STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Case No. 20-3324-PET

Petition of Washington Electric Cooperative Inc. for approval of its 2020-2039 Integrated Resource Plan	

MEMORANDUM OF UNDERSTANDING

WHEREAS, on November 2, 2020, Washington Electric Cooperative, Inc. (WEC) filed its 2020 Integrated Resource Plan ("IRP") with the Vermont Public Utility Commission (Commission or "UC) seeking its approval pursuant to 30 V.S.A. § 218c;

WHEREAS, WEC and the Department of Public Service (Department) have engaged in discussions and negotiations regarding the content of WEC's 2020 IRP;

NOW THEREFORE, in consideration of the mutual promises and representations contained herein, the parties agree and stipulate as follows:

TERMS AND CONDITIONS

1. The parties agree that WEC's 2020 IRP attached hereto should be approved by the Commission pursuant to 30 V.S.A. §218c(b) in that it describes a decision-making process that is likely to meet the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs.
2. The WEC 2020 IRP was found to be consistent with the State's Comprehensive Energy Plan.
3. WEC will file its next regularly scheduled IRP on or before November 1, 2023 (2023 IRP). In connection with the preparation of its next IRP, WEC agrees as follows:

a. WEC will engage the Department, beginning at least six months prior to the IRP filing deadline, to discuss IRP methods, contents, and to share drafts. WEC and the Department recognize that timely prefiling engagement by all parties can expedite preparation of the plan and contribute to the Department's timely review of the IRP.

b. With respect to WEC's Tier III Annual Plan and Commission Rule 4.415(6)(A), the Department notes the provisions of Tier 3 Best Practices and Minimum Standards state:

> For a Retail Electricity Provider implementing Energy Transformation Projects that increase the use of electric energy, the Provider's Tier III annual plan shall include: (A) reference to the load forecast developed in the Provider's most recently Commission approved Integrated Resource Plan and any relevant updates to or major deviations from the assumptions used in that load forecast.

The Department acknowledges WEC provided forecast estimates of Electric Vehicles and Cold Climate Heat Pumps in its IRP load forecast which are major end use measures that are part of WEC's Tier III plan. In future IRPs, the Department seeks minor refinement to WEC's load forecast efforts to explicitly note and include an estimate of the impacts that all Tier III measures in aggregate have on the load forecast. WEC agrees to include not only major Tier III measures in the load forecast estimates but also other minor measures to fully flesh out and incorporate its anticipated Tier III impacts to load.

WEC will also update its Tier III Annual Plan filings to note significant deviations in its projections from IRP load forecast filings.

c. WEC's next IRP will include an analysis that stresses the price of Tier I/ Class II RECs in addition to the analysis that was included in this IRP that stresses Tier II/ Class I prices.

d. WEC's next IRP, subject to data being readily available to WEC, will include an analysis of distribution-level impacts of electrification of transportation and heating, taking into account a number of factors including, but not limited to, historic deployment patterns, physical limits, penetration, areas of concentration, areas of opportunity and observed spatial patterns, as appropriate and available. WEC will assess strategies to manage these new loads to minimize integration challenges and costs in its next IRP

4. The Department and WEC agree that approval of the proposed IRP shall constitute approval of the decision-making process described in the IRP only and shall not constitute approval of

any of the specific decision-making tools, analytic methods, or outcomes described in the proposed IRP.

5. The Department and WEC agree that approval of the proposed IRP shall not relieve WEC of its ongoing duty to:

    a. monitor key uncertainties and the continued accuracy of assumptions and data in the IRP;

    b. continue to reevaluate the merits of the decision-making processes, including but not limited to the analytic methods used, and to adapt such processes to new techniques or information; and

    c. continue to reevaluate the merits of the strategies identified in the IRP as new information becomes available.

6. The stipulating parties have made compromises in order to reach this MOU. Accordingly, by agreement of the stipulating parties, this MOU shall not be construed by any party or tribunal as having precedential impact on any future proceedings involving the parties, except as necessary to implement this MOU or to enforce an order of the Commission resulting from this MOU. The stipulating parties reserve the right in future proceedings to advocate positions that differ from the positions set forth in this MOU, and this MOU may not in any future proceeding be used against any undersigned party, except for enforcement of this MOU or the Commission's Order adopting this MOU.

7. The parties, in accordance with 3 V.S.A. § 811, hereby waive the opportunity to file exceptions and present briefs and oral arguments with respect to a proposal for decision to be issued in this case, provided that the proposal for decision is consistent in all material respects with this MOU.

8. This MOU is expressly conditioned upon the Commission’s acceptance of all of its provisions, without material change or condition. In the event the Commission fails to

approve this MOU in its entirety or acts to overrule or disapprove any portion hereof, each such party agrees that their agreement set forth herein may terminate, if such party so determines in its sole discretion, and each shall have the same rights as each would have had absent this MOU. In the event any material modification or condition is made to the MOU, and a party exercises its option referenced above, each party hereto shall be placed in the position that it enjoyed in this proceeding before entering into this MOU.

9. This MOU may be executed in multiple counterparts, which together shall constitute one agreement.
10. This MOU is governed by Vermont law and any disputes under this MOU shall be decided by the Commission.
11. The Department will support issuance of the orders and findings of the Commission specified herein subject to the Department's obligations under Title 30 of the Vermont Statutes Annotated

Dated at Montpelier, Vermont, this 26th day of March, 2021.

VERMONT DEPARTMENT OF PUBLIC SERVICE

By: /s/ Daniel C. Burke
Dan Burke, Esq., Special Counsel

Dated at Montpelier, Vermont, this 26th day of March, 2021.

