to match the revenue. This project will show a decreasing loss for the remainder of the year as the revenue catches up but is expected to end the year $138K over budget.

5. AMI: The delay in receiving the grant funds has generated a timing difference on the anticipated expenditures for this project. VPPSA acquired the working capital loan for the project and the quarterly interest expense of $132K and Outside Services of $7K which are causing the project expense to be over budget.

6. Sander's: The delay in receiving the grant funds has generated a timing difference on the anticipated expenditures for this project. Year-to-date no expenses have been incurred causing the project revenue to be over budget by $240K.

7. GIS: Revenue loss of $9K from Ludlow leaving the project, depreciation expense of $5K and Admin expenses below budget by $8K results in the project being over budget by $6K YTD.

8. Operational: Personnel services continue to be below budget by $127K or 5.61% and are expected to remain slightly below budget by year end. Conferences, travel, and mileage are below budget by $42K or 42% YTD. This is also anticipated to remain below budget at year end. Legal fees are over budget YTD by $18K, Consulting Services are below budget by $73K YTD, and Building Maintenance is below budget by $10K YTD resulting in net expenses being below budget by $246K YTD.

Grace Sawyer

Respectfully submitted,
Grace Sawyer, Controller

Putting the Public in Power.

Vermont Public Power Supply Authority
Project Summary Balance Sheet
November 30, 2023

	Internal	McNeil	Highgate	C.Computer	P10	RES	NetMtr	AMI	GIS	Barton	Sander's	Total
ASSETS												
Fixed Assets												
Production Plant												
Land & Land Rights	0.00	79,273.96	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	79,273.96
Structures & Improvements	0.00	4,918,437.01	0.00	0.00	3,812,943.12	0.00	0.00	0.00	0.00	0.00	0.00	8,731,380.13
Equipment	0.00	17,921,869.33	0.00	0.00	20,034,585.87	0.00	0.00	0.00	0.00	0.00	0.00	37,956,455.20
Total Production Plant	**0.00**	**22,919,580.30**	**0.00**	**0.00**	**23,847,528.99**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**46,767,109.29**
Transmission Plant												
Land & Land Rights	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Structures & Improvements	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Equipment	0.00	0.00	0.00	0.00	1,467,289.54	0.00	0.00	0.00	0.00	0.00	0.00	1,467,289.54
Total Transmission Plant	**0.00**	**0.00**	**0.00**	**0.00**	**1,467,289.54**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**1,467,289.54**
Regional Transmission & Market Plant												
Computer Hardware/Software	0.00	0.00	0.00	0.00	308,821.73	0.00	0.00	0.00	0.00	0.00	0.00	308,821.73
Communication Equipment	0.00	0.00	0.00	0.00	26,606.04	0.00	0.00	0.00	0.00	0.00	0.00	26,606.04
TTL Transm & Mkt Plant	**0.00**	**0.00**	**0.00**	**0.00**	**335,427.77**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**335,427.77**
General Plant												
Land & Land Rights	141,098.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	141,098.99
Structures & Improvements	840,474.28	0.00	0.00	0.00	475,467.18	0.00	0.00	0.00	0.00	0.00	0.00	1,315,941.46
Meters	91,454.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	91,454.48
Equipment	514,146.59	126,939.04	0.00	26,102.42	5,561.44	0.00	0.00	0.00	29,767.06	0.00	0.00	702,516.55
Total General Plant	**1,587,174.34**	**126,939.04**	**0.00**	**26,102.42**	**481,028.62**	**0.00**	**0.00**	**0.00**	**29,767.06**	**0.00**	**0.00**	**2,251,011.48**
Total Fixed Assets	**1,587,174.34**	**23,046,519.34**	**0.00**	**26,102.42**	**26,131,274.92**	**0.00**	**0.00**	**0.00**	**29,767.06**	**0.00**	**0.00**	**50,820,838.08**
CWIP	**0.00**	**538,471.02**	**0.00**	**0.00**	**57,562.45**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**596,033.47**
Intangible Plant-Net of Amort.	635.34	1,156.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,791.90
Accumulated Depreciation	(1,205,492.94)	(21,767,575.95)	0.00	(25,377.39)	(15,362,863.97)	0.00	0.00	0.00	(20,340.85)	0.00	0.00	(38,381,651.10)
Net Utility Plant In Service	**382,316.74**	**1,818,570.97**	**0.00**	**725.03**	**10,825,973.40**	**0.00**	**0.00**	**0.00**	**9,426.21**	**0.00**	**0.00**	**13,037,012.35**
Investments:												
Bond Fund Investments	0.00	0.00	0.00	0.00	3,131,488.98	0.00	0.00	0.00	0.00	0.00	0.00	3,131,488.98
Vt. Transco Investments	33,711,080.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33,711,080.00
Other Investments	265,000.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	265,000.00

Vermont Public Power Supply Authority
Project Summary Balance Sheet
November 30, 2023

	Internal	McNeil	Highgate	C.Computer	P10	RES	NetMtr	AMI	GIS	Barton	Sander's	Total
Total Investments	**33,976,080.00**	**0.00**	**0.00**	**0.00**	**3,131,488.98**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**37,107,568.98**
Current Assets:												
Project Revenue Funds	0.00	325,534.65	12.35	0.00	336,693.24	0.00	0.00	0.00	0.00	0.00	0.00	662,240.24
Project Construction Funds	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4,001,020.87	0.00	0.00	0.00	4,001,020.87
Cash and Working Funds	1,645,069.39	0.00	0.00	(21,049.34)	0.00	(93,236.37)	(900.03)	(443,180.98)	(4,667.98)	(11,384.25)	221,928.91	1,292,579.35
Cash-Special Deposits-PEx	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cash - VEV Proceeds	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Temporary Investments	361,574.00	397,229.18	0.00	0.00	2,773,152.79	0.00	0.00	0.00	0.00	0.00	0.00	3,531,955.97
Accounts Receivable	6,999,268.67	626,396.34	0.00	13,548.42	218,087.79	69,016.68	1,587.68	0.00	7,360.28	61,221.66	9,165.26	8,005,652.78
Amounts Due From Members	0.00	0.00	0.00	0.00	0.00	(39,618.26)	0.00	(0.17)	0.00	0.00	0.00	(39,618.43)
Notes Receivable	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Interest/Distributions Receivable	1,224.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,224.06
Inventory	0.00	1,595,544.45	0.00	0.00	431,798.01	0.00	0.00	0.00	0.00	0.00	0.00	2,027,342.46
Prepayments	8,682.30	0.00	0.00	0.00	135,166.67	11,805.58	0.00	0.00	0.00	0.00	0.00	155,654.55
Total Current Assets	**9,015,818.42**	**2,944,704.62**	**12.35**	**(7,500.92)**	**3,894,898.50**	**(52,032.37)**	**687.65**	**3,557,839.72**	**2,692.30**	**49,837.41**	**231,094.17**	**19,638,051.85**
Other Assets:												
Deferred Debits-Other Reg Assets	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Debits	36,368.01	449,622.47	0.00	(276.57)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	485,713.91
Derivative Instrument Asset	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UnAmortized Debt Issue Expenses	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Other Assets	**36,368.01**	**449,622.47**	**0.00**	**(276.57)**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**485,713.91**
Total Assets	**$ 43,410,583.17**	**5,212,898.06**	**12.35**	**(7,052.46)**	**17,852,360.88**	**(52,032.37)**	**687.65**	**3,557,839.72**	**12,118.51**	**49,837.41**	**231,094.17**	**70,268,347.09**
LIABILITIES AND CAPITAL												
Current Liabilities:												
Accounts Payable	2,684,963.93	383,887.74	0.00	0.00	72,291.77	125,258.19	0.00	2,340.00	5,813.21	37,643.18	0.00	3,312,198.02
Other Payable	(0.02)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.02)
Security Deposits	229,890.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	229,890.36
Amounts due Members	494,226.07	0.00	12.13	0.00	0.00	(29,828.23)	0.01	1,482.38	1,492.76	0.00	0.00	467,385.12
Short-term Bank Notes Payable	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Current Maturities on L/T Debt	399,042.02	0.00	0.00	0.00	0.00	0.00	0.00	(300,000.00)	0.00	0.00	0.00	99,042.02
Derivative Instrument Liability	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accrued Interest	0.00	0.00	0.00	0.00	180,981.63	0.00	0.00	0.00	0.00	0.00	0.00	180,981.63
Accrued Taxes Payable	(1,436.44)	1,891.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	454.78
Accrued Salaries	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accrued Pension Contributions	1,935.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,935.38
Accrued Payroll Liabilities	3,453.59	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3,453.59
Other Misc. Accrued Liabilities	8,396.07	(32,619.03)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(24,222.96)
Total Current Liabilities	**3,820,470.96**	**353,159.93**	**12.13**	**0.00**	**253,273.40**	**95,429.96**	**0.01**	**(296,177.62)**	**7,305.97**	**37,643.18**	**0.00**	**4,271,117.92**
Long-Term Debt:												
LTD-Bonds	0.00	0.00	0.00	0.00	9,475,000.00	0.00	0.00	0.00	0.00	0.00	0.00	9,475,000.00

Vermont Public Power Supply Authority
Project Summary Balance Sheet
November 30, 2023

	Internal	McNeil	Highgate	C.Computer	P10	RES	NetMtr	AMI	GIS	Barton	Sander's	Total
LTD-Other-HG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LTD-Other-P10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LTD-Transco-Members	10,050,505.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10,050,505.16
LTD-Transco-HG	636,580.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	636,580.08
LTD-Transco-VEC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LTD-Transco-LCSF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LTD-Transco-LED	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LTD-2019 Building Upgrades	76,666.69	0.00	0.00	0.00	0.00	0.00	0.00	4,000,000.00	0.00	0.00	0.00	4,076,666.69
Unamortized Bond Premium	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Unamortized Loss of Reaq. Debt	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Long-Term Debt	**10,763,751.93**	**0.00**	**0.00**	**0.00**	**9,475,000.00**	**0.00**	**0.00**	**4,000,000.00**	**0.00**	**0.00**	**0.00**	**24,238,751.93**
Other Liabilities												
Deferred Revenues	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Def. Revenues - Members	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Vacation Wages	114,712.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	114,712.17
Deferred Contract Wages	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Deferred Credits-Other Reg Liability	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Deferred Credits	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Deferred Credits	**114,712.17**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**114,712.17**
Interfund-Project Allocations	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Captial Equity												
Unappropriated Retained Earnings	7,049,860.00	4,859,738.14	1,193,836.70	(7,052.45)	8,123,207.72	(147,462.33)	687.64	(145,982.66)	4,812.54	12,194.23	231,094.17	21,174,933.70
Unappropriated Earnings-Distributed	0.00	0.00	(1,193,836.48)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(1,193,836.48)
Appropriated Retained Earnings	21,661,788.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21,661,788.09
Other Comprehensive Income	0.00	0.00	0.00	0.00	879.76	0.00	0.00	0.00	0.00	0.00	0.00	879.76
Total Retained Earnings	**28,711,648.09**	**4,859,738.14**	**0.22**	**(7,052.45)**	**8,124,087.48**	**(147,462.33)**	**687.64**	**(145,982.66)**	**4,812.54**	**12,194.23**	**231,094.17**	**41,643,765.07**
Total Liabilities & Capital	**$43,410,583.15**	**5,212,898.07**	**12.35**	**(7,052.45)**	**17,852,360.88**	**(52,032.37)**	**687.65**	**3,557,839.72**	**12,118.51**	**49,837.41**	**231,094.17**	**70,268,347.09**
Assets	43,410,583.17	5,212,898.06	12.35	(7,052.46)	17,852,360.88	(52,032.37)	687.65	3,557,839.72	12,118.51	49,837.41	231,094.17	70,268,347.09
Liabilities & Prior Earnings	41,389,969.51	5,137,487.82	12.35	923.98	17,242,802.97	87,935.49	0.08	3,703,822.38	22,189.50	42,887.41	0.00	67,628,031.49
Current Yr Earnings	2,020,613.64	75,410.25	0.00	(7,976.43)	609,557.91	(139,967.86)	687.57	(145,982.66)	(10,070.99)	6,950.00	231,094.17	2,640,315.60
Total Liabilites & Earnings	**43,410,583.15**	**5,212,898.07**	**12.35**	**(7,052.45)**	**17,852,360.88**	**(52,032.37)**	**687.65**	**3,557,839.72**	**12,118.51**	**49,837.41**	**231,094.17**	**70,268,347.09**

Vermont Public Power Supply Authority
Project Summary Income Statement
November 30, 2023

	Non-Project	McNeil	Highgate	C. Computer	Swanton Pkr	RES	Net Mtr	AMI	GIS	Barton	Sanders	Total
REVENUES & OTHER INCOME												
Sales for ReSale	30,540,281.83	4,771,722.67	0.00	0.00	3,064,889.98	0.00	0.00	0.00	0.00	0.00	0.00	38,376,894.48
Service Revenues	0.00	0.00	0.00	152,013.66	0.00	1,396,294.91	26,309.59	27,843.90	215,718.28	0.00	0.00	1,818,180.34
Member & Non-Member Revenues	1,870,887.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	776,094.11	231,094.17	2,878,076.25
Project Revenues	665,588.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	665,588.17
REC Revenues	3,524,490.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3,524,490.75
Service Revenue-Direct Billable	78,143.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	78,143.22
VELCO Directorship	14,250.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14,250.00
Misc. Revenues	480.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	480.00
Total Operating Revenues	**36,694,121.94**	**4,771,722.67**	**0.00**	**152,013.66**	**3,064,889.98**	**1,396,294.91**	**26,309.59**	**27,843.90**	**215,718.28**	**776,094.11**	**231,094.17**	**47,356,103.21**
EXPENSES												
POWER PRODUCTION												
STEAM POWER PRODUCTION												
Operations	0.00	3,170,310.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3,170,310.49
Maintenance	0.00	419,765.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	419,765.94
Total Steam Power Production	0.00	3,590,076.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3,590,076.43
OTHER POWER PRODUCTION												
Operations	0.00	0.00	0.00	0.00	380,390.89	0.00	0.00	0.00	0.00	0.00	0.00	380,390.89
Maintenance	0.00	0.00	0.00	0.00	46,278.91	0.00	0.00	0.00	0.00	0.00	0.00	46,278.91
Total Other Power Production	0.00	0.00	0.00	0.00	426,669.80	0.00	0.00	0.00	0.00	0.00	0.00	426,669.80
TRANSMISSION												
Operations	11,567,852.97	3,662.02	0.00	0.00	8,236.15	0.00	0.00	0.00	0.00	0.00	0.00	11,579,751.14
Maintenance	0.00	0.00	0.00	0.00	30,647.03	0.00	0.00	0.00	0.00	0.00	0.00	30,647.03
Total Transmission Expense	11,567,852.97	3,662.02	0.00	0.00	38,883.18	0.00	0.00	0.00	0.00	0.00	0.00	11,610,398.17
OTHER POWER SUPPLY												
Purchase Power	21,559,404.55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21,559,404.55
System Control & Load Dispatch	0.00	7,979.77	0.00	0.00	4,506.48	0.00	0.00	0.00	0.00	0.00	0.00	12,486.25
REC Purchases	598,250.00	0.00	0.00	0.00	0.00	1,254,730.06	0.00	0.00	0.00	0.00	0.00	1,852,980.06
Total Other PS Expense	22,157,654.55	7,979.77	0.00	0.00	4,506.48	1,254,730.06	0.00	0.00	0.00	0.00	0.00	23,424,870.86
REGIONAL MARKET EXPENSES												
RME-Market Monitor/Compl-Gen	0.00	0.00	0.00	0.00	5,359.84	0.00	0.00	0.00	0.00	0.00	0.00	5,359.84
RME-Market Monitor/Compl-L&O	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Reg. Market Expense	0.00	0.00	0.00	0.00	5,359.84	0.00	0.00	0.00	0.00	0.00	0.00	5,359.84

Vermont Public Power Supply Authority
Project Summary Income Statement
November 30, 2023

	Non-Project	McNeil	Highgate	C. Computer	Swanton Pkr	RES	Net Mtr	AMI	GIS	Barton	Sanders	Total
CUSTOMER SVS & INFORMATION ADV												
Cust Svs & Info Adv	3,122.14	12,925.71	0.00	0.00	0.00	1,000.00	0.00	0.00	0.00	0.00	0.00	17,047.85
Total Cust Svs & Info Adv.	3,122.14	12,925.71	0	0	0	1,000.00	0	0	0	0	0	17,047.85
SALES EXPENSE												
Cust Assistance Expenses												
Sales Expense	10,581.18	237.15	0.00	0.00	0.00	262,255.00	0.00	0.00	0.00	0.00	0.00	273,073.33
Total Sales Expense	10,581.18	237.15	0.00	0.00	0.00	262,255.00	0.00	0.00	0.00	0.00	0.00	273,073.33
ADMINISTRATIVE & GENERAL												
Operations	2,777,106.53	345,254.13	0.00	152,014.32	581,688.50	83,878.71	25,622.02	42,592.05	220,331.95	769,144.11	0.00	4,997,632.32
Maintenance	0.00	429.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	429.07
Total A&G Expense	2,777,106.53	345,683.20	0.00	152,014.32	581,688.50	83,878.71	25,622.02	42,592.05	220,331.95	769,144.11	0.00	4,998,061.39
OTHER												
Taxes- In Lieu of Property Taxes	15,125.00	297,825.00	0.00	0.00	34,825.03	0.00	0.00	0.00	0.00	0.00	0.00	347,775.03
Depreciation Expense	32,084.14	463,697.63	0.00	7,975.77	1,125,838.34	0.00	0.00	0.00	5,457.32	0.00	0.00	1,635,053.20
Amortization Expense	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Direct Billable-Pass Thru Exp	86,132.59	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	86,132.59
Total Other Expense	133,341.73	761,522.63	0.00	7,975.77	1,160,663.37	0.00	0.00	0.00	5,457.32	0.00	0.00	2,068,960.82
Total Operating Expenses	**36,649,659.10**	**4,722,086.91**	**0.00**	**159,990.09**	**2,217,771.17**	**1,601,863.77**	**25,622.02**	**42,592.05**	**225,789.27**	**769,144.11**	**0.00**	**46,414,518.49**
Net OPERATING Earnings(Loss)	**44,462.84**	**49,635.76**	**0.00**	**(7,976.43)**	**847,118.81**	**(205,568.86)**	**687.57**	**(14,748.15)**	**(10,070.99)**	**6,950.00**	**231,094.17**	**941,584.72**
NON-OPERATING (INCOME) EXPENSES												
OTHER NON-OPERATING (INCOME) EXPENSES												
Interest/Finance Chg Income	(111,057.70)	(25,774.49)	0.00	0.00	(193,427.11)	0.00	0.00	(1,025.87)	0.00	0.00	0.00	(331,285.17)
TRANSCO Distribution/Income	(3,162,436.62)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(3,162,436.62)
Transco "Net Settlement" Expense	940,337.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	940,337.08
Misc. Non-Operating Income	(76,387.04)	0.00	0.00	0.00	0.00	(73,601.00)	0.00	0.00	0.00	0.00	0.00	(149,988.04)
Misc. Non-Operating Expenses	85,876.04	0.00	0.00	0.00	0.00	8,000.00	0.00	0.00	0.00	0.00	0.00	93,876.04
Total Other Non-Operating (Inc) Exp	(2,323,668.24)	(25,774.49)	0.00	0.00	(193,427.11)	(65,601.00)	0.00	(1,025.87)	0.00	0.00	0.00	(2,609,496.71)
FINANCING COSTS												

Vermont Public Power Supply Authority
Project Summary Income Statement
November 30, 2023

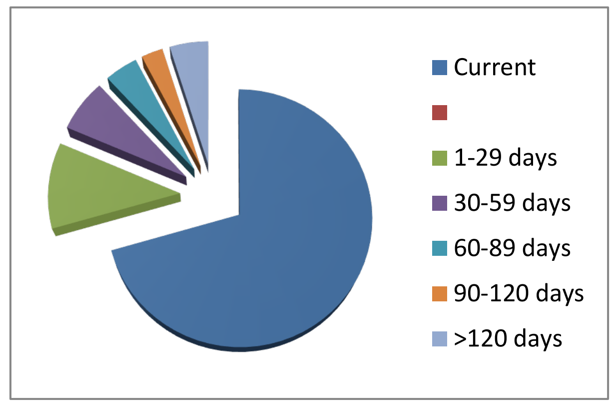
	Non-Project	McNeil	Highgate	C. Computer	Swanton Pkr	RES	Net Mtr	AMI	GIS	Barton	Sanders	Total
Interest on LTD-Bonds	0.00	0.00	0.00	0.00	430,988.01	0.00	0.00	0.00	0.00	0.00	0.00	430,988.01
Interest on LTD-Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	132,260.38	0.00	0.00	0.00	132,260.38
Interest on LTD-Transco	345,874.59	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	345,874.59
Interest on LTD-2019 Bldg Renov.	1,642.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,642.85
Interest on Short-term Debt	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Financing Costs on LTD-Swp Rel.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amortizations on Financing Activities	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Financing Expenses	347,517.44	0.00	0.00	0.00	430,988.01	0.00	0.00	132,260.38	0.00	0.00	0.00	910,765.83
Total Non-Operating (Inc) Exp	**(1,976,150.80)**	**(25,774.49)**	**0.00**	**0.00**	**237,560.90**	**(65,601.00)**	**0.00**	**131,234.51**	**0.00**	**0.00**	**0.00**	**(1,698,730.88)**
TOTAL Net Earnings(Loss)	**2,020,613.64**	**75,410.25**	**0.00**	**(7,976.43)**	**609,557.91**	**(139,967.86)**	**687.57**	**(145,982.66)**	**(10,070.99)**	**6,950.00**	**231,094.17**	**2,640,315.60**

Vt. Public Power Supply Authority
Consolidated Balance Sheet
November 30, 2023

	2023	2022
ASSETS		
Electric Utility Plant	50,820,838.08	50,453,229.17
Accumulated Depreciation	(38,381,651.10)	(36,575,208.42)
Utility Plant in Service		
	12,439,186.98	13,878,020.75
CWIP-General	0.00	0.00
CWIP-McNeil	538,471.02	474,767.77
CWIP-Highgate	0.00	0.00
CWIP-P10	57,562.45	0.00
Net Electric Plant	13,035,220.45	14,352,788.52
Intangible Plant-Net of Amort.	1,791.90	2,215.45
Current Assets:		
Special Funds	7,794,750.09	2,330,669.66
Cash and Working Funds	280,980.95	2,431,654.38
Cash - REC's	0.00	0.00
Cash - Vt. Transco	1,011,598.40	1,333,486.76
Cash - VEV Proceeds	0.00	0.00
Special Deposits-Collateral	0.00	0.00
Temporary Investments	3,531,955.97	4,432,646.49
Investment in Associated Co.	265,000.00	265,000.00
Investment in Vt. Transco	33,711,080.00	33,711,080.00
Accounts Receivable	8,005,652.78	5,561,350.10
Amounts Due From Members	(39,618.43)	37,115.59
Notes Receivable	0.00	0.00
Interest/Distributions Receivable	1,224.06	0.12
McNeil Inventory	1,595,544.45	1,640,478.45
P10 Inventory	431,798.01	350,300.44
Meter Inventory	0.00	515.00
Other Current Assets	155,654.55	148,418.58
Total Current Assets	56,745,620.83	52,242,715.57
Other Assets:		
Deferred Debits-Other Regulatory Assets	0.00	25,000.00
Deferred Debits	485,713.91	658,729.73
Derivative Instrument Asset	0.00	0.00
Unamortized Dbt Iss Exp-LetCrd	0.00	0.00
Unamort Debt Issue Exp-McN	0.00	0.00
Unamort Debt Issue Exp-HG	0.00	0.00
Unamortiz Debt Issue Exp-P10	0.00	0.00
Total Other Assets	485,713.91	683,729.73
Total Assets	**$ 70,268,347.09**	**$ 67,281,449.27**

11/30/2023

A/R Aging Analysis		
Current	5,648,624	70.56%
1-29 days	872,664	10.90%
30-59 days	537,674	6.72%
60-89 days	337,918	4.22%
90-120 days	219,187	2.74%
>120 days	389,587	4.87%
Total	$8,005,653	100.00%



