



Regular Board of Directors Meeting

March 5, 2025

9:30 a.m.

5195 Waterbury-Stowe Road, Waterbury Center, VT 05677

CALL IN NUMBER: 1-347-991-8065

Meeting ID: 516 477 295#

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Directors

Vacant, Barton	John Dasaro, Enosburg	Sarah Braese, Hardwick
James Weber, Jacksonville	Erik Bailey, Johnson	Chris Recchia, Ludlow
Vacant, Lyndon	Scott Johnstone, Morrisville	Steve Fitzhugh, Northfield
John Morley III, Orleans	Bill Sheets, Swanton	James Gibbons, Burlington (Strategic Member)

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)**

Action Items

4. Minutes of the 02/05/2025 Regular Board of Directors Meeting **(3) (9:36)**
5. Monthly Financial Report for period ending 1/31/2025 (Grace) **(5) (9:39)**
6. Establishment of Consolidated Communication Negotiating Committee (Director Mason) **(15) (9:44)**

Discussion Items

7. Reg Beliveau – Guest (Chair Fitzhugh) **(30) (9:59)**
8. Open NEPPA Board Seat (Chair Fitzhugh) **(10) (10:29)**
9. DPS Grid Resiliency Grant (Grace/Steve) **(15) (10:39)**
10. AMI Update (Grace) **(10) (10:54)**
11. Power Supply Status (Heather/Morgan) **(10) (11:04)**
12. Government Affairs Update (Steve/John A.) **(15) (11:14)**
13. VSPPC/Operating Committee Update (Committee Reps) **(20) (11:29)**
14. EMS Project Backlog Review (Grace) **(15) (11:49)**
15. Board Member Updates **(5) (12:04)**

Executive Session

None

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
Ken Mason, Lyndon	Emily Stebbins-Wheelock, BED (Strategic Member)

DRAFT



Regular Board of Directors
Meeting Minutes
February 5, 2025

Board of Directors:

	Vacant, Barton	X	Jonathan Elwell, Lyndon
P	John Dasaro, Enosburg	X	Scott Johnstone, Morrisville
X	Sarah Braese, Hardwick	X	Stephen Fitzhugh, Northfield
X	James Weber, Jacksonville		John Morley, Orleans
	Erik Bailey, Johnson	X	Bill Sheets, Swanton
X	Chris Recchia, Ludlow	P	James Gibbons, BED

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

Alternate Directors present:

Penny Jones, Morrisville (P)	Lynn Paradis, Swanton (X)
Abbey Miller, Enosburg (P)	Denis Fortin, Barton (X)
Emily Stebbins-Wheelock, BED (P)	

Others present:

Ken Nolan, VPPSA (X)	Grace Sawyer, VPPSA (X)	Heather D'Arcy, VPPSA (X)
Garth Dunkel, VPPSA (P)	Morgan Williams, VPPSA (X)	Amanda Simard, VPPSA (P)
Steve Farman, VPPSA (X)	Kylie Bray, VPPSA (P)	Jackie Pratt, Guest (P)
Kerrick Johnson, DPS Commissioner (X)	Ken Mason, Guest (X)	

Numbers in bold type correspond with agenda item numbers:

1. Chairman Fitzhugh called the meeting to order at 9:32 a.m.
2. Chairman Fitzhugh asked if there were requests for changes and or/modifications to the current agenda. There were no changes. Director Johnstone has asked to add an item related to the upcoming voltage reduction test.
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 Johnstone made a motion to accept the minutes of the Board of Directors meeting held January 8, 2025. The motion was seconded by Director Elwell. The motion was approved.
5. Director Weber made a motion to approve the preliminary Monthly Financial reports for the period ending December 31, 2024. The motion was seconded by Director Johnstone.

DRAFT

Ms. Sawyer, VPPSA's Controller provided a summary of the operational revenue vs expenses for the period ending December 31st, 2024. Ms. Sawyer summarized the budget to actual variance of the various projects. There was a brief discussion.

The motion was approved.

6. The Chairman introduced Commissioner Johnson who gave a brief presentation on his plans to take the DPS on a technology upgrade journey. The Commissioner discussed his vision for the future of the DPS including but not limited to ways to reduce duplication of data collection, information sharing, & the Integrated Resource Plans (IRP). A significant discussion ensued. The Commissioner also discussed some issues on the regional transmission level. The General Manager noted that there are some significant needs for equity in the future and that VPPSA could be the funding entity for the utilities in Vermont by utilizing funding sources available that may include the Vermont Bond Bank. Additional discussion ensued on data collection and information sharing challenges.

7. The General Manager provided an update on the status of several key areas in the Advanced Metering Infrastructure project; including but not limited to the DCU deployment, Meters and First Article Testing (FAT), various integrations, Water Meters, AclaraOne, and public outreach. A brief discussion ensued around customer versus utility expenses on the meter replacements.

8. Heather D'Arcy, VPPSA's Manager of Power Resources, 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. A discussion followed on how the new tariffs might affect the prices of natural gas and wholesale electricity going forward.

Director Johnstone asked Ms. D'Arcy if she had any insight into why the voltage tests were being scheduled during the evening hours. A brief conversation ensued.

9. The General Manager provided an overview of the legislative landscape and gave a high-level review of emerging issues. The core areas the presentation addressed were related to the changes in the governing structure following the election results. Steve Farman, VPPSA's Manager of Planning and Support, provided the Board with a brief review of the comments filed on the VELCO Long Range Transmission Plan. Discussion followed on various topics including the Integrated Resource Plan timeline. Director Elwell asked if there was any update on the potential impact of the Canadian tariffs recently enacted and a brief discussion ensued.

10. The Chairman opened the floor to allow representatives from both the Vermont System Planning Committee (VSPC) and the VELCO Operating Committee to brief the Board of Directors on items of interest and receive feedback on general VPPSA positions. Director Johnstone gave a brief overview of items that have surfaced since the last Board Meeting. The General Manager noted that he had put comments into the VELCO Governance Committee annual survey about how municipal owner governance concerns continue to fester.

11. The General Manager provided an overview of VPPSA's transition to setting up an Agile work structure. He gave a summary of the training that has been completed and the structure that is being implemented. The General Manager presented the Executive Meta Scrum (EMS) backlog and the current organizational prioritization which will replace the General Manager report going forward.

12. Board Member Updates: Director Johnstone noted that they were seeing residential customers trip into the demand rate possibly related to heat pumps and Electric Vehicles and wondered if other members had seen the same thing. A brief discussion ensued. Director Johnstone also noted that the Hydro bills that are in the House and Senate are moving forward and may need local support. Director Weber let the Board know that due to the recent ice storm there were several broadband lines on the ground in Jacksonville and they were reaching out to the CUD for a resolution. They could not contact anyone over the weekend.

DRAFT

13. Director Weber made a motion to enter Executive Session, under the provisions of 1 V.S.A. §313(a) to discuss the McNeil Plant pertaining to contractual negotiations. The motion was seconded by Director Elwell. The motion was approved.

The Board entered the Executive Session at 12:52 pm

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

The Board returned to Regular Session at 1:14 pm. No action was taken.

18. Other business: N/A

Director Weber made a motion to adjourn the meeting. The motion was seconded by Director Sheets. Motion approved.

The meeting was adjourned at 1:15 p.m.

Respectfully submitted,

A handwritten signature in blue ink that reads "Grace Sawyer". The signature is written in a cursive, flowing style.

Grace Sawyer, Secretary

Vermont **Public Power** Supply Authority



Monthly Financial Report January 31, 2025

(Unaudited)

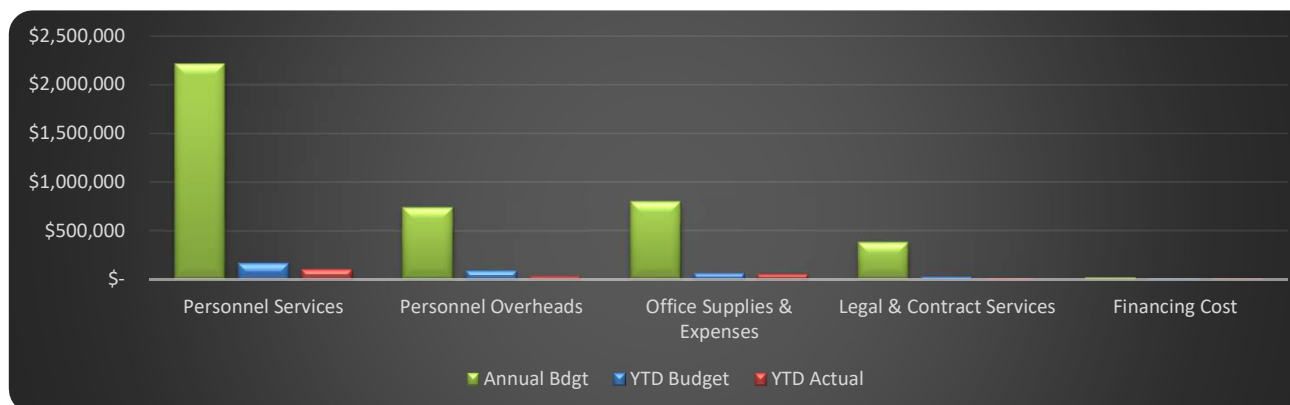
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VERMONT PUBLIC POWER SUPPLY AUTHORITY
OPERATIONAL REVENUE & EXPENSE SUMMARY
2025 YTD ACTUAL VS. BUDGET

Reconciliation Month: **January-2025**

	2025 YTD Budget	2025 YTD Actual	Variance (\$)	Variance (%)	2025 Annual Bdgt	YTD Act % of Budget
Revenues:						
McNeil Plant #2	\$ 19,753	\$ 19,753	\$ (0)	0.0%	\$ 237,037	8%
Central Computer #4	\$ 6,584	\$ 6,584	\$ (0)	0.0%	\$ 79,013	8%
Swanton Peaker #10	\$ 28,771	\$ 28,943	\$ 172	0.6%	\$ 327,009	9%
Renewable Energy Standards	\$ 32,922	\$ 32,922	\$ 0	0.0%	\$ 395,062	8%
AMI #7	\$ 9,877	\$ 9,877	\$ 0	0.0%	\$ 118,519	8%
GIS & Mapping	\$ 3,292	\$ 3,292	\$ (0)	0.0%	\$ 39,506	8%
Barton Management #12	\$ 2,713	\$ 7,693	\$ 4,979	183.5%	\$ 32,557	24%
Member Revenues	\$ 199,159	\$ 199,371	\$ 213	0.1%	\$ 2,389,905	8%
Non-Member Revenues	\$ 354	\$ (1,153)	\$ (1,508)	-425.4%	\$ 484,806	0%
Total Revenues:	\$ 303,426	\$ 307,282	\$ 3,856	1.3%	\$ 4,103,414	7%
Billable Expenses:						
Personnel Services	\$ 170,761	\$ 105,661	\$ (65,100)	-38.1%	\$ 2,219,890	5%
Personnel Overheads	\$ 92,681	\$ 34,898	\$ (57,782)	-62.3%	\$ 739,396	5%
Office Supplies & Expenses	\$ 66,092	\$ 54,516	\$ (11,576)	-17.5%	\$ 793,104	7%
Legal & Contract Services	\$ 31,854	\$ 13,765	\$ (18,089)	-56.8%	\$ 382,250	4%
Financing Cost	\$ 6,871	\$ 6,600	\$ (271)	-3.9%	\$ 22,456	29%
Total Billable Expenses:	\$ 368,259	\$ 215,440	\$ (152,819)	-41.5%	\$ 4,157,096	5%
Net Income(Loss):	\$ (64,833)	\$ 91,842	\$ 156,675			



Vermont Public Power Supply Authority

VPPSA | Monthly Financial Report-Variance Analysis

Jan 2025

Financial Row	Amount	Budget Amount	\$ Over Budget	% of Budget
Power Supply				
Power Supply Income	\$4,646,315.93	\$3,712,407.33	\$933,908.60	125.16%
Power Supply Expenses	(\$4,788,924.95)	(\$3,811,501.33)	(\$977,423.62)	125.64%
Power Supply	(\$142,609.02)	(\$99,094.00)	(\$43,515.02)	143.91%
Transco				
Transco - Expenses	(\$24,581.60)	(\$21,329.70)	(\$3,251.90)	115.25%
Transco	(\$24,581.60)	(\$21,329.70)	(\$3,251.90)	115.25%
Other				
Other - Income	\$25,981.39	\$0.00	\$25,981.39	0.00%
Other - Expenses	(\$19,818.41)	\$0.00	(\$19,818.41)	0.00%
Other	\$6,162.98	\$0.00	\$6,162.98	0.00%
Operational				
Operational - Income	\$670,470.36	\$421,672.83	\$248,797.53	159.00%
Operational - Expenses	(\$218,368.11)	(\$387,356.00)	\$168,987.89	56.37%
Operational	\$452,102.25	\$34,316.83	\$417,785.42	1,317.44%
Net Income	\$291,074.61	(\$86,106.87)	\$377,181.48	-338.04%

Vermont Public Power Supply Authority VPPSA Budget vs. Actual Jan 2025

McNeil

Financial Row	Actual Jan 2025	Budget Jan 2025	\$ Over Budget	% of Budget
Income	\$718,015	\$700,095	\$17,920	102.56%
Expense	\$707,138	\$700,096	\$7,042	101.01%
Net Income	\$10,877	(\$0)	\$10,877	-2,364,534.78%

GIS

Financial Row	Actual Jan 2025	Budget Jan 2025	\$ Over Budget	% of Budget
Income	\$18,617	\$18,617	\$0	100.00%
Expense	\$62,502	\$14,862	\$47,640	420.54%
Net Income	(\$43,885)	\$3,755	(\$47,640)	-1,168.72%

Central Computer

Financial Row	Actual Jan 2025	Budget Jan 2025	\$ Over Budget	% of Budget
Income	\$13,877	\$13,877	\$0	100.00%
Expense	\$6,763	\$7,403	(\$640)	91.35%
Net Income	\$530	(\$1)	\$531	-60,197.73%

Project 10

Financial Row	Actual Jan 2025	Budget Jan 2025	\$ Over Budget	% of Budget
Income	\$319,827	\$317,911	\$1,916	100.60%
Expense	\$612,497	\$272,956	\$340	224.39%
Net Income	(\$292,670)	\$44,955	(\$337,625)	-651.02%

RES

Financial Row	Actual Jan 2025	Budget Jan 2025	\$ Over Budget	% of Budget
Income	\$132,737	\$132,737	\$0	100.00%
Expense	\$43,887	\$80,422	(\$36,535)	54.57%
Net Income	\$88,851	\$52,315	\$36,535	169.84%

Sander's Grant

Financial Row	Actual Jan 2025	Budget Jan 2025	\$ Over Budget	% of Budget
Income	\$0	\$0	\$0	0.00%
Expense	\$197	\$0	\$197	0.00%
Net Income	(\$197)	\$0	(\$197)	0.00%

AMI

Financial Row	Actual Jan 2025	Budget Jan 2025	\$ Over Budget	% of Budget
Income	\$525	\$16,784	(\$16,260)	3.13%
Expense	\$165,700	\$342,668	(\$176,968)	48.36%
Net Income	(\$165,175)	(\$325,883)	\$160,708	50.69%



Budget to Actual Variance Narrative - January 2025

Summary: VPPSA's Year-to-date (YTD) Net Income is \$291,075 which is above budget by \$377,181. This is primarily due to Operational Revenue being above budget \$249K due to REC revenue being greater than budgeted and Operational Expenses being below budget \$169K. VPPSA's Operational revenue is \$92K which is greater than the budget by \$157K primarily due to expenditures being below budget.