WASHINGTON ELECTRIC COOPERATIVE, INC.

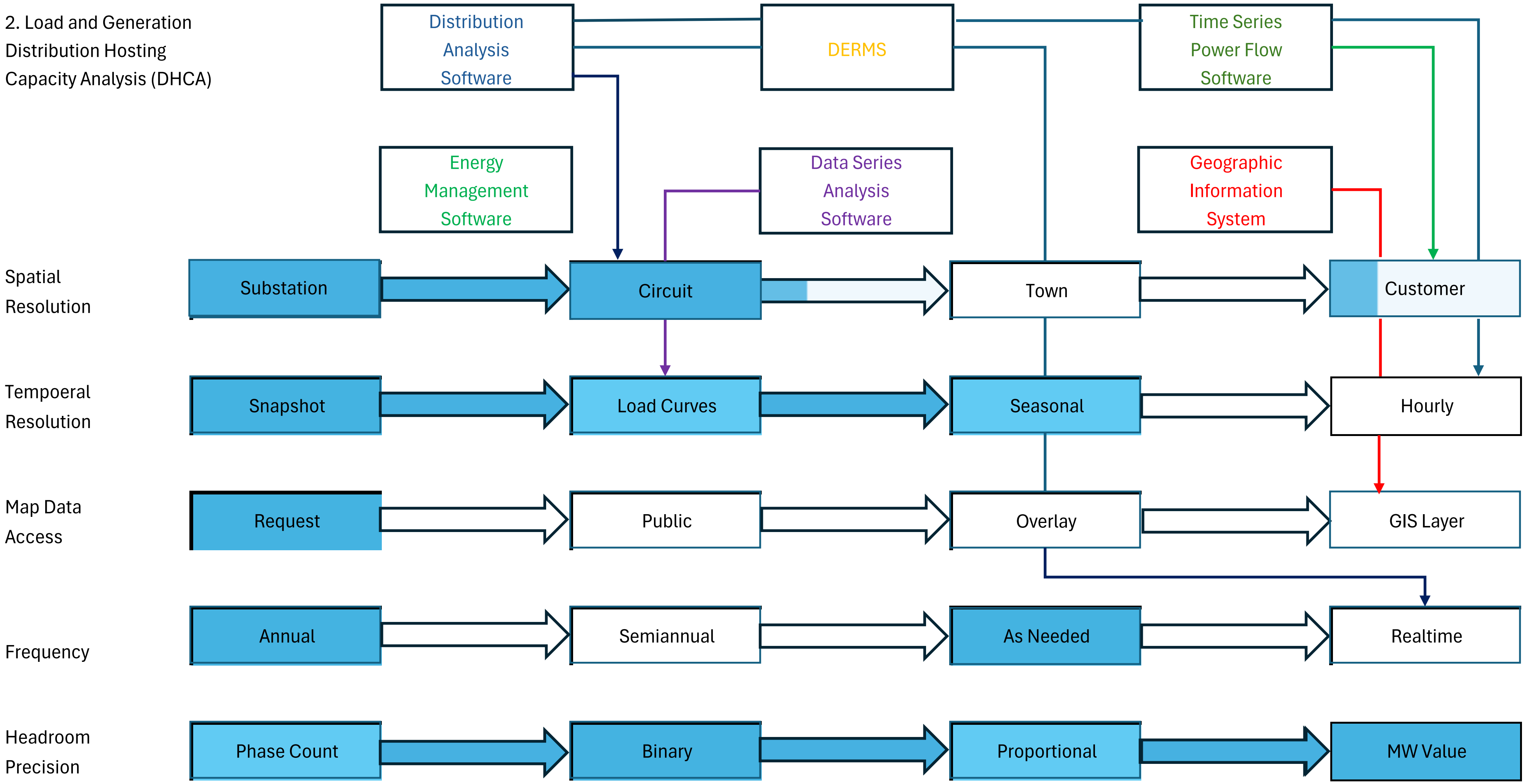
By: /s/ Ronald A. Shems
Ronald A. Shems, Esq., its attorney