Vt. Public Power Supply Authority
Consolidated Balance Sheet
November 30, 2023

	2023	2022
LIABILITIES AND CAPITAL		
Unappropriated Retained Earnings	21,174,933.70	20,726,530.42
Unappropriated Earnings-Distributed	(1,193,836.48)	(1,193,836.48)
Appropriated Retained Earnings	21,661,788.09	19,245,844.80
Other Comprehsive Income	879.76	(52,538.58)
Total Retained Earnings	41,643,765.07	38,726,000.16
Long-Term Debt:		
LTD-P10 Bonds - Series A	8,960,000.00	10,215,000.00
LTD-P10 Bonds - Series B	515,000.00	590,000.00
LTD-Transco 2011 Consolid Refi	4,524,161.63	5,655,202.05
LTD-Transco 2012-2014 Members	1,582,435.40	1,978,044.16
LTD-Vt Transco "16 Members	470,290.00	680,290.00
LTD-Vt Transco Financing-HG	636,580.08	795,725.08
LTD-Vt Transco '17 Members	789,288.00	986,610.00
LTD-Vt Transco '18 Members	586,070.00	703,284.00
LTD-Vt Transco '18 VPPSA	37,790.00	45,348.00
LTD-Vt Transco '19 Members	261,443.42	304,420.42
LTD-Vt Transco '20 Members	468,198.00	535,082.00
LTD-Vt Transco '21 Members	1,330,828.71	1,481,859.13
LD-2019 Building Upgrades	76,666.69	90,000.02
LTD-AMI Working Capital Loan	4,000,000.00	0.00
Net Long-Term Debt	24,238,751.93	24,060,864.86
Def. Revenues - Members	0.00	0.00
Def. Credits-Accrued Vac Liab.	114,712.17	126,991.54
Def Credits-Other Reg Liabilities	0.00	25,000.00
Total Deferred Revenues/Credits	114,712.17	151,991.54
Current Liabilities:		
Accounts Payable	3,312,198.00	3,141,590.66
Amounts due Members	467,385.12	455,905.48
Security Deposits	229,890.36	143,534.97
Short-term Bank Notes Payable	0.00	0.00
Current Maturities on L/T Debt	99,042.02	391,838.64
Derivative Instrument Liability	0.00	0.00
Accrued Interest	180,981.63	208,338.41
Accrued Taxes Payable	454.78	(16,934.92)
Accrued Salaries	0.00	0.00
Accrued Pension Contributions	1,935.38	2,800.00
Accrued Payroll Liabilities	3,453.59	7,156.79
Other Misc. Accrued Liabilities	(24,222.96)	8,362.68
Total Current Liabilities	4,271,117.92	4,342,592.71
Total Liabilities & Capital	**$ 70,268,347.09**	**$ 67,281,449.27**

Vermont Public Power Supply Authority
Non-Project Operations - Profit & Loss Statement
November 30, 2023

	Year to Date Actual	Year to Date Budget	Actual as % of Budget	Annual Budget
Operating Revenues				
Sales for Resales	29,478,010.50	35,817,286.01	82.30	39,290,370.83
Sales for Resales-Standard Offer	1,062,271.33	1,233,235.86	86.14	1,264,391.47
Serv. Fees, Members & Affiliates	1,870,887.97	1,893,391.50	98.81	2,065,518.04
Admin Fees Allocated to Projects	505,029.33	570,896.81	88.46	622,796.56
Project Labor & OH Revenue	160,558.84	336,461.62	47.72	367,049.04
VELCO Directorship	14,250.00	14,250.00	100.00	19,000.00
Renewable Energy Certificates	3,524,490.75	2,518,826.00	139.93	2,701,635.00
Serv. Revenue-Direct Billable	78,143.22	22,916.63	340.99	25,000.00
Misc. Revenues	480.00	1,350.00	35.56	1,350.00
Total Operating Revenues	36,694,121.94	42,408,614.43	87%	46,357,110.94
Operating Expenses				
Other Power Supply Expense				
OPSE-Purchased Power	20,700,358.35	25,542,829.45	81.04	28,068,976.43
OPSE-REC Purchase Exp.	598,250.00	0.00	0.00	0.00
OPSE-Purchase Pwr-'15 SO (Lyn)	189,821.01	187,797.51	101.08	192,541.90
OPSE-Purchase Pwr-'17 SO(Trom)	129,925.70	150,415.99	86.38	154,215.99
OPGE-Purchase Pwr-'19SO (Hess)	257,763.37	329,030.68	78.34	337,343.09
OPGE-Purchase Pwr-'19SO(Davis)	281,536.12	324,010.42	86.89	332,196.00
Total Other Power Supply Expense	22,157,654.55	26,534,084.05	84%	29,085,273.41
Transmission Expense				
TRSM-Oper-Transm by Others	11,561,633.18	12,782,282.54	90.45	13,911,029.38
TRSM-Oper-Misc Transm Exp	6,219.79	11,000.00	56.54	12,000.00
Total Transmission Expense	11,567,852.97	12,793,282.54	90%	13,923,029.38
Cust Svs & Informational Expense				
Customer Svs & Informational	3,122.14	8,167.50	38.23	8,910.00
Total Customer Svs & Informational Exp	3,122.14	8,167.50	38%	8,910.00
Sales Expense				
REC Sales Expenses	10,581.18	0.00	0%	0.00
Total Sales Expense	10,581.18	0.00	0%	0.00
Admin & General Expense				
Salaries	1,598,748.28	1,685,263.22	94.87	1,827,382.01
Payroll Overheads	123,140.13	132,607.12	92.86	142,701.77
Office Supplies & Expense	227,760.85	286,870.88	79.39	312,942.00
Outside Services	261,621.11	316,708.26	82.61	345,500.00
Insurances	66,088.90	58,368.42	113.23	63,675.00
Employee Benefits	418,190.62	445,525.25	93.86	485,030.52
Memberships/Dues	32,020.63	33,183.26	96.50	36,200.00
Conference & Travel Expenses	47,281.54	87,527.88	54.02	95,485.00
Rents	0.00	0.00	0.00	0.00
Transportation Expenses	2,254.47	2,750.00	81.98	3,000.00
A & G Transferred Credit	0.00	0.00	0.00	0.00
Total A & G Expenses	2,777,106.53	3,048,804.29	91%	3,311,916.30

Vermont Public Power Supply Authority
Non-Project Operations - Profit & Loss Statement
November 30, 2023

	Year to Date Actual	Year to Date Budget	Actual as % of Budget	Annual Budget
Other Operating Expenses				
A&G- Billable to Others	0.00	0.00	0.00	0.00
A&G-OS&E-PTE-IT Related	46,676.15	0.00	0.00	0.00
A&G-OS&E-PTE-Consulting	18,481.34	0.00	0.00	0.00
A&G-OS&E-PTE-Supplies	0.00	0.00	0.00	0.00
A&G-OS&E-PTE-Misc	20,975.10	0.00	0.00	0.00
Other Operating Exp-Direct Pass-Thru	86,132.59	0.00	0%	0.00
Property Taxes	15,125.00	15,125.00	100.00	16,500.00
Depreciation Expense	32,084.14	17,081.13	187.83	18,634.00
Amortization Expense	0.00	0.00	0.00	0.00
Other Operating Expenses-Misc	47,209.14	32,206.13	14658%	35,134.00
Total Other Operating Expenses	133,341.73	32,206.13	414%	35,134.00
Total Operating Expenses	36,649,659.10	42,416,544.51	86%	46,364,263.09
Total Operating Income (Loss)	44,462.84	(7,930.08)	-561%	(7,152.15)
Non-Operating (Income) Expenses				
Interest/Finance Chg Income	(111,057.70)	0.00	0.00	0.00
Vt. Transco Income	(3,162,436.62)	(3,161,384.13)	100.03	(4,215,178.83)
Non-Operating Income-Member Purch.	0.00	0.00	0.00	0.00
Non-Operating Inc-Gain on Disp of Plant	0.00	0.00	0.00	0.00
Non-Operating Inc-Program Rebates	0.00	(550.00)	0.00	(1,350.00)
Misc. Non-Operating Income	(76,387.04)	0.00	0.00	0.00
Non-Operating Expenses-Member Purchas	0.00	0.00	0.00	0.00
Misc. Non-Operating Expenses	84,037.04	0.00	0.00	0.00
Misc. Non-Operating Exp-Transco Amort Fe	1,839.00	1,845.00	99.67	2,460.00
Net Other Non-Operating (Inc) Exp	(3,264,005.32)	(3,160,089.13)	103%	(4,214,068.83)
Financing Costs				
Other Interest Expense	0.00	18,333.00	0.00	18,333.00
Other Interest Expense-Transco	0.00	0.00	0.00	0.00
Interest on LTD-Transco	345,874.59	349,862.25	98.86	450,690.94
Interest on LTD-19 Building Upgrades	1,642.85	2,251.37	72.97	2,456.00
Amort. of Debt Issue Exp-Transco	0.00	0.00	0.00	0.00
Transco Net Settlement Exp.	940,337.08	946,092.54	99.39	1,261,456.72
Interest on LTD	0.00	0.00	0.00	0.00
Amortiz of Debt Iss. Exp-LtrCr	0.00	0.00	0.00	0.00
Net Financing Costs	1,287,854.52	1,316,539.16	98%	1,732,936.66
Total Non-Operating (Inc) Exp	(1,976,150.80)	(1,843,549.97)	107%	(2,481,132.17)
Total Net Earnings (Loss)	$ 2,020,613.64	$ 1,835,619.89	110%	$ 2,473,980.02

Vermont Public Power Supply Authority

Putting the Public in Power.

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Memorandum

To: VPPSA Board of Directors
From: Ken Nolan, General Manager
Date: December 29, 2023
Subject: Agenda Item #8 – Legislative Committee

Some Members have approached staff expressing concern that the 2023-2024 legislative session will be very active on a number of fronts, and that given recent turnover VPPSA is not adequately staffed to handle the increased exposure.

As the Board may recall, the FY24 budget includes a new legislative/communications position, but that position is not yet hired and whoever fills the position will spend most of the session coming up to speed. This has prompted at least one Member to consider establishing their own presence in the statehouse that would work alongside VPPSA. A prospect that is somewhat concerning as it creates the possibility for daylight between VPPSA and its Members that could be perceived as weakness.

The proposed solution to these concerns is to re-create a Board Legislative Committee that would by copied on VPPSA lobbyist reports, meet at least monthly during the session to discuss strategies, and be available to testify as needed.

VPPSA would still rely heavily on Primmer Piper Egelston & Cramer as its lobbyist to provide eyes and ears in the statehouse, while utilizing the General Manager and Assistant General Manager for testimony, but the committee would provide extra resources for specific topics.

Proposed Motion

That the VPPSA Board creates a Legislative Committee to be active during the 2023-2024 legislative session.

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Memorandum

To: VPPSA Board of Directors
From: Ken Nolan, General Manager
Date: December 29, 2023
Subject: Agenda Item #9 – VELCO

In response to the VELCO Governance Committee and executive team attendance at the Board's July 2023 meeting, staff was requested to work with VELCO to set up periodic check-ins at future board meetings. This will be VELCO's first return for a follow up discussion.

It is expected that a portion of the VELCO executive team will attend and that they will provide updates on VELCO's strategic plan, especially around communications and IT issues, as well as debriefing on common threads that emerged in their discussions with individual Members.

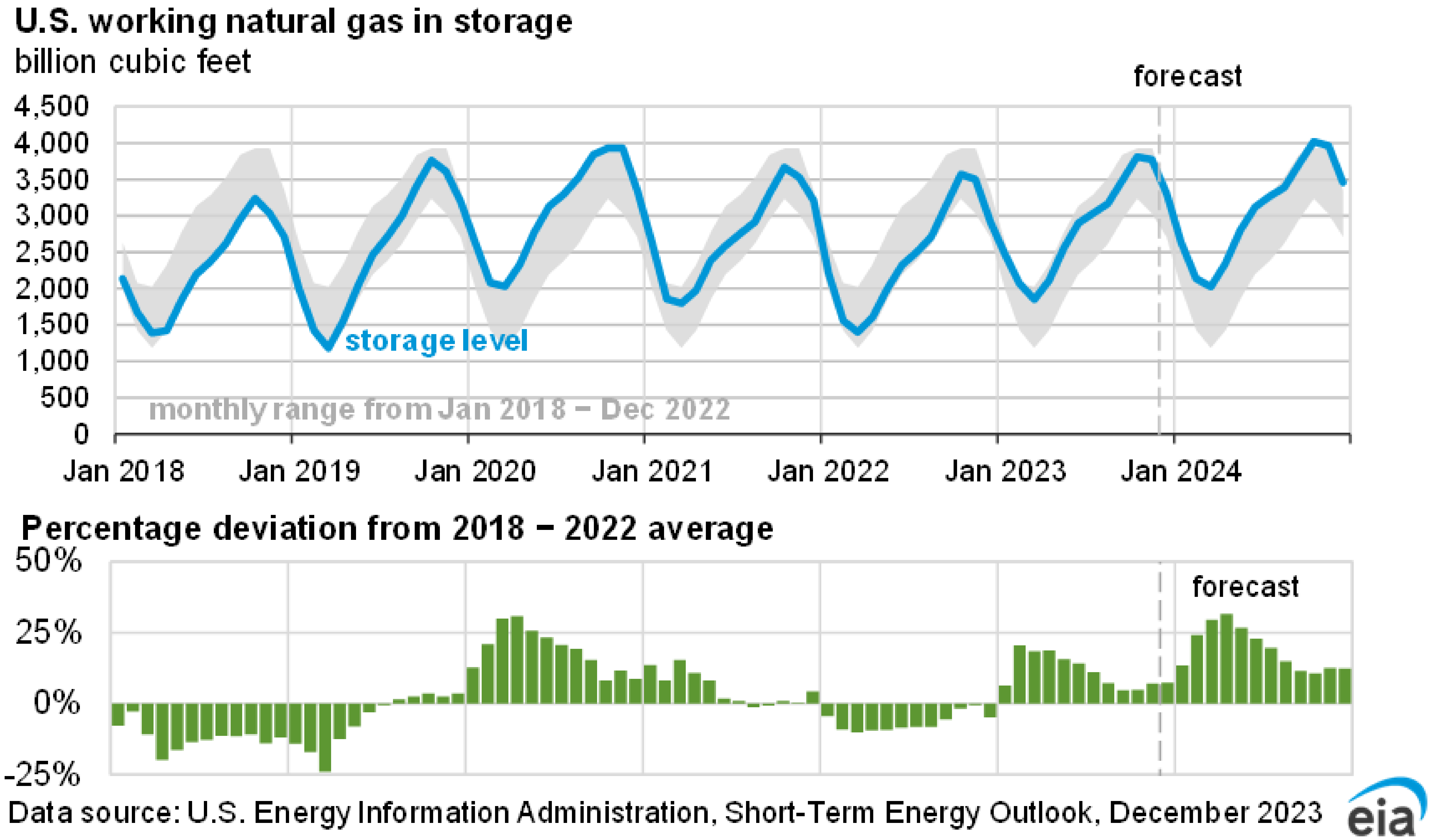
Vermont Public Power Supply Authority

November 2023
Power Supply Update

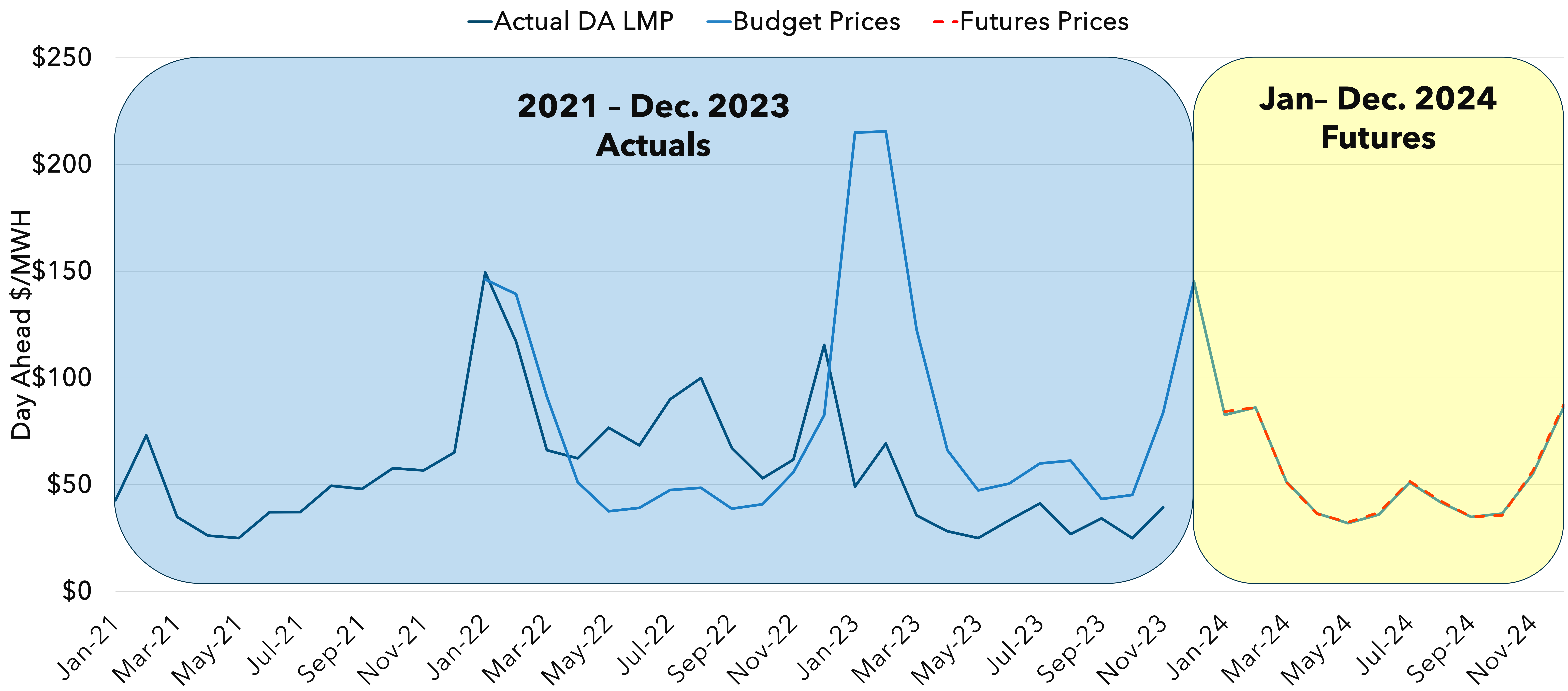
Power Supply Update

1. Natural Gas & Electricity Price Updates
2. YTD 2023 Budget to Actuals
3. Mystic Station Costs
4. Renewable Energy Credit Updates
5. Budget Review

1. Natural Gas Price and Storage Trends (EIA data)



1. Actual and Future Electricity Prices (7x24)



2. November YTD 2023 Variances

Member System	Total Load - Including Losses	Hydro Generation	Coverage Ratio
Barton	3%	34%	115%
Enosburg	2%	51%	106%
Hardwick	4%	0%	93%
Jacksonville	2%	25%	97%
Johnson	-4%	39%	105%
Ludlow	-5%	37%	109%
Lyndon	2%	31%	99%
Morrisville	0%	23%	103%
Northfield	2%	32%	97%
Orleans	-7%	3%	106%
Swanton	-1%	22%	124%

Dollar Variance	% Dollar Variance	% Rate Variance
-$196,980	-18%	-20%
-$107,833	-4%	-4%
$43,548	1%	-2%
$9,048	1%	0%
-$26,919	-2%	2%
-$273,251	-5%	0%
-$52,149	-1%	-3%
-$72,154	-2%	-1%
-$88,819	-3%	-4%
-$69,755	-6%	2%
-$665,966	-30%	-29%

- **Most members in November had loads greater than budget. Ludlow, Johnson and Orleans were low compared to budget.**
- **Hydro that's functioning continues to do well.**
- **Energy coverage was mostly within range. Barton and Swanton had a high coverage ratio.**
- **The largest variances overall in VPPSA (some differences for individual members)**
    - Lower LMPs: reduced energy credits and lower energy market costs. Overall costs were slightly increased
    - Lower capacity charges and increased credits reduced costs
    - Less REC revenue increased costs
    - More P10 reserve revenue