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

1. McNeil: Generation was underbudget YTD by 245,199 Kwh or 3.8%. Both expenses are slightly below budget due to the lower generation. Interest income is above budget by \$2K leading to a net budget variance of \$11K above budget.
2. Renewable Energy Standards: The project expenses are below budget by \$37K. REC purchases are \$16K below budget, Sales expense is also below budget by \$20K YTD causing a net budget variance of \$36K.
3. AMI: The project is under budget by \$161K YTD. Anticipated expenditures are below budget \$177K primarily due to the timing difference between the budget and actual project expense. Revenue is below budget by \$16K primarily because of no reimbursement revenue being collected from the grant yet.
4. GIS: The project is over budget by \$48K primarily due to the new data collection service that mPower is providing to specific members. These costs will ultimately be billed back to the individual members who receive the service and may be moved to the Operational budget to facilitate the project.
5. Project 10: The project expense is over budget by \$338K YTD. This is primarily due to a budget versus actual expense for Property Insurance. This was paid in January but spread evenly throughout the year for the budget. This can either remain as a decreasing variance throughout the year or be moved to a prepaid and expensed throughout the year.
6. Operational: Personnel expenses are trending below budget by \$123K due to several factors. One employee is out on FMLA, a Power Supply analyst who left at the beginning of January has not yet been replaced and one of the hires budgeted for January did not start until February. Outside services are below budget by \$18K and Computer maintenance is also below budget \$13K. Both Outside Services and Computer Maintenance are expected to come in line with the budget. These variances result in an Operational revenue of \$157K greater than budget.

Respectfully submitted,
Grace Sawyer, Controller

Vermont Public Power Supply Authority
Parent Company : Vermont Public Power Supply Authority
Balance Sheet
End of Jan 2025

Financial Row	00 Gen - General Amount	02 McN - McNeil Amount	03 HG - HighGate Amount	04 CC - Central Computer Amount	05 RES - Renewable Energy Standards Amount	06 NM - Net Metering Amount	07 Adv - Advanced Metering Infrastructure Amount	08 GIS - Geographic Information System Amount	10 P10 - Project 10 Amount	12 Bar - Barton Management Amount	14 San - Sander's Grant Amount	Total Amount
ASSETS												
Current Assets												
Bank	\$3,052,709.06	\$919,884.23	\$12.35	(\$32,252.83)	(\$332,975.58)	(\$926.06)	\$2,633,560.33	(\$25,730.27)	\$6,092,056.35	(\$129,212.89)	(\$423,793.00)	\$11,753,331.69
Accounts Receivable	\$9,382,370.12	\$1,064,128.00	\$0.00	\$13,876.67	\$151,076.15	\$0.00	\$2,550.31	\$16,357.70	\$202,725.85	\$70,963.96	(\$4.40)	\$10,904,044.36
Other Current Asset	\$205,809.87	\$1,035,933.07	\$0.00	\$0.00	\$85,397.97	\$0.00	(\$2,084.48)	\$0.00	\$443,664.40	\$0.00	(\$0.01)	\$1,768,720.82
Total Current Assets	\$12,640,889.05	\$3,019,945.30	\$12.35	(\$18,376.16)	(\$96,501.46)	(\$926.06)	\$2,634,026.16	(\$9,372.57)	\$6,738,446.60	(\$58,248.93)	(\$423,797.41)	\$24,426,096.87
Fixed Assets												
400.900 - Net UPIS	\$422,760.09	\$1,700,599.54	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2,976.71	\$9,786,117.21	\$0.00	\$0.00	\$11,912,453.55
Total Fixed Assets	\$422,760.09	\$1,700,599.54	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2,976.71	\$9,786,117.21	\$0.00	\$0.00	\$11,912,453.55
Other Assets												
123.700 - Sub-TTL Long Term Investments	\$165,230.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$165,230.00
123.800 - Investment in VT Transco, LLC Rest.	\$9,398,583.69	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$9,398,583.69
123.900 - LT Investments	\$25,621,606.31	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$604,166.67	\$26,225,772.98
186.900 - Total Other Assets	(\$3,588.92)	\$647,277.31	\$0.00	\$40,923.54	\$0.00	\$0.00	\$58,611.73	\$0.00	\$0.00	\$0.00	\$0.00	\$743,223.66
Total Other Assets	\$35,181,831.08	\$647,277.31	\$0.00	\$40,923.54	\$0.00	\$0.00	\$58,611.73	\$0.00	\$0.00	\$0.00	\$604,166.67	\$36,532,810.33
Total ASSETS	\$48,245,480.22	\$5,367,822.15	\$12.35	\$22,547.38	(\$96,501.46)	(\$926.06)	\$2,692,637.89	(\$6,395.86)	\$16,524,563.81	(\$58,248.93)	\$180,369.26	\$72,871,360.75
Liabilities & Equity												
Current Liabilities												
Accounts Payable	\$5,509,914.23	\$342,169.02	\$12.13	\$21,762.91	\$20,539.09	\$0.00	\$157,306.07	\$6,562.72	\$131,085.93	\$0.00	\$2,147.24	\$6,191,499.34
Other Current Liability	\$3,777,234.39	\$3,501.45	\$0.00	\$0.00	(\$15,541.77)	\$0.00	\$407,406.45	(\$4,125.20)	\$1,490,438.02	\$0.00	\$0.00	\$5,658,913.34
Total Current Liabilities	\$9,287,148.62	\$345,670.47	\$12.13	\$21,762.91	\$4,997.32	\$0.00	\$564,712.52	\$2,437.52	\$1,621,523.95	\$0.00	\$2,147.24	\$11,850,412.68
Long Term Liabilities												
221.900 - Long Term Debt	\$6,908,951.27	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2,800,000.00	\$0.00	\$6,615,000.00	\$0.00	\$0.00	\$16,323,951.27
253.100 - Def. Credits-Accrued Vac Liab.	\$142,579.16	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$142,579.16
Total Long Term Liabilities	\$7,051,530.43	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2,800,000.00	\$0.00	\$6,615,000.00	\$0.00	\$0.00	\$16,466,530.43
Equity												
200.900 - Total Retained Earnings												
216.000 - Unappropriated Retained Earnings	\$4,458,486.57	\$4,931,840.31	\$1,193,836.70	(\$7,777.54)	(\$8,489.90)	\$0.07	(\$152,457.94)	\$8,930.13	\$8,024,358.79	\$12,194.23	\$0.00	\$18,460,921.42
216.100 - 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)
219.100 - Other Compreh. Inc-G/L Inv.	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$40,368.07	\$0.00	\$0.00	\$40,368.07
Total - 200.900 - Total Retained Earnings	\$4,458,486.57	\$4,931,840.31	\$0.22	(\$7,777.54)	(\$8,489.90)	\$0.07	(\$152,457.94)	\$8,930.13	\$8,064,726.86	\$12,194.23	\$0.00	\$17,307,453.01
Retained Earnings	\$27,073,317.63	\$79,441.62	\$0.00	\$8,032.27	(\$181,859.43)	(\$846.36)	(\$354,441.52)	\$26,121.66	\$515,982.51	\$11,157.39	\$179,666.52	\$27,356,572.29
Net Income	\$291,074.61	\$10,876.86	\$0.00	\$529.74	\$88,850.55	\$0.00	(\$165,175.19)	(\$43,885.24)	(\$292,669.62)	\$987.83	(\$197.20)	(\$109,607.66)
Total Equity	\$31,822,878.81	\$5,022,158.79	\$0.22	\$784.47	(\$101,498.78)	(\$846.29)	(\$672,074.65)	(\$8,833.45)	\$8,288,039.75	\$24,339.45	\$179,469.32	\$44,554,417.64
Total Liabilities & Equity	\$48,161,557.86	\$5,367,829.26	\$12.35	\$22,547.38	(\$96,501.46)	(\$846.29)	\$2,692,637.87	(\$6,395.93)	\$16,524,563.70	\$24,339.45	\$181,616.56	\$72,871,360.75

Vermont Public Power Supply Authority
Parent Company : Vermont Public Power Supply Authority
Income Statement
Jan 2025

Financial Row	00 Gen - General Amount	02 McN - McNeil Amount	04 CC - Central Computer Amount	05 RES - Renewable Energy Standards Amount	07 AMI - Advanced Metering Infrastructure Amount	08 GIS - Geographic Information System Amount	10 P10 - Project 10 Amount	12 Bar - Barton Management Amount	14 San - Sander's Grant Amount	Total Amount
Ordinary Income/Expense										
Income										
411.900 - Total Other Income or Expense										
421.400 - Misc. Non-Oper Inc-Grants	\$1,850.33	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,850.33
Total - 411.900 - Total Other Income or Expense	\$1,850.33	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,850.33
419.900 - Total Interest & Distribution Income										
419.000 - Interest Income	\$2,187.12	\$2,379.67	\$0.00	\$0.00	\$59.06	\$0.00	\$11,917.67	\$0.00	\$0.00	\$16,543.52
419.300 - Interest Income-Finance Chgs	\$2,125.53	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2,125.53
Total - 419.900 - Total Interest & Distribution Income	\$4,312.65	\$2,379.67	\$0.00	\$0.00	\$59.06	\$0.00	\$11,917.67	\$0.00	\$0.00	\$18,669.05
451.900 - Total Revenue										
447.900 - Total Sales for Resale										
447.000 - Sales for ReSale	\$4,481,454.65	\$715,635.25	\$0.00	\$0.00	\$0.00	\$0.00	\$307,909.79	\$0.00	\$0.00	\$5,504,999.69
447.100 - Sales for Resale-'15 SO(Lyn)	\$7,634.62	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$7,634.62
447.105 - Sales for Resale-'17 SO(Tromb)	\$4,025.43	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$4,025.43
447.110 - Sales for Resale-'19 SO(Hess)	\$8,261.24	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$8,261.24
447.115 - Sales for Resale-'19 SO(Davis)	\$10,299.99	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$10,299.99
Total - 447.900 - Total Sales for Resale	\$4,511,675.93	\$715,635.25	\$0.00	\$0.00	\$0.00	\$0.00	\$307,909.79	\$0.00	\$0.00	\$5,535,220.97
451.000 - Service Revenues	\$275.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$275.00
451.100 - Service Revenue-Member Fees	\$199,158.76	\$0.00	\$6,474.50	\$69,193.13	\$466.00	\$18,617.22	\$0.00	\$0.00	\$0.00	\$293,909.61
451.101 - Service Revenue-Member Dir Fee	\$212.50	\$0.00	\$0.00	\$21,814.50	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$22,027.00
451.105 - Service Revenues-Members-EM	\$0.00	\$0.00	\$7,402.17	\$41,729.78	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$49,131.95
451.110 - Misc. Service Rev-Affil & Othe	\$15,427.60	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$70,963.96	\$0.00	\$86,391.56
451.200 - Service Revenue-McN to VP	\$19,753.09	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$19,753.09
451.210 - Service Revenues-CComp to VPPS	\$6,584.38	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$6,584.38
451.220 - Service Revenues-P10 to VPPSA	\$13,168.75	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$13,168.75
451.221 - Service Revenues-P10 Lbr&OH	\$15,774.68	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$15,774.68
451.223 - Service Revenues-RES to VPPSA	\$32,921.86	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$32,921.86
451.226 - Service Revenues-AMI to VPPSA	\$9,876.56	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$9,876.56
451.227 - Service Revenues-GIS to VPPSA	\$3,292.18	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$3,292.18
451.230 - Service Revenues - Barton P12	\$7,692.50	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$7,692.50
451.410 - Service Revenue-Direct PassThr	\$19,818.41	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$19,818.41
451.500 - Service Revenues-Hydro REC	\$134,640.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$134,640.00
451.505 - Service Revenues-GEN 5 RECs	\$48,905.50	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$48,905.50
451.520 - Service Revenue-Fitchburg RECs	\$297,427.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$297,427.00
Total - 451.900 - Total Revenue	\$5,336,604.70	\$715,635.25	\$13,876.67	\$132,737.41	\$466.00	\$18,617.22	\$307,909.79	\$70,963.96	\$0.00	\$6,596,811.00
Total - Income	\$5,342,767.68	\$718,014.92	\$13,876.67	\$132,737.41	\$525.06	\$18,617.22	\$319,827.46	\$70,963.96	\$0.00	\$6,617,330.38
Expense										
403.000 - Depreciation Expense	\$2,916.74	\$36,173.46	\$0.00	\$0.00	\$0.00	\$0.00	\$102,348.94	\$0.00	\$0.00	\$141,439.14
408.200 - Property Taxes	\$1,541.67	\$27,481.13	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$29,022.80
427.900 - Total Interest Expense										
427.100 - Interest on LTD - Bonds	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$30,438.02	\$0.00	\$0.00	\$30,438.02
427.221 - Interest on LTD '12-'14 Transco	\$3,597.41	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$3,597.41
427.222 - Interest on LTD '16 Transco	\$632.07	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$632.07
427.224 - Interest on LTD '18 Transco (V)	\$113.24	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$113.24
427.225 - Interest on LTD '18 Transco (M)	\$1,756.26	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,756.26
427.226 - Interest on LTD '19Transco (M)	\$508.86	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$508.86
427.229 - Interest on LTD 23 Transco (M)	\$18,087.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$18,087.00
427.400 - Interest on LTD '17 HG Transco (M)	\$678.28	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$678.28
427.405 - Interest on LTD '17 HG Transco (V)	\$768.88	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$768.88
431.000 - Other Interest Expense	\$6,600.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$74.85	\$0.00	\$0.00	\$6,674.85
Total - 427.900 - Total Interest Expense	\$32,742.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$30,512.87	\$0.00	\$0.00	\$63,254.87