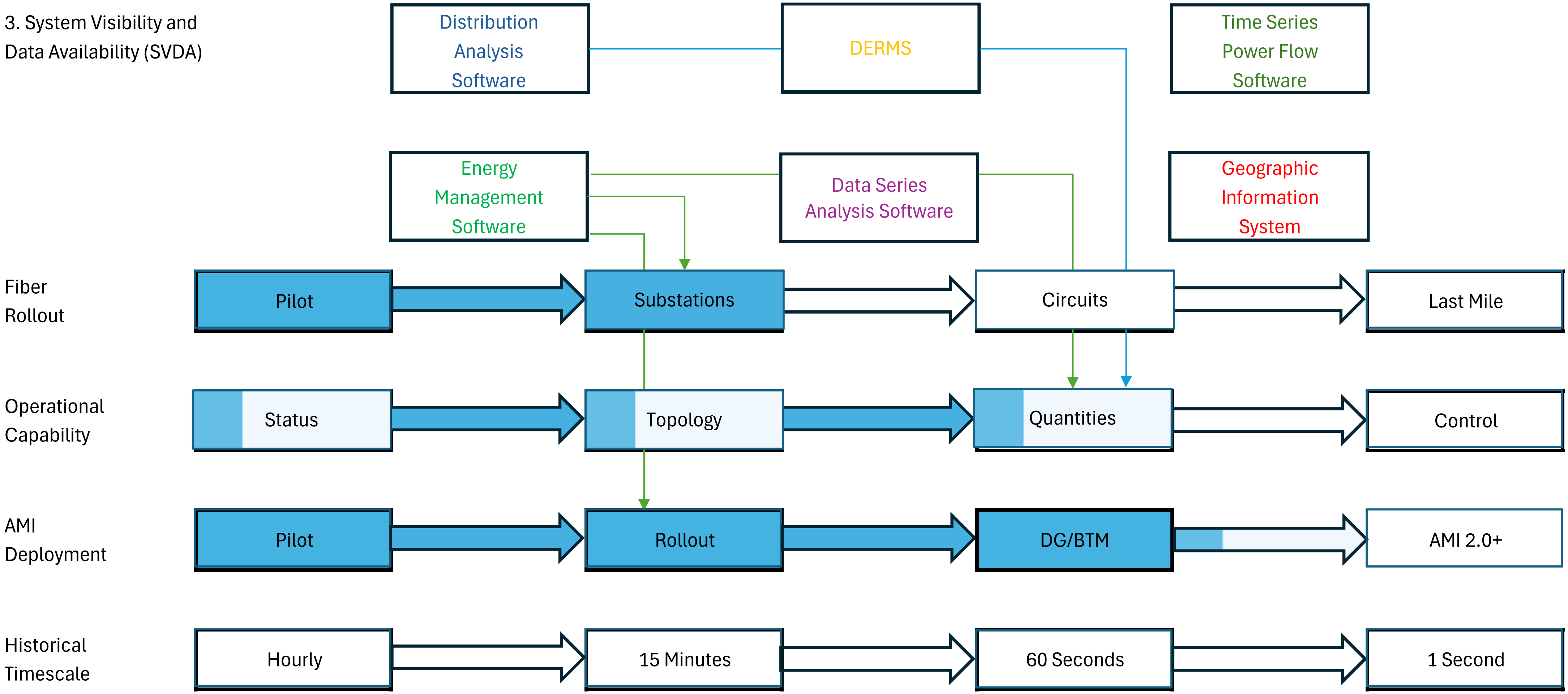
cc: Filed in ePUC

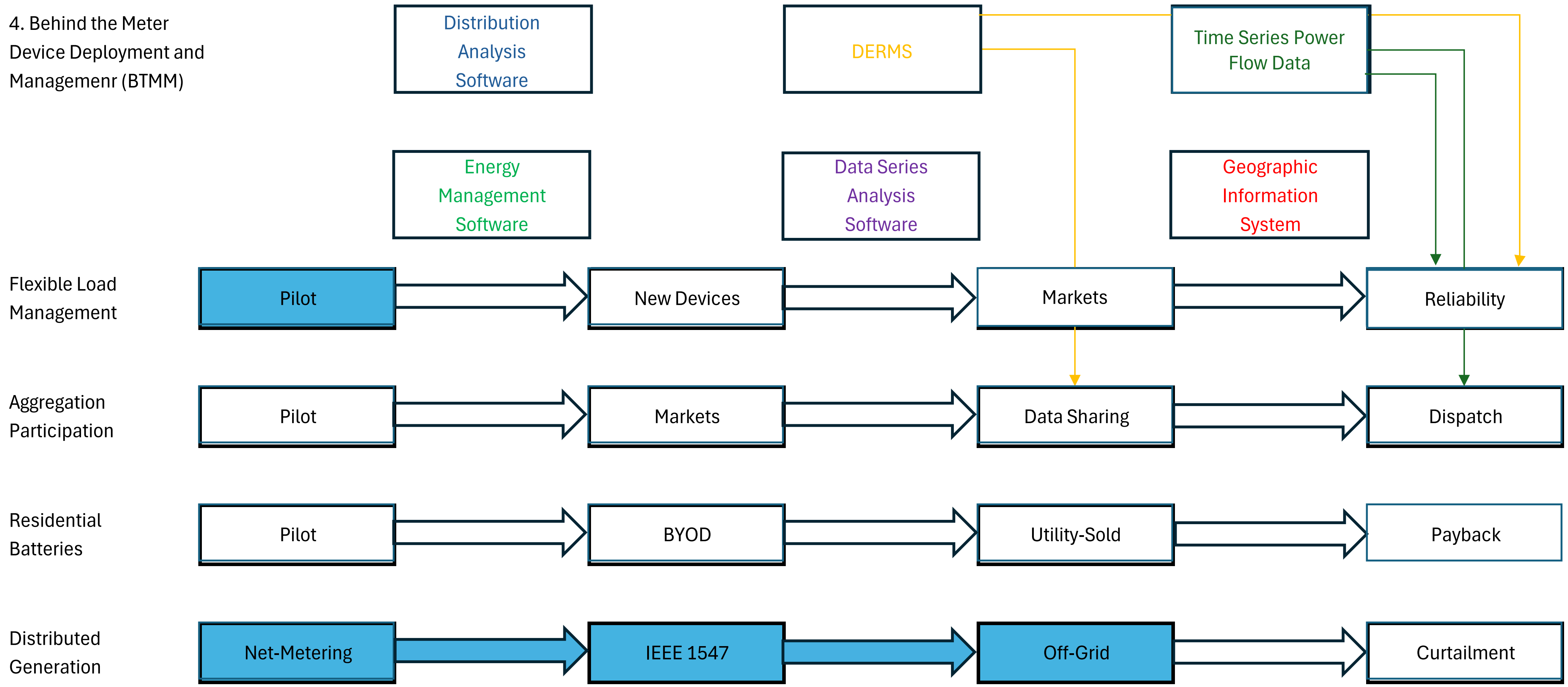
Initiative Flowcharts

In the following pages, please find WEC's attempt to complete the new IRP flowchart requirement. For some initiatives, it is very difficult to give precise estimates of how far along we are, or the numbers are so slight that a visual representation is not helpful. To avoid creating a false sense of precision, we defaulted to the use of categories representing 0% (which could also be "not applicable"), 1-25%, 26%-50%, 51%-75% and 76-100% completion categories for both the individual steps and for the progress arrows, knowing the actual values are within those bands. Note that in some cases, the sequence of progress for WEC does not match the flow diagram, in which case some individual steps will be left unshaded between others.