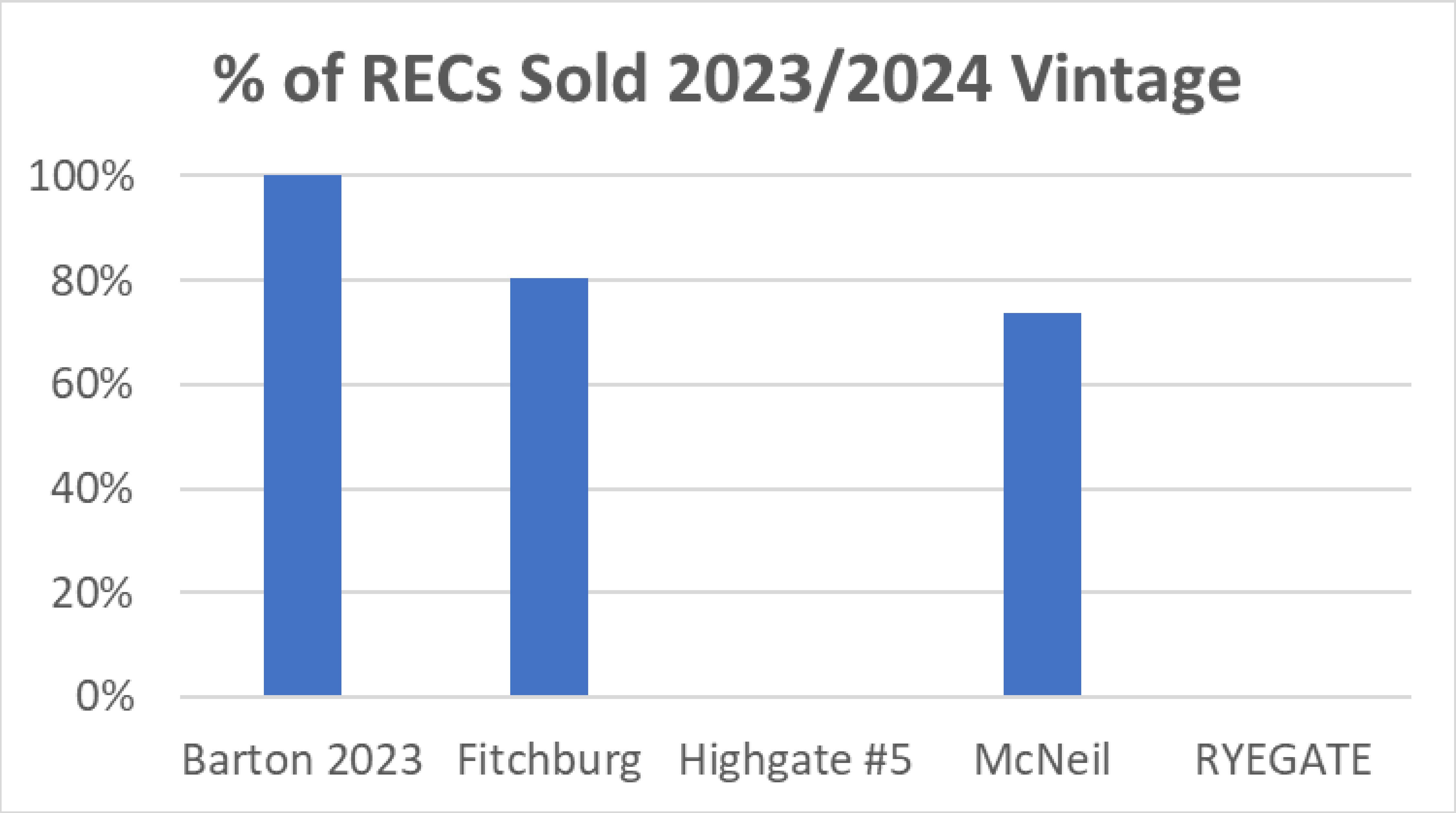
3. Mystic Station Costs

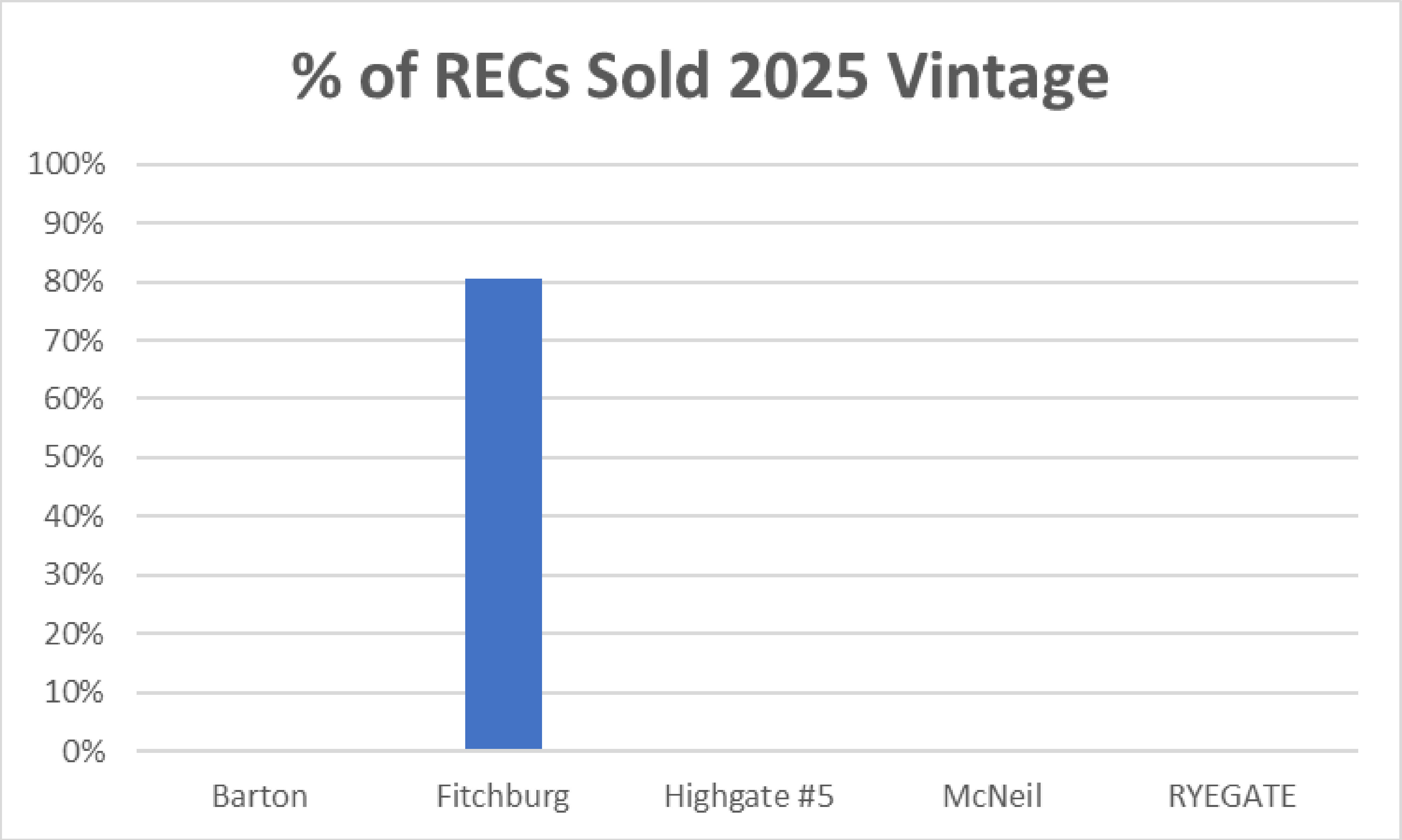
	2022						2023											2023	12 Month	Contract
	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Total	Total	Total
Barton	$1,149	$4,856	$325	$1,190	$1,028	$4,440	$2,086	$9,442	$12,089	$5,887	$3,173	$3,270	$1,045	$1,409	$1,037	$870	$1,034	**$41,343**	**$45,783**	**$54,331**
Enosburg	$2,373	$8,549	$532	$2,076	$2,045	$8,976	$3,659	$22,237	$21,042	$12,744	$7,313	$6,614	$2,079	$3,820	$2,462	$1,941	$2,250	**$86,162**	**$95,138**	**$110,713**
Hardwick	$2,939	$10,484	$720	$3,125	$3,050	$15,686	$8,390	$38,007	$33,024	$17,463	$11,697	$8,098	$2,515	$5,309	$4,204	$3,003	$3,776	**$135,485**	**$151,171**	**$171,489**
Jacksonville	$579	$1,912	$120	$541	$570	$2,929	$1,637	$7,291	$6,501	$3,393	$2,334	$1,871	$488	$955	$670	$483	$569	**$26,193**	**$29,122**	**$32,844**
Johnson	$1,233	$3,952	$256	$1,186	$1,247	$6,311	$3,129	$14,569	$12,910	$6,853	$4,732	$3,955	$1,043	$1,943	$1,363	$1,006	$1,194	**$52,698**	**$59,009**	**$66,883**
Ludlow	$5,093	$15,436	$1,004	$4,330	$4,314	$26,825	$18,016	$78,167	$65,311	$30,360	$23,440	$14,136	$3,424	$6,314	$4,939	$3,198	$4,248	**$251,554**	**$278,379**	**$308,556**
Lyndonville	$6,115	$19,095	$1,266	$5,536	$5,551	$30,261	$16,925	$75,981	$60,277	$31,711	$23,656	$16,951	$4,666	$9,013	$6,308	$4,647	$5,666	**$255,802**	**$286,062**	**$323,626**
Morrisville	$4,243	$14,111	$931	$4,014	$3,870	$19,303	$9,150	$42,805	$37,567	$19,871	$12,938	$10,067	$3,269	$6,731	$5,031	$3,557	$3,904	**$154,890**	**$174,193**	**$201,361**
Northfield	$2,718	$6,272	$592	$3,060	$6,264	$13,395	$6,419	$30,992	$26,941	$14,162	$10,163	$7,327	$2,215	$4,303	$3,134	$2,611	$3,121	**$111,387**	**$124,782**	**$143,689**
Orleans	$1,440	$3,653	$273	$1,189	$1,314	$6,258	$3,222	$15,204	$13,930	$7,308	$4,925	$4,459	$1,117	$1,348	$1,288	$973	$1,211	**$54,984**	**$61,243**	**$69,113**
Swanton	$50	$10,806	$1,008	$1,784	$300	-$141	-$14	-$1	$4,131	$891	$3,690	$3,487	$2,544	$686	$413	$2,151	$1,094	**$19,074**	**$18,933**	**$32,881**
Grand Total	$27,933	$99,125	$7,029	$28,031	$29,554	$134,245	$72,619	$334,695	$293,723	$150,644	$108,061	$80,234	$24,404	$41,831	$30,852	$24,441	$28,068	**$1,189,571**	**$1,323,816**	**$1,515,487**

3.1 Mystic Station Costs Compared to Total Variance

Member	Nov Variance	Nov Mystic	Nov Net	YTD Variance	YTD Mystic	YTD Net
Barton	-$3,626	$1,034	-$4,660	-$196,980	$39,438	**-$236,418**
Enosburg	-$36,497	$2,250	-$38,747	-$107,833	$81,970	**-$189,803**
Hardwick	-$1,255	$3,776	-$5,031	$43,548	$128,706	**-$85,158**
Jacksonville	-$710	$569	-$1,279	$9,048	$25,140	**-$16,092**
Johnson	-$12,468	$1,194	-$13,662	-$26,919	$50,498	**-$77,417**
Ludlow	-$114,594	$4,248	-$118,842	-$273,251	$244,108	**-$517,359**
Lyndonville	-$80,706	$5,666	-$86,372	-$52,149	$245,489	**-$297,638**
Morrisville	-$36,270	$3,904	-$40,174	-$72,154	$147,429	**-$219,583**
Northfield	-$43,059	$3,121	-$46,180	-$88,819	$105,656	**-$194,475**
Orleans	-$13,769	$1,211	-$14,980	-$69,755	$52,801	**-$122,556**
Swanton	$53,571	$1,094	$52,477	-$665,966	$15,828	**-$681,794**
Grand Total	**-$289,383**	**$28,068**	**-$317,451**	**-$1,501,230**	**$1,137,062**	**-$2,638,292**

4. Renewable Energy Credits – Forward Sales Update





- **2023-2025 REC Sales**
  - Vintage year MWH.
  - High confidence volumes sold forward.
  - Lower confidence volumes not sold yet.
  - Barton 2023 sale entirely UC. No 2024 Barton RECs sold yet

4. Renewable Energy Credits – VT1 Purchase

- 2023 VT1 Vintage purchase of 100k for $1.75.
- These will be banked for use in future years.

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Memorandum

To: VPPSA Board of Directors
From: Ken Nolan, General Manager
Date: December 29, 2023
Subject: Agenda Item #11 – Legislative RES Outcome

The legislative RES working group has completed its work and its final report has been submitted. A copy is attached to the Board packet.

While the body of the report captures the committee discussions well, the legislative members of the committee also requested that legislative counsel prepare a draft Bill based on the discussions which was also intended to be included in the body of the report. This addition created strong opposition from nearly all committee members, making the group's final meeting very contentious.

The ultimate solution put forward by the co-Chairs was to move the proposed Bill to an appendix, describing it as legislative counsel's best attempt based on their understanding of the conversations. They also encouraged participants to take advantage of the ability to submit so-called "minority reports".

That outcome led to a concerted effort among the distribution utility representatives to develop our own framework to counterweight the proposed Bill. After 10-days of intensive conversations the utilities agreed to a four (4) track RES framework that was ultimately shared with all of the non-legislative working group members and received broad support. The framework is also included in the working group report appendices.

For VPPSA Members the framework would essentially result in the following RES revisions:

Tier 1 – 100% Renewable by 2035 with all existing resources remaining eligible

New Tier 1A – for all Members except BED and Swanton (they are in Tier 1B) 10% new renewables by 2035. Resources need to be built after 2010 and deliverable to New England. Resources are similar to Tier 1 except that no new biomass or large hydro would qualify.

New Tier 1B – only for BED and Swanton (100% renewable utilities) new load growth after 2023 or 2024 (TBD) must be met by new renewables meeting the definition in Tier 1A. Tier 2 resources are eligible to be used to meet this requirement.

Tier 2 – increased to 20% by 2035. Eligible resources expanded to include all municipally owned hydroelectric facilities <5MW in size. Eligible resource date moved back to 2010.

Tier 3 – Minor changes to add language allowing utilities to over-produce without prudency challenges (BED) and allowing Global Foundries to use industrial process changes that create emissions reductions as Tier 3 credits (GF).

Net Metering – The utilities were in agreement that all of the above is only agreed to if coupled with significant changes to net metering. However, the utilities were fractured regarding what those changes will look like with several undertaking one-off negotiations with the environmental community. There was broad agreement that "group" net metering should be eliminated, that a non-net metering program should be established for low-to-moderate income multi-family units, and that the PUC should be encouraged to continue moving compensation for excess generation toward the value of energy produced. Other positions included:

> VEC – working with REV to gain access to pre-2017 RECs where net meter customers were not required to choose a disposition.
>
> WEC – by far the strongest position, seeking value based compensation for all net metered systems, and all production, and elimination of group net metering.

While the framework obtained broad support it is still just a framework. Significant negotiation on specific language will be required in the legislative session. VPPSA will need to remain vigilant to protect the agreed upon structure and include net metering changes into the ultimate Bill.

STATE OF VERMONT
GENERAL ASSEMBLY

REPORT OF THE LEGISLATIVE WORKING GROUP ON RENEWABLE ENERGY STANDARD REFORM

PURSUANT TO 2023 ACTS AND RESOLVES NO. 33

December 20, 2023

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1. 2023 Acts and Resolves No. 33, Sec. 10a
2. Sample Bill and Discussion of Sample Bill
3. Comments Provided by Committee Members
4. Brattle Group Report- Economic Impacts of Expanding Vermont’s Renewable Energy Standards

Legislative Working Group on Renewable Energy Standard Reform- List of Members

Senator Christopher Bray, Addison County, Co-Chair
Representative Amy Sheldon, Middlebury, Co-Chair
Senator Anne Watson, Washington County
Representative Laura Sibilia, Dover
Jeffrey Cram - Senior Manager and Deputy Director of Facilities Engineering, GlobalFoundries
William Driscoll - Vice President, Associated Industries of Vermont
Michael Lazorchak - Regulatory Compliance Manager, Stowe Electric Department
Shana Louiselle - Communications and Public Relations Manager, Vermont Electric Power Company
Brian Evans-Mongeon - General Manager, Village of Hyde Park
Candace Morgan - Director of Corporate Affairs, Green Mountain Power
Ken Nolan - General Manager, Vermont Public Power Supply Authority
Christopher Pearson - Sierra Club
Louis Porter - General Manager, Washington Electric Cooperative
Brian Shupe - Executive Director, Vermont Natural Resources Council
Darren Springer - General Manager, Burlington Electric Department
Peter Sterling - Executive Director, Renewable Energy Vermont
Rebecca Towne - Chief Executive Officer, Vermont Electric Cooperative
Ben Edgerly Walsh - Climate and Energy Program Director, Vermont Public Interest Research Group
Mia Watson - Special Programs Manager, Vermont Housing Finance Agency
Chase Whiting - Staff Attorney, Conservation Law Foundation

Introduction

This report is submitted by the Legislative Working Group on Renewable Energy Standard Reform (the Working Group), which was created by 2023 Acts and Resolves No. 33 (Act 33). The report concerns the statutes and program established by 2015 Acts and Resolves No. 56, known as the Renewable Energy Standard (RES).

The Working Group held eight formal meetings as well as worked between meetings to prepare, share, and process information. Even so, given the complexity of the issue, both the RES itself and its operation, as implemented by Vermont's diverse population of 18 electric distribution utilities, the Working Group found itself time-constrained and recognizes that this report represents partial progress toward the ultimate goal of reforming Vermont's RES.

Member of the Working Group have committed to continuing to work together in the 2024 legislative session to assist the General Assembly if it takes up this work.

Last, because the Working Group could not arrive at a consensus position at this time, it chose to draft a Sample Bill to demonstrate where the issues discussed would be placed in statute, but the group is not endorsing or recommending that sample bill. The Sample Bill is provided Appendix 2. In addition, in order to capture the range of perspectives that should be kept in mind if the General Assembly decides to draft legislation to reform the RES, the group created Appendix 3, which gathers the comments of committee members who wished to provide them. The vote on adopting this report excluded consideration of the contents of these appendices.

Working Group Charge

Act 33 created a working group of four legislators and 16 nonlegislative members to "draft legislation to be considered by the General Assembly during the 2024 Legislative session."[1] The Working Group had the assistance of the Office of Legislative Counsel, the Joint Fiscal Office, and two independent consultants: Jennifer Knauer, a facilitation and mediation specialist and the Brattle Group, who conducted macroeconomic analysis for the Working Group based on the analysis conducted for the Department of Public Service by Sustainable Energy Advantage (SEA).

The Working Group met eight times between September 6 and December 13, 2023. During those meetings, the Group used polling and survey questions to facilitate discussions about the different aspects of the RES. The recordings of their meetings can be found here: https://www.youtube.com/channel/UCgHFernWVwH5MD0Se9NmVhg/featured

The Working Group's webpage with all of its agendas and documents can be found here: https://ljfo.vermont.gov/committees-and-studies/renewable-energy-standard-working-group

Duties

Sec. 10a (c) of Act 33—The Working Group spent varying amounts on time on each of the duties listed in subsection (c) of Sec. 10a of Act 33. Here are some of the Group's findings related to those tasks.

[1] 2023 Acts And Resolves No. 33, Sec. 10a(a)

Regarding (1) "whether any changes to Vermont's existing renewable energy requirements, or other energy policies, are needed to increase grid stability, resiliency, modernization, and reliability" the Working Group determined that changes are needed to the existing renewable energy requirements found in the RES. Specific considerations related to this task can be found in more detail in the appendix of this report that describes the Working Group's sample legislation.

Regarding (2) "identifying any barriers to moving to a 100 percent renewable standard for all electrical utilities by 2030," the Group received feedback on this from the members of the Working Group. Identified barriers include the following: the permitting process for new renewables; inadequate infrastructure to handle the load that 100% renewable would require; transmission grid stability; the cost of renewables; the availability of new regional renewables; and the differences between the utilities, including their size, current portfolio, and ownership.

Regarding (3) "recommending cost effective procurement policies to increase new renewable energy, storage, and flexible load management to offset increasing in-State load, improve grid stability and resiliency, and that consider integrated resource planning electric load growth projections," the Working Group did not develop a specific response to this.

Regarding (4) "whether increasing the requirement for out-of-state renewable procurements within or delivered into the ISO-New England territory can ensure affordable electric rates," the Working Group did not develop a specific response to this task.

Regarding (5) "evaluating the impact legislative recommendations may have on Tier 3 implementation," the Working Group did not develop a specific response to this task, but acknowledges that Tier 3 has an important role in the RES. The Group did hear concerns that the Clean Heat Standard could impact Tier 3 once it goes into effect.

Regarding (6) "evaluating the impact recommended legislative changes to procurement programs will have on Vermont jobs and the Vermont economy," the Working Group is not recommending any changes to procurement programs. However, the Brattle Group looked at how changes in the RES more generally will affect Vermont jobs and the Vermont economy. Modeling by SEA generates paths of additional investment in renewable energy in Vermont as a result of various changes to the RES. The Brattle Group used those paths of new investment to model new Vermont jobs in different sectors. The impact of new jobs and new investment in renewables combined with the slightly reduced consumption of non-electricity goods by households (relative to Business As Usual because electricity rates are higher) determine the overall effect on the Vermont GDP.

Regarding (7) "how current programs impact environmental justice focus populations, households with low income, and households with moderate income and how a revised Renewable Energy Standard can ensure that benefits and burdens are distributed equitably," the Working Group did not develop a specific response to this task, but the economic analysis developed by the Brattle Group, as discussed in their report in Appendix 4, may provide some information on this.

Regarding (8) "how any changes to the Renewable Energy Standard will address the inequity of distribution of benefits of renewables between different residential properties," the Group finds that requiring all of Vermont's utilities to have a total of 100% renewable energy will ensure that all residents of the State are served by renewable energy, not just those who can afford to generate it on their own property.

Summary of Straw Polls and Discussion from November 29, 2023

During the November 29th meeting, the Group took straw poll votes on potential components of proposed legislation. The results of those conversations follow.

Proposed Amendment for Tier 1

Tier 1- 30 V.S.A. § 8005(a)(1)(B)—Total Renewable Energy

- **Increase 75% in 2032 to 100% in 2030**
  - This will require an increase in the rate of increase
    - Currently, this requirement increases 4% every 3rd year— would need to change to 10.6% every other year or something similar

1. Straw Poll: Should the increase in Total Renewable Energy (Tier 1) to 100%?

YES – 13. NO – 2.

Vote	Rationale	Working Group Member
No	Prefer a Clean Energy Standard rather than Renewable Energy Standard.	*Jeffrey Cram, GlobalFoundries*
No	Options for Clean (energy) should be part of the mix – don't want to close the door on evolving technologies that may come up. I have questions about batteries and storage and other issues to deal with intermittency if we move to 100% Renewable in such a short time frame.	*William Driscoll, Associated Industries of Vermont*
Abstain	Waiting to see the modeling data on the impact this change would have on low-income household rates.	*Mia Watson, Vermont Housing Finance Agency*

2. Straw Poll: Should the increase in Total Renewable Energy (Tier 1) take place in 2030?

YES – 12. NO – 2.

Vote	Rationale	Working Group Member
Yes	Climate crisis is urgent, and we are hearing that this is feasible from the bulk of the utilities.	*Christopher Pearson, Sierra Club*
Yes	Some utilities have already adjusted planning timeline to 2030—so consistent with what we are doing.	• *Rebecca Towne, Vermont Electric Cooperative* • *Candace Morgan, Green Mountain Power* • *Louis Porter, Washington Elective Power*
No	Planning is geared for 2032.	*Jeffrey Cram, GlobalFoundries*
No	For some utilities: all planning is geared for 2032. Fine to increase to 100%, but to also increase the timeline may impact the early rate impacts for minimal benefits (2 additional years).	*Ken Nolan, Vermont Public Power Supply Authority*

3. Discussion: How should be the rate of increase [to Tier 1] be structured?

A. **Planning horizons** are important—we need time to be able to shift. Straight line [increase] is fine depending on when it starts; allows us to do more on the back end than the front end and allows us to adjust to higher prices. **The more complexity in mix of requirements (Tier 1, 1a, and Tier 2), the longer the timeline needed.** *– Rebecca Towne, Vermont Electric Cooperative*

B. We buy power in 5-year blocks, so immediate jumps upset planning—with contracting, permits, and supply chain (currently at 14 months). **A slower ramp-up or back loading the requirement would make it easier to shift to 2030**. *– Ken Nolan, Vermont Public Power Supply Authority*

An example of how to write legislation that back loads: exponential ramp up. Embed amounts in statute (example 5% to 8% to 10%) *Representative Laura Sibilia's question, Legislative Counsel Ellen Czajkowski's example.*

C. Smooth out rate increases so that it is less of a [financial] shock to household budgets. *– Mia Watson, Vermont Housing Finance Agency*

D. Want to go as fast as we can for environmental impacts, without messing with rate impacts that would disrupt affordability. *– Ben Edgerly Walsh, Vermont Public Interest Research Group*

4. Discussion re. Potential Development of Tier 1a (New Regional Renewables),

Working Members stressed the need for **a clear definition of what would be considered "renewable" under Tier 1a** prior to final voting. Components of this definition:

- Projects constructed after 2010* *Not unanimous. See comments.*
- Includes expansions of existing generation projects
- Constructed in New England or able to be imported into ISO New England
- Excludes any new large hydro that requires flooding. *Question* Does there need to be language around if there is expansion of existing large hydro if it does not require flooding? For example, a technical upgrade like updated turbines. – Christopher Pearson, Sierra Club*
- Exclusion of any new biomass and exclusion of expansion of existing wood biomass* *Counterpoint: ...at least as applies to electricity. Propose that the example of thermal purposes for wood biomass (as in Burlington) fall under Tier 3 credits instead of Tier 1a. – Darren Springer, Burlington Electric Department*

A Counterproposal/Complement to Tier 1a:

- Have a different construct focused on load growth, available for the utilities that are already at 100% Renewable. The question then shifts from *"How to incorporate new renewables"* to *"How do we address the load growth that we anticipate, given that that growth may not fit under current structure we have for purchasing?"*
  – Darren Springer, Burlington Electric Department
  – Louis Porter, Washington Electric Cooperative

Straw Poll Results: Are you in favor of developing a Tier 1a requirement?

YES – 7. NO – 3. ABSTAIN – 6.