Financial Row	00 Gen - General Amount	02 McN - McNeil Amount	04 CC - Central Computer Amount	05 RES - Renewable Energy Standards Amount	07 AMI - Advanced Metering Infrastructure Amount	08 GIS - Geographic Information System Amount	10 P10 - Project 10 Amount	12 Bar - Barton Management Amount	14 San - Sander's Grant Amount	Total Amount
500.900 - Total Power Production Expense										
500.000 - SPG-Oper-Supv&Engineering	\$0.00	\$7,297.88	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$7,297.88
501.100 - SPG-Oper-Steam Exp-Fuel Oil	\$0.00	\$2,262.96	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2,262.96
501.110 - SPG-Oper-Wood Fuel Expense	\$0.00	\$368,734.31	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$368,734.31
501.120 - SPG-Oper-Cap Rel Wood Ene Cost	\$0.00	\$6,514.73	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$6,514.73
501.130 - SPG-Oper-Natural Gas Fuel Exp.	\$0.00	\$724.36	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$724.36
502.000 - SPG-Oper-Steam Expenses	\$0.00	\$43,520.56	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$43,520.56
505.000 - SPG-Oper-Electric Expenses	\$0.00	\$12,662.97	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$12,662.97
506.000 - SPG-Oper-Misc Steam Power Exp.	\$0.00	\$10,681.93	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$10,681.93
506.100 - SPG-Oper-Misc Store,Parts, Mat	\$0.00	\$2,536.65	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2,536.65
511.000 - SPG-Maint-Structures	\$0.00	\$352.94	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$352.94
512.000 - SPG-Maint-Boiler	\$0.00	\$7,175.11	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$7,175.11
513.000 - SPG-Maint-Electric Plt	\$0.00	\$7,182.67	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$7,182.67
514.000 - SPG-Maint-Steam Plant	\$0.00	\$2,680.29	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2,680.29
547.100 - OPG-Oper-Fuel Oil Exp.	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$21,820.31	\$0.00	\$0.00	\$21,820.31
548.000 - OPG-Oper-Generation Exp-Dir Lb	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$4,602.65	\$0.00	\$0.00	\$4,602.65
548.300 - OPG-Oper-Generation Exp-OH	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,822.72	\$0.00	\$0.00	\$1,822.72
549.105 - OPG-Oper-Misc Gen-Comp. Har/So	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$202.08	\$0.00	\$0.00	\$202.08
549.107 - OPG-Oper-Misc Gen-Electric	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$11,106.83	\$0.00	\$0.00	\$11,106.83
549.109 - OPG-Oper-Misc Gen-Tel/Internet	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$465.33	\$0.00	\$0.00	\$465.33
549.113 - OPG-Oper-Misc Gen-Water	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$191.84	\$0.00	\$0.00	\$191.84
550.105 - OPG-Rents-Land Lease-P10	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$126.26	\$0.00	\$0.00	\$126.26
553.000 - OPG-Maint-Gen&Elec Eq-Dir Lbr	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2,751.03	\$0.00	\$0.00	\$2,751.03
553.300 - OPG-Maint-Gen & Elec Eq-OH	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,089.45	\$0.00	\$0.00	\$1,089.45
Total - 500.900 - Total Power Production Expense	\$0.00	\$472,327.36	\$0.00	\$0.00	\$0.00	\$0.00	\$44,178.50	\$0.00	\$0.00	\$516,505.86
555.900 - Total Purchased Power Expense										
555.000 - OPSE-Purchased Power	\$3,408,134.16	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$3,408,134.16
555.200 - OPSE-Purchase Pwr-'15 SO (Lyn)	\$6,254.73	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$6,254.73
555.205 - OPSE-Purchase Pwr-'17 SO(Trom)	\$3,528.30	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$3,528.30
555.210 - OPGE-Purchase Pwr-'19SO (Hess)	\$6,777.02	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$6,777.02
555.215 - OPGE-Purchase Pwr-'19SO(Davis)	\$8,221.53	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$8,221.53
556.000 - OPSE-Syst. Ctrl & Load Dispa	\$0.00	\$1,037.80	\$0.00	\$0.00	\$0.00	\$0.00	\$1,004.25	\$0.00	\$0.00	\$2,042.05
Total - 555.900 - Total Purchased Power Expense	\$3,432,915.74	\$1,037.80	\$0.00	\$0.00	\$0.00	\$0.00	\$1,004.25	\$0.00	\$0.00	\$3,434,957.79
560.900 - Total Transmission Expense										
565.000 - TRSM-Oper-Transm by Others	\$1,354,512.38	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,354,512.38
566.000 - TRSM-Oper-Misc Transm Exp	\$1,496.83	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,496.83
567.000 - TRSM-Oper-Rent	\$0.00	\$354.07	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$354.07
Total - 560.900 - Total Transmission Expense	\$1,356,009.21	\$354.07	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,356,363.28
575.900 - Total Regional Market Expense										
575.600 - RME-Market Monitor/Compl-Gen	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$5,508.83	\$0.00	\$0.00	\$5,508.83
Total - 575.900 - Total Regional Market Expense	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$5,508.83	\$0.00	\$0.00	\$5,508.83
921.900 - Total Administration & General Expense										
909.000 - Cust Svs & Info-Info Adv Exp	\$0.00	\$1,293.24	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,293.24
916.110 - Sales-Misc Sales Exp-RES T3(P)	\$0.00	\$0.00	\$0.00	\$8,825.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$8,825.00
920.000 - A&G-Salaries	\$13,694.81	\$21,981.98	\$0.00	\$0.00	\$0.00	\$0.00	\$6,836.25	\$0.00	\$0.00	\$42,513.04
920.100 - A&G-Salaries-Overtime	\$321.03	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$321.03
920.115 - A&G-Wages Non-Salary	\$28,536.78	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$28,536.78
920.120 - A&G-Salaries-Benefits Bonus	\$26,400.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$26,400.00
920.160 - A&G-Salaries-Leave Time	\$33,823.93	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$33,823.93
920.180 - A&G - Salaries - Medical BO	\$2,884.64	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2,884.64
920.200 - A&G-Salaries-AdminAlloc-RES T1	\$0.00	\$0.00	\$0.00	\$8,908.83	\$5,127.19	\$1,709.09	\$0.00	\$0.00	\$0.00	\$15,745.11
920.210 - A&G-Salaries-AdminAlloc-RES T2	\$0.00	\$0.00	\$0.00	\$2,808.85	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2,808.85
920.220 - A&G-Salaries-AdminAlloc-RES T3	\$0.00	\$0.00	\$0.00	\$5,372.95	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$5,372.95
921.000 - A&G-Office Supplies & Expense	\$0.00	\$6,056.08	\$0.00	\$0.00	\$0.00	\$0.00	\$44.47	\$0.00	\$0.00	\$6,100.55
921.101 - A&G - Bank Fees	\$907.77	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$907.77
921.102 - A&G-General Office Supplies	\$376.23	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$376.23
921.108 - A&G-Local Mileage Reimburse.	\$815.52	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$82.97	\$0.00	\$107.20	\$1,005.69
921.112 - A&G-Local Meals Expense	\$128.05	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$128.05
921.115 - A&G-Computer Hard/Soft Maint.	\$2,831.39	\$0.00	\$6,762.55	\$0.00	\$0.00	\$3,162.78	\$0.00	\$0.00	\$0.00	\$12,756.72
921.118 - A&G-Equipment Maintenance	\$84.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$84.00

Financial Row	00 Gen - General	02 McN - McNeil	04 CC - Central Computer	05 RES - Renewable Energy Standards	07 Amf - Advanced Metering Infrastructure	08 GIS - Geographic Information System	10 P10 - Project 10	12 Bar - Barton Management	14 San - Sander's Grant	Total Amount
	Amount	Amount	Amount	Amount	Amount	Amount	Amount	Amount	Amount	Amount
921.127 - A&G-Utilities-Electric	\$624.49	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$624.49
921.131 - A&G-Utilities-Propane	\$1,116.25	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,116.25
921.133 - A&G-Utilities-Telephone	\$1,302.81	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$164.22	\$0.00	\$0.00	\$1,467.03
921.136 - A&G-Janitorial	\$756.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$756.00
921.142 - A&G-Trash Removal	\$315.95	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$102.21	\$0.00	\$0.00	\$418.16
921.145 - A&G-Subscriptions	\$240.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$240.00
921.150 - A&G-On Line Charges	\$379.90	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$379.90
921.153 - A&G-Building Maintenance	\$1,053.40	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,053.40
921.155 - A&G-Meeting Expenses	\$258.20	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$258.20
921.158 - A&G-Membership/Registration Du	\$10,073.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$10,073.00
921.164 - A&G-Computer Hard/Softw Equip	\$6,352.84	\$0.00	\$0.00	\$472.22	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$6,825.06
921.167 - A&G-Web Site Maintenance	\$370.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$370.00
921.200 - A&G-Office Sup&Exp-HG Adm Allo	\$0.00	\$0.00	\$0.00	\$3,445.18	\$1,982.75	\$660.92	\$2,643.68	\$0.00	\$0.00	\$8,732.53
921.210 - A&G-O S&E-AdminAlloc-RES T2	\$0.00	\$0.00	\$0.00	\$1,086.22	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,086.22
921.220 - A&G-O S&E-AdminAlloc-RES T3	\$0.00	\$0.00	\$0.00	\$2,077.80	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2,077.80
921.301 - A&G-OS&E-PTE-IT Related Exp	\$19,818.41	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$19,818.41
921.304 - A&G-OS&E-PTE-Misc.	\$0.00	\$0.00	\$0.00	\$0.00	\$134,323.69	\$0.00	\$0.00	\$0.00	\$0.00	\$134,323.69
924.000 - A&G-Property Insurance-Gen.	\$0.00	\$107,297.83	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$107,297.83
924.100 - A&G-Insurance-Property	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$411,755.92	\$0.00	\$0.00	\$411,755.92
925.000 - A&G-Injuries & Damages-Gen	\$0.00	\$12,840.73	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$12,840.73
925.100 - A&G-Injuries&Dam-W/C	\$0.00	\$1,209.88	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,209.88
925.105 - A&G-Injuries&Dam-Prof/Emp Liab	\$3,033.22	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$3,033.22
926.000 - A&G-Employee Benefits	\$0.00	\$3,509.67	\$0.00	\$3,049.16	\$1,754.85	\$0.00	\$2,339.80	\$0.00	\$0.00	\$10,653.48
926.010 - A&G-Employee Ben Alloc-RES T2	\$0.00	\$0.00	\$0.00	\$961.36	\$0.00	\$584.92	\$0.00	\$0.00	\$0.00	\$1,546.28
926.020 - A&G-Employee Ben Alloc-RES T3	\$0.00	\$0.00	\$0.00	\$1,838.96	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,838.96
926.100 - A&G-Employee Ben-Pension Contr	(\$986.97)	\$8,641.24	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$7,654.27
926.110 - A&G-Employee Ben-Pension Adm.	\$2,129.41	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2,129.41
926.300 - A&G - Employee Ben-Health&Dent	\$17,987.01	\$8,235.46	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$26,222.47
926.305 - A&G - Employee Benefits-Vision	\$666.18	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$666.18
926.310 - A&G - Employee Ben-H.S.A. Cont	\$3,000.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$3,000.00
926.330 - A & G - Employee Ben-Life&Dis.	\$3,643.46	\$113.09	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$3,756.55
926.350 - A&G-P/R Ovhd Alloc-McN	\$0.00	(\$22,658.76)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	(\$22,658.76)
926.400 - A&G-Employers FICA Expense	\$5,746.78	\$5,695.11	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$11,441.89
926.420 - A&G-Employers SUTA Expense	\$1,368.56	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,368.56
926.430 - A&G-Employers Medicare Expense	\$1,343.95	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,343.95
930.000 - A&G-General Advertizing	\$4,523.34	\$400.36	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$4,923.70
930.110 - A&G-Misc Organizational Dues	\$3,743.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$3,743.00
930.200 - A&G-Conferences	\$10,135.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$10,135.00
930.220 - A&G-Travel-Lodging	\$1,534.60	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,534.60
930.230 - A&G-Travel-Air Transportation	\$142.42	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$142.42
930.240 - A&G-Travel-Ground Transportat.	\$131.47	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$131.47
930.250 - A&G-Travel-Meals	\$18.50	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$18.50
930.300 - A&G-Miscellaneous	\$30.41	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$30.41
933.000 - A&G-Transportation Expenses	\$147.07	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$147.07
Total - 921.900 - Total Administration & General Expense	\$211,802.81	\$154,615.91	\$6,762.55	\$38,846.53	\$143,188.48	\$6,117.71	\$423,969.52	\$0.00	\$107.20	\$985,410.71
923.900 - Total Outside Services										
923.000 - A&G-Outside Services-Legal	\$10,366.75	\$15,148.33	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$90.00	\$25,605.08
923.200 - A&G-Outside Services-Other	\$3,398.15	\$0.00	\$0.00	\$900.00	\$21,500.00	\$56,047.50	\$3,700.00	\$69,976.13	\$0.00	\$155,521.78
923.210 - A&G-Outside Svs-HG Admin Alloc	\$0.00	\$0.00	\$6,584.38	\$1,758.01	\$1,011.77	\$337.25	\$1,274.17	\$0.00	\$0.00	\$10,965.58
923.211 - A&G-Outside Svs-RES T2 Admin	\$0.00	\$0.00	\$0.00	\$554.28	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$554.28
923.212 - A&G-Outside Svs-RES T3 Admin	\$0.00	\$0.00	\$0.00	\$1,828.04	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$1,828.04
Total - 923.900 - Total Outside Services	\$13,764.90	\$15,148.33	\$6,584.38	\$5,040.33	\$22,511.77	\$56,384.75	\$4,974.17	\$69,976.13	\$90.00	\$194,474.76
Total - Expense	\$5,051,693.07	\$707,138.06	\$13,346.93	\$43,886.86	\$165,700.25	\$62,502.46	\$612,497.08	\$69,976.13	\$197.20	\$6,726,938.04
Net Income	\$291,074.61	\$10,876.86	\$529.74	\$88,850.55	(\$165,175.19)	(\$43,885.24)	(\$292,669.62)	\$987.83	(\$197.20)	(\$109,607.66)