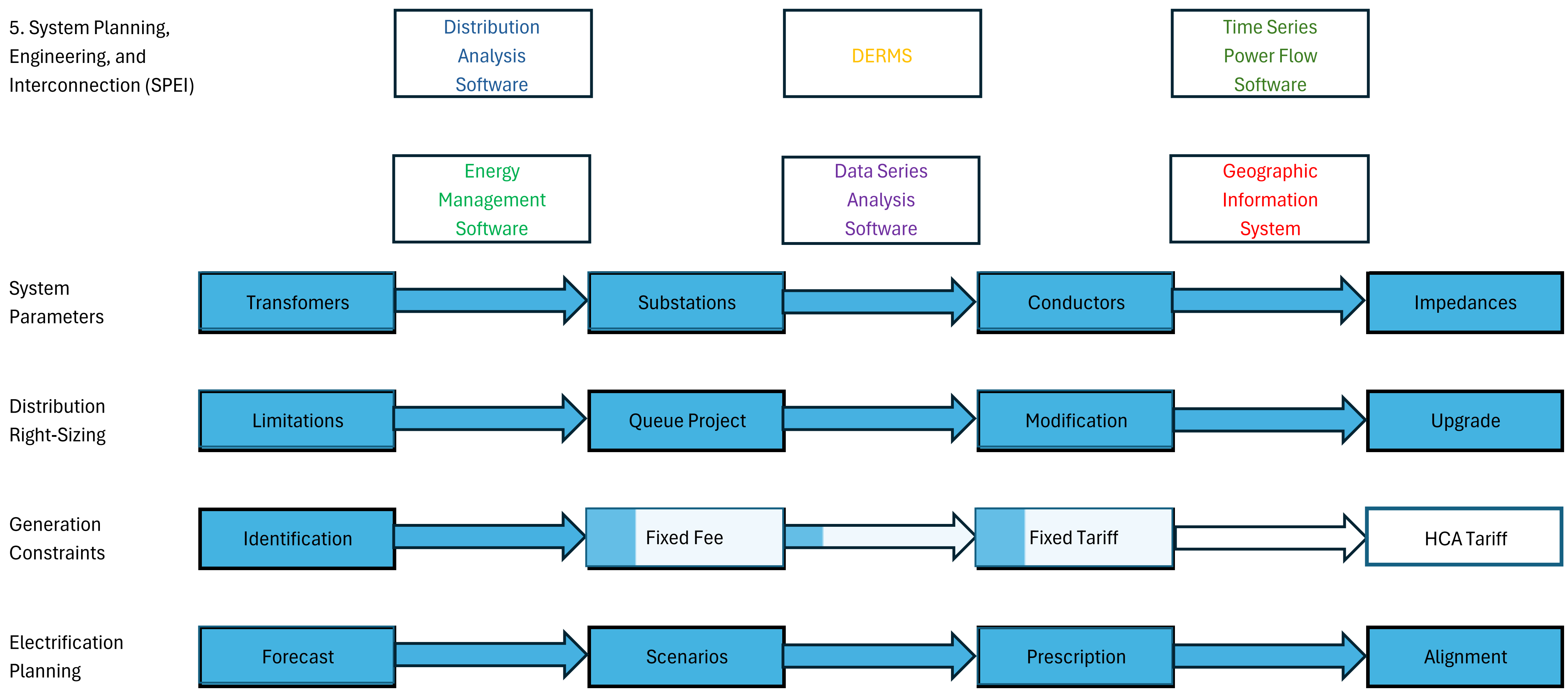
2. Load and Generation Distribution Hosting Capacity Analysis (DHCA)