Those in favor of developing Tier 1a: Rationale	**Working Group Member**
Allows us to procure more renewables (supports additionality). Encourages a *diversity* of new renewables other than small solar (for example, regional wind). Currently the Tier 1 definition allows for the newer resources but not at an optimum price point.	*Candace Morgan, Green Mountain Power*
This is how you reduce greenhouse gases—by bringing new renewables online that are more flexible in terms of where they are coming from.	*Ben Edgerly Walsh, Vermont Public Interest Research Group*
VT has a lower regional new renewable requirement. This is an important part of encouraging new renewables coming online.	*Peter Sterling, Renewable Energy Vermont*
Allowing regional new renewables to come online that are *larger than Tier 2* allows VT to tap into cost savings that come with larger projects.	*Chase Whiting, Conservation Law Foundation*

Those opposed of developing Tier 1a: Rationale	**Working Group Member**
With move to 100% in Tier 1, an additional Tier 1a simply adds more requirements and removes flexibility, thus compromising ability to get the most cost-effective resources. A *Regional* Renewable may not be the most cost-effective renewable source. A lot of the HQ power we get wouldn't fall under Tier 1a. Example: under Tier 1a we could still negotiate HQ power, but would have to specify that it would come from a new renewable installation—and this would probably add additional dollars to ensure that it comes from this new installation (e.g. a new wind farm). This is the tension of making a Requirement vs. Opportunity, based on the markets.	*Rebecca Towne, Vermont Electric Cooperative*
Additionality, arguments may not hold up because VT is not an island, and New England will build renewables as needed without Tier 1a. VT shouldn't be mandated to create new renewables that we don't need.	*William Driscoll, Associated Industries of Vermont*
Trying to administer multiple levels of a standard makes it more difficult to secure workable deals—the effort it takes to fit our portfolio into those requirements is problematic. (Stowe, Hyde Park, and Burlington are not part of aggregate contracting.)	*Brian Evans-Mongeon, Village of Hyde Park*
Those who are neither in favor nor opposed to developing Tier 1a: Rationale	**Working Group Member**
Need to understand magnitude of Tier 1a and any changes to Tier 2 in order to see overall impact.	*Jeffrey Cram, GlobalFoundries*
Need to know how this applies to utilities that are already at 100% Renewable.	*Darren Springer, Burlington Electric Department* *Louis Porter, Washington Electric Cooperative*

If there was a definition for biomass or wood that was getting looped into Tier 1a, we'd want to make sure that it continues to count the way we talked about for Tier 1 and Tier 3.	*Darren Springer, Burlington Electric Department*
From grid operators' perspective, our view is informed on impact of resource selection on system reliability. In terms of Tier 1a, we don't have a specific [position] in favor or opposed.	*Shana Louiselle, Vermont Electric Power Company*
The definition of resources that qualify for Tier 1a and Tier 2 – and the interaction between the two of them – needs to be clarified/determined before assessing support.	*Ken Nolan, Vermont Public Power Supply Authority*

Additional Comments, regarding definition of new renewable under Tier 1a:

<u>Topic: Currently, in statute, the definition of "new renewable" is set at anything constructed after 2015 but perhaps pull this back to 2010. Include expansions to existing projects and retrofits—the incremental increase counts as renewable.</u>

- The date of 2010 was picked to bring wind projects into new regional tier—what about other VT projects that would be eligible for Tier 1 but not Tier 1a given the structure. – *Ken Nolan, Vermont Public Power Supply Authority*
- New Renewable Plant Coventry in 2005 – want to be sure that this group is not penalized. Would count as part of Tier 1, but not Tier 1a – this may be seen/result as a reduction in the financial incentive. – *Louis Porter, Washington Electric Cooperative*
- If moving from 2015 to 2010—what is the rationale for why? – *Senator Bray*
- Caution: Once at 100% Renewable, caution about not wanted to disincentivize continuing to run existing renewable projects (that may have been built before the definition date, for example – would be hard to keep that project running).
- There are projects that started in 2010 sparked in part by VT policy (Standard Offer)—Not just wind but also solar and small farm methane resources. Additionality, the goal is getting more renewables to come online. If resources built at earlier dates have to be retired in Vermont, that means that new renewables will need to be built somewhere in the region, which provides a little more flexibility for utilities (if they retired a wind or solar resource under one of these policies). – *Ben Edgerly Walsh, Vermont Public Interest Group*
- Why not set the date at the time of passage of the bill and adjust Tier 1a down a bit? – *Louis Porter, Washington Electric Cooperative*
- Counterpoint: this means that there would be less additionality coming online in the region broadly, rather than rehome to Vermont utilities and encouraging more renewables in the region. Would prefer to keep the requirement higher. – *Ben Edgerly Walsh, Vermont Public Interest Group*
- Moving date from 2015 to 2010 creates winners and losers among utilities—some utilities are already positioned favorably to benefit from this, but not all. And those that don't will need to make different market decisions to meet their needs—buy something on the market that we don't already have and sell something that we do have, which may have a higher cost. Might want to look at providing support for these utilities through Tier 2—allows these other utilities flexibility. – *Ken Nolan, Vermont Public Power Supply Authority*

<u>Question:</u> Need to look at how statute is handling this: currently sources/plants from within a system of generating plants *aren't* considered renewable?

Caution: Would have to be a requirement that the electricity would actually be able to enter the ISO New England system. If not, could get into a situation where renewable energy credits (RECS) could be acquired from far away and used in VT [despite the fact that] the energy itself could not be used in VT. – *Chase Whiting, Conservation Law Foundation*

If there was to be Tier 1a requirement, what percentage would you propose?

- 20% by 2030; 30% by 2035
  Rationale: experiencing urgency with climate and reducing greenhouse gas emissions but not wanting to push numbers so high that it would create a massive rate impact. Reinforce ability to use inflation reduction act federal funds (if built by 2032). – *Ben Edgerly Walsh, Vermont Public Interest Group*

- 20% by 2035 for Tier 1a.
  Rationale: looking at what we anticipate in the New England energy supply and when it could be available. Also want to signal the importance of additionality and substantial increase in renewables. – *Candace Morgan, Green Mountain Power*

- X %
  I would rather tie requirements to increase renewables to keep in step with actual load growth. I'm hearing that pricing is up, and availability is not certain for offshore wind. Flexibility is key. If the IRA or the IAJ make these projects cheaper and they are economical, utilities will buy into them. But mandating these projects in isolation of those factors displaces current renewables at a higher price. – *Ken Nolan, Vermont Public Power Supply Authority*

  Comment: Historically it has been very imprecise to estimate when new renewables will be available – for solar the installation/availability has been much quicker than projections expected. Energy future is moving so quickly—so take the projections out to 2035 with a grain of salt. – *Peter Sterling, Renewable Energy Vermont*

- 10%, potentially backloaded
  Rationale: This already doubles the new renewable requirements—plus Tier 2 changes TBD. Both growth load and availability of renewables is projected but uncertain! If we do go forward with Tier1a, 10% more backloaded is doable, but above that starts to limit flexibility in a worrisome way. – *Rebecca Towne, Vermont Electric Cooperative*

Ideas for How to Preserve Flexibility

- Backloading increased requirements
- Outline big picture goals with as much flexibility in how to meet them as possible. Every requirement that is added limits flexibility.
- Time frames for changes take into account a planning horizon
- Shift to a requirement that is tied to actual load-growth concept

5. Show of hands: Who wishes to consider changes to the definition of resources that qualify for Tier 1?

YES – 3.

Those in favor of considering changes to definition of resources that qualify for Tier 1: Rationale	Working Group Member
Want to clarify biomass and whether we expect to allow that in perpetuity	*Christopher Pearson, Sierra Club*
Want to be looking at clean rather than renewable	*William Driscoll, Associated Industries of Vermont*
Looking for consistency in definition of Tier 1 and Tier 1a re constraints of new wood biomass/wood biomass expansion	*Chase Whiting, Conservation Law Foundation*

Proposed Amendment for Tier 2

Tier 2–30 V.S.A. § 8005(a)(2)(C)—Distributed Renewable Energy

- **Increase <u>10%</u> in <u>2032</u> to <u>20%</u> in <u>2032</u>**
  - This will require an increase in the rate of increase
    - Currently, the requirement increases <u>0.6% every year</u>—would need to increase to <u>1.5% every year</u> or something similar
- **No change to definitions**

1. Straw Poll: Should the Distributed Renewable Energy (Tier 2) requirement increase to 20%?

YES – 9. NO – 3. ABSTAIN – 4.

Vote	Rationale	Working Group Member
Yes	This is doable. Want to support Vermont. Prefer a Tier 2 addition to renewables rather than Tier 1. **But very important to us that any addition to Tier 2 be tied to net metering reform,** as this is very expensive for us.	*Rebecca Towne, Vermont Electric Cooperative*
No	Would be okay with 20% but want to change the definition to allow for other resources—hydro facilities that municipalities have invested in historically ought to count in Tier 2 to keep them online and running. If 20% was coupled with this change in definition, would change vote to Yes.	*Ken Nolan, Vermont Public Power Supply Authority*
No	Utilities should be able to pursue the mix that makes sense for what they need. Do not want to force utility to invest in more energy than they need.	*William Driscoll, Associated Industries of Vermont*
Abstain	Need to understand the complete picture of how this all fits together (Tier 1a and Tier 2)	*Jeffrey Cram, GlobalFoundries*

2. Straw Poll: If there were an increase, should the increase take place by 2032?

By 2032: YES – 8. NO – 1. ABSTAIN – 7.
By 2030: YES – 5. NO – 3. ABSTAIN – 8.
Why the change in votes, per the shift from 2032 – 2030?

- More time is helpful. Our predictions show that it is easier to get there by 2032 – *Rebecca Towne, Vermont Electric Cooperative*
- Agreed. – *Candace Morgan, Green Mountain Power*
- In principle, don't want to be accelerating legislative requirements that were previously set. *– Brian Evans-Mongeon, Village of Hyde Park*

3. Discussion: How should be the rate of increase be structured for Tier 2, if applicable?

- Preference to see more linear than backloaded because getting a plan online a couple of years earlier really does have an impact on cumulative greenhouse gases. *– Ben Edgerly Walsh, Vermont Public Interest Group*

4. Discussion: What specific changes should be made to the net metering program?

See RESRWG Member Poll Results from November 9-12. There were several mentions of the need for net metering reform, with an interest towards adjusting the compensation arrangement to avoid an inequitable cost shift between net metering customers to non-net metering customers. In sum, the survey yielded these proposals:

1. *Adjust net metering subsidies*
2. *Adjust net metering compensation to a rate that matches actual avoided costs. Rationale: required value for excess generation is currently over-market—drives higher rates for all*
3. *Specific to the RES: a note that net metered RECs "must" be retired in Tier 2 means that the RES is reinforcing inequity and shifted costs among customers*
4. *Consider net metering projects serving low and moderate income (LMI) households, including multifamily affordable housing, included as a preferred site*

https://ljfo.vermont.gov/assets/Meetings/Renewable-Energy-Standard-Reform-Working-Group/2023-11-15/637a4e813f/RESRWG-Member-Pre-Mtg-Survey-November-9-13-2023-RESPONSES.pdf

Net Metering Reform. Initial Proposals

A. Direct the Public Utility Commission (PUC) to set a statewide net metering rate based on avoided costs. Example: a compensation rate based on the value at the time of the generation.
– Louis Porter, Washington Electric Cooperative
– Rebecca Towne, Vermont Electric Cooperative

B. Might need to pair this idea with potentially removing the caps (on the size of the project that qualifies for net metering). Cap has been in place because of cost structure, but if the financial incentive decreases, then the bigger systems could build solar for municipalities/school buildings/public buildings – *Christopher Pearson, Sierra Club*

Counterpoint: However, in the example of municipal systems—this strategy hides the cost of the electricity, and the cost of the system is folded into municipal taxes for residents, rather than in residents' electricity bills. *– Louis Porter, Washington Electric Cooperative*

C. Be more specific/directive in legislation to the PUC, distinguishing between net metering that is generated and used on site (valuable and useful) vs the *excess* generation that then flows into the grid and is used by others at a much higher cost than other resources of electricity. *– Rebecca Towne, Vermont Electric Cooperative*

D. Concerned about hardening/reliability of the grid. *– Representative Sibilia*
   - As long as 500 kW group net metering located away from load does not do much to harden the grid. Can actually create issues and is very expensive. *– Ken Nolan, Vermont Public Power Supply Authority*
   - H.320 of 2023 proposed to eliminate off-site net metering because it is often not located in places where it is needed and becomes very expensive. *– Peter Sterling, Renewable Energy Vermont*
   - However, want to maintain option for off-site net metered projects that assist housing developments *– Mia Watson, Vermont Housing Finance Agency*
   - Seconded by *Chase Whiting, Conservation Law Foundation*

E. If looking at a shift in changing net metering, take the time to explore and understand anticipated and unintended impacts. *– Peter Sterling, Renewable Energy Vermont*

F. Is there another revenue stream to support the affected cost shift? *– Senator Bray*

G. Reluctant to change net metering because it favors solar on the built environment and that's a benefit. *– Brian Shupe, Vermont Natural Resources Council*

H. Would like to retain how net metering reinforces solar on the built environment. *– Chase Whiting, Conservation Law Foundation*

I. Agree with Chris that if figure out cost structure, we don't have to care about size. On flip size, if cost structure is too tricky, the size of allowable rays is also another way to get at net metering costs. Reduce allowable size. *– Rebecca Towne, Vermont Electric Cooperative*

J. A useful structure, potentially: set incentive with a time frame. Example—very high net metering rates go away after 10 years. *– Rebecca Towne, Vermont Electric Cooperative*

K. Early arrays—there was no incentive for them to assign RECs to the utility, and the PUC has ruled that they cannot change their minds about that, so it is in-State solar that does not count at all even though we pay high rates for it. Build an incentive to (1) change their minds and (2) have an incentive to assign those RECs to the utility to count towards Tier 2. *– Rebecca Towne, Vermont Electric Cooperative*

Proposed Amendment for Tier 3

Tier 3-30 V.S.A. § 8005(a)(3)(B)—Energy Transformation

- **No changes**

1. **Straw Poll: Do you agree with the assessment that Tier 3 reform(s) are not necessary at this time?**

   YES – 10. NO – 3. ABSTAIN – 1.

Proposed Amendment for RES Goals

RES goals—30 V.S.A. § 8001

- Amendments to existing goals to reference climate change, reduction of greenhouse gases, resiliency, and anything else the Working Group wants to update.

1. **Straw Poll: Should the goals of the RES established in 30 V.S.A. § 8001 be amended?**

   YES – 1. NO – 0. ABSTAIN – 13.

Based on the discussion summarized here, the Working Group provides sample legislation in Appendix 2.

Committee Vote on Acceptance of the Final Report

The vote on adopting this report excluded consideration of the contents of the appendices.

Those members voting in the affirmative were:

Senator Christopher Bray
Representative Amy Sheldon
Senator Anne Watson
Representative Laura Sibilia
Jeffrey Cram, GlobalFoundries
William Driscoll, Associated Industries of Vermont
Shana Louiselle, Vermont Electric Power Company
Candace Morgan, Green Mountain Power
Ken Nolan, Vermont Public Power Supply Authority
Christopher Pearson, Sierra Club
Louis Porter, Washington Electric Cooperative
Brian Shupe, Vermont Natural Resources Council
Darren Springer, Burlington Electric Department
Peter Sterling, Renewable Energy Vermont
Rebecca Towne, Vermont Electric Cooperative
Ben Edgerly Walsh, Vermont Public Interest Research Group
Mia Watson, Vermont Housing Finance Agency
Chase Whiting, Conservation Law Foundation

Those members voting in the negative were:
Brian Evans-Mongeon, Village of Hyde Park
Michael Lazorchak, Stowe Electric Department

Appendix 1- 2023 Acts And Resolves No. 33

Sec. 10a. RENEWABLE ENERGY STANDARD WORKING GROUP

(a) Established. The Legislative Working Group on Renewable Energy Standard Reform is created to draft legislation to be considered by the General Assembly during the 2024 Legislative session.

(b) Membership.

(1) The Legislative Working Group on Renewable Energy Standard Reform will be convened by two members from the House appointed by the Speaker of the House and two members of the Senate appointed by the Committee on Committees. One member from the House and one member from the Senate shall be the co-chairs of the Work Group.

(2) The Working Group shall also be made up of one representative from each of the following: Green Mountain Power, Burlington Electric Department, Vermont Public Power Supply Authority, Washington Electric Coop, Vermont Electric Coop, Vermont Public Interest Research Group, Renewable Energy Vermont, Conservation Law Foundation, Vermont Electric Power Company, Vermont Housing Finance Agency, Vermont Natural Resources Council, GlobalFoundries, Associated Industries of Vermont, and the Sierra Club. Stowe Electric and Hyde Park Electric may each name a representative to the Working Group if they choose.

(c) Duties. In addition to submitting draft legislation, the Working Group shall report on the following:

(1) whether any changes to Vermont's existing renewable energy requirements, or other energy policies, are needed to increase grid stability, resiliency, modernization, and reliability;

(2) identifying any barriers to moving to a 100 percent renewable standard for all electrical utilities by 2030;

(3) recommending cost effective procurement policies to increase new renewable energy, storage, and flexible load management to offset increasing in-State load, improve grid stability and resiliency, and that consider integrated resource planning electric load growth projections;

(4) whether increasing the requirement for out-of-state renewable procurements within or delivered into the ISO-New England territory can ensure affordable electric rates;

(5) evaluating the impact legislative recommendations may have on Tier III implementation;

(6) evaluating the impact recommended legislative changes to procurement programs will have on Vermont jobs and the Vermont economy;

(7) how current programs impact environmental justice focus populations, households with low income, and households with moderate income and how a revised Renewable Energy Standard can ensure that benefits and burdens are distributed equitably; and

(8) how any changes to the Renewable Energy Standard will address the inequity of distribution of benefits of renewables between different residential properties.

(d) Assistance.

(1) The Working Group shall have legal assistance from the Office of Legislative Council and administrative assistance from the Office of Legislative Operations.

(2) On or before July 15, 2023, the Joint Fiscal Office may retain the services of one or more independent third parties to provide facilitation and mediation services to the Working Group, and data analysis recommendations at the direction of the legislative members.

(3) The Department of Public Service shall be invited to advise the Working Group on the results of its ongoing public process to review the Renewable Energy Standard and any other items as needed.

(e) Compensation and reimbursement.

(1) For attendance at meetings during adjournment of the General Assembly, a legislative member of the Working Group serving in the legislator's capacity as a legislator shall be entitled to per diem compensation and reimbursement of expenses pursuant to 2 V.S.A. § 23 for not more than eight meetings.

(2) Other members of the Working Group who are not otherwise compensated by their employer shall be entitled to per diem compensation and reimbursement of expenses as permitted under 32 V.S.A. § 1010 for not more than eight meetings.

(3) The payments under this subsection (e) shall be made from monies appropriated by the General Assembly.

(f) Report. The Working Group shall submit draft legislation and a report on its deliberations and findings to the House Committee on Environment and Energy and Senate Committee on Natural Resources and Energy by December 1, 2023. Working Group members may submit minority opinions that shall be included with the report containing the draft legislation.

(g) Appropriation. In fiscal year 2024, it is the intent of the General Assembly to appropriate funds if available from the General Fund to the Joint Fiscal Office to hire the consultants pursuant to this section.

Appendix 2- Sample Legislation

Working Group Sample Legislation

Amendments to existing Tiers 1 and 2

Sec. 1. 30 V.S.A. § 8005 is amended to read:

§ 8005. RES CATEGORIES

(a) Categories. This section specifies three categories of required resources to meet the requirements of the RES established in section 8004 of this title: total renewable energy, distributed renewable generation, and energy transformation.

(1) Total renewable energy.

* * *

(B) Required amounts. The amounts of total renewable energy required by this subsection shall be ~~55~~ 63 percent of each retail electricity provider's annual retail electric sales during the year beginning on January 1, ~~2017~~ 2025, increasing by an additional ~~four~~ 7.4 percent each ~~third~~ January 1 thereafter~~,~~ until reaching ~~75~~ 100 percent on and after January 1, ~~2032~~ 2030.

* * *

(2) Distributed renewable generation.

* * *

(C) Required amounts. The required amounts of distributed renewable generation shall be ~~one~~ 4.9 percent of each retail electricity provider's annual retail electric sales during the year beginning January 1, ~~2017~~ 2025, increasing by an additional ~~three-fifths of a~~ 2.15 percent each subsequent January 1 until reaching ~~10~~ 20 percent on and after January 1, 2032.

* * *

Addition of New Tier for New Regional Energy

(3) New renewable energy.

(A) Purpose; establishment. This subdivision (3) establishes a new regional renewable energy category for the RES. This category encourages the use of new renewable generation to support the reliability of the regional ISO-NE electric system. To satisfy this requirement, a provider shall use renewable energy with environmental attributes attached or any class of tradeable renewable energy credits generated by any renewable energy plant coming into service after January 1, 2010 whose energy is capable of delivery in New England.

(B) Required amounts. The amount of new renewable energy required by this subsection (a) shall be one percent of each retail electricity provider's annual retail electric sales during the year beginning on January 1, 2025, increasing by an additional 3.8 percent each January 1 thereafter, until reaching 20 percent on and after January 1, 2030.

(C) Relationship to other categories. Distributed renewable generation used to meet the requirements of subdivision (2) of this subsection (a) shall not also count toward the requirements of this subdivision (3). An energy transformation project under subdivision (4) of this subsection (a) shall not count toward the requirements of this subdivision (3).

~~(3)~~(4) Energy transformation.

* * *

Discussion of Sample Legislation

As described above, a majority of members of the Working Group voted to increase the Tier 1 requirement of total renewable energy from 75% to 100% in 2030. There was not a full discussion on the options for the rate of increase to reach 100%, so there is no current consensus from the Working Group. The sample legislation includes increasing by an additional 7.4 percent each third January 1. The issue should be evaluated by the General Assembly. There was no majority opinion on changing the definition of what is included as renewable energy under the Renewable Energy Standard. The Working Group discussed whether to change to a "clean" energy standard or to revise the definition of "renewable" regarding the inclusion of biomass facilities, large hydroelectric facilities, and nuclear facilities, but consensus was not reached.

For Tier 2, distributed renewable energy, a majority of the Working Group members voted to increase the requirement from 10% in 2032 to 20% in 2032. There was discussion of whether to make the year 2030, but more members of the Group favored 2032, which would give utilities additional time for the increase. There was not a full discussion on the options for the rate of increase to reach 20% so there is no current consensus from the Working Group. The sample legislation includes increasing by an additional 2.15 percent each subsequent January 1. The issue should be evaluated by the General Assembly. As described above, multiple members of the Working Group are specifically interested in making changes to the net metering program, which is an important part of Tier 2. Working Group members provided some specific ideas on what changes could be made to improve the net metering program, which are on pages 13–14 of this report. The Working Group did not vote on any of the specific ideas.

For Tier 3, the Working Group voted not make any changes at this time.

While there was discussion during earlier meetings about updating the statutory goals of the RES, there was little support among the members during the straw poll vote, so no changes are included.

Finally, the Working Group discussed the addition of a "Tier 1a," which has been designated in the sample legislation as Tier 3, making the existing Tier 3 Tier 4. There are multiple ways this could be drafted, including making it Tier 4. This Tier would require utilities to acquire new regional renewable energy. There was discussion about how much of a percentage this requirement should be and there was not a clear consensus. The sample legislation includes 20% by 2030 for discussion purposes in the General Assembly. The sample legislation also does not change the definition of "new renewable energy" in the definition section of the statute. Instead, it specifies what qualifies for this Tier as "generated by any renewable energy plant coming into service after January 1, 2010 whose energy is capable of delivery in New England." The current definition of "new renewable energy" is provided in 30 V.S.A. § 8002 (17) and it applies to Tier 2 of the RES. The difference is that currently it is defined as plants that came into service after June 30, 2015, not 2010. The Working Group did not discuss whether date of January 1, 2010 should apply to projects that count towards Tier 2. This is an issue for the General Assembly to consider.

Appendix 3- Working Group Member Comments

Senator Christopher Bray:
In discussions in committee on the final meeting (December 13, 2023), a number of considerations relating to the redesign of the RES were noted by members of the Working Group. The RES redesign needs to address the following:

1. the differing needs and abilities of the state's 18 DUs to implement the RES; also referred to as "one size does not fit all;"
2. how net metering should be revised as part of the RES revision;
3. how distribution utilities that are already 100% renewable energy in 2023 will be accommodated in any new version of the RES;
4. the ramping rates for the transitions in each Tier;
5. the definition of resources that will qualify as Tier 1 resources;
6. the definition of resources that will quality as Tier 1a resources; and
7. the definition of resources that will qualify as Tier 2 resources.

Brian Evans-Mongeon, Village of Hyde Park:

For Hyde Park, it would be our desire for the legislation not to advance or increase any requirements under the original legislation provisions due to the prior commitments made by HPE. These commitments include power resources already secured out to 2034, current workforce structure, technology concerns, and timing for infrastructure changes to support the desired future outcome. HPE asks that utilities having made such commitments not be penalized as those actions were conducted in good faith under the currently enforced legislation. Given our current capabilities, any changes prior to 2032 will create upward pressures on costs and force imbalances within our current retail pricing structures. Based upon the current proposal, I cannot support the parts of the report or the draft legislation.

Michael Lazorchak, Stowe Electric Department:

The Town of Stowe Electric Department ('SED') appreciates the opportunity to participate as a committee member in the Legislative Working Group ('Working Group') on Renewable Energy Standard Reform.

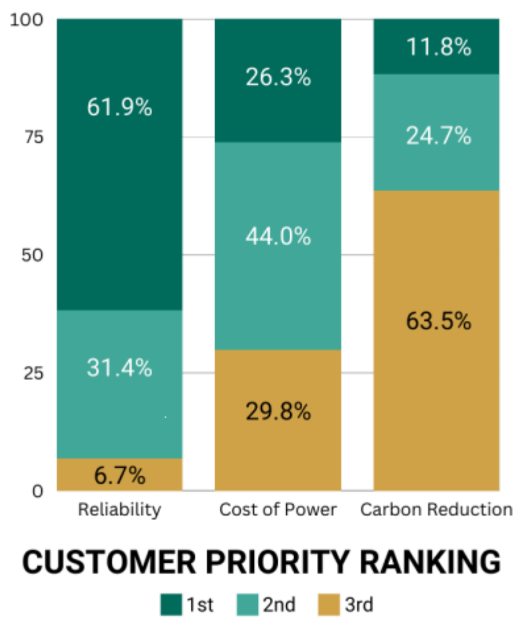
The Working Group was unable to agree on draft legislation and provided findings only on four (4) of the eight (8) categories identified in Act 33 of 2023. Absent from the Working Group findings was also a meaningful discussion on how net-metering creates cross-subsidization concerns between ratepayer classes and that Standard Offer projects remain expensive power supply obligations for distribution utilities. Instead of producing a comprehensive document, the Working Group determined that committee members and public participants could file minority reports voicing individual perspectives on the Report. Because of these factors, SED voted no on the Report of the Legislative Working Group on Renewable Energy Standard Report.