Vermont Public Power Supply Authority
Parent Company : Vermont Public Power Supply Authority
Comparative Balance Sheet
End of Jan 2025

Financial Row	Jan-25	Jan-25	Variance	% Variance
ASSETS				
Current Assets				
Bank	\$11,753,331.69	\$13,437,270.81	(\$1,683,939.12)	-12.53%
Accounts Receivable	\$10,904,044.36	\$9,813,676.80	\$1,090,367.56	11.11%
Other Current Asset	\$1,768,720.82	\$3,142,317.93	(\$1,373,597.11)	-43.71%
Total Current Assets	\$24,426,096.87	\$23,684,479.44	\$741,617.43	3.13%
Fixed Assets				
400.900 - Net UPIS	\$11,912,453.55	\$12,940,163.27	(\$1,027,709.72)	-7.94%
Total Fixed Assets	\$11,912,453.55	\$12,940,163.27	(\$1,027,709.72)	-7.94%
Other Assets				
123.700 - Sub-TTL Long Term Investments	\$165,230.00	\$165,230.00	\$0.00	0.00%
123.800 - Investment in VT Transco, LLC Rest.	\$9,398,583.69	\$11,903,628.72	(\$2,505,045.03)	-21.04%
123.900 - LT Investment	\$26,225,772.98	\$23,116,561.28	\$3,109,211.70	13.45%
186.900 - Total Other Assets	\$743,223.66	\$84,765.65	\$658,458.01	776.80%
Total Other Assets	\$36,532,810.33	\$35,270,185.65	\$1,262,624.68	3.58%
Total ASSETS	\$72,871,360.75	\$73,774,737.82	(\$903,377.07)	-1.22%
Liabilities & Equity				
Current Liabilities				
Accounts Payable	\$6,191,499.34	\$4,707,774.57	\$1,483,724.77	31.52%
Other Current Liability	\$5,658,913.34	\$5,708,169.73	(\$49,256.39)	-0.86%
Total Current Liabilities	\$11,850,412.68	\$10,415,944.30	\$1,434,468.38	13.77%
Long Term Liabilities				
221.900 - Long Term Debt	\$16,323,951.27	\$20,731,193.94	(\$4,407,242.67)	-21.26%
253.100 - Def. Credits-Accrued Vac Liab.	\$142,579.16	\$137,580.74	\$4,998.42	3.63%
Total Long Term Liabilities	\$16,466,530.43	\$20,868,774.68	(\$4,402,244.25)	-21.09%
Equity				
200.900 - Total Retained Earnings				
216.000 - Unappropriated Retained Earnings	\$18,460,921.42	\$20,875,743.95	(\$2,414,822.53)	-11.57%
216.100 - Unappropriated Earnings - Distributed	(\$1,193,836.48)	(\$1,193,836.48)	\$0.00	0.00%
219.100 - Other Compreh. Inc-G/L Inv.	\$40,368.07	\$13,984.76	\$26,383.31	188.66%
Total - 200.900 - Total Retained Earnings	\$17,307,453.01	\$19,695,892.23	(\$2,388,439.22)	-12.13%
Retained Earnings	\$27,356,572.29	\$22,291,567.30	\$5,065,004.99	22.72%
Net Income	(\$109,607.66)	\$502,559.31	(\$612,166.97)	-121.81%
Total Equity	\$44,554,417.64	\$42,490,018.84	\$2,064,398.80	4.86%
Total Liabilities & Equity	\$72,871,360.75	\$73,774,737.82	(\$903,377.07)	-1.22%

Vermont Public Power Supply Authority
Parent Company (Consolidated)
VPPSA | Monthly Financial Report-Variance Analysis
Jan 2025

Financial Row	Jan-25	Budget \$	\$ Over Budget	% of Budget
Power Supply				
Power Supply Income				
451.900 - Total Revenue	\$4,646,315.93	\$3,712,407.33	\$933,908.60	125.16%
451.500 - Service Revenues-Hydro REC	\$134,640.00	\$0.00	\$134,640.00	0.00%
451.501 - Service Revenues-McN REC/CDA	\$0.00	\$29,404.00	(\$29,404.00)	0.00%
447.900 - Total Sales for Resale				
447.000 - Sales for ReSale	\$4,481,454.65	\$3,646,712.33	\$834,742.32	122.89%
447.100 - Sales for Resale-'15 SO(Lyn)	\$7,634.62	\$6,865.00	\$769.62	111.21%
447.105 - Sales for Resale-'17 SO(Tromb)	\$4,025.43	\$5,191.00	(\$1,165.57)	77.55%
447.115 - Sales for Resale-'19 SO(Davis)	\$10,299.99	\$12,316.00	(\$2,016.01)	83.63%
447.110 - Sales for Resale-'19 SO(Hess)	\$8,261.24	\$11,919.00	(\$3,657.76)	69.31%
Total - 447.900 - Total Sales for Resale	\$4,511,675.93	\$3,683,003.33	\$828,672.60	122.50%
Power Supply Income	\$4,646,315.93	\$3,712,407.33	\$933,908.60	125.16%
Power Supply Expenses				
555.900 - Total Purchased Power Expense	(\$3,432,915.74)	(\$2,577,083.11)	(\$855,832.63)	133.21%
560.900 - Total Transmission Expense	(\$1,356,009.21)	(\$1,234,418.22)	(\$121,590.99)	109.85%
Total - Power Supply Expenses	(\$4,788,924.95)	(\$3,811,501.33)	(\$977,423.62)	125.64%
Power Supply	(\$142,609.02)	(\$99,094.00)	(\$43,515.02)	143.91%
Transco				
Transco - Expenses				
427.900 - Total Interest Expense	(\$24,581.60)	(\$21,329.70)	(\$3,251.90)	115.25%
Transco - Expenses	(\$24,581.60)	(\$21,329.70)	(\$3,251.90)	115.25%
Transco	(\$24,581.60)	(\$21,329.70)	(\$3,251.90)	115.25%
Other				
Other - Income				
419.900 - Total Interest & Distribution Income	\$4,312.65	\$0.00	\$4,312.65	0.00%
411.900 - Total Other Income or Expense	\$1,850.33	\$0.00	\$1,850.33	0.00%
451.900 - Total Revenue	\$19,818.41	\$0.00	\$19,818.41	0.00%
Other - Income	\$25,981.39	\$0.00	\$25,981.39	0.00%
Other - Expenses				
921.900 - Total Administration & General Expense	(\$19,818.41)	\$0.00	(\$19,818.41)	0.00%
Other - Expenses	(\$19,818.41)	\$0.00	(\$19,818.41)	0.00%
Other	\$6,162.98	\$0.00	\$6,162.98	0.00%
Operational				
Operational - Income				
451.900 - Total Revenue	\$670,470.36	\$421,672.83	\$248,797.53	159.00%
Operational - Income	\$670,470.36	\$421,672.83	\$248,797.53	159.00%
Operational - Expenses				
403.000 - Depreciation Expense	(\$2,916.74)	(\$1,833.33)	(\$1,083.41)	159.10%
408.200 - Property Taxes	(\$1,541.67)	(\$1,666.67)	\$125.00	92.50%
427.900 - Total Interest Expense	(\$8,160.40)	(\$4,787.92)	(\$3,372.48)	170.44%
921.900 - Total Administration & General Expense	(\$191,984.40)	(\$345,151.38)	\$153,166.98	55.62%
923.900 - Total Outside Services	(\$13,764.90)	(\$33,916.70)	\$20,151.80	40.58%
Total - Operational - Expenses	(\$218,368.11)	(\$387,356.00)	\$168,987.89	56.37%
Operational	\$452,102.25	\$34,316.83	\$417,785.42	1,317.44%
Net Income	\$291,074.61	(\$86,106.87)	\$377,181.48	-338.04%

Memorandum

To: VPPSA Board of Directors
From: Ken Nolan, General Manager
Date: February 28, 2025
Subject: **Agenda Item #6** – Consolidated Communications

Alternate Director Mason called me last week to discuss problems Lyndon was having in getting Consolidated Communication to pay bills for tree trimming and pole setting. He asked me if others were having similar issues, and I let him know that several of you had mentioned similar concerns over time.

Mr. Mason then went on to explain that the last agreements, for Lyndon at least, were actually negotiated decades ago with AT&T before the various sales and mergers occurred. He also noted that the last agreement was negotiated through the Municipal Electric Association of Vermont (MEAV) which is no longer active, and questioned whether VPPSA could negotiate an updated contract.

I let Mr. Mason know that GMP and VEC were negotiating a buyout of Consolidated Communications' poles as a way to resolve the issue. Consolidated would then become an "attacher" on the utility pole with the electric utility taking full responsibility. I also noted that VPPSA does not have the staff expertise to negotiate such a contract directly affecting field services but could act as a conduit for discussions.

My suggestion was that the Board establish a negotiating committee to lead the conversation with Consolidated, with VPPSA providing admin support as needed and potentially acting as the signatory if that is determined to be beneficial.

This item is on the agenda as an action item in case the Board determines to move forward.

Memorandum

To: VPPSA Board of Directors
From: Ken Nolan, General Manager
Date: February 28, 2025
Subject: **Agenda Item #7** – Reg Beliveau

Now that Reg Beliveau has been nominated by the public power utilities to replace Steve Kaminski on the VELCO Board, Reg is entering the onboarding phase. He is set to be elected at VELCO's annual meeting in April and has scheduled an orientation with the VELCO management team.

He also reached out asking for time to discuss his role with the VPPSA Board before he is elected. Since he is out of state on vacation during your April meeting we decided to add the discussion to the March meeting.

Memorandum

To: VPPSA Board of Directors
From: Ken Nolan, General Manager
Date: February 28, 2025
Subject: **Agenda Item #8** – Open NEPPA Board Seat

With Jon Elwell's departure from Lyndon, the seat he held on the NEPPA Board has also become vacant. Similar to the Independent VELCO Directors, this is also a position to be filled by the Vermont Public Power utilities that are members of NEPPA.

As a reminder Lynn Paradis, Penny Jones, and I are the other Vermont Board members of NEPPA. In addition, Penny Chairs the Finance Committee, and I am the 1st Vice President. We both serve on the Executive Committee.

The vacancy created by Jon's departure was discussed at the Executive Committee meeting on February 27th, and the Executive Committee determined not to fill any vacancies until the August annual meeting (which will be in Burlington this year), so there is a little time to pick a replacement.

This is not a VPPSA, or VPPSA Board decision, as Hyde Park, Stowe, and VEC also need to be consulted, but I felt the VPPSA Board meeting was a good place to begin discussions and re-establish a process for moving forward.

As an FYI, Rebecca Towne had expressed interest in the position when the last vacancy occurred, and Jackie Pratt held the Rhode Island seat for a short time previously when it became an "At Large" due to lack of interest from Rhode Island personnel. She has also expressed interest in rejoining.

Memorandum

To: VPPSA Board of Directors
From: Ken Nolan, General Manager
Date: February 28, 2025
Subject: **Agenda Item #9** – DPS Grid Resiliency Grant

The DPS was awarded \$7.5 million in IJA grant funding specifically targeted to improving grid resiliency. In turn they are sub-granting those funds to all of the Vermont distribution utilities through a semi-competitive process.

Application's are due by April 28th, and are limited to distribution utilities or developers that can prove they are working in conjunction with distribution utilities. The following types of projects are eligible to apply

- (1) Fire-resistant technologies and fire prevention systems
- (2) Monitoring and control technologies
- (3) Undergrounding of electrical equipment
- (4) Utility pole management
- (5) Relocation of power lines or the reconductoring of power lines with low sag, advanced conductors
- (6) Vegetation and fuel load management
- (7) Use or construction of distributed energy resources for enhancing system adaptive capacity during disruptive events, including microgrids and battery storage subcomponents
- (8) Adaptive protection technologies
- (9) Advanced modeling technologies
- (10) Hardening of power lines, facilities, substations, or other systems
- (11) Replacement of old overhead conductors and underground cables

According to the DPS grant description the funds have been allocated to each distribution utility based on a formula utilizing your customer counts, SQRP results, and other resiliency metrics. In other words, although the grant is listed as "competitive", any utility that applies with a valid project is essentially guaranteed an award. The only real caveat being that these are IJA funds which are being heavily targeted by the Trump Administration for claw-back. The opportunity may not materialize if the Administration is successful in redirecting funding.

This Board discussion is to talk through whether VPPSA should play a role in gathering projects and drafting either individual applications or possibly a joint application.

Memorandum

To: VPPSA Board of Directors
From: Ken Nolan, General Manager
Date: February 28, 2025
Subject: **Agenda Item #10** – AMI Update

AMI will be a standing item on the agenda for the next 2-3 years as the project proceeds.

Status of various items are:

DCU Deployment

Swanton's DCU's have been commissioned and test meters have been attached

Remaining Tranche 1 DCU's will be deliveries are in process

Meters

FAT meters have been attached to the Swanton DCU's and are undergoing testing by Aclara and Jackie Lemmerhirt's team.

A workshop to complete the "witness" testing is expected in early March

Integrations

CIS

Cogsdale (Swanton) work remains generally on track. Jackie Lemmerhirt has begun expressing concern that the project may slip based on the present status.

Munis (Northfield) discussions had begun with Northfield's contact once again becoming engaged. However we recently received notice that that person would no longer be on the project. Her supervisor has scheduled a meeting to discuss who will take over the project.

El Dorado (Orleans, Jacksonville, Barton, Johnson) is still delayed pending the completion of Barton install and net metering calculation completion. This delay is becoming a critical path item warranting more direct management to closeout out the open items.

NISC (Enosburg) is beginning as part of the CIS deployment.

mPower

The GIS integration requirements are being built into the CIS vendor discussions to try to streamline efforts.