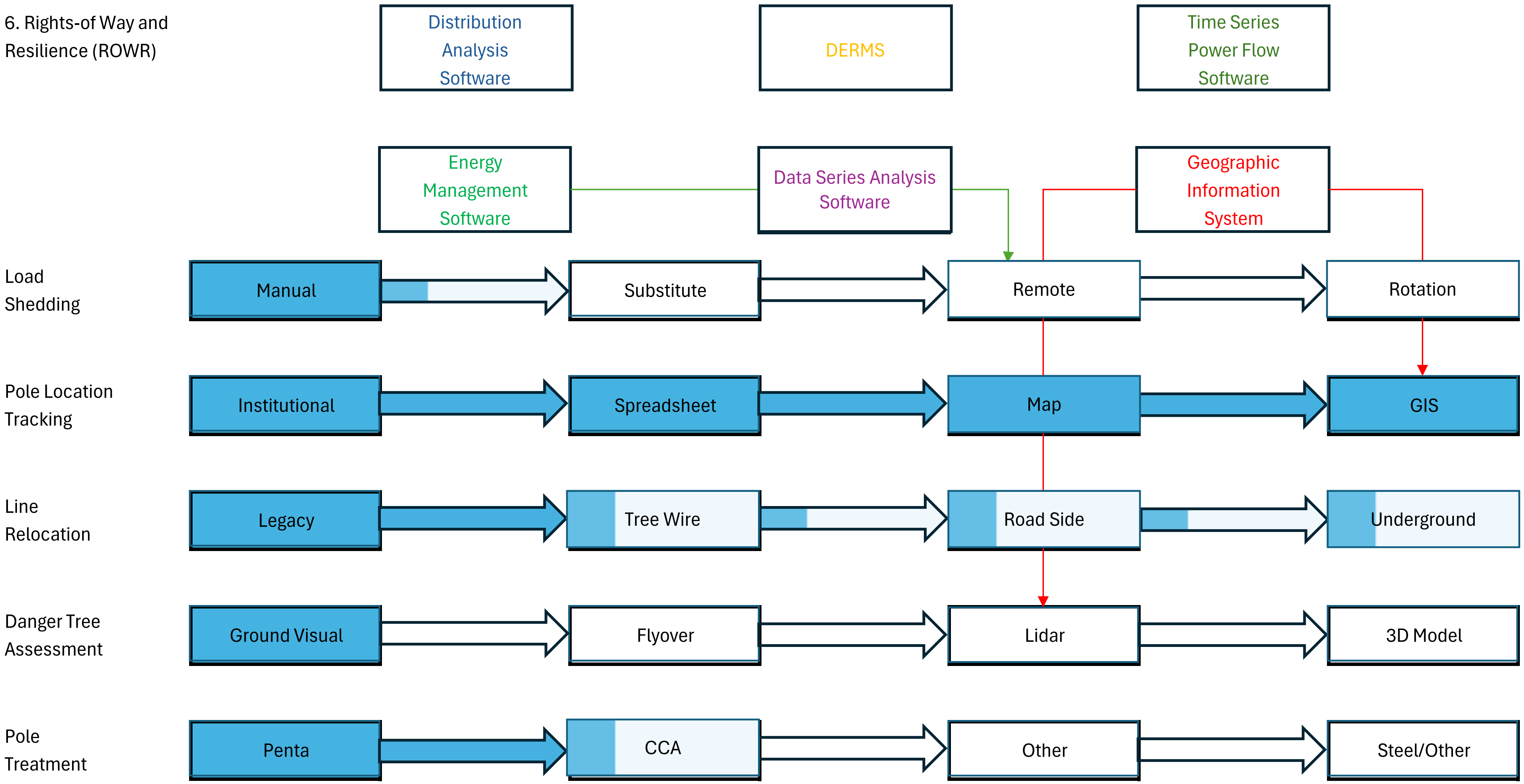

3. System Visibility and Data Availability (SVDA)
Distribution Analysis Software
DERMS
Time Series Power Flow Software
Energy Management Software
Data Series Analysis Software
Geographic Information System
Fiber Rollout
Pilot
Substations
Circuits
Last Mile
Operational Capability
Status
Topology
Quantities
Control
AMI Deployment
Pilot
Rollout
DG/BTM
AMI 2.0+
Historical Timescale
Hourly
15 Minutes
60 Seconds
1 Second