Thanks to the current Renewable Energy Standard ('RES'), Vermont has one of the cleanest electricity transmission and distribution system in the United States. The most significant sources of greenhouse gas emissions in Vermont come from the transportation and building heating sectors. Vermont's decarbonization pathway also relies heavily on the electricity grid to decarbonize the transportation and heating and cooling sectors. The hope is that as Vermonters transition to electric vehicles and heat pump technologies, the generation, transmission, and distribution systems can provide electricity for this additional load in a safe, reliable, and least-cost manner.

For SED, flexibility in power supply procurement is critical to meeting changes to the RES and new load growth. SED has a power supply market strategy that is 85% hedged in the winter and 80%

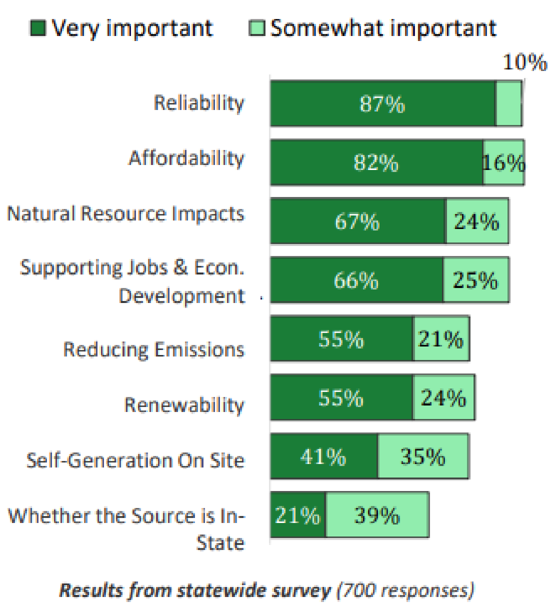
in the shoulder seasons and SED has power purchase agreements that run through 2038. SED anticipates that nuclear and hydro will remain important components of our distribution system that can rely heavily on intermittent renewables and battery storage.

SED also wants to draw attention to the fact that ratepayers' most pressing concerns are reliability and cost. Stowe's 2023 customer survey showed customers' #1 priority is reliability and #2 is cost. Carbon reduction is a distant #3:



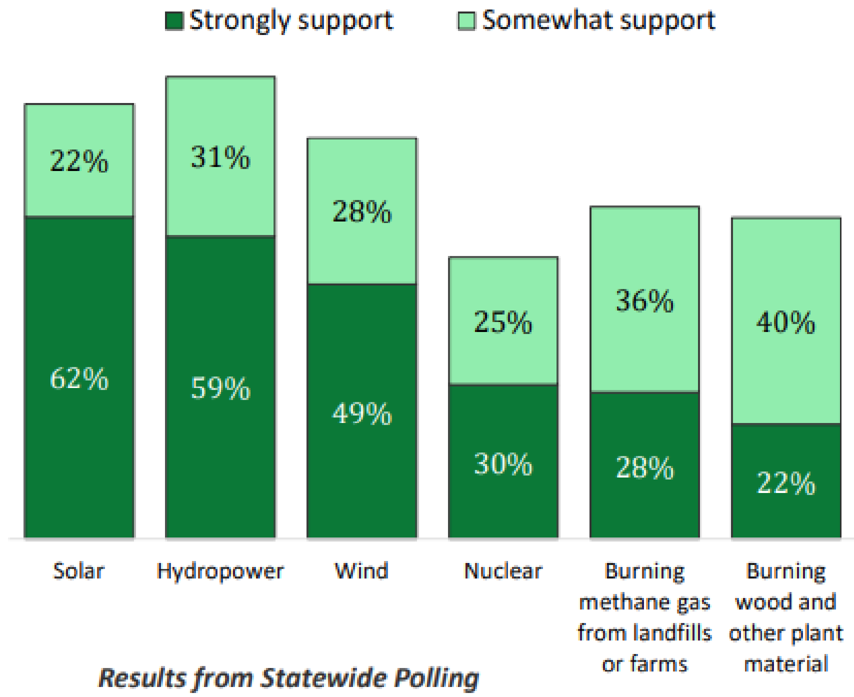
https://www.stoweelectric.com/_files/ugd/ca8289_fb60307d7e24403a9992984688634736.pdf

The Vermont Department of Public Service's ('DPS') survey showed similar priorities state-wide, with reliability #1, cost #2, and emissions reduction showing up as the #5 priority for Vermonters:



vt-psd-res-engagement-becc (vermont.gov)

The DPS state-wide survey also showed the strongest support (90% net-positive) for hydro. Nuclear has a net-positive rating of 55%, which is a cost-effective, non-emitting, reliable baseload power source.



Results from Statewide Polling
% who strongly or somewhat support Vermont getting electricity from each source

The goal should be rapid, affordable, reliable decarbonization of our power supply using both in-state and regional resources with strong support for continued use of baseload non-emitting resources like Hydro Quebec and nuclear. Any transition away from those key resources in our portfolio is going to decrease reliability and increase rates. Those actions are in direct opposition to stated consumer desires both locally in Stowe and statewide as indicated by DPS's own survey data. We look forward to working with the Vermont General Assembly and stakeholders in the coming session.

<u>Mia Watson, Vermont Housing Finance Agency:</u>
• Vermont Housing Finance Agency (VHFA) agrees that a transition to a 100% renewable energy standard is an important step in addressing our climate crisis and can offer important social benefits for Vermont households by reducing carbon emissions in the state and region.
• However, the legislation establishing the RES working group included a charge to review "how current programs impact environmental justice focus populations, households with low income, and households with moderate income and how a revised Renewable Energy Standard can ensure that benefits and burdens are distributed equitably; how any changes to the Renewable Energy Standard will address the inequity of distribution of benefits of renewables between different residential properties."
• VHFA feels that there is more work to be done to properly assess the impact of changes to the RES on low and moderate-income households, particularly those who are part of environmental justice focus populations, and to consider new policy solutions to mitigate potential harmful impacts.

• The Technical Analysis of a 100% Renewable or Clean Energy Standard produced through the Stakeholder Advisory Group found that the average total electricity rate increase from 2025 through 2035 under various potential RES scenarios is expected to at most result in a 6% increase from a business-as-usual scenario. This increase could potentially be less depending on the specific RES structuring and other future changes in the market. This forecast has alleviated some concerns of VHFA that RES could result in severe hardship for low-income households, who face the highest energy burdens.
• However, even a moderate increase in electricity costs will nevertheless be felt by low and moderate households, as it will come on top of a 13% rate increase by 2035 that is expected without any changes to the RES.
• In addition, rate impacts from potential adjustments to the RES outside modeled scenarios must be considered. Although most of the research produced for the working group models the impact of various scenarios through 2035, the draft legislation included in the appendix of this report targets 2030 for a transition to 100% renewable resources. Moving up the date ahead of the modeled targets will also likely compress the rate increases. VHFA remains concerned that legislators considering RES changes targeted for 2030 will not have adequate data to predict the financial impact on households.
• Furthermore, if different utilities will be required to make different changes to their supply to meet the RES requirements, their rate structures could be variably impacted, which might potentially result in much larger impacts to some customers or to some demographic groups.
• Work on the RES should consider a range of public feedback from different sources. The working group heard comments from many members of the public, nearly all of whom were in favor of an entirely renewable standard and ambitious decarbonization. However, there was little in-committee discussion of the report Vermont Weighs In: Public Opinion on Renewable Electricity, prepared by the Department of Public Service. Most survey respondents showed general support for efforts to decrease emissions, including by increasing RES targets. But those respondents also rated reliability and affordability as their highest concerns about where Vermont gets its electricity. 31% of respondents reported that they were unwilling to pay any higher rates for 100% renewable electricity, and an additional 24% were willing to pay between $1 and $25 per month. The structuring of a new RES must attempt to balance affordability and reliability concerns alongside the urgency for climate action.
• VHFA remains concerned that Vermont as a state is not doing enough to help low and moderate households experience the benefits of a cleaner electrical grid. Without deeply subsidizing fuel switching for the lowest income households, particularly for renters, the climate transition may result in increased income inequality. The RES working group ultimately voted to not reconsider mandates on energy transformation projects covered by Tier III, in part due to the anticipated implementation of the Clean Heat Standard. However, VHFA feels that the RES discussions in the upcoming legislative session remain a valuable opportunity to keep energy equity and climate justice a central part of policy and funding discussions.
• VHFA appreciates the concerns that other RES members have discussed around net-metering, including that the current system can result in a rate cost shift from high income households that install solar to lower-income households that cannot afford to do so. If changes to net-metering are proposed, VHFA would urge the Legislature to consider a compromise approach that preserves community net-metering as an option for households that cannot install solar, and that better facilitates solar projects that serve affordable housing. This potentially could include designating solar projects serving subsidized affordable housing projects as a preferred site or setting a preferred rate for projects benefiting low-income households.

<u>Louis Porter Washington Electric Cooperative:</u>

Washington Electric Cooperative is grateful to have been able to participate in the Legislative Working Group on Renewable Energy Standard Reform. Providing an opportunity for an in-depth and candid conversation among key legislators, utilities, advocates for the renewable energy industry and others was valuable, especially given the complexity of these topics.

WEC has for years provided 100% renewable power to its members. Our Board and a majority of our owner/members believe strongly that all Vermonters should have access to 100% renewable, low carbon, electricity as soon as practical.

In the interests of WEC's environmental and social goals for its members and the communities we serve, we also believe that the renewable energy that Vermonters use should be provided at the lowest feasible cost to facilitate a viable transition to renewable power for heating and transportation, and to avoid unnecessarily burdening those Vermonters who are struggling financially.

Because of this, we are disappointed that reforms to net metering regulations did not play a larger role in the working group's discussions and report. An examination of net metering was clearly within the purview of the group, whose charge included an examination not only of the renewable energy standard but also "other energy policies" as they relate to "grid stability, resiliency, modernization and reliability".

The Public Utility Commission in its biennial update of the program was quite clear net metering continues to be "one of the highest-cost sources of new renewable capacity in Vermont" and that the Commission "remains concerned about the overall cost of the net-metering program and its corresponding impact on non-participating Vermonters, particularly those Vermonters who are highly energy-burdened."

The PUC also warned that net metering could actually be counter-productive to the goal of encouraging the use of electricity for transportation and heating, due to the rate increases it causes, noting that "over-reliance on net-metered systems for renewable generation could have the unintended, counterproductive effect of reducing investment in more cost-effective means of reducing Vermont's greenhouse gas emissions, such as electric vehicles and cold-climate heat pumps."

The transportation and heating sectors each account for about 36 percent of Vermonters' carbon emissions while the entire electric sector is only responsible for about 2 percent. To cut carbon emissions, we must focus our public policies on directly addressing impediments to decarbonizing heating and transportation in Vermont.

The PUC has acknowledged that its recent changes to net metering represent "only a modest decrease in compensation".

To avoid putting undue costs on members who are struggling financially, and to avoid disincentivizing the adoption of electric vehicles and heat pumps, WEC believes the Legislature should direct the PUC to alter the compensation for excess generation by net metering to be set at avoided costs. In other words, the non-net-metering ratepayers of a utility should be paying for excess net metering generation at the value that power actually provides, rather than an inflated and subsidized rate.

That will allow those who wish to develop net metering systems to do so, without causing the harm to their neighbors outlined above.

Subsidizing net metering was an important public investment to help kickstart the residential-scale renewable energy sector in Vermont. However, as the industry has become well established, the public benefits of these subsidies are no longer in balance with the costs. The economic structure of net metering as it currently stands allows rate payers who have the means and upfront capital to install net metered systems to incur private economic benefit at the expense of publicly shared assets like the grid and our cooperatively owned utility. Members who are not able to install net metered systems are now directly paying for their net metering neighbors, as well as providing profit to renewable energy developers.

As an early adopter of renewable power, WEC is an essential part of Vermont's transition to 100% renewable, low carbon energy. We are eager to help identify and pursue the most effective strategies for decreasing our members' total carbon emissions, while also meeting their needs for safe, reliable energy. Our priorities include strengthening our shared grid infrastructure and increasing storage capacity to improve our ability to efficiently utilize renewable generation, expanding investments in weatherization, and supporting transitions to beneficial electrification technologies. In its current format, Vermont's net metering program makes achieving all three of these priorities more difficult.

William Discoll, Associated Industries of Vermont

Although AIV does not sign on to the updated framework language submitted by GMP on behalf of many of the utilities and other working group members, we do recognize and appreciate that it makes positive progress, and that we hope to work on further changes on outstanding issues in the Legislature, including the treatment of clean energy alternatives, additional flexibility in tier requirements, and the timing and scope of PUC review of implementation in the coming years.

The following comments and proposal are from the following Working Group members:

GlobalFoundries
Stowe Electric Department
Vermont Public Power Supply Authority
Washington Electric Cooperative
Burlington Electric Department
Vermont Electric Cooperative
Vermont Electric Power Company
Green Mountain Power
Sierra Club
Vermont Natural Resources Council
Renewable Energy Vermont
VPIRG
Conservation Law Foundation

We appreciate the opportunity to provide additional comment on a potential framework to update the Renewable Energy Standard (RES) in the upcoming session. Vermont was at the forefront of energy policy when the original RES was enacted in 2015. Since adoption, we have seen substantial decreases in the carbon intensity of the electricity consumed in Vermont, paving the way for clean electrification of the transportation and thermal sectors. The updates spelled out to the RES will further decarbonize the electric sector and bring Vermont in line with the renewable energy requirements elsewhere in New England.

Vermont continues to lead the way and we believe there is a path for achieving 100% renewable energy delivered to Vermonters in a way that balances affordability and additional new renewables. Some Vermont utilities have already achieved and maintain a 100% renewable status. They will bring on new renewables as their load grows. For the utilities who are not yet at 100%, this proposal moves to 100% renewable by 2030 with additional targets for in-state and new renewables in subsequent years.

What follows is a framework that reflects each utility's approach, and a shared commitment to achieve bold renewable requirements with enough flexibility to ensure cost-effectiveness for customers. It is important to note that we view this framework as comprehensive, meaning that we offer it as a complete package, while also recognizing that not all of the co-signatories below agree completely on all these provisions. That is why changes to the RES should not move forward without this agreed upon framework.

The structure of the Renewable Energy Standard Legislative Working Group provided a productive forum for discussion, and we look forward to continuing the dialogue as the 2024 legislative session gets underway.

Group A: Distribution utilities who were 100% on or before 2015 continue similar treatment as in current RES
- WEC
- BED
- Swanton

Group B: Municipal Utilities
- VPPSA member utilities
- Hyde Park
- Stowe

Group C: All others
- GMP
- VEC

Group D: Distribution Utility with One Customer

Proposed Tier Amendment for Tier 1
Tier 1 - 30 V.S.A. § 8005(a)(1)(B) – Total Renewable Energy
- Increase 75% in 2032 to 100% in 2030
- No changes to eligible resources. Please refer to the updated definition of biomass eligibility under "Other Considerations" on page 3.
- Ramp rate
  - Minimum of same path that would have got you to 75% by 2032
  - Backloaded for the remainder - or flexibility for the DU's to ramp as needed to achieve 100% by 2030
- Utility Approach
  - Group A, C, and D included
  - Group B by 2035

Proposed Tier Amendment for Tier 2
Tier 2 - 30 V.S.A. § 8005(a)(2)(C) - Distributed Renewable Energy
- Increase from 10% in 2032 to 20% in 2032/2035
  - Keep ramp rate linear starting in 2025 increasing to 20% by 2032
- Eligible resources expanded to include: for Group B, owned hydro facilities under 5MW; for nonmunicipal DUs this would include owned hydro under 5MW that are LIHI certified. Can include facilities that become LIHI certified in the future.
  - Please refer to the updated definition of biomass eligibility under "Other Considerations" on page 3
  - Resources dated January 1, 2010 or later

- For utilities subject to Tier 1A or Tier 1B, Tier 2 resources are also eligible to be used to satisfy Tier 1A/1B requirements
- Utility Approach
  - Group A excluded
  - Group B included by 2035
  - Group C by 2032
  - Group D by 2035, including on-site projects >5MW

Proposed NEW Tiers: 1A and 1B
Tier 1A (New Renewables any size capable of being delivered into ISO-NE, commissioned post 2010 excludes new large hydro and new biomass unless it meets the performance standard below; expansions of existing eligible plants, not including expansions of biomass or large hydroelectric plants, would count) - 30 V.S.A. § XXXX

- [20%, GMP by 2032 or 2035] [10%, VPPSA/VEC/GF by 2035]
  - Ramp rate: Allow DU's the flexibility to meet the obligation with appropriate ramp rate for the DU.
  - ACP considerations
    - How should Tier 1A ACP be set? Reference Massachusetts Class 1 language
    - If ACP payment is required, funds paid by the utility are available to be used to benefit of the customers of the same utility for specific projects/programs with a focus on LMI customers
- Tier 2 are also eligible to be used to satisfy Tier 1A requirements
- Utility Approach
  - Group A excluded
  - Group B and VEC included at 10% by 2035
  - GMP at 20%
    - Load growth met with new renewables post-2035 or 2032 if the PUC determines that the date should be moved up from 2035 to 2032 by evaluating availability and affordability of resources capable of being delivered to the region
  - Group D included in Tier 1A. Group D may utilize additional Tier 1A to satisfy Tier 2 requirements beyond what is met with on-site Tier 2 qualifying projects (as defined above) if Tier 2 eligible projects would exceed the T2 ACP or are not economically feasible

Tier 1B (load growth Tier for 100% utilities) - 30 V.S.A. § XXXX

- Same definition of "new renewables" as defined in Tier 1A
- Portion of load growth over a set baseline [2023 or 2024 DU Total Load] met with Tier 1A qualified renewables
  - ACP considerations. Reference Massachusetts Class 1 language?
- Tier 2 resources are also eligible to be used to satisfy Tier 1A requirements
- RES Compliance provision and flexibility to use other resources if needed (add in language under existing RES)
- Utility Approach
  - Group A included
  - Group B, C, and D excluded

Tier 3
Tier 3 - 30 V.S.A. § 8005(a)(3)(B) - Energy Transformation

● BED: language allowing utilities to go above and beyond what is needed in Tier 3
● GF: amend 8006 to allow GHG credit eligible projects to satisfy Tier 3 requirements (does not require amendment to Tier 3 language)

Net Metering
Net Metering - 30 V.S.A. §

● Eliminate GNM (language from H.320) amending 30 V.S.A. § 8002
● Maintain path for affordable housing which may be a separate program outside of net metering
● Update net metering language to include the ability for eligible utilities to sell net metering RECs and be able to access pre-2017 net metering 1.0 RECs to meet Tier 2 obligations
● Any agreement on this framework is contingent upon agreement with broader net metering reform

Note: Washington Electric Cooperative is not supportive of this net metering approach as WEC does not believe it goes far enough to address issues of cost shifting and increased rates and has submitted additional comments outlining these concerns.

Other Considerations
30 V.S.A. §

● Retain exemptions for 100% utilities except for Tier 1B
● Have PUC revisit economics and resource availability in 2028 (5-year point)
● For the eligibility of biomass throughout the proposed updated RES, please refer to this section:

○ (1) Distributed renewable generation that employs biomass to produce electricity shall be eligible to count toward a provider's distributed renewable generation or energy transformation requirement only if the plant satisfies the requirements of 30 VSA 8005(d)(3) and produces both electricity and thermal energy from the same biomass fuel and the majority of the energy recovered from the plant is thermal energy.
○ (2) Distributed renewable generation and energy transformation projects that employ forest biomass to produce energy shall comply with renewability standards adopted by the Commissioner of Forests, Parks and Recreation under 10 V.S.A. § 2751. Energy Transformation Projects that use wood feedstock, except for non-commercial applications, that are eligible at time of project commissioning to meet the renewability standards adopted by the Commissioner do not lose eligibility due to a subsequent change in the renewability standards after the project commissioning date.
○ (3) No new wood biomass electricity generation facility or wood biomass combined heat and power facility coming into service after January 1, 2023, shall be eligible to satisfy any requirements of sections 8004 and 8005 of this title unless that facility achieves 60% overall efficiency and at least a 50% net lifecycle greenhouse gas emissions reduction relative to the lifecycle emissions from the combined operation of a new combined-cycle natural gas plant using the most efficient commercially available technology. Any energy generation using wood feedstock from an existing wood biomass electric generation facility placed in service prior to January 1, 2023, remains eligible to satisfy any requirements of 8004 and 8005 of this Title. Changes to wood biomass electric facilities that were placed in service prior to January 1, 2023, including converting to a combined heat and power facility, adding or modifying a district energy system, replacing electric generation equipment or repowering the facility with updated or different electric generation technologies, do not change the in service date for the

facility, or affect its eligibility to satisfy the requirements of sections 8004 and 8005 of this title, or qualify it as new renewable energy.

Appendix 4- Brattle Group Report- Economic Impacts of Expanding Vermont's Renewable Energy Standards- Attached as PDF.

Economic Impacts of Expanding Vermont's Renewable Energy Standards

PRESENTED BY

Dr. Dean Murphy

Dr. Wonjun Chang

Ellie Curtis

Paige Vincent

PRESENTED FOR

Renewable Energy Standard Reform Working Group

DECEMBER 14TH 2023

Brattle

Objective and Approach

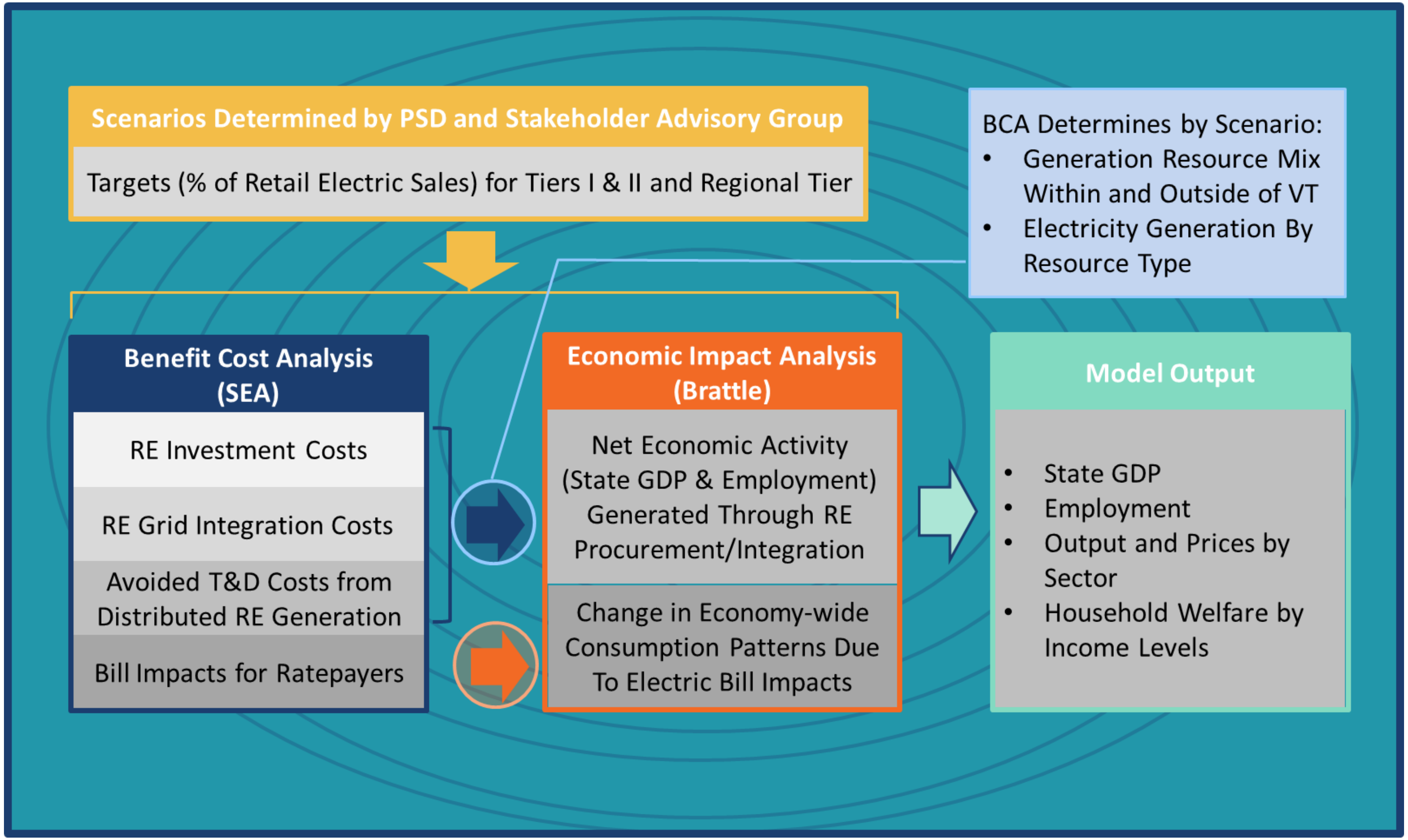
Project Objective

- Assess the macroeconomic impacts to Vermont under various scenarios of Vermont's Renewable or Clean Energy Standard (RES), including impacts to gross domestic product and employment.