Discussions also continue with mPower to use an mPower Field Maps application during meter deployment. This would allow for consistent treatment of meter conversions and import collected data directly into member maps. mPower has indicated that customizing a VPPSA collection template would be a few hours of development work once to occur once we have placed the production meter orders.

External UPC readers are being ordered for Swanton to allow for using the mPower system to complete the meter reading.

Water Meters

All of the water meter vendors that members desire to use have now been validated by Aclara as compatible with their MTUs. MTU orders remain on hold pending DCU order completion.

Swanton has received MTU's for test meters.

AclaraOne

Aclara is beginning software development of the Headend and MDM structure. The software for each member needs to be complete as DCU's are deployed so that that the DCU's can be registered in the system as the last step in verifying commercial operation.

Swanton software testing is underway in conjunction with the FAT meter testing; however, Aclara has informed us that some portions of the software test will not be completed until the CIS and GIS integrations are complete.

Discussions on the structure of the "super user" overlay have begun.

Public Outreach

Garth continues to prepare talking points to be used in the public events. A second draft is under review.

In addition, a website draft has been developed and is being reviewed.

The first tranche utilities have indicated that there is no need for VPPSA to attend a follow up Trustee/Commission meeting to review the project. Managers are leading discussion with public groups as appropriate.



January 2025 Power Supply Update

Power Supply Update

- 1. Natural Gas & Electricity Price Updates**
- 2. Near-term Pricing**
- 3. CDA Variances**
- 4. Market Changes**

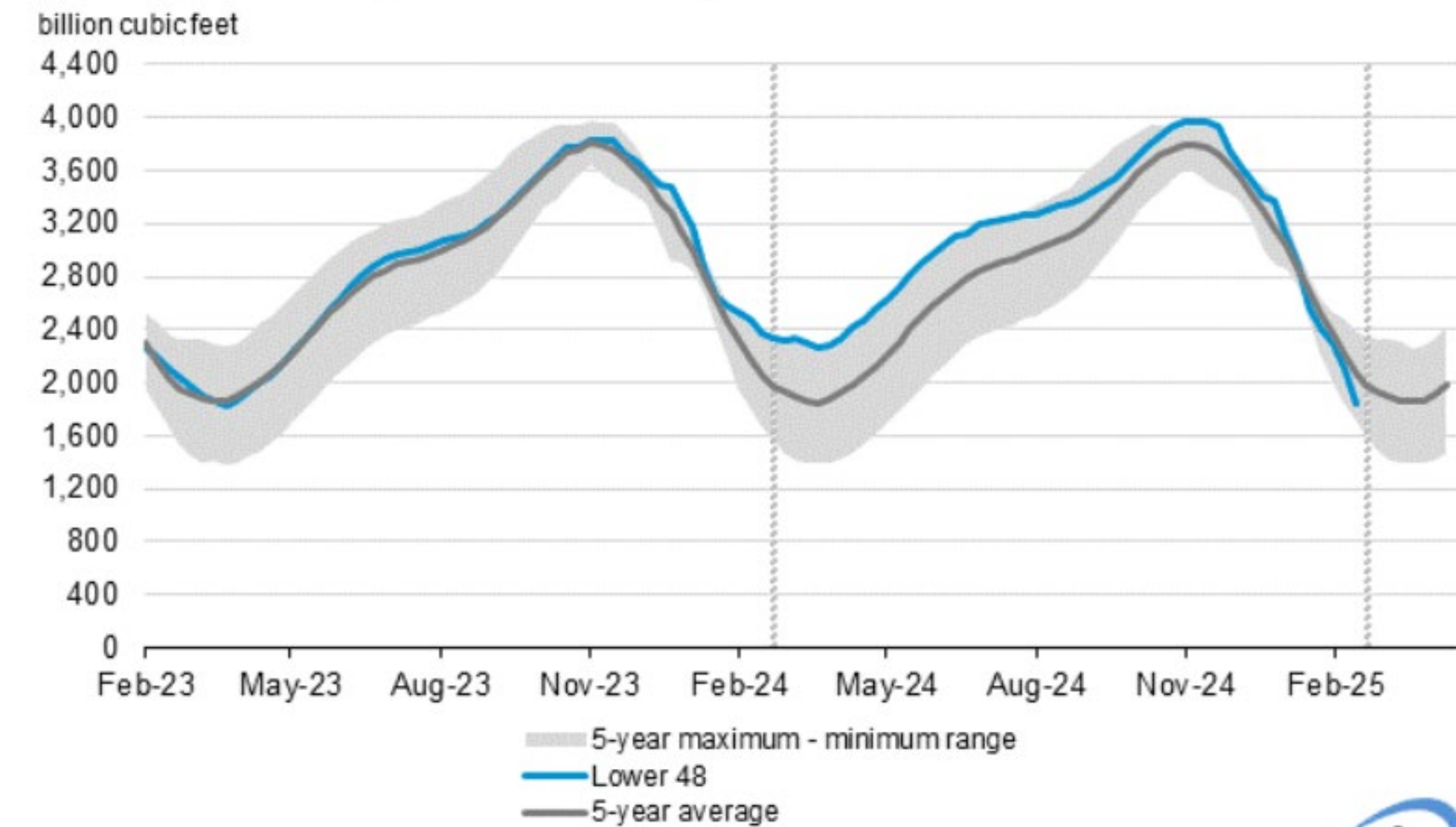
1. Natural Gas Price and Storage Trends (EIA data)

Natural gas spot prices (Henry Hub)
dollars per million British thermal units



Data source: Natural Gas Intelligence

Working gas in underground storage compared with the 5-year maximum and minimum

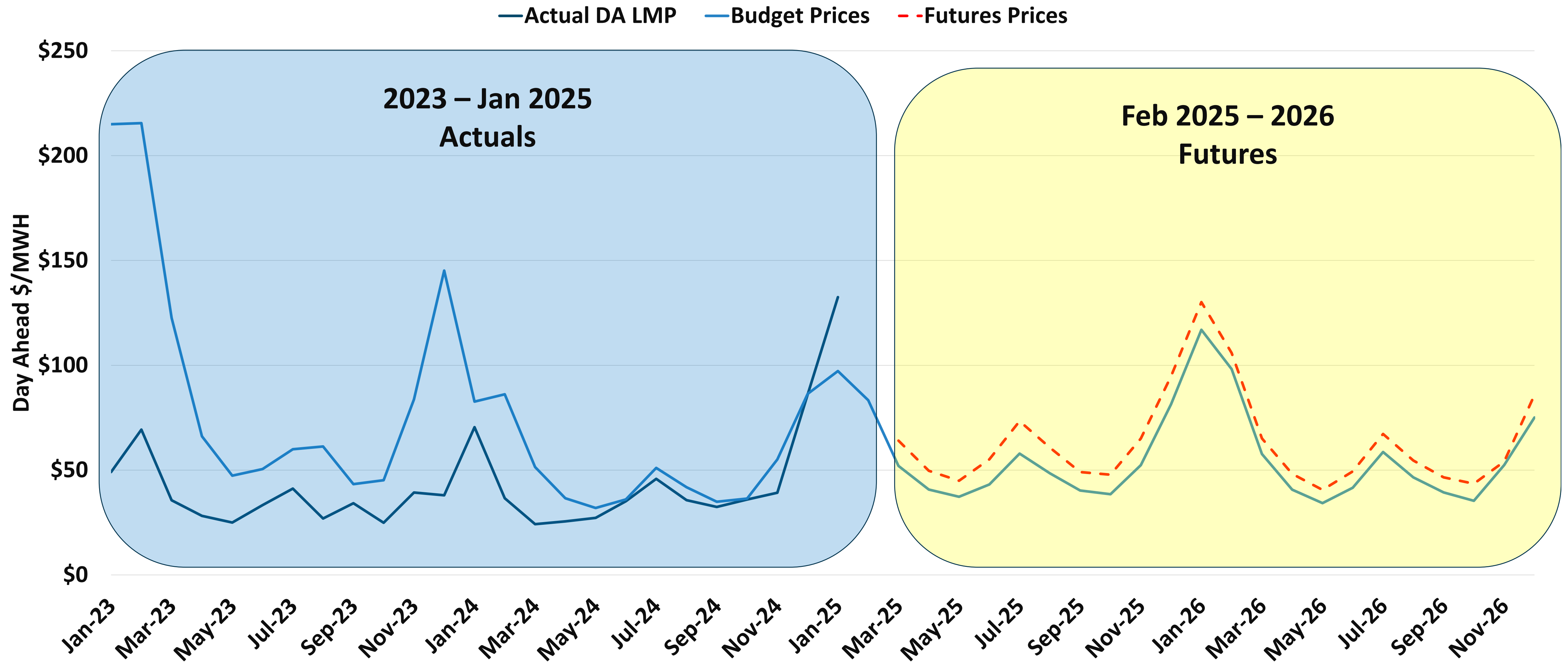


Data source: U.S. Energy Information Administration

Note: The shaded area indicates the range between the historical minimum and maximum values for the weekly series from 2020 through 2024. The dashed vertical lines indicate current and year-ago weekly periods.



2. Actual and Future Electricity Prices (7x24)



3. January 2025 Variances

Member System	Total Load - Including Losses	Hydro Generation	Coverage Ratio
Barton	↑ 3%	↑ 7%	● 102%
Enosburg	↑ 3%	→ 4%	● 105%
Hardwick	↑ 8%	→ -1%	● 97%
Jacksonville	↑ 8%	↓ -12%	● 103%
Johnson	↓ -3%	↓ -16%	● 117%
Ludlow	↑ 7%	↓ -15%	● 102%
Lyndon	→ 0%	↓ -9%	● 109%
Morrisville	↑ 9%	↓ -5%	● 104%
Northfield	↑ 14%	↑ 53%	● 93%
Orleans	↑ 5%	→ 0%	● 112%
Swanton	↑ 4%	↓ -11%	● 108%

Dollar Variance	% Dollar Variance	% Rate Variance
-\$136,432	-103%	✓ -103%
-\$18,580	-7%	✓ -9%
\$40,554	8%	! 0%
\$8,254	10%	! 1%
-\$5,307	-3%	! 0%
\$99,135	11%	✗ 3%
-\$35,882	-4%	✓ -4%
\$51,823	10%	! 1%
-\$76,905	-17%	✓ -27%
\$22,914	14%	✗ 9%
\$52,671	36%	✗ 31%

- BTM Solar
 - 2 of the 3 generated more than budget
 - Lawrence Brook generated significantly more than budget
- BTM Hydro
 - Most hydros generated more than budget
 - Both Swanton units generated less.

- Resources
 - Stetson generation 83% more than budget.
 - Higher than budget LMPs increased energy credits from majority of resources.
- Load
 - Most members' loads were higher than budget
 - Johnson only member lower than budget

4. Market Changes

- Inventoried Energy Program Ended at end of February
- FRM sunset at end of February
- DASI Began March 1. Replaces FRM and adds additional products

Memorandum

To: VPPSA Board of Directors
From: Steve Farman, Mgr. Planning & Support
Date: March 3, 2025
Subject: **Agenda Item 12** – Government Affairs Update

Regulatory

Welcome John Abbott , our new Regulatory Specialist

EVT Triennial Plan 2025 Update

filed 2/5/25 (24-3335-INV), followed by workshop 2/18. No parties filed comments. EVT updates appeared to be minor with no changes at all in the Data Analytics & FLM section.

EV Rate PUC workshop 2/20/25

Demo of Bellawatt customer experience (enrollment & pricing) portion of system and supporting educational materials;

PUC reaction seemed favorable and supportive, much reduced angst relative to enrollment and pricing complexity

PUC suggested exploring converting pilot filings to the 218(d)(o) innovative rate process to take advantage of existing protocols better suited to pilot process. The pace of implementation process will be generally slowed for a month or two while process is figured out with DPS/PUC and more extended pilot process is possible.

Grid Resilience

DPS RFP seeking \$7.9M grant applications that reduce outages

Proposals due by 4/28/25

Need to decide on Joint or individual proposal submittal

May need to consider an outside grant writer for joint approach

Legislative

S.57 - Senate Natural Resources is considering a Bill to extend the Standard Offer program for 5-years more with 20MW allowed each year. The Bill includes a carve-out for up to 2.2 MW of community solar to be awarded through the program. Unlikely to meet crossover but the Chair has stated the committee will continue working on it.

S.65 - also in Senate Natural Resources. This would dramatically expand EVT's authorities allowing it to use EEC funds for any project reducing greenhouse gas emissions. Originally it included battery storage and active demand management, but all parties requested this be removed.

H.289 - Governor's Bill proposing to revise the Renewable Energy Standard into a Clean Energy Standard, is in House Energy & Digital Services. The Bill is partly helpful and partly harmful:

- Changes the name to a Clean Energy Standard and broadens the definition to include any non-carbon emitting resources (ie. nuclear)
- Prohibits construction of generation in "constrained areas". This would impact any VPPSA members inside the SHEI constraint
- Creates a community solar requirement on all utilities and requires regular RFP's seeking such supply. Unclear how this would be implemented for small utilities.

S.50 - expedited net metering approval. The Bill increases the exemption for expedited approval of net metering from 15kW to 25kW. Voted out of Senate Natural Resources and headed to floor. Senate Natural Resources Chair views this as the vehicle for adding any other priorities the committee passes after crossover.

H.125 - In House Energy & Digital Services, would require the DPS to conduct an economic study of the energy transition.

H.265 - In House Energy & Digital Services, would prohibit convenience fees. This directly pertains to prohibiting utilities (electric, water, wastewater) from charging customers for using credit cards.

Transportation Bill - once again has a number of issues around EV charging, incentives, and mileage taxation on EV's.

In addition, there are numerous Bills proposing to repeal the Renewable Energy Standard and the Global Warming Solutions Act.

Memorandum

To: VPPSA Board of Directors
From: Ken Nolan, General Manager
Date: February 28, 2025
Subject: **Agenda Item #13** – VSPC/OC Updates

As requested, this will be a standing item to give VPPSA representatives to the VSPC and VELCO Operating Committee time to discuss items of interest.

There is one item of specific interest this month:

Bill Jordan, DPS Chief Engineer, requested that utilities review the DPS “Electric Risk Assessment and Mitigation Report” and provide any feedback prior to the March VELCO Operating Committee meeting. VELCO subsequently forwarded the report to Operating Committee members, and Bill clarified that the items to focus on are on pages 9-11.