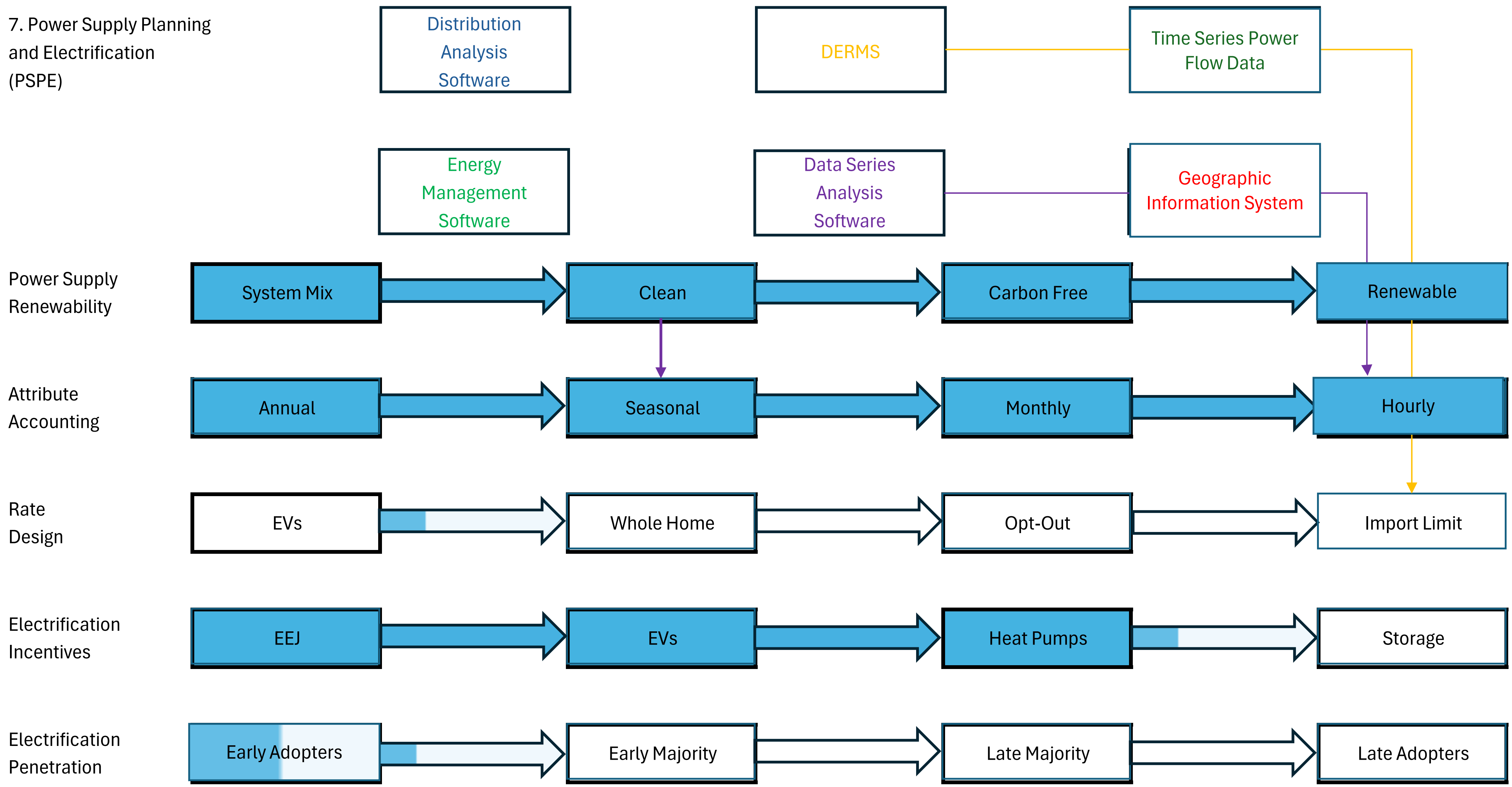


4. Behind the Meter Device Deployment and Managemenr (BTMM)
Distribution Analysis Software
DERMS
Time Series Power Flow Data
Energy Management Software
Data Series Analysis Software
Geographic Information System
Flexible Load Management
Pilot
New Devices
Markets
Reliability
Aggregation Participation
Pilot
Markets
Data Sharing
Dispatch
Residential Batteries
Pilot
BYOD
Utility-Sold
Payback
Distributed Generation
Net-Metering
IEEE 1547
Off-Grid
Curtailment


5. System Planning, Engineering, and Interconnection (SPEI)
Distribution Analysis Software
DERMS
Time Series Power Flow Software
Energy Management Software
Data Series Analysis Software
Geographic Information System
System Parameters
Transfomers
Substations
Conductors
Impedances
Distribution Right-Sizing
Limitations
Queue Project
Modification
Upgrade
Generation Constraints
Identification
Fixed Fee
Fixed Tariff
HCA Tariff
Electrification Planning
Forecast
Scenarios
Prescription
Alignment

6. Rights-of Way and Resilience (ROWR)




7. Power Supply Planning and Electrification (PSPE)
Distribution Analysis Software
DERMS
Time Series Power Flow Data
Energy Management Software
Data Series Analysis Software
Geographic Information System
Power Supply Renewability
System Mix
Clean
Carbon Free
Renewable
Attribute Accounting
Annual
Seasonal
Monthly
Hourly
Rate Design
EVs
Whole Home
Opt-Out
Import Limit
Electrification Incentives
EEJ
EVs
Heat Pumps
Storage
Electrification Penetration
Early Adopters
Early Majority
Late Majority
Late Adopters

2023 LONG-TERM DEMAND FORECAST SUMMARY

Washington Electric Cooperative

Prepared For:
Vermont Public Power Supply Authority

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March 8, 2024

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2023 LONG-TERM DEMAND FORECAST SUMMARY – WASHINGTON ELECTRIC COOPERATIVE

Washington Electric Cooperative (WEC) serves approximately 11,200 residential customers and 690 commercial customers across 41 towns located in the center of the state, near Montpelier. Figure 1 shows the WEC service area.

FIGURE 1: WEC SERVICE AREA

Compared with the rest of the state, WEC has experienced relatively strong sales with 1.0% average annual sales growth between 2013 and 2022. Most of this growth has been driven by residential customer growth that has averaged 0.9% annually over this period. Another contributing factor has been the strong heat pump adoption with the state averaging 10,000 unit sales over the last three years. Residential sales account for 88% of WEC sales. WEC is one of the few state utilities that has seen positive sales growth; total 2022 sales are 74,017 MWh compared with sales of 68,086 MWh in 2013. In comparison state electric sales averaged 0.3% annual decline over this period.

COVID-19 had a muted impact on sales as loss in commercial sales was countered by an increase in residential sales. TABLE 1 shows historical residential customers and class billed sales.