Approach

- Provide economic impact analysis (EIA) for six core scenarios regarding how to expand Vermont's RES. Scenarios were designed jointly by the Department of Public Service and Stakeholder Advisory Group.
- Maintain consistency with the Benefit-Cost Analysis (BCA) conducted by *Sustainable Energy Advantage, LLC* (SEA). BCA output such as rate impacts, incremental generating resource additions and incremental costs of renewable energy are used as inputs in the economic impact analysis.

Benefit-Cost & Economic Impact Analysis Overview



Overview of Scenario Definitions

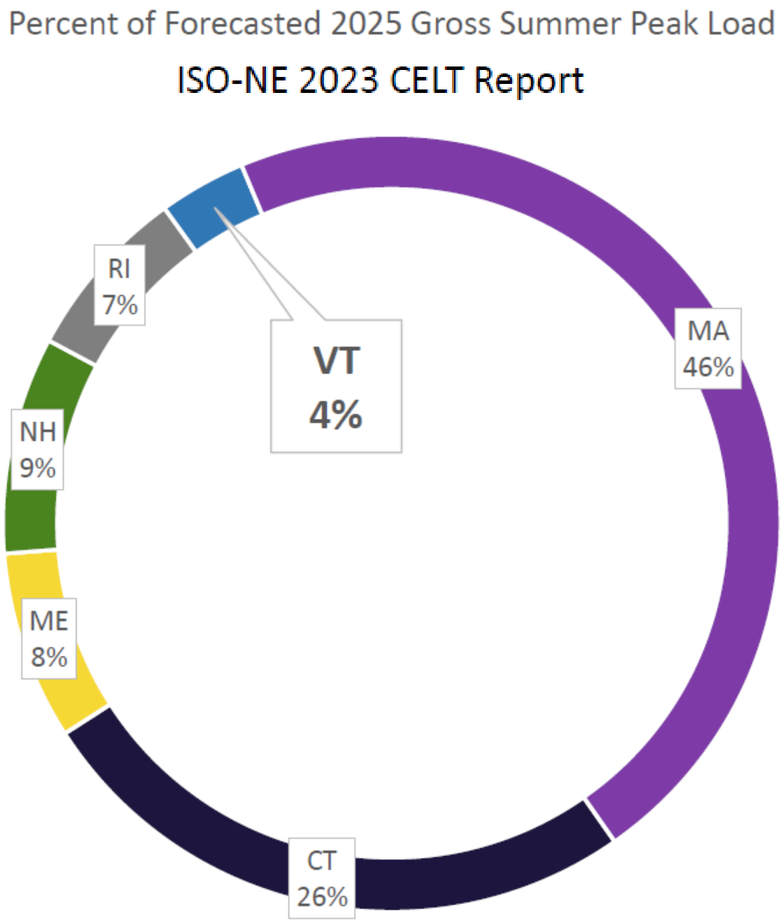
We model the six core scenarios defined by the Department and Stakeholder Advisory Group.

- **Business as Usual (BAU):** 75% by 2032 consisting of 10% Tier I, 65% Tier II.

Scenarios → Design Element ↓		BAU	Scenario 1: 100% RES	Scenario 2: 100% RES, incl. Regional Tier	Scenario 3: 100% CES	Scenario 4: 100% CES, incl. Regional Tier	Scenario 5: 100% RES, no biomass	Scenario 6: 100% CES, no biomass, Reg + T-II combo
Tier I, Net	Target	65%	70%	40%	70%	40%	50%	40%
	Target Date	2032	2035	2035	2035	2035	2035	2035
	Eligibility Changes	N/A	None	None	Add nuclear	Add nuclear	Remove biomass	Add nuclear; remove biomass
Tier II	Target	10%	30%	30%	30%	30%	20%	Combined with Regional Tier
	Target Date	2032	2035	2035	2035	2035	2035	
	Eligibility Changes	N/A	None	None	None	None	None	
Regional Tier	Target	N/A	N/A	30%	N/A	30%	30%	60%
	Target Date	N/A	N/A	2035	N/A	2035	2035	2035
	Eligibility*	N/A	N/A	2010+	N/A	2010+	2010+	2010+

- Six core scenarios varying allocation of tiers and technology eligibility in Tier I:
  - **Tier II:** 10%, 20%, 30%; **Regional Tier:** 0%, 20%, 30%, 40%, 50%; **Tier I:** Fills 'gap' to 100%
  - **Tier I eligibility:** with/without Biomass; with/without nuclear

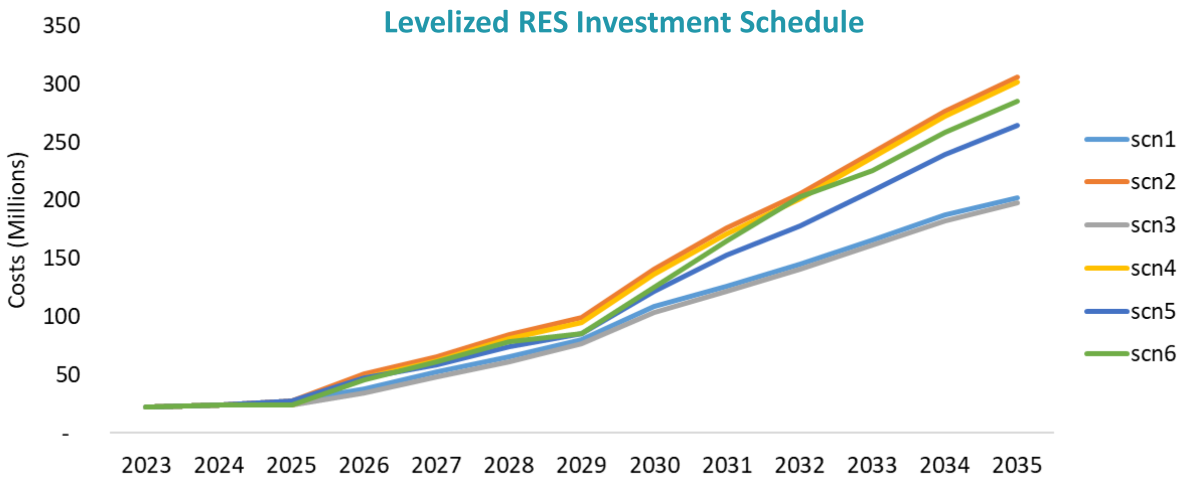
RES Investment Costs Borne by Vermont

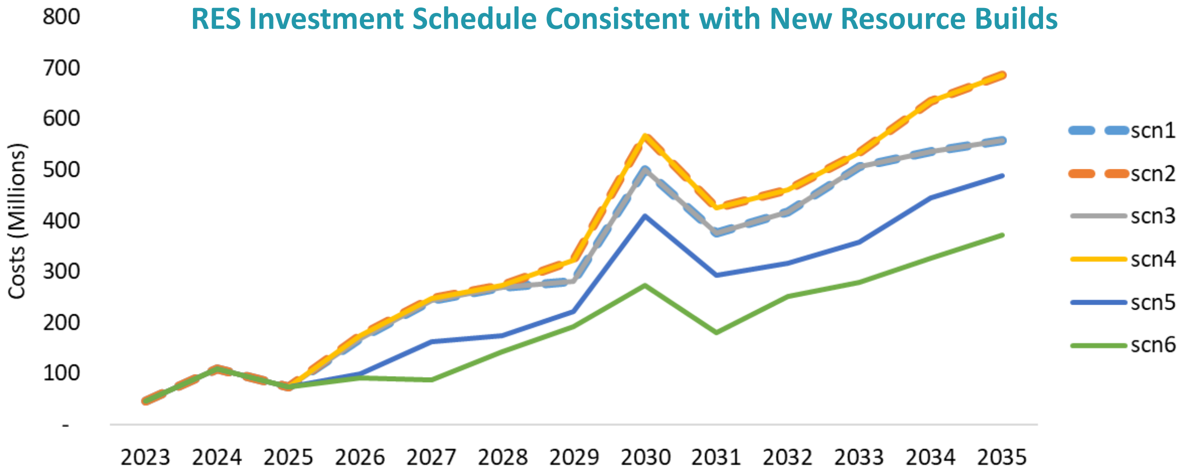


- Vermont consumers bear the costs of RES expansion:
  - Benefits of new renewable generation are shared by all New England ratepayers.
  - Vermont similarly benefits from resources driven by programs originating from other New England states.
  - In the BCA’s incremental cost calculation, only the 3-4% of benefits accruing to Vermont are accounted for.

RES Investment Costs: New Resource Investment

- In the BCA, the costs of renewable energy are levelized:
  - The “lumpiness” of investments involved in building and operating resources are smoothed over the life of resources.
  - Cost smoothing is important in comparing costs and benefits across RES scenarios.
- To capture the economic impacts from investment in *new resources*, Brattle and SEA estimated an “unlevelized” investment schedule that assumes new facility builds occur immediately prior to deployment.
- Costs of *existing resources* are assumed to included in the macroeconomic dataset.

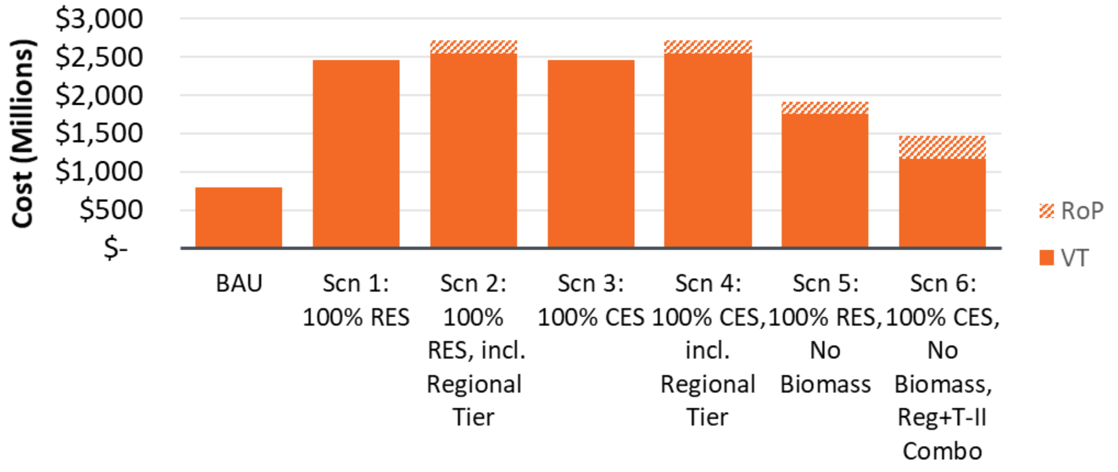




Geographic Distribution of New Resource Investment

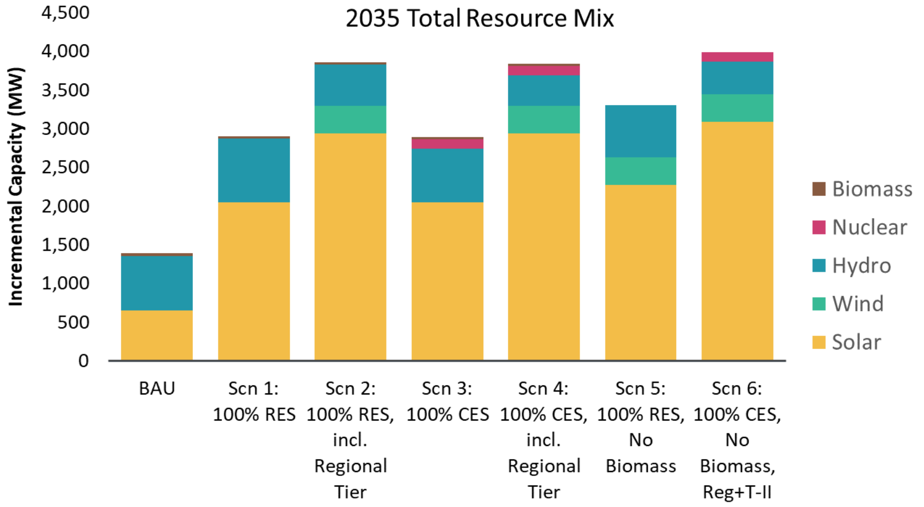
- Incremental resources procured within Vermont create economic activity (increased state GDP and employment) predominantly within Vermont.
  - Projects within Vermont will still require some out-of-state and foreign industrial inputs.
- Out-of-state resource procurement projects are assumed to create economic activity in the rest of the pool (RoP).

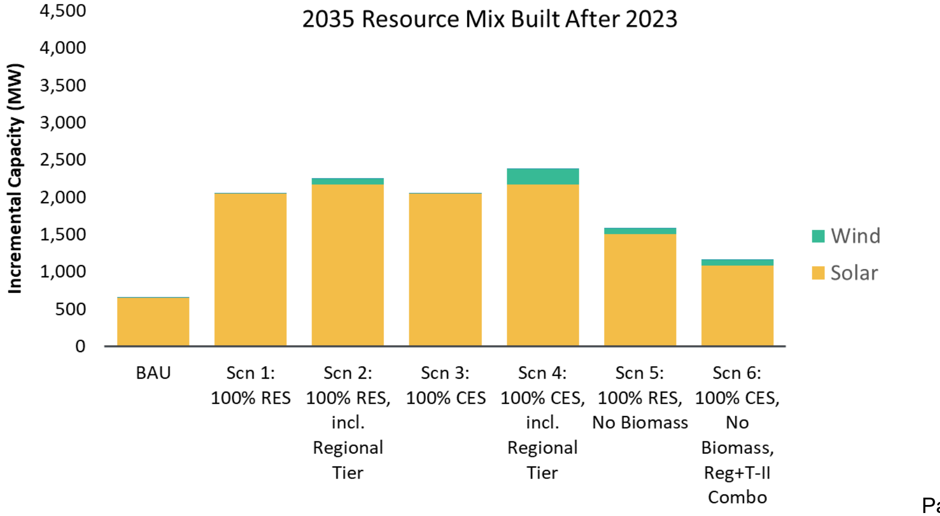
Cost Breakdown of Incremental New Build Costs by Region: VT vs. Rest of Pool (RoP)



Distribution of New Resource Investment by Resource Type

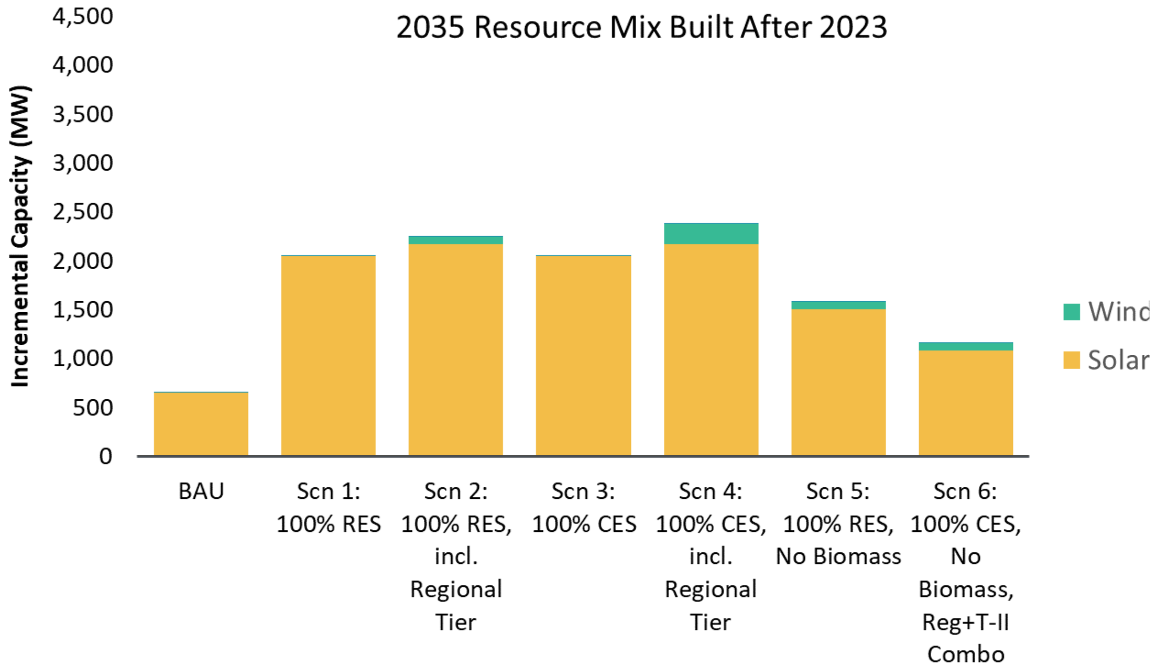
- BCA also provides incremental resource additions by scenario. Incremental renewable energy costs are used to invest in a scenario-specific resource mix.
- Costs incurred by Vermont's electricity sector are payments to the production sectors of the economy involved in the procurement of resources.
- Different resource types will use different (and different amounts of) industrial inputs; i.e., the resource mix will determine how investment costs are distributed throughout the economy.

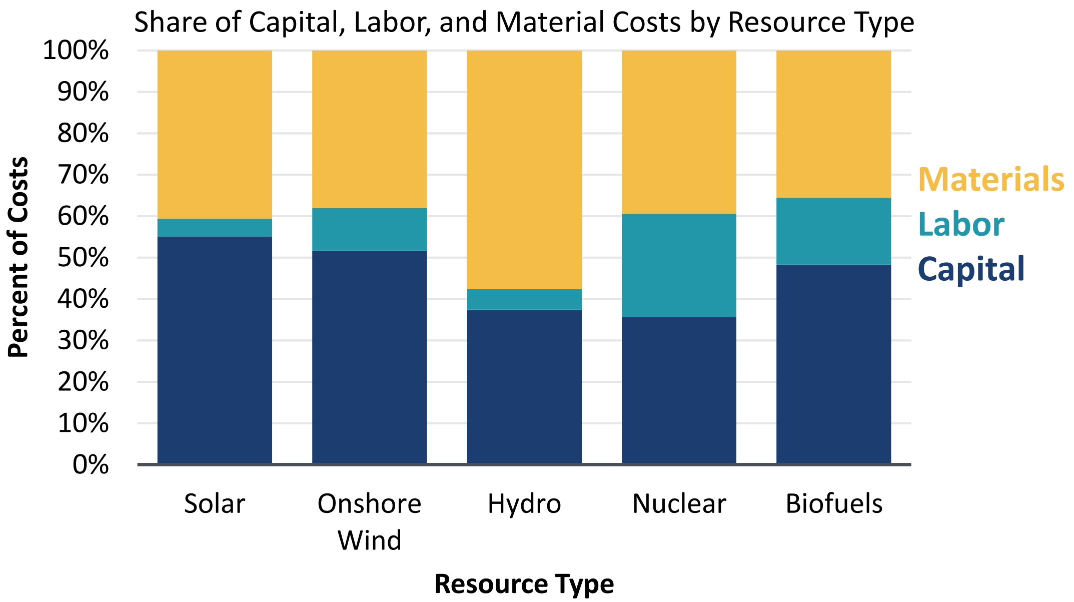




Translating New Resource Investment into Industrial Inputs

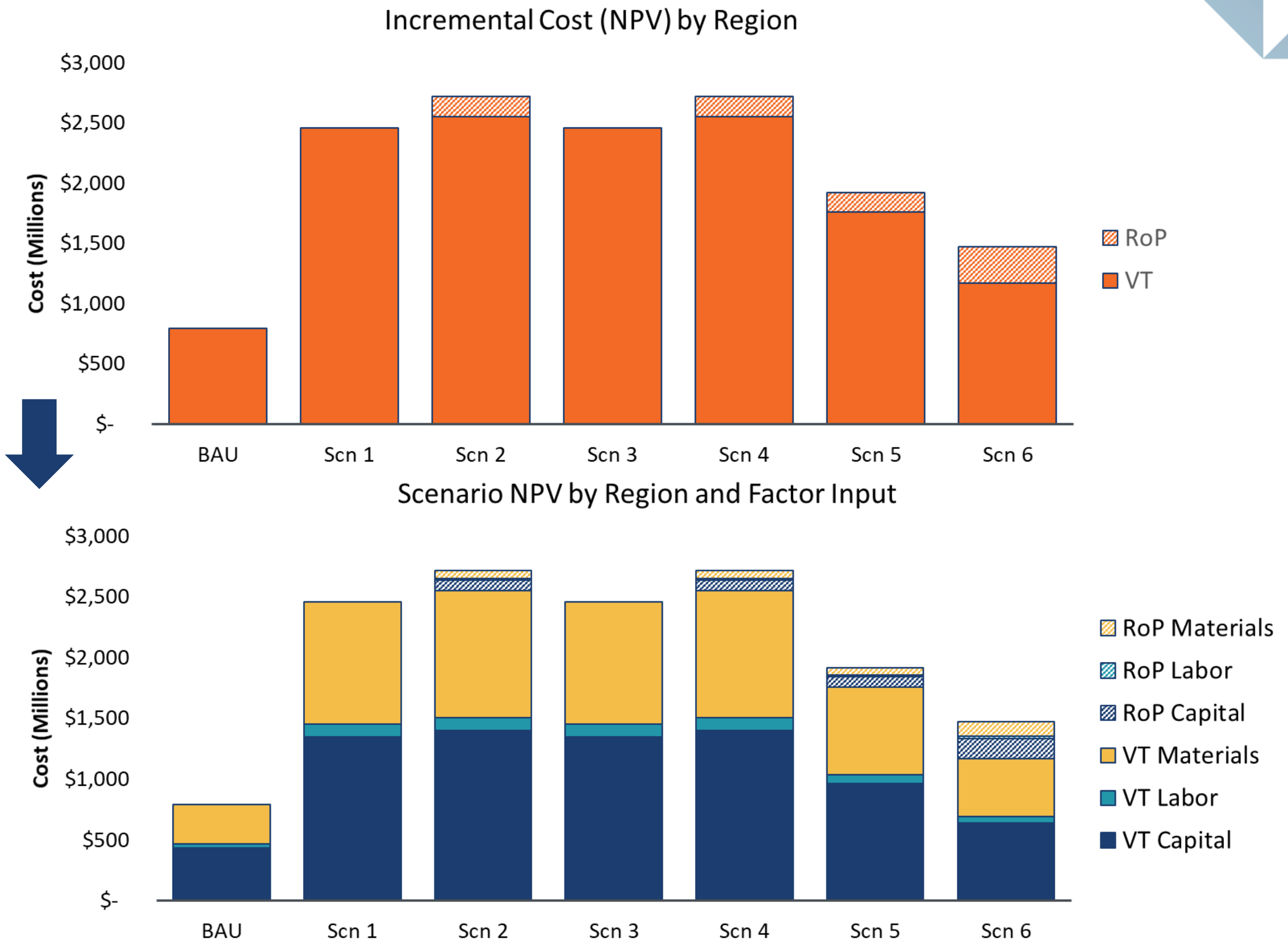
- Electricity generation technology cost data from the Energy Information Administration (EIA), International Energy Agency (IEA) and the National Renewable Energy Laboratory (NREL), are used to breakdown resource costs into economic factors of production.
- Factors include physical capital (e.g., computers), labor employment and intermediate input goods (materials). Intermediate goods refer to goods produced by other sectors.