A copy of the report is included in the Board packet.

Separately, related to the VSPC, I sat in on the PUC workshop related to EVT’s Triennial Plan update, and during the workshop EVT was asked about how it was engaging in Flexible Load Management. EVT management responded that they were focused on installing controls that the utilities could then use for their programs, **and they were participating in the VSPC load management committee that was reviewing the issue.**

VERMONT

STATE ENERGY SECURITY PLAN

September 30, 2024

VERMONT

STATE ENERGY SECURITY PLAN

Revision 5.0

WORK PERFORMED UNDER AGREEMENT

DE-EE0010104

SUBMITTED BY:

Vermont Department of Public Service
112 State Street
Montpelier, VT 05620-2601

Direct Project Communications to:
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SUBMITTED TO:

U. S. Department of Energy
Office of Cybersecurity, Energy Security, and Emergency Response
energysecurityplans@hq.doe.gov

Emerging Energy Security Considerations

Electrification

Vermont Electric Power Company (VELCO) – Vermont’s statewide transmission company – is required to periodically complete a long-range transmission plan¹ that is vetted through a stakeholder group called the Vermont System Planning Committee (VSPC). The VSPC is made up of VELCO, electric distribution utilities, the Department of Public Service, representatives of demand and supply resources, and representatives of the general public. The long-term VELCO demand forecast is based on forecasts by customer class and energy end uses. That is, the forecast captures changes in customer class and end-use sales trends that are driven by long-term structural changes — such as changes in housing size, improvements in thermal efficiency, and changes in end-use saturation and end-use efficiency trends. The forecast is weather-normalized (adjusted for year-to-year weather variability), and it incorporates expected effects from the most recent appliance efficiency standards. In addition, the VELCO forecast reflects a projection of program efficiency savings as completed by Efficiency Vermont, behind-the-meter solar, heat pumps, and electric vehicles.

Overall, the most recent VELCO summer forecast (Figure 15, left graph) projects a relatively modest increase in peak load over the next ten years, to 1,119 MW in 2030 (from a historical five-year average of 950 MW), and then a more significant increase thereafter (to 1,294 MW in 2040), primarily driven by electrification of heating and transportation. The VELCO winter forecast (Figure 15, right graph) shows a much more significant increase, given the expected load from electric vehicles and heat pumps. The 2030 winter peak forecast is 1219 MW (from a historical five-year average of 970 MW), increasing to a forecasted 1499 MW in 2040. For both forecasts, solar is shown as not impacting peak load, as the peak hours are expected to be after dark, consistent with experience over the past several years.

¹ The 2021 Long Range Transmission Plan is available at [2021 VLRTP to PUC. FINAL.pdf \(velco.com\)](https://www.velco.com/2021_VLRTP_to_PUC_FINAL.pdf).

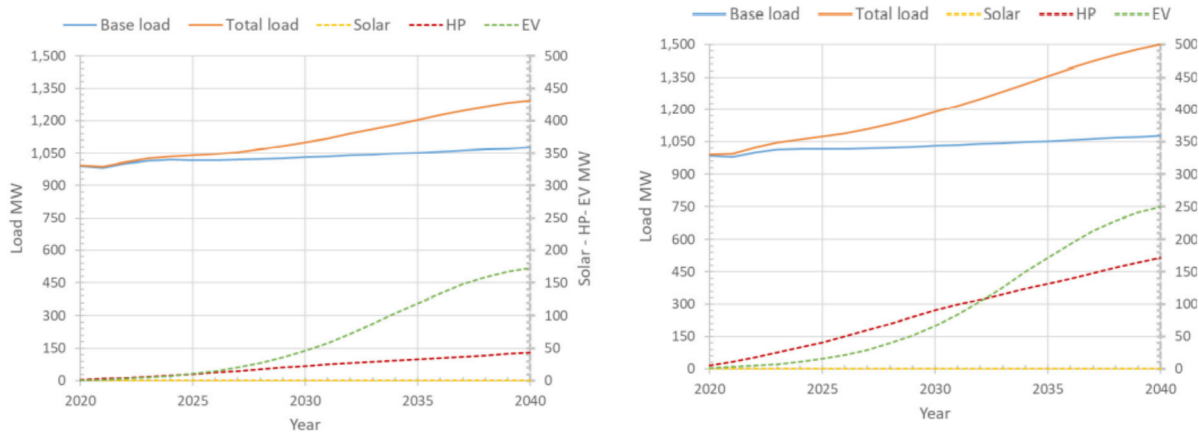


Figure 15. VELCO summer (left) and winter (right) load forecasts.

Source: VELCO 2021 Long-Range Transmission Plan at 21. Available at: [2021 VL RTP to PUC FINAL.pdf \(velco.com\)](#). The base and total load lines use the scale to the left. The dashed lines for solar photovoltaics (PV), heat pumps (HP), and electric vehicles (EV) use the scale to the right.

VELCO's system has been winter-peaking for the past several years, due in part to long-term growth in electric efficiency and behind-the-meter solar. Going forward, Vermont will see higher growth in the winter peak load than in the summer peak, as a result of increased adoption of heat pumps and electric vehicles. Although heat pumps will be used for air conditioning in the summer, these devices use significantly more electricity to provide heat; in addition, electric vehicles are much less efficient in cold weather, and therefore more charging is needed to provide the same amount of mobility.

The above VELCO forecasts can generally be considered a "Business-as-Usual" or "Baseline" forecast of what might occur without significant action to meet our climate and energy policy needs. VELCO created a high load scenario to examine load growth that might be expected to occur if Vermont were to meet its energy and greenhouse gas emission goals. Without load management, it was observed that the winter peak load could reach as high as 1,800 MW. In order to limit system impacts, VELCO implemented load management measures for electric vehicles in line with present and expected utility practices. Doing so reduced the winter peak to 1,471 MW; it was found that this load level could generally be served reliably from a transmission perspective, with minimal modifications to transmission equipment. Further analysis by the distribution utilities would be needed to ascertain what degree of impact there would be to distribution equipment at this load level. This highlights not only the increasingly critical importance of reliable and resilient electric supply and delivery to the daily lives of Vermonters but also significant opportunities to manage demand and meet remaining needs with efficient, affordable, and cleaner supply.

Flexibility

System flexibility, as discussed above in relation to loads, will be essential to managing future electrification loads and for matching the output of variable generation resources such as those Vermont is rapidly deploying. System flexibility can be achieved in a number of ways, from using advanced metering infrastructure capabilities to monitor and influence the timing of loads (e.g., through whole-home or technology specific time-of-use rates) to direct control of loads by utilities (e.g., managed electric vehicle charging) to deployment of energy storage and other distributed energy resources and grid resources to smooth and integrate demand and supply for optimizing and easing stresses on the grid.

Advanced Metering Infrastructure

AMI is the use of smart (i.e., digital) meters with two-way communication that record parameters such as usage (consumption in kWh), voltage, demand (kW), and power factor in intervals of one hour or less. AMI can also be used to enable dynamic pricing, due to the interval consumption data, in an attempt to reduce peak demand. AMI can also be used for other functions, such as remote disconnect tamper detection, and enabling the use of smart appliances. AMI can also be used to detect electrical outages in the first place, to determine the extent of the outages, and to increase the efficiency of restoration.

During the 2007-2008 session the Vermont General Assembly ordered the Vermont Public Service Board (the “Board”) to investigate the implementation of Smart Meters capable of sending two-way signals that would allow for innovative, dynamic rate designs for every rate class and to report back to the Legislature by December 31, 2008 on the plans of the Vermont electric distribution utilities for implementation of Advanced Metering Infrastructure (“AMI”). On April 18, 2007, Docket No. 7307 was opened by the Board to investigate the use of Smart Meters and Time-based rates. In November 2008, the Department of Public Service and the electric utilities reach agreement in a Core Memorandum of Understanding (the “Core MOU”), which described our collective understanding of AMI, specified minimal functional requirements for utility AMI systems, and provided a process for State review of each utility’s AMI plan.

In 2009, the Vermont utilities applied for, and received, a DOE Smart Grid Investment Grant, which funded 50% of certain AMI and DA projects. As of the September 2022, five electric utilities (Burlington Electric, Green Mountain Power Stowe Electric, Vermont Electric Cooperative, and Washington Electric Cooperative) have AMI installed in their service territories. These five utilities account for approximately 92% of Vermont electric customers and a similar percentage of the State’s geographic area.

More recently, the Vermont Public Power Supply Authority (VPPSA) has started a project on behalf of its 11 member utilities to procure smart meters using a centralized approach, which is expected to roll out over the next two to three years. One benefit of implementing smart meters now is that utilities can benefit from technology advancements over the last decade, as well as lessons learned from deployments.

While smart meters have succeeded in supplanting physical meter readers, help utilities remotely scope the extent of outages, and provide historical load and system performance metrics that can be used to help model the system, they have not yet provided actionable, real-time intelligence for use by customers and utilities. For some utilities, that's due in part to physical limitations of communications networks, especially in systems that use power line carrier communications to transmit data, and also to the challenge of managing and applying the sheer volume of data coming from smart meters. For others, the ability to integrate with an increasing and evolving diversity of energy devices in buildings has been disappointing, leading in a refocus on connecting to those devices via the internet. The "internet-of-things" includes energy "things," and is one more impetus for building out and future-proofing robust, secure statewide communications networks.

In 2023, the Public Service Department began disbursing \$11 million in funding allocated by the Vermont General Assembly to help some utilities implement smart meters for the first time, and others replace legacy fleets with more modern systems. As these investments roll out, maximizing grid-modernization value is essential. As technology advances, new ways of communicating with customers and DERs will materialize that may ultimately supplant one or more roles that AMI currently plays or has potential to play (including as replacements for traditional grid sensing technology). These include smart inverters paired with DERs, smart plugs, and smart load panels. As these are implemented, it will be important for utilities and other partners to think realistically and strategically about the costs, benefits, data management, communications pathways, cybersecurity, integration with legacy systems, and interoperability of these emerging resources and develop plans to ensure an optimal rollout.

Energy Storage

Electricity (i.e., batteries) usually comes to mind when thinking about energy storage, but oil in tanks, natural gas in pipes, and hot water are also some other forms of energy storage. This discussion will be limited to the storage of electricity. In the absence of electricity storage, the electric system is operated under the principle that supply must equal demand at each instant. One of the main benefits of electricity storage is that electricity generated at one time may be used at some other (future) time. This might be useful for saving electric energy generated

during a period of low demand for a time of high demand (for price or capacity reasons), and could be useful for smoothing out the sometimes rapidly-varying output of intermittent sources such as solar or wind. In its 2017 report on deploying energy storage, the Department discussed the “Swiss army knife” nature of storage, which can help manage peaks, time-shift demand and supply, smooth renewables integration, provide frequency regulation and other grid support, and — if properly configured — provide resilience during grid outages.

The residential, commercial, and community storage that is being developed in Vermont can perform many of these functions, with some services (such as peak shaving and regulation) helping offset the costs for other services that are harder to monetize, such as resilience. As of September 2023, Vermont had about 53 MW of installed storage. Vermont currently has two solar + storage microgrids, one in Rutland capable of islanding the nearby high school (which is also an emergency shelter) and another in Panton that is undergoing design work to enable an expansion to support even more critical facilities. Green Mountain Power (GMP) is currently pursuing an additional three of these so-called Resiliency Zones, in Rochester, Grafton, and Brattleboro. The models being explored by GMP include microgrids to island downtowns/clusters of critical facilities as well as concentrated deployments of residential batteries to offer resilience in lieu of traditional grid upgrades such as feeder backup in rural territories.

These utility-supported geotargeted microgrids complement the 25 MW worth of residential- and small commercial-scale battery storage systems in Vermont that are used in the aggregate to reduce peak demand, but that also provide resiliency to specific customers in the event of an outage. The Department continues to work with utilities and other stakeholders to develop a common and sensible framework for valuing and planning for resilience, and to ensure resilience opportunities are available to customers statewide.

Other Distributed Energy Resources

In Order 2222, the Federal Energy Regulatory Commission defined a distributed energy resource (DER) as, “any resource located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment.” Increasingly, these resources can be controlled to reduce load, and especially peak demand. Reducing peak demand can assist with electric reliability (i.e., energy assurance) by increasing the gap at the transmission level between actual load and the load at which one more contingency would result in an outage. Vermont deploys DERs through many different avenues, including its Energy Efficiency Utility (Efficiency Vermont),

distributed generation programs such as net-metering, Tier III of the Renewable Energy Standard, and utility pilots and tariffed offerings.

Resiliency

The high-voltage transmission network in Vermont is operated by the Vermont Electric Power Company (VELCO) at voltages ranging from 115 kV to 345 kV. This network – as part of the broader regional transmission system – provides access to electric sources beyond VT borders from the rest of New England, New York, or Canada.

GMP, and the other 16 Vermont distribution utilities, connect to VELCO and serve loads at sub-transmission and distribution voltages. Distribution grid reliability is governed by industry rules and standards; distribution utilities are also required to file Service Quality and Reliability Plans with the Vermont Public Utility Commission and Public Service Department, reporting on reliability performance metrics such as the frequency and duration of outages, along with a list of the utility's worst-performing circuits and plans to improve their reliability.

Infrastructure resiliency – differentiated from reliability by virtue of the duration, scale, and scope of the disruptive event – is increasingly a topic of discussion in Vermont. The State's inaugural [Climate Action Plan](#) includes recommendations related to energy infrastructure resilience, which encompass the domains of prevention, survivability, and recovery. The overarching strategies – each with its own set of action items – include:

- A. Create a policy, planning, and organizational foundation to support effective investments in infrastructure resilience.
- B. Public, private, and nonprofit entities should be prepared to respond and recover quickly to disruptions caused by severe weather and other climate change threats.
- C. Increase the resilience of critical infrastructure to severe weather and other climate change threats by reducing vulnerabilities of specific facilities.
- D. Increase the resilience of critical infrastructure to severe weather and other climate change threats by improving system efficiency, reliability, and redundancies.

Part of the ongoing work under the Climate Action Plan is the development of a Municipal Vulnerability Index, which is currently under development. In part, the Index is expected to build upon mapping done by Green Mountain Power to identify so-called resiliency zones, where areas with a confluence of poor reliability, electric-dependent telecommunications, and social vulnerability factors are being identified to target resiliency interventions such as

microgrids. In future iterations of this Plan, the Department will provide an update of that work and how it is being used to enhance energy reliability.