TABLE 1: WEC HISTORICAL CALENDARIZED BILLED SALES AND CUSTOMERS

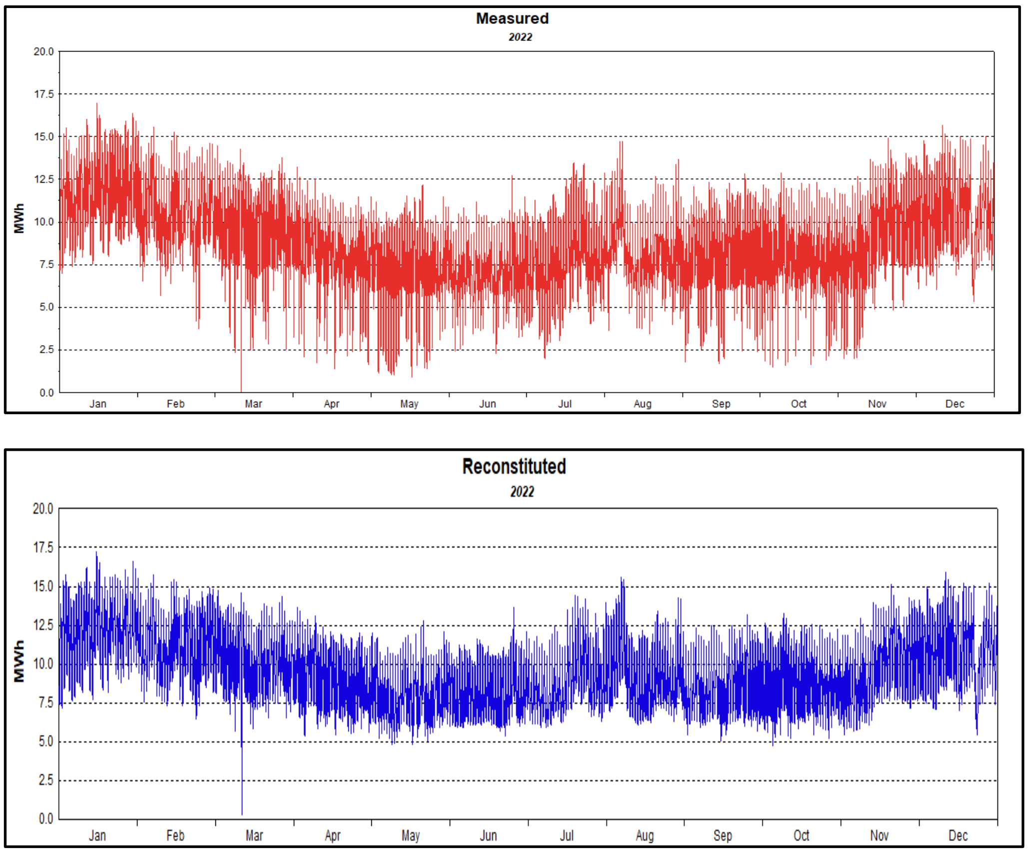
Customers and Sales										
Year	Res Sales (MWh)	Chg	Res Custs	Chg	Res Avg Use (kWh)	Chg	Non-Res Sales (MWh)	Chg	Total Sales (MWh)	Chg
2013	60,244		10,294		5,852		7,842		68,086	
2014	60,474	0.4%	10,291	0.0%	5,876	0.4%	7,792	-0.6%	68,266	0.3%
2015	58,531	-3.2%	10,325	0.3%	5,669	-3.5%	8,173	4.9%	66,704	-2.3%
2016	56,539	-3.4%	10,346	0.2%	5,465	-3.6%	8,881	8.7%	65,420	-1.9%
2017	59,691	5.6%	10,418	0.7%	5,730	4.8%	8,763	-1.3%	68,454	4.6%
2018	60,038	0.6%	10,798	3.6%	5,560	-3.0%	8,809	0.5%	68,847	0.6%
2019	61,594	2.6%	10,882	0.8%	5,660	1.8%	8,721	-1.0%	70,315	2.1%
2020	63,017	2.3%	10,976	0.9%	5,741	1.4%	8,272	-5.2%	71,289	1.4%
2021	64,607	2.5%	11,076	0.9%	5,833	1.6%	8,543	3.3%	73,150	2.6%
2022	65,314	1.1%	11,165	0.8%	5,850	0.3%	8,703	1.9%	74,017	1.2%
2013 - 2022		0.9%		0.9%		0.0%		1.2%		1.0%

FORECAST APPROACH

The WEC long-term forecast is based on a bottom-up modeling framework where the forecast starts at the revenue-class (e.g., residential, small commercial, and large commercial) with heating, cooling, and base-use sales derived from the sales models then used to drive system energy and peak demand. The system energy forecast is based on a linear regression model that relates monthly energy to monthly rate class sales. The baseline peak demand is derived from a monthly regression model that relates peak demand to peak-day weather conditions combined with end-use estimates of heating, cooling, and non-weather sensitive loads from the customer class sales models. The same model structure is used for all VPPSA members, GMP, Burlington Electric, and VELCO.

One of the challenges in modeling WEC loads is the significant amount of solar generation embedded in sales and system load data. To illustrate, Figure 2 shows measured system load and load with solar generation added back in (Reconstituted).

FIGURE 2: WEC SYSTEM LOAD 2022



As our objective is to forecast customer and system energy requirements (regardless of the source), models are estimated with reconstituted sales and loads. The final forecast is derived by then subtracting out the solar generation forecast.

Baseline Sales Forecast Models

Baseline sales models are estimated for each customer class. For WEC, this includes residential, small, and large commercial. Models are estimated using monthly linear regression models with historical billed sales and customer counts from January 2011 to December 2022. Residential sales are "reconstituted" for embedded solar own-use; this is the solar generation consumed by the customer. Residential forecast is derived as the product of the average use and customer forecast. Commercial sales models are based on total sales models. Model coefficients, statistics, and actual and predicted results are included in APPENDIX A.

The baseline forecast captures expected load growth before adjustments for new PV adoptions, electric vehicle (EV), and cold climate heat pumps (CCHP). The baseline forecast is driven by customer growth projections, state economic forecasts, end-use efficiency (both due to standards and state EE program activity) and saturation projections and temperature trends. Residential and commercial models are estimated using a Statistically Adjusted End-Use (SAE) model specifications. The SAE model integrates end-use saturation and efficiency trends that change slowly over time with variables that impact month-to-month sales variation and capture economic growth; this includes temperatures (HDD and CDD), economic conditions (household income, employment, and state output), and demographic trends (population, number of households, household size).

Economic Drivers

Historical and forecasted economic data is provided by Moody's Analytics. Forecasts are based on the December 2022 economic forecast. Model inputs include number of households, household income, gross state product, and employment.

Efficiency and End-Use Saturations

End-use efficiency and saturations are derived from the 2022 Annual Energy Outlook (AEO) for the New England Census Division. Historical and projected residential saturations are adjusted to reflect Vermont where data is available. We assume commercial building energy intensities (measured in kWh per sq. ft.) for Vermont are like those of New England. The forecast is further adjusted for state energy efficiency program savings derived from the current state Demand Resource Plan (DRP).