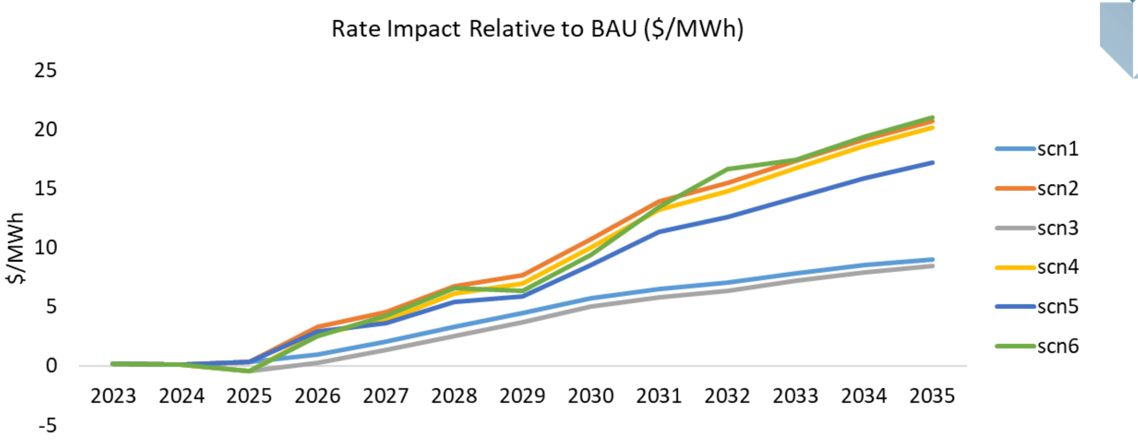
Translating RES Investment into Production Factors

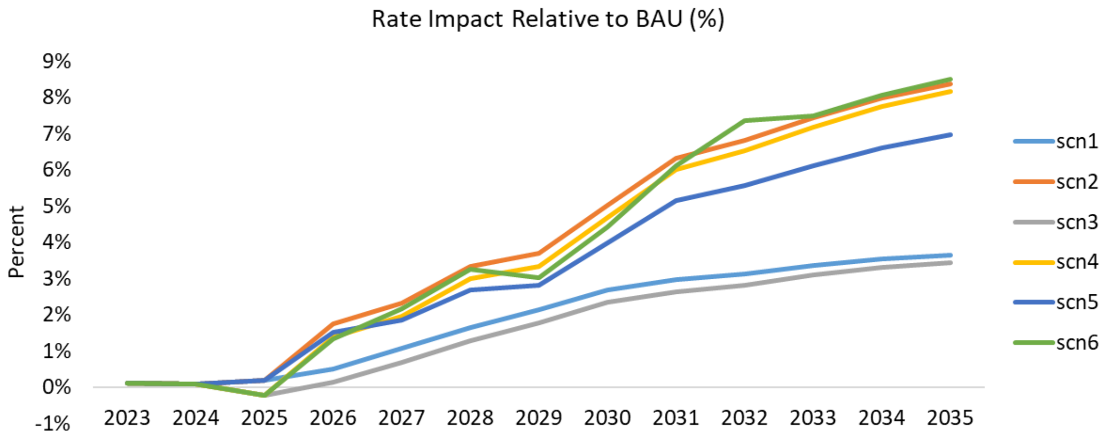
- The result is each regional electricity sector's incremental factor use, which is obtained using:
  - Resource mix for each scenario
  - Geographic distribution of resources in Vermont and the rest of the pool
  - Resource cost breakdown into economic factors of production
- Procurement of renewable and clean energy resources in New England generates demand for other goods and services and creates price effects in the labor and capital markets.



Rate Impacts by Scenario

- Rates are expressed as change from the BAU scenario. Rates account for both incremental costs and benefits that would impact bills.
- BCA shows that rate impact increases as RES target increases.
- Scenario 6 has the highest rate impact in 2035. Rate increase relative to BAU reaches approximately 8.5% by 2035.
- All else equal, increased rates translate to less disposable income for ratepayers:
  - Less income for non-electricity goods can lead to decreased demand for those goods
  - Less budget for non-electricity inputs can induce less production in production sectors.





BCA Perspective Used in Calculating Net Costs

SEA outputs BCA results based on two perspectives: Reference Case

- Societal Cost Test (SCT)
  - Includes all market costs and benefits
- Ratepayer Impact Measure (RIM)
  - Includes only costs and benefits that would affect Vermont electricity bills

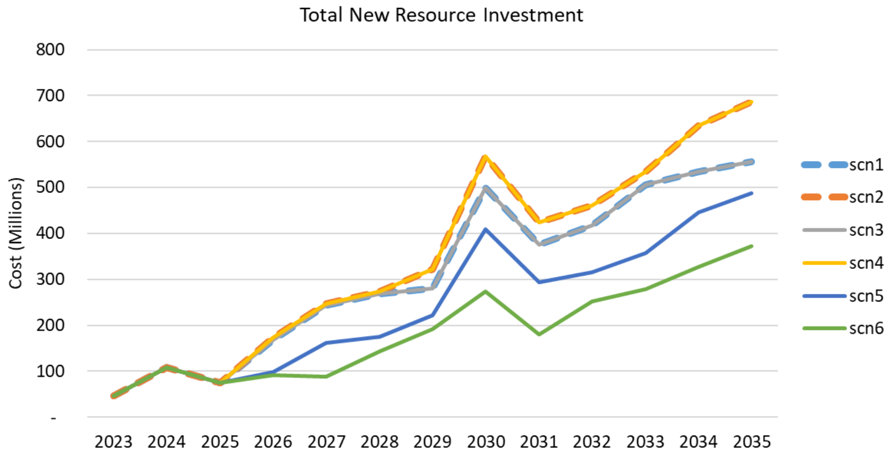
Economic impact analysis (EIA) uses the RIM-based BCA results.

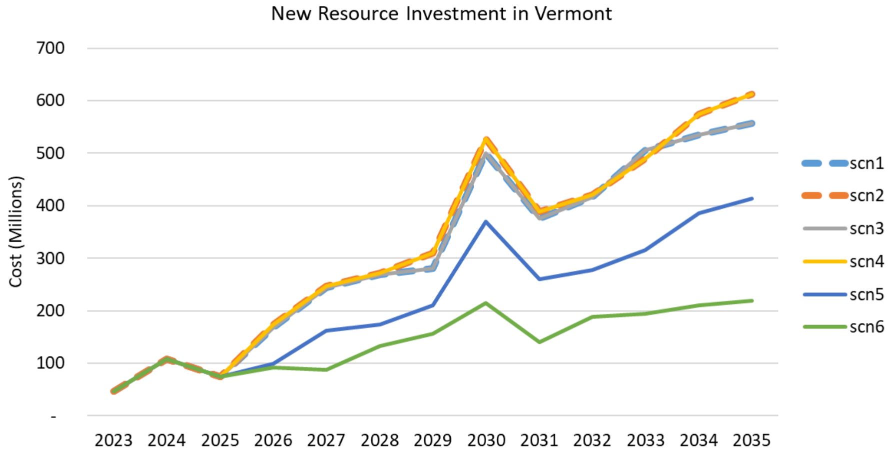
Value Stream	Societal Cost Test (SCT)	Ratepayer Impact Measure (RIM)
Incremental cost of resource	Cost	Cost
Transmission integration costs	Cost	Cost (VT only)
Intercxn distribution system upgrades	Benefit	Benefit
Uncleared capacity value	Benefit	Benefit (VT only)
Reduced share of capacity costs	N/A	Benefit
Price suppression	Benefit	Benefit (VT only)
Avoided transmission costs	Benefit	Benefit (VT only)
Reduced share of transmission costs	N/A	Benefit
Reduced distribution costs	Benefit	Benefit
Reduced transmission losses	Benefit	Benefit (VT only)
Reduced distribution losses	Benefit	Benefit
Improved generation reliability	Benefit	Benefit (VT only)
Non-embedded GHG emissions	Benefit	N/A
NOx emissions	Benefit	N/A
Local pollutants	Benefit	N/A
RE development land use	Cost (not monetized)	N/A
Fossil fuel water use	Benefit (not monetized)	N/A

Key Drivers of Economic Impacts

Economic impacts in each scenario are driven by:

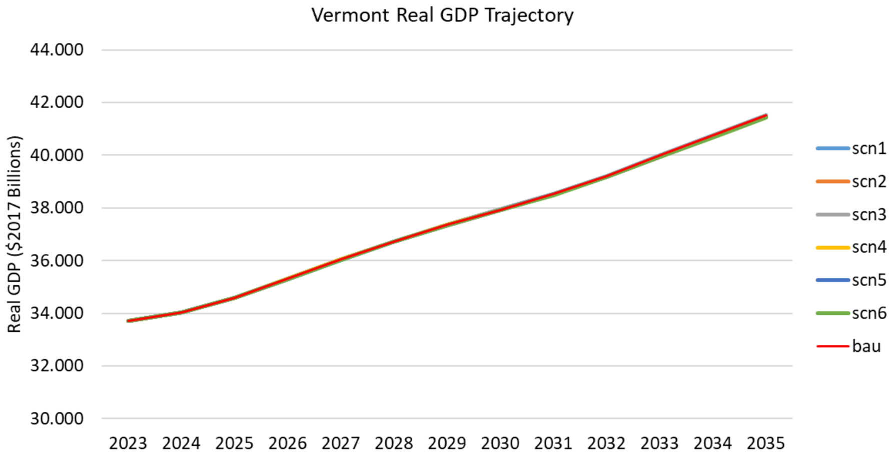
- **Total investment needs to meet Vermont's RES:**
  Total investment costs determine the efficiency in which the RES is satisfied. A more cost-efficient scenario means more production ending up as final consumption and less as industrial inputs used for electricity generation.
- **Amount of investment that takes place in Vermont:**
  Incremental resources built within Vermont create economic activity in non-electricity sectors. Production and employment in the transportation, energy-intensive manufacturing, and services sectors contribute to GDP.
- **Electricity rate changes:**
  Increase in rates results in less disposable income for consumers and producers to spend on non-electricity goods and services.

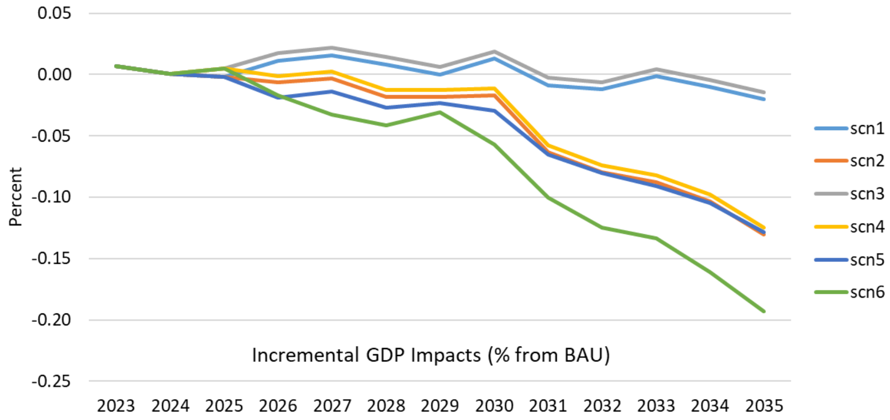




Economic Impacts: GDP Growth

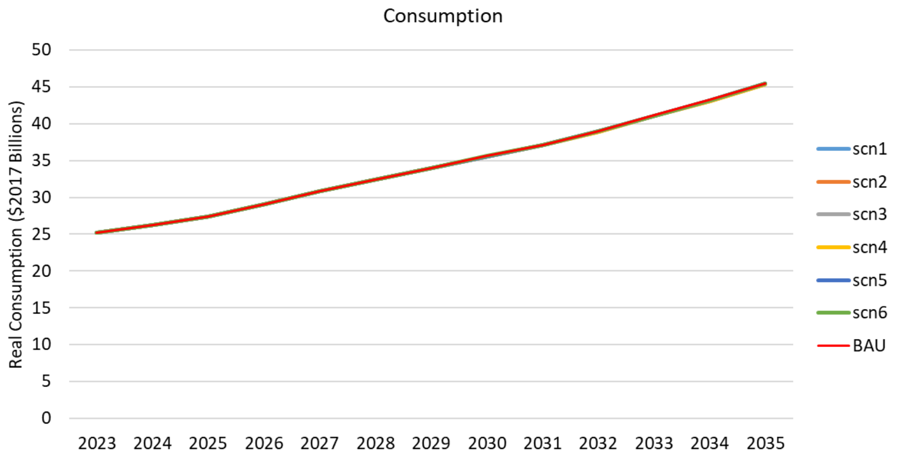
- GDP grows but at a *slightly* slower rate relative to BAU
- 100% RES (Scn1) and CES (Scn3) scenarios result in the highest GDP growth
  - High investment in new renewable resources in Vermont
  - Low rate changes
- 100% CES, No Biomass, Regional+T-II Combo scenario (Scn6) results in the lowest GDP growth
  - Low investment in new renewable resources in Vermont
  - High rate changes
- High VT investment levels and high rates offset each other in the 100% RES (Scn2) and CES (Scn4) scenarios
  - Produces similar GDP impact as in the 100% RES, No Biomass scenario (Scn5) characterized by medium rates and medium VT investment.

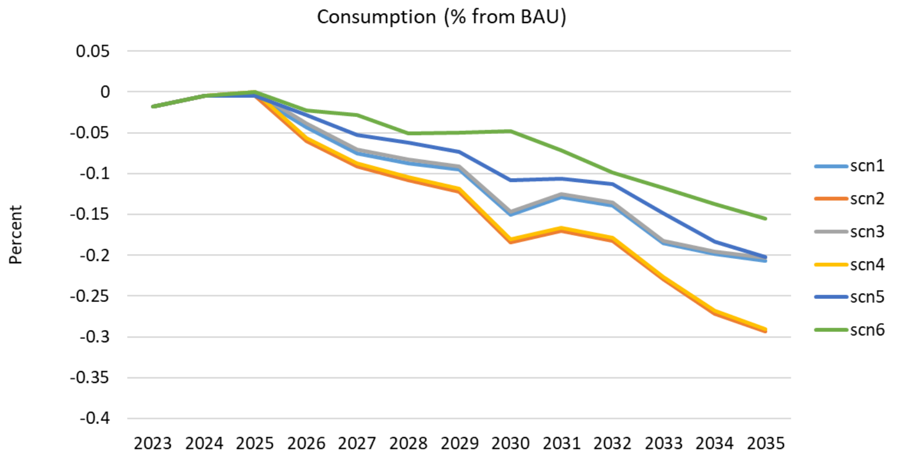




Economic Impacts: Consumption

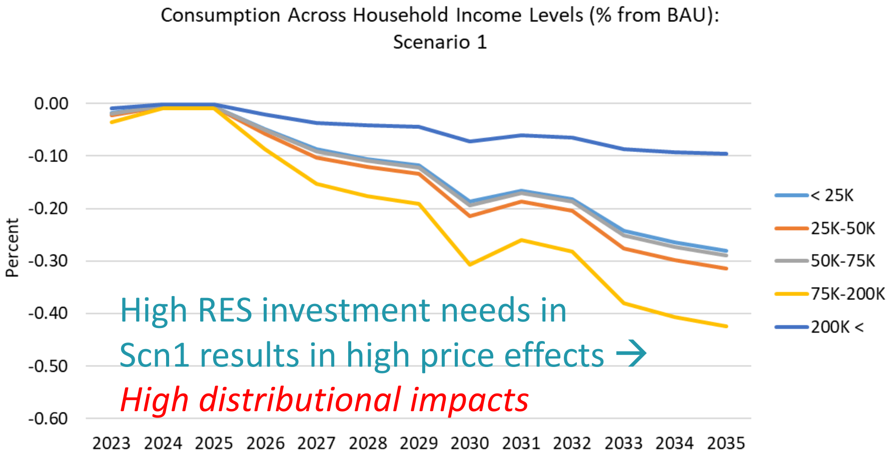
- Similar to GDP, consumption grows at a *slightly* slower rate relative to BAU.
- Consumption impacts are driven largely by the total investment needs to meet RES, and rate impacts.
- The 100% RES and CES w/ Regional Tier scenarios (Scn 2,4) have the slowest consumption growth since:
  - Increased production from high VT investment is consumed by the electricity sector to satisfy RES.
  - Higher demand for industrial inputs due to high-RES investment needs raises prices in non-electricity goods; e.g., services, energy-intensive manufacturing goods.
  - Coupled with higher rates, consumption decreases.
- Scenario 6 has the fastest growth due to low new investment needs. Scn 6 boosts GDP growth in RoP, also contributing to faster consumption growth.

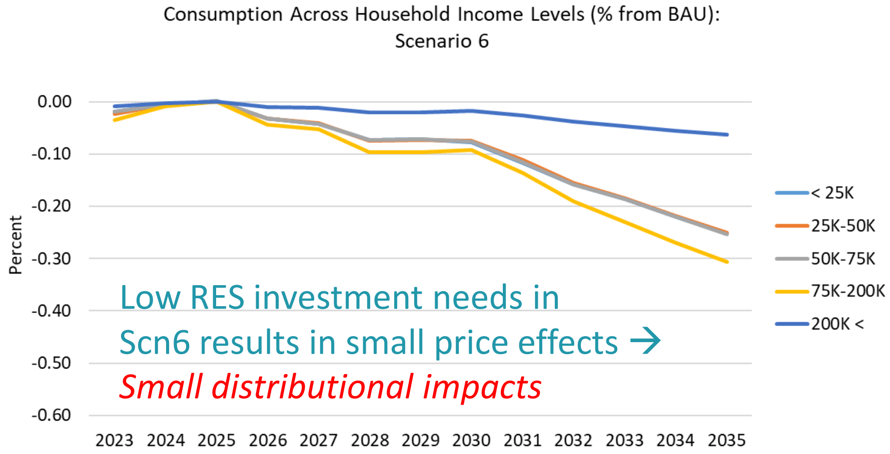




Economic Impacts: Consumption Across Income Levels

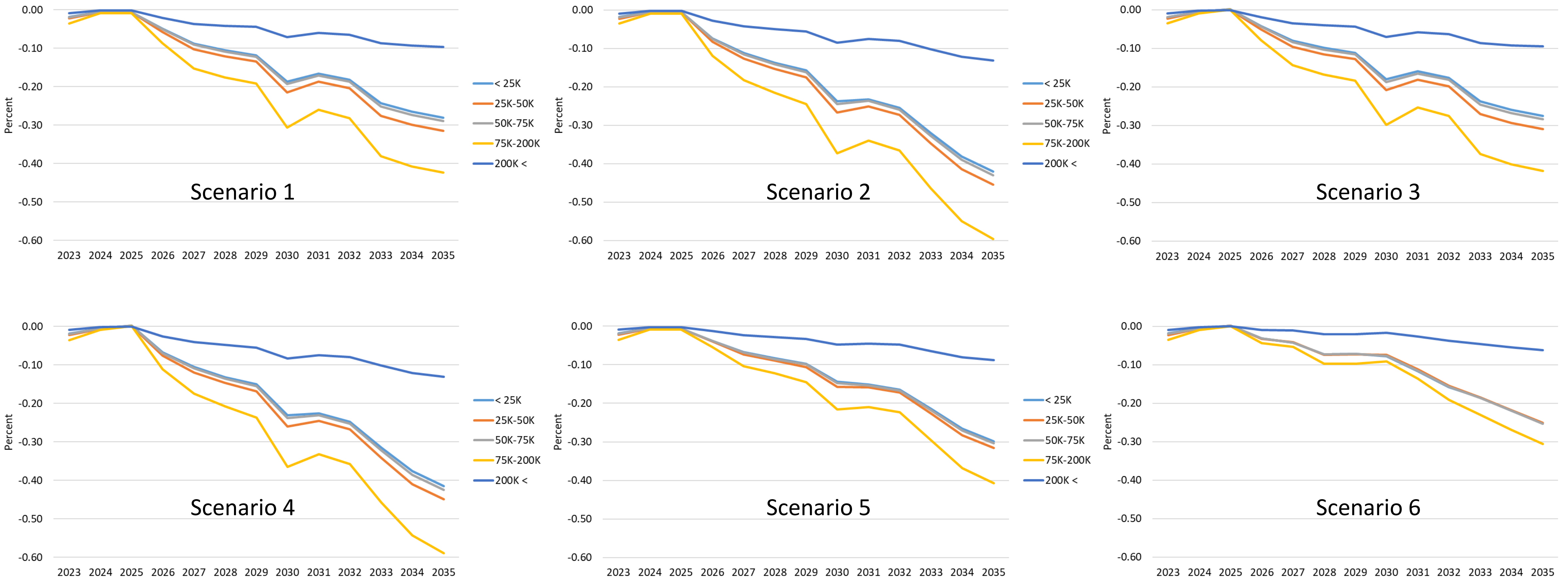
- Model uses input-data from the peer-reviewed work of the Wisconsin National Data Consortium (WiNDC).
  - Representative households by income group, used to characterize the economic behavior of an average consumer in their respective income levels, are modeled based on the Statistics of Income (SOI) data from the IRS.
- Consumption impacts across income groups are driven by the income share spent on consumption goods.
  - Lowest income households spend highest share of income on electricity.
  - But all income groups spend far more on services and energy-intensive manufacturing goods, goods that experience the highest price increase due to RES.
  - Among the sub-200K income groups, 75K-200K income group spends the most on these goods.





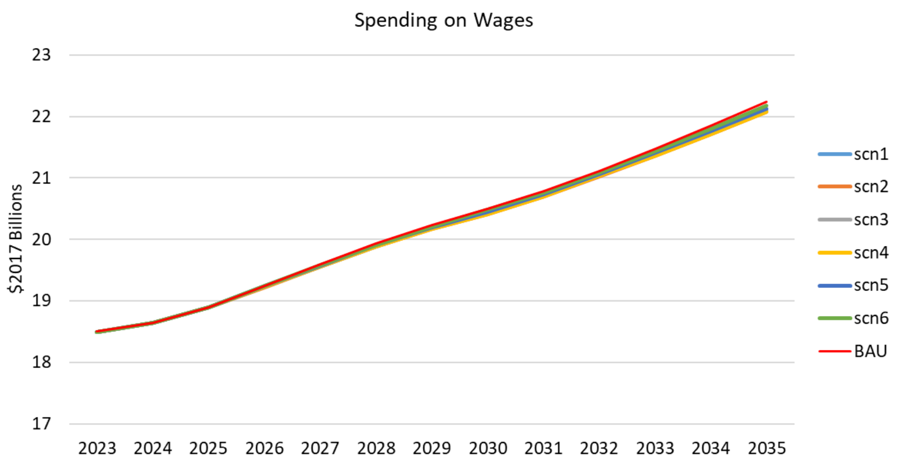
Economic Impacts: Consumption Across Income Levels

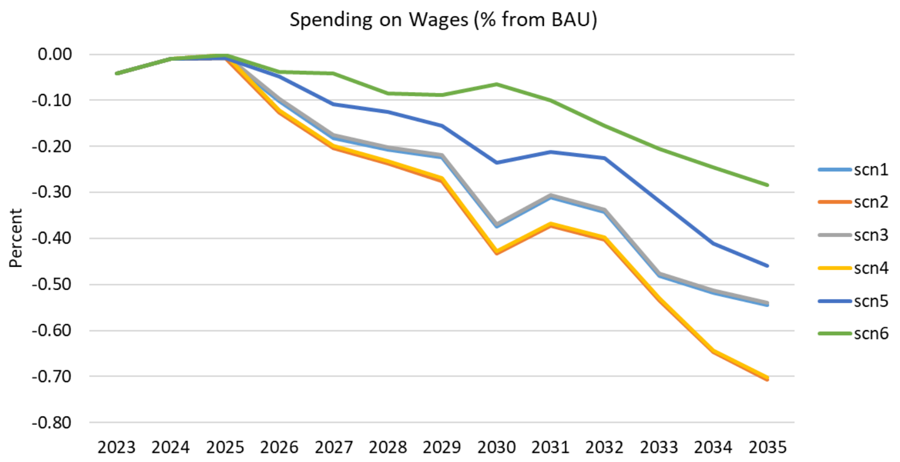
Change in Consumption Across Household Income Levels (% from BAU)



Economic Impacts: Employment

- Similar to GDP and consumption, spending on wages grows at a *slightly* slower rate relative to BAU.
- Employment follows a similar trajectory to consumption as both are driven largely by the total investment needed to meet Vermont's RES.
- Lower investment needs to satisfy the RES generally means less employment demanded to meet the policy goal. This results in more employment growth in non-RES related functions of the economy.
- Faster growth in scenario 6 is attributed to lower total resource builds.
  - Scenario 6 also has highest out-of-state investment, contributing to an increase in GDP for the rest of New England and hence employment in Vermont.