The Climate Action Plan also recommends that federal funds be sought to defray the cost of utility resilience upgrades that exceed benefits to ratepayers, such as:

- Ubiquitous communications networks that enable full utilization and participation of distributed energy resources in an interactive grid.
- Resilience Zones: batteries installed at or near critical facilities, potentially paired with solar (and/or small wind) and with a microgrid /islanding where possible, to allow them to continue to operate in the event of extended disruptions to electric service.
- Strategic upgrades to substations, distribution, and transmission capacity across the Vermont grid needed to enable the state's renewable and electrification goals, after first exploring feasibility of any lower-cost options, e.g. flexible load management, curtailment, and storage.
- Emerging non-wires technologies that address major challenges system resilience (e.g., long-duration outages).

The Department has applied for both formula and competitive federal funds in 2023 to bolster grid resilience. The next State Energy Security Plan will include a summary of funding received and planned uses.

Winter Energy Adequacy

Increasingly, the New England electric system has become reliant on natural gas for power generation year-round. Available pipeline capacity limits the amount of natural gas that it is possible to procure from our neighboring regions and, during a cold snap, some natural gas plants would find their fuel supply restricted by the competing demand of residential heating. While it is possible for some generating stations to utilize liquid natural gas (LNG) in place of the gas piped in from neighboring regions, it may still be difficult for these plants to obtain fuel given supply chain challenges and competing demand from foreign markets.

The growth of renewable, intermittent resources in Vermont and elsewhere in the region has begun to decrease the demand for electricity from fossil fuel generators, and indications are that this essential process will continue. However, the efficacy and availability of these resources can be severely hampered by extreme weather conditions. It is expected that, in a winter weather event, wind turbines may be shut down due to blade icing or high wind, solar panels may be covered by snow or ice, and that small-scale hydro turbines could suffer from deficient water flow. Reduction of this risk will require the diversification of renewable resources with regard to

technology type and geographical location across Vermont and, expressly, across New England.

Other types of resources for generating electricity that are already connected to Vermont's grid, such as biomass and large-scale hydro, can operate efficiently even during periods of extreme cold. It is possible to store biomass fuel like wood chips at quantities that allow several consecutive days of operation, and large hydro facilities do not incur the same fuel transport concerns of other resource types. It is important to recognize that these resources provide unique reliability advantages.

Threats/Vulnerabilities

The Vermont Public Utility Commission (PUC) [Rule 4.900 \(Electric Outage Reporting\)](#) requires all electric utilities to annually report the number and duration of outages in the following categories:

Trees — Outages caused by the interaction of trees and tree branches (regardless of whether the tree originated inside or outside of the right-of-way) with the electric system, including Outages resulting from trees interacting with the electric system during severe weather. Tree-related Outages which result from operator error, accidents, or animals (e.g., beavers) should be listed under the respective cause-related category. Vermont is over 70% forested and the likelihood of trees falling into the rights-of-way (ROW) of electric lines is very high. The vulnerability of transmission lines is very low due to the large width of the ROW. The vulnerability of distribution lines varies considerably: for underground lines it is very low, for overhead storm-hardened lines it is low, and for overhead lines that are not storm-hardened it is very high.

Weather — Outages caused by wind, snow, lightning, ice, and flooding. Outages from weather events which cause trees to interact with the electrical system are listed in the "trees" category. Weather events such as wind, heavy wet snow or ice build-up on power and communication lines can lead to lines being forced out-of-service or damaged. Some outages can be caused by weather events such as lightning strikes. The likelihood of wind, snow, and lightning events happening each year is very high, while the likelihood of ice and flooding is low. The vulnerability of the underground electrical infrastructure is very low, and the vulnerability of the overhead electrical infrastructure to the weather itself (i.e., not trees falling due to weather) is low.

Company Initiated — Outages caused by utility scheduled construction and maintenance. The likelihood of these outages is historically low, but is also generally within the utilities' control

and the duration tends to be brief. The vulnerability to a company-initiated outage is, by definition, very high.

Equipment Failure — Outages caused by specific equipment failures such as transformer or arrester failures. The likelihood of this threat has been historically low, while the vulnerability is moderate to high, depending on the equipment, as this would typically affect overhead and underground.

Operator Error — Outages caused by utility or utility contractor error, including contract tree trimmer error. The likelihood of this threat has been historically very low, and the vulnerability is also very low.

Accidents — Outages caused by accidents by other than utility employees or contractors, including the felling of trees into utility lines, excavation damage, car-pole accidents, as well as outages resulting from emergencies such as police or fire department requests for shutdowns. The likelihood of this threat has been historically low, and the vulnerability is also low.

Animals — Outages caused by the interaction of animals such as birds, squirrels, and raccoons with the electric system. Outages also caused by trees, in which the root cause is the action of an animal, should also be placed in this category. The likelihood of this threat has been historically low to moderate, and the vulnerability is low and decreasing as utilities install more animal guards (see mitigation section).

Power Supplier — Outages caused by the loss of power supply from another utility or non-utility provider. The likelihood of this threat has been historically very low, and the vulnerability is also very low.

Other — Outages with known causes that fall outside of the categories listed above. This may also include vandalism and terrorism. Likelihood and vulnerability scores have not been assigned due to variable nature of this thread. The Department of Public Service will work with the utilities to better understand and minimize use of this category.

Unknown — Outages with causes unknown. Likelihood and vulnerability scores have not been assigned due to unknown nature of this thread. The Department of Public Service will work with the utilities to better understand and minimize use of this category.

Table 4 indicates actual outage data for calendar years 2020 through 2023 for Vermont's largest

electric utility. There were instances of each type of outage category (threat) in each year (with the exception of Other, which had zero instances in 2020, 2021, and 2022, and nine instances in 2023). Regarding the eight specific threats (trees through power supplier), the likelihood of an outage event in each of these eight categories occurring at least once in each year is “1” or 100%; however, the number of times per year varies greatly. Therefore, the likelihood score for each threat takes into account the relative differences between these threats. The data in Table 4 present the actual risk profile of each threat, rather than a theoretical assessment.

Table 4. Electric Outage Data for Calendar Years 2020 through 2023.

Outage Cause	Totals (four years)			Annual Averages			% By Outage Cause		
	Events	Customers Affected	Customer Hours Out	Events	Customers Affected	Customer Hours Out	Events	Customers Affected	Customer Hours Out
Trees	23,868	1,517,517	7,636,896	5,967	379,379	1,909,224	53.28%	58.91%	71.74%
Weather	4,998	198,085	1,537,111	1,250	49,521	384,278	11.16%	7.69%	14.44%
Company Initiated	1131	186,811	240,157	283	46,703	60,039	2.52%	7.25%	2.26%
Equipment Failure	4,325	197,412	408,651	1,081	49,353	102,163	9.65%	7.66%	3.84%
Operator Error	63	10,552	3,789	16	2,638	947	0.14%	0.41%	0.04%
Accident	1399	165,850	373,478	350	41,463	93,370	3.12%	6.44%	3.51%
Animal	4394	70,284	84,860	1,099	17,571	21,215	9.81%	2.73%	0.80%
Power Supplier	105	36,175	73,093	26	9,044	18,273	0.23%	1.40%	0.69%
Other	9	5,646	5,022	2	1,412	1,256	0.02%	0.22%	0.05%
Unknown	4,506	187,535	282,204	1,127	46,884	70,551	10.06%	7.28%	2.65%
Grand Total	44,798	2,575,867	10,645,261	11,200	643,967	2,661,315	100%	100%	100%

Cyber attacks are an additional threat relevant to all utility types. The likelihood of a cyber attack is very high, as some utilities are reporting thousands of attempts per day. Given the sensitive nature of cybersecurity information, a discussion of vulnerabilities will not be included in this document. High vigilance must continually be maintained due to the evolving nature of the attacks and because the consequences of a successful attack can be very high. The cyber threat and mitigation measures are discussed in more detail in a separate “Cybersecurity” section immediately following the “Risk Mitigation Measures” section below.

Risk Mitigation Approach and Measures for the Electric Distribution System

Vermont’s approach to mitigating risk to energy supplies is to increase the reliability and resilience of critical infrastructure by reducing likelihood and/or consequences of the threats described above. As stated above, one of Vermont’s Climate Action Plan strategies (which the Vermont SESP also adopts) is to “increase the resilience of critical infrastructure to severe

weather and other climate change threats by improving system efficiency, reliability, and redundancies.” Although all of the risk mitigation measures discussed below for electric and natural gas utilities are required to be addressed by existing processes, the risk mitigation measures that respond to the most common and highest impact hazards for outages are given higher emphasis. Below, the risk mitigation measure for each risk described above is folded into a risk scenario and connected to risk mitigation measures that partners in the state’s energy sector are implementing.

Risk Scenario: Trees Falling on Power Lines

As seen in Table 4, the threat of trees falling on power lines is, by far, the highest risk to the electric system in Vermont. To put it in perspective, trees result in more customers out and more customer hours out than all other outage causes combined. The consequence of a tree falling on an overhead distribution line that has not been storm-hardened (most of the lines in Vermont) is that it will cause a fault (short-circuit) to ground by either: 1) resting on the line and the tree becomes the path to ground or 2) the tree breaks the line and the line drops and comes in direct contact with the ground. The fault causes the nearest upstream protective device to open, resulting in an outage to all customers downstream of that protective device. The duration of the outage is the time it takes the utility to first become aware of the outage and then to remove the tree or repair the conductor (or switch to a feeder backup system, if available). Mitigation measures to trees include: vegetation management, storm-hardening overhead power lines, and placing lines underground. Public Utility Commission (PUC) Rule 3.600 requires all electric utilities in Vermont to have a vegetation management plan and each utility’s actual and projected vegetation management activity is reviewed at least every three years during the Integrated Resource Plan (IRP) process. Vegetation management is the highest priority mitigation measure for the highest risk to the electric system, but it is becoming increasingly challenging because trees are, of course, growing taller every year and utilities typically only trim ten feet on either side of a distribution line, which enables trees outside the ROW (i.e., where utilities don’t have an easement to trim) to fall on the line. Utilities do have danger/hazard tree programs and do seek landowner permission to remove trees that have been identified to be a hazard to the line; however, otherwise healthy trees commonly fall on lines due to powerful wind or snow storms. As stated above in the Threats/Vulnerabilities section, the vulnerability of overhead lines that have not been storm-hardened is therefore very high. Further mitigation measures to trees falling are to storm-harden the line with spacer-cable construction (which can handle a tree on the line without causing an outage) and placing lines underground. As utilities rebuild distribution lines, they are employing spacer cable construction or placing lines underground, as appropriate. GMP has recently deployed a cable-in-conduit underground system that is cost-comparable to overhead construction. These measures will reduce the risk to end-use reliability by reducing the

likelihood of a tree falling on an overhead line and cause an outage.

Risk Scenario: Severe Weather

Weather is the second most significant threat to electric lines, although it results in approximately one-fifth of the outages as due to trees. Heavy wind, snow, and ice can directly bring down conductors and poles, causing as a consequence a fault to ground and resulting in outages to all customers downstream of the protective device that tripped due to the fault. The vulnerability of the existing lines to normal weather is very low, but the duration of the outage is the time it takes the utility to first become aware of the outage and then to repair the line (or switch to a feeder backup system, if available). Mitigation measures to prevent the occurrence of outages include storm hardening and placing lines underground in order to withstand or eliminate the threats of wind, snow, ice, and lightning. These two mitigation measures are being utilized as necessary (locations of frequent outages) and as cost effective as a preventative measure when lines are rebuilt. PUC Rule 3.500 requires that all utility construction comply with the National Electrical Safety Code (NESC). Another mitigation measure is better weather forecasting to strategically stage crews to reduce the duration of outages. The utilities employ an outside resource as a weather forecaster and also have some in-house resources. Through the IRP process, utilities are asked to review the location of all of their substations and other critical infrastructure with respect to the FEMA 100-year flood plain maps and to plan relocations where there is a possibility of infrastructure being inundated or washed away. These measures will reduce the risk to end-use reliability by 1) reducing the likelihood that weather (wind, snow, ice, flooding) can directly cause an outage to the electric system, and 2) reducing the duration of the outage if one does occur.

Risk Scenario: Wildlife Compromises the Grid

Animals are the third most significant risk to electric lines. Mitigation measures for this threat are to install animal guards on equipment to prevent animals from contacting two facilities of different potential simultaneously and causing a short, which as a consequence would result in an electrical outage to all customers downstream of the protective device that tripped. When animal contact happens inside a substation, all customers on one entire circuit or all customers served by the substation on all circuits can be out of service. Approximately 15 years ago, a squirrel inside the substation serving Montpelier caused an extensive outage to Vermont's capital city during business hours. Animal guards are a cost-effective mitigation measure to reduce the vulnerability of electric equipment to animals, and utilities are installing them where possible. The use of animal guards is reviewed during the IRP process. This will reduce the risk to end-use reliability by reducing the likelihood of an animal causing an outage.

Risk Scenario: Catastrophic Equipment Failure

The fourth most significant threat to electric lines is equipment failure. Two specific examples of equipment that could fail and cause an outage include, but are not limited to, a transformer and a pole. Consequences of equipment failure are outages to all customers downstream of the protective device upstream of the equipment that failed and caused a fault on the system. The duration of the outage is related to how long it takes the utility to become aware of the outage, the availability of new equipment to replace the equipment that failed, and the time it takes the utility to make the repair. Equipment such as poles and common transformer sizes are usually in stock or readily available, but utilities should plan for equipment that may have long lead times to procure to avoid the consequence of a long outage. Mitigation measures to equipment failure are increased monitoring, maintenance, and replacement before failure. Transformers are frequently in place for more than 50 years, and over time and heavy use the insulation can break down, leading to a catastrophic failure. Utilities monitor dissolved gases in the transformer oil, which can be an indicator of insulation breakdown. As a mitigation measure, a transformer is replaced if dissolved gas levels are unfavorable. During the IRP process, the utility's pole-inspection program and philosophy for cost-effectively replacing equipment are reviewed, but there are no requirements placed on the utilities in this area. Writing this plan has brought to light that the Department of Public Service could do more to investigate equipment failure and determine if more could be done to mitigate this risk. This will reduce the risk to end-use reliability by reducing the likelihood of equipment failure in the first place, and if equipment needs to be replaced, it can be done during a time of least disruption (consequence) and also likely with a shorter outage duration.

Risk Scenario: Accidents

Accidents pose the fifth most significant risk to electric lines. Due to the variable nature of accidents, the mitigation measures are also variable. Vermont has an active [Underground Damage Prevention Program](#) that investigates all damage for its root cause and determines ways to prevent re-occurrences. Part of the prevention is a fine structure for the entity responsible for the damage. On a voluntary basis, some electric, communications, and gas companies have written Underground Damage Prevention Plans for their organization. This will reduce the risk to end-use reliability by reducing the likelihood of excavation damage.

Risk Scenario: Company-initiated Outages

Company-initiated outages pose the sixth most significant risk to electric lines. Under this scenario, a utility may identify during its regular maintenance that a transformer or a pole is nearing the end of its useful life or is in imminent danger of failing and needs to be replaced. Mitigation measures that the utilities are already employing are to schedule the outage during a

time of least disruption and to carefully plan an efficient work schedule to minimize the duration. It should be noted that company-initiated outages are typically performed to replace equipment that is a high risk for failure, and, therefore, company-initiated outages are a mitigation measure for equipment failure. This will reduce the risk to end-use reliability by ensuring that the outage is of a short a duration as possible and during the time of least disruption (consequence).

Risk Scenario: Power Supplier Outage

Mitigation measures for this threat would be the same as for the other specific threats discussed in this section, depending upon which threat caused the outage to the transmission line supplying the distribution utility. This will reduce overall risk to end-use reliability by ensuring that distribution utilities receive reliable transmission service.

Risk Scenario: Operator Error

While not a significant risk to the electric system, more could be done to reduce this risk. Mitigation measures to reduce this risk would be for the utility to have proper procedures and training of employees to perform tasks that, if done improperly, could result in an outage. There are currently no such requirements for electric utilities (as opposed to natural gas utilities, which are required to have and follow procedures, and are required to have Operator Qualification training programs). Writing this plan has brought to light that the Department of Public Service could do more to investigate operator error and determine if more could be done to mitigate this risk. Developing proper procedures and training for tasks that could affect reliability should reduce the risk to end-use reliability by reducing outages caused by errors made by utility employees or contractors.

General Risk Mitigation Measures.

Other mitigation measures are discussed on pages 27-32 (in the Flexibility, Resiliency, and Winter Energy Adequacy sections) and are listed below. Energy storage (see page 29) is a general mitigation measure for all threats and is being deployed through utility programs.

Energy Conservation

When the power system appears to be headed for a shortage of capacity to handle the load, distribution utilities may, in coordination with VELCO and at the ultimate direction of ISO-NE, send a message to the public asking for reduction in the use of electricity. This will reduce overall risk to end-use reliability by reducing stress on the electric system during a capacity shortage.

Load Management (Demand Response)

There are commercial customers who can manage their loads by shutting down a portion of their load or starting another source of power to perform the work that was previously done from the power supplied from the electric grid. This could be their own electric generation or in Vermont in the winter it might be diesels to operate snow-making equipment at the ski resorts. There are also customers who can manage their loads by rotating what processes are on at any given time and shutting off those not immediately needed. This will reduce overall risk to end-use reliability by reducing demand on the electric system to below the level at which an overload would occur and potentially cause a blackout.

Vandal / Terrorist Protection

Physical protection is in part the securing of facilities from unauthorized access by utilizing various monitoring and surveillance techniques. In addition, close working relationships with law enforcement agencies and the Department of Homeland Security would serve to provide a more rapid response to breaches in security. Part of the response is to also alert other utilities of possible threats. This will reduce overall risk to end-use reliability by reducing likelihood and duration (consequence) of an attack on critical infrastructure which would result in mass outages.

Planning

Vermont's electric and natural gas utilities report data on the reliability and efficiency of their operations in their Integrated Resource Plans (IRPs), which are submitted every three years. And, as noted previously, VGS is required to develop rigorous transmission and distribution integrity management programs to identify and mitigate risks to its natural gas pipeline system. Also, for electric utilities, PUC Rule 4.900 requires the following assessment to be performed annually: "An overall assessment of system reliability that addresses the areas where most Outages occur and the causes underlying most Outages. This assessment should be based on long-term reliability trends and consider the most recently compiled reliability data. Based on this assessment, the utility should describe, for both the long and short terms, appropriate and necessary activities, action plans, and implementation schedules for correcting any problems identified in the above assessment." Most of the risk mitigation measures mentioned in this section are discussed and reviewed in the above-mentioned planning processes. Taken together, all of these processes require utilities to have knowledge of their system and to operate it in a safe, reliable, and cost-effective fashion. This will reduce overall risk to end-use reliability and resilience by reducing likelihood and duration (consequence) of outages.

Cyber Security

With the increase in smart grid technologies (including AMI and DA – see above), employee remote access via computer and mobile device, and customer account access and online payments, cyber security has correspondingly become increasingly important and necessary. Recent reports indicate that the number of cyber attacks across all sectors is increasing, and the number of attacks on the energy sector is also increasing. Consequences of a successful cyber attack range from the release of customer data, such as credit card and banking information, to shutting down the power grid by remotely controlling devices or causing damage to devices. While the increase of the number of digital and smart devices on the grid can increase reliability, it also increases the “attack surface” of the grid (i.e., increases the number of points through which the system can be accessed). Cyber security is not just a technical problem, however; it is also just as importantly both a business process problem and a personnel problem (people can often be the weakest link).

While the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards apply to the bulk electric system (100 kV and above, and certain other facilities), there are not clear standards for the distribution system. One of the requirements of the Smart Grid Investment Grant is that the utilities develop a cyber security plan, which was approved by DOE. In addition, in December 2019, the Vermont Public Utility Commission approved a set of Cyber Security Principles, which are as follows:

1. Vermont’s electric utilities (“Utilities”) acknowledge the importance of adhering to all cyber security requirements imposed by law, of being familiar with relevant industry standards and recommendations of best practices; and of working collaboratively to ensure appropriate and coordinated approaches to cyber security.
2. Cyber Security Plans developed by any Utility shall be tailored to that Utility’s specific needs. Utilities shall comply with the terms of any cyber security requirements included in applicable law, regulation and industry standards, and those voluntarily adopted by the Utility. Any such plans should reflect consideration of the nature of the Utility’s specific infrastructure.
3. Not less often than twice annually, representatives of the Utilities shall meet with the DPS to discuss:
 - a. Any significant developments arising from the plans of each Utility under paragraph 2 above;
 - b. The existence and impact of any new state or federal cyber security standards;
 - c. Areas of prospective collaboration in the interest of ensuring the existence of effective and efficient cyber security protections for Vermont electric utilities and customers, including the adoption of voluntary plans pursuant to paragraph 2 above.
4. At least annually, the group described in paragraph 3 above shall offer a written report to the Vermont Public Service Board and the Vermont Department of Public Service relative to the activities of the group, including: 1) a list enumerating known attacks or

- attempts; 2) outcomes and steps taken to address such attacks/attempts; and, 3) a plan for future remediation.
5. In the event that utility safeguards are overcome by a cyber-security attack and customer information or grid reliability is compromised, Utilities will comply with applicable reporting and take necessary steps to mitigate future breaches.
 6. Nothing in these principles shall be deemed to limit the responsibility or authority of utilities to take appropriate measures to implement and maintain appropriate cyber security measures.

The National Association of Regulatory Commissioners (NARUC) has issued whitepaper entitled [“Cybersecurity for State Regulators 2.0 With Sample Questions for Regulators to Ask Utilities”](#). This primer is an excellent resource for understanding the basics of cyber security, and for providing assistance for regulators to:

- Develop internal cybersecurity expertise;
- Ask good questions of their utilities;
- Engage in partnerships with the public and private sector to develop and implement cost-effective cybersecurity; and
- Begin to explore the integrity of their internal cybersecurity practices.

Attachment A to the NARUC primer includes 48 sample questions for regulators to ask utilities when discussing cyber security. The Department of Public Service will ask these questions (and others) when meeting with the utilities pursuant to the above-mentioned Cyber Security Principles. When regulators meet with utilities to discuss cyber security, it is important to ask questions in such a way that the answers by the utilities don't disclose details of vulnerabilities.

A strong need of regulatory commissions is internal expertise in cyber security. For this reason, in 2013, the New England Conference of Public Utilities Commissioners, Inc. (NECPUC) issued an RFP for a consultant to provide assistance on cyber security planning, coordination, and evaluation (for the time period September 15, 2013 through March 15, 2014). NECPUC is a non-profit 501(c)(3) corporation comprising the utility regulatory bodies of the six New England states (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont) and provides regional regulatory assistance on matters of common concern to the six New England states. NECPUC states have identified a need to bring on expertise to assist in creating cyber security plans, policies and standards. In conjunction with working with the six states on possible cyber security plans, NECPUC would look to the consultant for advice and analysis of cyber security policies and standards. NECPUC wants a consultant's expert advice on what the New England regulators need to do to make sure the New England utilities are ready to thwart cyber attacks and able to recover quickly and effectively when a cyber attack is successful.

The consultant will support NECPUC member states with the following tasks:

1. Assist states in conducting on-site visits of regulated utilities to evaluate protection and recovery measures from cyber security breaches;
2. Recommend cyber security and resiliency-related areas of improvement as well as best practices to be shared with other utilities;
3. Work with state commissions in developing recommended reporting requirements regarding cyber attacks and breaches;
4. Recommend future work areas to ensure continued cyber security and resiliency of utility control systems; and
5. Recommend measures for state commissions to ensure cyber security and resiliency of their regulated utilities.

The Department of Public service should continue to build expertise in cyber security through interaction with the consultant, remaining up-to-date on various cyber security standards and guidance that are issued, participating in cyber security training sessions, and while visiting utilities. The Department of Public Service also participates in the NARUC Critical Infrastructure subcommittee, which holds regular conference calls to share information and stay abreast of current topics. To date, the Department has attended cyber security training conducted by Sandia National Laboratory, NARUC, and the Vermont Department of Public Safety.

The section on the Role of Telecommunications in Energy Assurance describes the interdependency between electricity and telecommunications. Since electrical networks depend on telecom networks, a telecom network outage, no matter its cause, can affect electrical service. Electric utilities should therefore consider cyber security among the other various vulnerabilities of their telecom service providers.

Enhanced cyber training, technical assistance, and coordination, such as those efforts described above, should serve to decrease the potential likelihood and consequences of a cyber event by better preparing the relevant stakeholders. This will reduce overall risk to end-use reliability, as Vermont will be better prepared to respond to cyber incidents and reduce the severity or duration.

ISO-New England Emergency Operating Procedures

The Independent System Operator of New England (ISO-NE) has several emergency operating procedures, including the three listed below. These measures are designed to maintain the high voltage system grid as reliably as possible.

ISO New England Operating Procedure No. 4 - Action During a Capacity Deficiency (OP-4)

This procedure establishes criteria and guidelines for actions during capacity deficiencies of the ISO-NE electrical grid. There are 11 Actions that ISO-NE can implement to remedy the capacity deficiencies. The first two actions are internal to ISO-NE except that a public Power Caution is issued, and Action 3 asks Local Control Centers (LCC) to reduce their own load. Actions 4 through 8 get all reserve generation on line and implement a 5% voltage reduction and issue a Power Alert at Action 4 that loads are getting high. Action 9 requests all non-contracted generation to be put online and request large industrial and commercial facilities to voluntarily reduce load. Action 10 is to initiate radio and television appeals for voluntary load curtailment and issue a Power Warning. Action 11 is a request to each New England Governor to reinforce the Power Warning appeals, as initiated in Action 10. Depending on the situation, some actions may be initiated simultaneously, and ISO-NE may initiate actions in any order as needed.

ISO New England Operating Procedure No. 7 - Action in an Emergency (OP-7)

The OP-7 procedure is designed to handle situations where the time required to implement OP-4 is too long, or when the load reduction and generation increase from OP-4 is not sufficient. The procedure is to be used in the event of an operating emergency involving unusually low frequency, equipment overload, capacity or energy deficiency, unacceptable voltage levels, or any other emergency that ISO New England (ISO) deems appropriate in an isolated or widespread area of New England.

If the Local Control Center cannot reach ISO-NE in a reasonable time, then they can initiate procedures on their own. Normal procedure is for ISO-NE to consult all parties and reach a consensus decision and if they cannot, then either party can act on its own.

The typical process is for utilities to shed load to stabilize the system. Consumers would have no say in the matter.

ISO New England Operating Procedure No. 21 - Action During an Energy Emergency (OP-21)

This Procedure establishes criteria and guides for actions in anticipation of and during energy emergencies as directed by the ISO and as implemented by the ISO and the Local Control Centers. Energy emergencies may occur as a result of sustained national or regional shortages in fuel availability or deliverability to the New England region's generation resources. Such shortages of fuel may come in many forms, including, but not limited to; severe drought, interruption to availability or transportation of natural gas, liquefied natural gas (LNG), oil, or coal.

Energy Emergencies are envisioned to last longer than capacity deficiencies, which are managed through ISO Operating Procedure No. 4 – Actions during a Capacity Deficiency (OP 4) and, under extreme circumstances, through ISO Operating Procedure No. 7 – Actions in an Emergency (OP 7).

The events contemplated here may last days or weeks at a time. The ISO will initiate fuel surveys whenever information received from the media, fuel suppliers, or generators warrants that the ISO conduct a fuel survey, e.g., based on reports of fuel shortages or fuel deliverability issues. In conjunction with the fuel surveys, the ISO will perform an assessment of system generation requirement by fuel type to estimate the amount of generation required to serve expected New England system load requirements. This assessment will be used to better quantify fuel inventory impacts and highlight potential supplemental fuel needs.

Memorandum

To: VPPSA Board of Directors
From: Ken Nolan, General Manager
Date: February 28, 2025
Subject: **Agenda Item #14** – EMS Backlog

As noted at the February Board meeting, VPPSA has now implemented an Agile project management approach and has developed an “EMS Backlog” to manage significant projects. Review of the top items on that backlog will become a standing item on the Board agenda.

The goal of including this discussion is to both make the Board aware of major efforts staff has underway and surface any concerns members have related to activities that staff should consider a higher priority.