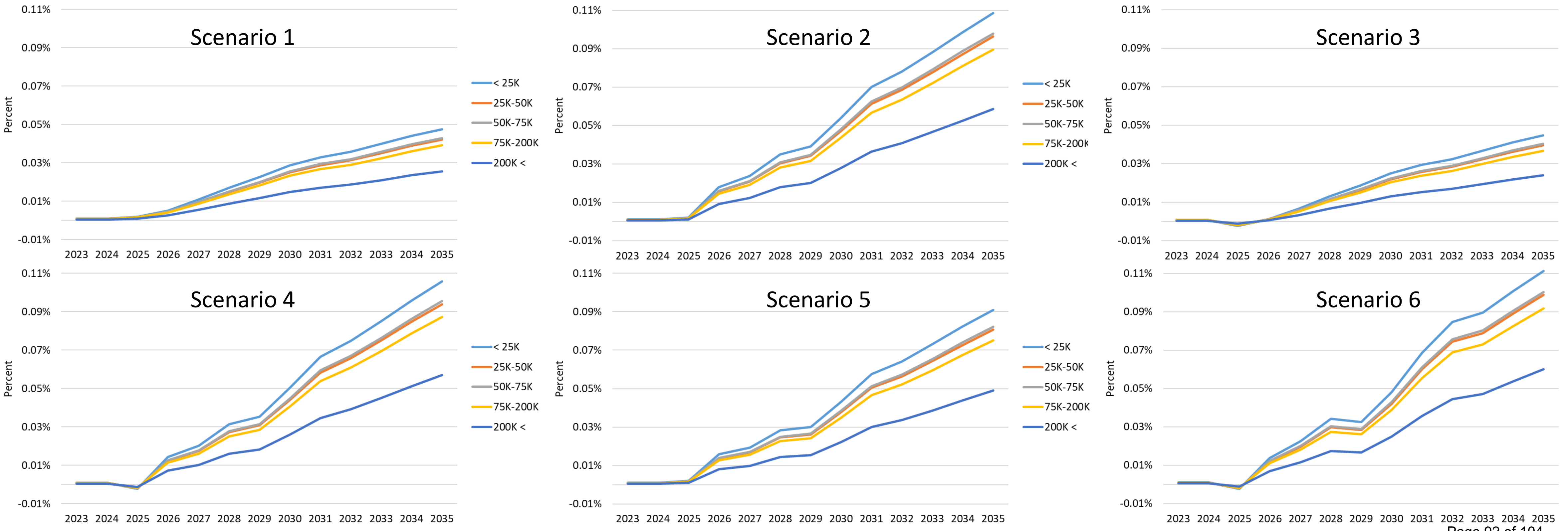


Economic Impacts: Energy Burden Across Income Levels

Energy burden is defined as the percentage of gross household income spent on energy costs.

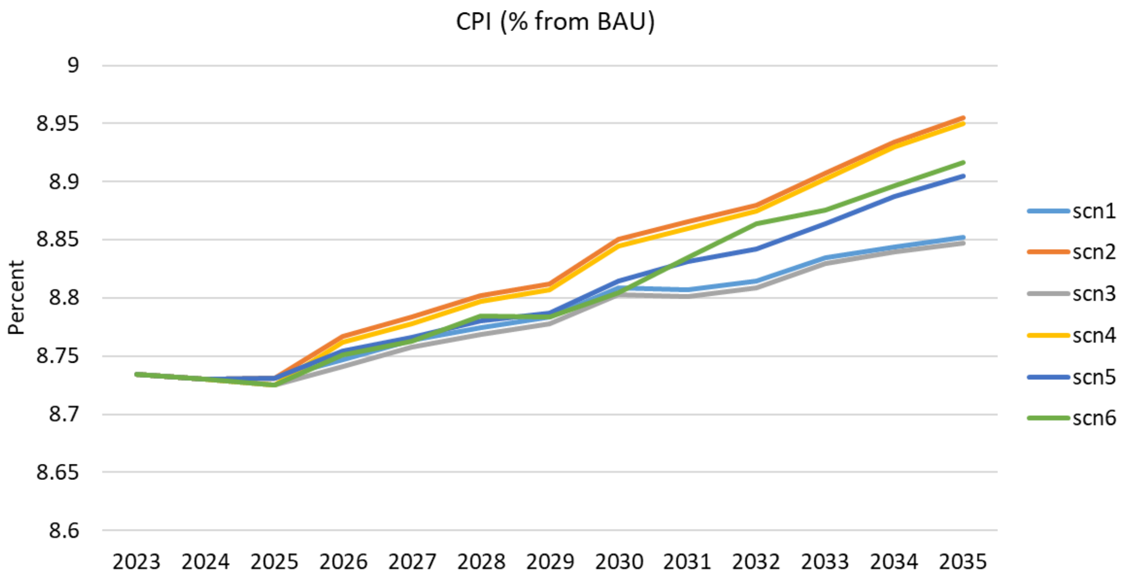
- Impacts on energy burden are largely driven by rate impacts (higher rates → higher energy burden)
- Energy burden increases more for lower income households

Change in Energy Burden Across Income Levels (From BAU)



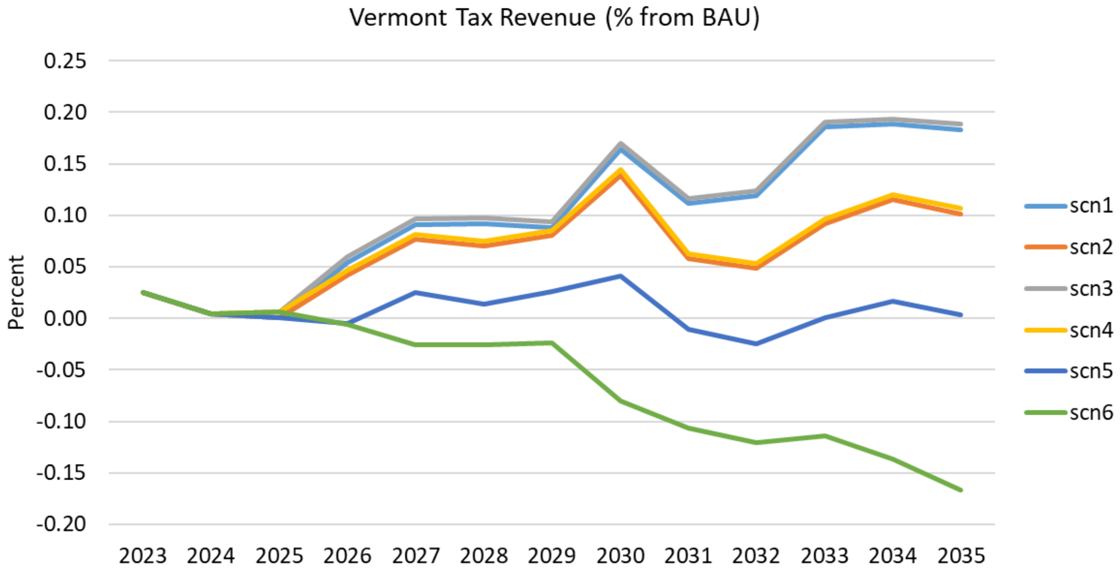
Economic Impacts: Consumer Price Index (CPI) in Vermont

- Similar to consumption, growth in the Consumer Price Index (CPI) is largely driven by total investment needs to meet RES, and rate impacts.
- The 100% RES and CES scenarios w/ Regional Tier (Scn 2,4) result in the highest increase in the CPI due to high rate impacts and high-investment needs.
  - High-investment needs create competition for resources in the economy, raising their prices.
- The 100% RES and CES scenarios (Scn 1,3) result in the lowest CPI increase due to low rate impacts.



Economic Impacts: Tax Revenue

- Sector output, the use of production inputs (capital, labor, goods produced by other sectors) and final consumption by households, are taxed.
- Scenarios 1-4 (Combination of 100% RES and CES w/ and w/out Regional Tier) have high new resource investment in Vermont, leading to higher production levels in parts of Vermont’s economy. This leads to higher tax revenue than in the BAU.
- Scenario 6 has the least amount of investment in Vermont, leading to low tax revenue from production. High rates also slow the economy down, contributing to lower tax revenue that BAU.



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Memorandum

To: VPPSA Board of Directors
From: Sarah Braese, Assistant General Manager
Date: December 29, 2023
Subject: Agenda Item # 12 Assistant GM & Regulatory/Power Services Update

Renewable Energy Standard Compliance (Tier 3)

As previously reported, on November 29, 2023, the PUC issued two Orders, one approving the 2022 RES Compliance Filings under Case No. 23-0773-INV, and a second Order denying the use of a proxy on EVT administered rebates to calculate low-income benchmark spending under Case No. 22-4421-INV.

These Orders call for VPPSA to resubmit its revised 2022 RES Compliance Filing with updated low-income benchmark spending. VPPSA's revised calculations show that while the MWhe Savings for Low-Income Customers represents 15% of Total Savings, Low-Income Participation represents 27% of Total Incentives paid through the Program.

Low-income Definition [s]	# LI Participants [t]	% LI Participants [u]	MWhe Total [v]	% LI MWhe [w]	LI Incentive total [x]	% Incentive [y]
VPPSA Administered: At or Below 80% Statewide AMI	67	12%	781	6%	$ 28,950	14%
EVT Administered: As Reported for Mid-/Down-Stream Rebates	43	8%	1,113	9%	$ 27,750	13%
TOTAL	**110**	**20%**	**1,894**	**15%**	**$ 56,700**	**27%**

Customer Class	Total Savings (MWhe)	Total Incentive	Total Gross Cost	Savings %
Program	29,811	$327,799	$355,613	100%
Residential	12,606	$210,359	$222,121	42%
Commercial and Industrial	17,205	$117,440	$133,492	58%
Low Income *	1,894	$56,700	$58,467	15%

VPPSA will be reviewing and revising its 2024 RES Tier III Annual Plan to reflect the PUC's November Order and adjust equitable opportunity tactics as needed for the January 19, 2024 Filing Deadline.

Rulemaking Proceedings:

Case No.19-0855-RULE PUC Rule 5.100 Net Metering – Comments on standardized statewide reporting format requested.

Case No. 19-0856-RULE PUC Rule 5.500 Interconnection Rules & Procedures – Comments on standardized statewide interconnection application format requested.

Case No. 23-2220-RULE Clean Heat Standard (CHS)

New public facing website has been launched by the PUC to monitor and track the Clean Heat Standard's Regulatory Proceedings, see: https://puc.vermont.gov/clean-heat-standard.

In December, inaugural meetings of the Clean Heat Standard's Equity Advisory Group (EAG) and the Technical Advisory Group (TAG) were held to discuss design and implementation of the Standard. There are now multiple "Tags" being assigned to various elements of the rulemaking proceeding, with multiple concurrent comment and filing deadlines (see upcoming dates below). See Also: Case No. 23-2221-INV Establishing Default Delivery Agent(s)

Investigative Proceedings:

Case No. 17-4999-INV Disconnect Rules & Procedures – i.e. Act 47 Requirements

PSD filed a Status Update on Dec. 1st, including a recommended Schedule for Comment deadlines. The PSD then proposed revisions on Dec. 15th to comply with Act 47 requirements continuing with a "recommended reply comments" deadline of December 22nd. While several utilities filed their responses, no official PUC Order was issued on a Reply Comments Deadline and thus VPPSA will solicit additional feedback from members to file a response.

Case No. 23-3604-PET VPPSA Petition to Design EV/EVSE Tariff Rider Program for Member Utilities

Though somewhat stalled due to staff time and resource constraints, several staff continue to negotiate with the software developer to present and execute a comprehensive Master Services Agreement and Statement of Work to support the EV/EVSE rate rider and compliance obligations.

On Dec. 21st the PUC issued its Scheduling Conference Order, inclusive of a Public Workshop to be held Thursday, January 11th at 9:30 am via GoToMeeting.

Efficiency Vermont

EVT filed their 2024-2026 Triennial Plan on December 1st. They also filed with the PUC to amend their Demand Resource Plan on November 17th. The PSD and VPPSA filed comments on December 15th which challenge and question duplicative resources and costs that EVT has proposed. EVT responded on December 22nd.

Important Upcoming Dates & Deadlines

DATE	CASE NO./DESCRIPTION
January 3, 2024	SESSION BEGINS: 2023-2024 Vermont General Assembly
January 4, 2024	GOVERNOR'S STATE-OF-THE-STATE ADDRESS: Gov. Phil Scott (R)
January 8, 2024	COMMENTS DUE: Case No. 23-2220-RULE, 9-Other, Clean Heat Standard Funding Streams Report LEGAL BRIEFS DUE: Case No. 23-2220-RULE; 6 Regulated Entities PUC Authority to Maintain Regulated Entity Confidentiality or Required to Publish Data 2023 RES TIER III REBATE CLAIMS DUE: Customers should submit their Tier III Rebate Claims by January 8, 2024 for inclusion in the 2023 Program Year Reporting.
January 11, 2024 *9:30 am*	PUBLIC WORKSHOP: Case No. 23-3604-PET Petition of Vermont Public Power Supply Authority for approval of a proposed EV/EVSE tariff rider
January 12, 2024	COMMENTS DUE: Case No. 19-0855-RULE Net Metering – Standardized Data Collection Forms VELCO DATA REQUEST DUE: 2023 Load Distribution Data (Net and Gross Loads) COMMENTS DUE: Case No. 23-2220-RULE; 0 Procedural Issues – Comments on Proposed Schedule and Process to Solicit Public Input
January 12, 2024	VPPSA SERVES DISCOVERY ON PSD: Case No. 23-2861-PET VPPSA Advanced Metering Infrastructure Project
January 16, 2024	REPLY COMMENTS DUE: Case No. 23-2220-RULE Clean Heat Credit Ownership PSD SERVES FIRST ROUND OF DISCOVERY: Case No. 23-3604-PET EV/EVSE Tariff Rider Program
January 19, 2024	COMMENTS DUE: Case No. 19-0856-RULE Standard Application Forms for PUC Rule 5.500 Interconnection Rules and Procedures REVISED FILING DUE Case No. 23-3715-INV 2024 Annual Plan PSD FILES DISCOVERY RESPONSES: Case No. 23-2861-PET VPPSA Advanced Metering Infrastructure Project
(Week of) January 22, 2024	PUBLIC WORKSHOP: Case No. 23-2221-INV Investigation into the Clean Heat Standard Default Delivery Agent Costs & Quantities
January 23, 2024	GOVERNOR'S BUDGET ADDRESS: Gov. Phil Scott (R) FY2025 Budget
January 24, 2024 (9:30 am)	VSPC Quarterly Meeting (Delta Hotel, South Burlington, VT)
January 26, 2024	VPPSA REBUTTAL DUE: Case No. 23-2861-PET VPPSA Advanced Metering Infrastructure Project

January 31, 2024	VPPSA DISCOVERY RESPONSE DUE: Case No. 23-3604-PET EV/EVSE Tariff Rider Program
February 2, 2024	DEADLINE FOR STIPULATIONS/FURTHER PROCESS: Case No. 23-2861-PET VPPSA Advanced Metering Infrastructure Project
February 7, 2024	PSD SERVES SECOND ROUND OF DISCOVERY: Case No. 23-3604-PET EV/EVSE Tariff Rider Program
February 21, 2024	VPPSA DISCOVERY RESPONSE DUE: Case No. 23-3604-PET EV/EVSE Tariff Rider Program
March 13, 2024	DEADLINE FOR STIPULATIONS/FURTHER PROCESS: Case No. 23-3604-PET EV/EVSE Tariff Rider Program
March 15, 2024	COMPLIANCE FILING DUE: Annual Report of 2023 Tier III Energy Transformation Projects & Savings Claims
April 17, 2024 (9:30 am)	VSPC Quarterly Meeting (Middlebury, VT)
June 30, 2024	COMPLIANCE DEADLINE: EV/EVSE Rates
July 17, 2024 (9:30 am)	VSPC Quarterly Meeting (Trapp Family Lodge, Stowe, VT)
August 31, 2024	COMPLIANCE FILING DUE: Renewable Energy Standard Compliance for Program Year 2023
October 23, 2024 (9:30 am)	VSPC Quarterly Meeting (Killington Grand Hotel, Killington, VT)
November 1, 2024	COMPLIANCE FILING DUE: RES Tier III Annual Plan for 2025 Program Year

As always, if you have any questions, comments, or concerns, please contact me directly.

Respectfully,

Sarah Elise Braese
Assistant General Manager
sbraese@vppsa.com
802-595-3146

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Memorandum

To: VPPSA Board of Directors
From: Ken Nolan, General Manager
Date: December 29, 2023
Subject: Agenda Item #13 – GM Update

As suggested earlier this year, several of the monthly status update reports (in particular those that do not require Board discussion) will be moved into the GM Update.

IT Cyber Review

The cyber review of VPPSA and member systems under the Homeland Security grant from 2022 is continuing. Remaining reviews are down to a handful that have not completed the entire process, and Johnson which has chosen not to proceed with the review. Staff continues to implement upgrades both at VPPSA and at Members where reasonable.

Federal Grants

Staff continues to work with DOE to try to get access to the 2022 Sanders Congressionally Directed Spending (CDS) $1 million. Another set of questions was received between Christmas and New Years. I have notified DOE that I will be reaching out to Senator Sanders office for support. We appear unable to make all of the various departments within DOE simultaneously happy and are spending scarce resources continually bringing them "another rock".

The DPS has reconvened the statewide group preparing a GRIP grant under category 3 (for state sponsored applications), and is trying to make the application more palatable to DOE by strengthening utility obligations to coordinate battery/load dispatch. I have expressed VPPSA concern with giving up autonomy over our resources and committed to redline the application. To be determined whether VPPSA continues to participate.

Given other priorities, DOE's expressed desire for cutting edge projects in the competitive GRIP program, and the uncertainty of whether appropriations to actually fund grant awards will be approved by Congress, staff chose not to re-apply for our $100 million grant. This will allow pending projects to proceed again without being held up, or subject to redesign, based on DOE funding.

Jacksonville

VPPSA staff continues to manage Jacksonville's office operation, and Steve Farman continues to spend time working in Jacksonville to address any issues and assist with research. Lance has begun a comprehensive overhaul of Jacksonville's IT infrastructure.

Amy is providing remote accounting assistance to Jacksonville's part-time staff.

The Trustees interviewed one applicant and I am now discussing compensation with that individual. One other is under consideration.

Amy and Crystal are working with Jacksonville's auditor (KBS) to prepare for the 2022 audit, which will then allow work to begin on a rate case review. Part-way through the 2022 audit it became clear that the auditor adjustments for 2021 were never completed, so 2022 needs to be adjusted to reflect the deficiency. This has slowed the effort.

Overall, Jacksonville has stabilized and steps are beginning to improve the operations. Progress continues to be made in bringing down past due amounts to VPPSA.

Barton

VPPSA continues to look at how it can assist Barton with significant needed hydro facility capital improvements. Bill Ellis has reviewed outstanding bond covenants and determined that a purchase or lease by VPPSA is not feasible. Those options would require hiring of a third party "engineer" to determine that the transaction was appropriate and would also require bond counsel signoff. Those requirements make the structure expensive and potentially risky.

Bill has suggested that a more workable approach may be for Barton to hire VPPSA to operate the facility under an "Operating Agreement" that includes provisions for VPPSA to make capital investments in the plant and recoup the funds through the operating fees. The approach would require moving the plant operator from Barton's payroll to VPPSA's but would avoid bond issues. This structure would also avoid the PPA requirement for Barton to "buy back" the plant's output. A draft agreement is being prepared.

Barton was recently approached by a private entity that purchases and/or operates hydro facilities. I will be reaching out to this firm as a possible alternative to VPPSA operation.

Pecos Wind

Staff has received the pricing proposal for the Swanton location and is presently evaluating the long-term viability of a PPA. The pricing is favorable in the short term, but has an escalator component that may be problematic over the full PPA term.

Transmission Joint Ownership

The proposal VPPSA has been working on with MMWEC and CMEEC has passed another milestone in state (NESCOE) review. The group had another follow up call with NESCOE prior to Christmas to answer further specific questions. The states informed us that they need to make a filing with DOE in early January and are considering how the CMEEC, MMWEC, VPPSA approach could be incorporated into that filing.

CMEEC and MMWEC have also informed VPPSA that they are leaning more and more toward establishing a VTTRANSCO-like organization if our proposal gains traction. This approach would allow the joint action agencies to banks together to invest in New England-wide transmission while receiving a rate of return. Based on this initial feedback I have scheduled an exploratory meeting with Tom Dunn to discuss.

AMI

The AMI project is now up and running. Allen Stamp is holding weekly project meeting to push forward and Jackie Lemmerhirt is actively engaged with Aclara to begin designing the meter configurations. Aclara had the FCC license testers onsite in December and will be moving to lock down DCU locations.

I had lunch with TJ Poor just before Christmas to discuss a number of topics, including AMI. TJ informed me that he did not foresee any significant issues to be raised in the DPS, but they would be recommending some reporting requirements related to the projected project savings components. The Docket will be sliding into February but I am hopeful that we can move to MOU discussions once the DPS testimony is filed.

GIS

VPPSA continues to work with mPower to convert operations. A webinar was held in December to reset operations. Dave DeSimone is working with mPower to schedule onsite training of each Member during January-March. After the training it is expected that each Member on the new VPPSA server will be in a position to start collecting further data.

A specific visit is being scheduled for Lyndon to review the issues that are experiencing with adding new data, and to train them on the overall process. mPower has requested a video call with Lyndon prior to the onsite visit in order to do some initial troubleshooting. Dave DeSimone will be setting that up.

Staffing

Effective December 15th Ken St. Amour moved to working 1-day/week focused on Project 10 security and NERC requirements. Lance became Manager of Information and Security Services.

With the budget approval VPPSA will be hiring three new positions:

- Power Analyst
- IT Analyst/Administrator
- Legislative/Communications Analyst

The position descriptions are being developed and will be posted shortly. If you know of any potential candidates, please let us know.

2023 Bonus

Since I arrived in 2016 (and likely for many years before) VPPSA has been wrestling with an oddity in its payroll process. Staff is paid bi-weekly but unlike other businesses pay is related to the current 2-week period (not in arrears). As an example, our final paycheck for 2023 arrived on Wednesday 12/27, and was for the work week through 12/29.

This has meant that whenever a person leaves VPPSA there either needs to be a true-up of pay to claw back the two unworked days, or VPPSA needs to pay leaving staff for days not worked. This is even more problematic if employees leave on less than favorable terms.

The issue is coming to a head with regard to federal grants VPPSA is beginning to receive because the federal agencies are requiring "certified" timesheets to be submitted with any invoices. As a result, it has become imperative that VPPSA re-align its payroll to pay in arrears. However, doing so would require staff to forego one paycheck now – and receive it after their employment terminates. After discussion with the staff around this issue, there was significant pushback on any solution that would negatively impact staff.

At the same time VPPSA has run more than $200,000 under budget in 2023 with a significant portion of that resulting from delays or an inability to hire staff as positions turned over, or employees went on disability. All staff stepped up and worked extra hours at various times to make sure we got the job done.

Given this confluence of events I decided to provide all employees with a year-end bonus. This bonus not only serves to recognize everyone's hard work in 2023 but will also allow the pay periods to be reset to paying in arrears, behind the scenes and with no impact on staff.

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Memorandum

To: VPPSA Board of Directors
From: Ken Nolan, General Manager
Date: December 29, 2023
Subject: Agenda Item #14 – McNeil Executive Session

Since the special board meeting in December several steps have been taken:

- Heather has evaluated the power supply impacts of different scenarios

- Gerry Tarrant, an attorney that works with VPPSA when Bill Ellis has a conflict, has been consulted and provided some legal analysis of options.

- Sustainable Energy Advisors (SEA) has been asked to prepare a statement of work to assist VPPSA is evaluating the long term viability of McNeil RECs in various New England markets and how that might impact VPPSA's decisions.

The brief executive session will allow staff to present the results of these analyses/discussions and the Board to assess the information.