Weather

Both actual and normal heating degree-days (HDD) and cooling degree-days (CDD) are based on Burlington International Airport temperature data. Since 1970, average temperatures have been increasing 0.085 degrees per year (0.85 degrees per decade). This is reflected in the number of cooling degree-days (CDD) which are increasing 1.2% per year on a relatively low base and decrease in heating degree-days (HDD) of 0.3% per year. We assume average temperature continues to increase at the current rate through the forecast period with decline in HDD contributing to lower heating requirements and increase in CDD to higher cooling requirements.

COVID-19

Unlike the rest of the state, COVID-19 "work at home" and business closures had a minimum impact on sales. Residential saw a small increase over this period, but this growth was just slightly higher than the pre-COVID years. Small C&I saw a relatively small drop in 2020 sales but rebounded in 2021. Only the large C&I class saw a significant drop in sales, but sales are recovering; we expect large C&I sales to reach pre-COVID levels over the next couple of years.

Baseline Results

Itron

Baseline sales growth averages 0.2% annually through the forecast period. Residential customers average 0.4% per year while average use declines 0.1% reflecting expected efficiency gains from both new standards and state energy efficiency programs; this does not include the expected sales growth due to heat pump adoption. Baseline sales are expected to reach 78,952 MWh in 2033 and 80,919 MWh in 2043 compared with expected year-end 2022 sales of 74,017 MWh. TABLE 2 shows WEC baseline customer and sales forecast.

TABLE 2: WEC BASELINE SALES FORECAST (Adjusted for Embedded Solar Own-Use Generation)

Year	Res Sales (MWh)	Chg	Res Custs	Chg	Res Avg Use (kWh)	Chg	Non-Res Sales (MWh)	Chg	Ttl Sales (MWh)	Chg
2023	69,465		11,230		6,186		8,676		78,142	
2024	69,664	0.3%	11,290	0.5%	6,170	-0.2%	8,667	-0.1%	78,332	0.2%
2025	69,669	0.0%	11,369	0.7%	6,128	-0.7%	8,704	0.4%	78,373	0.1%
2026	69,857	0.3%	11,448	0.7%	6,102	-0.4%	8,724	0.2%	78,581	0.3%
2027	69,939	0.1%	11,514	0.6%	6,074	-0.5%	8,731	0.1%	78,670	0.1%
2028	70,227	0.4%	11,576	0.5%	6,066	-0.1%	8,737	0.1%	78,964	0.4%
2029	70,076	-0.2%	11,634	0.5%	6,023	-0.7%	8,713	-0.3%	78,789	-0.2%
2030	70,178	0.1%	11,686	0.4%	6,005	-0.3%	8,669	-0.5%	78,847	0.1%
2031	70,238	0.1%	11,735	0.4%	5,985	-0.3%	8,622	-0.5%	78,860	0.0%
2032	70,511	0.4%	11,784	0.4%	5,984	0.0%	8,591	-0.4%	79,102	0.3%
2033	70,407	-0.1%	11,834	0.4%	5,949	-0.6%	8,545	-0.5%	78,952	-0.2%
2034	70,461	0.1%	11,884	0.4%	5,929	-0.3%	8,511	-0.4%	78,972	0.0%
2035	70,595	0.2%	11,933	0.4%	5,916	-0.2%	8,481	-0.4%	79,076	0.1%
2036	71,016	0.6%	11,981	0.4%	5,928	0.2%	8,468	-0.2%	79,485	0.5%
2037	71,076	0.1%	12,027	0.4%	5,910	-0.3%	8,432	-0.4%	79,508	0.0%
2038	71,350	0.4%	12,073	0.4%	5,910	0.0%	8,410	-0.3%	79,759	0.3%
2039	71,625	0.4%	12,118	0.4%	5,911	0.0%	8,390	-0.2%	80,015	0.3%
2040	72,068	0.6%	12,163	0.4%	5,925	0.2%	8,375	-0.2%	80,443	0.5%
2041	72,084	0.0%	12,207	0.4%	5,905	-0.3%	8,342	-0.4%	80,426	0.0%
2042	72,327	0.3%	12,252	0.4%	5,903	0.0%	8,323	-0.2%	80,650	0.3%
2043	72,610	0.4%	12,297	0.4%	5,904	0.0%	8,309	-0.2%	80,919	0.3%
23-33		**0.1%**		**0.5%**		**-0.4%**		**-0.2%**		**0.1%**
33-43		**0.3%**		**0.4%**		**-0.1%**		**-0.3%**		**0.2%**

Adjusted Forecast

The baseline forecast is adjusted for new behind-the-meter (BTM) solar projections starting in 2023, electric vehicles, and cold climate heat pumps (CCHP). Future electricity sales and demand growth will largely be driven by these technologies that are being promoted as part of the state's electrification programs designed to reduce greenhouse gas emissions. Two of the primary targets are heating – converting fossil fuel heat to cold climate heat pumps (CCHP) and Electric Vehicles (EV). The state, through VEIC and state utilities, is promoting the adoption of CCHP and EVs with rebates, low-interest loans, and building out electric vehicle infrastructure. Expected increase in behind the meter solar adoption (PV) mitigates some of the long-term energy growth. The statewide forecast of these technologies (CCHP, EV, and PV) were developed through a collaborative process as part of the *Vermont Electric Power Company (VELCO) 2023 Long-Term Transmission Plan*. Forecast contributors include the Department of Public Service (DPS), the Vermont Energy Investment Company (VEIC), state utilities, and other state stakeholders. We are beginning work to update these assumptions as result of the recently passed *Vermont Climate Action Plan*.

CCHP, EV, and PV forecasts are derived by allocating the state forecast based on WEC' share of state residential customers. TABLE 3 shows the resulting forecast.

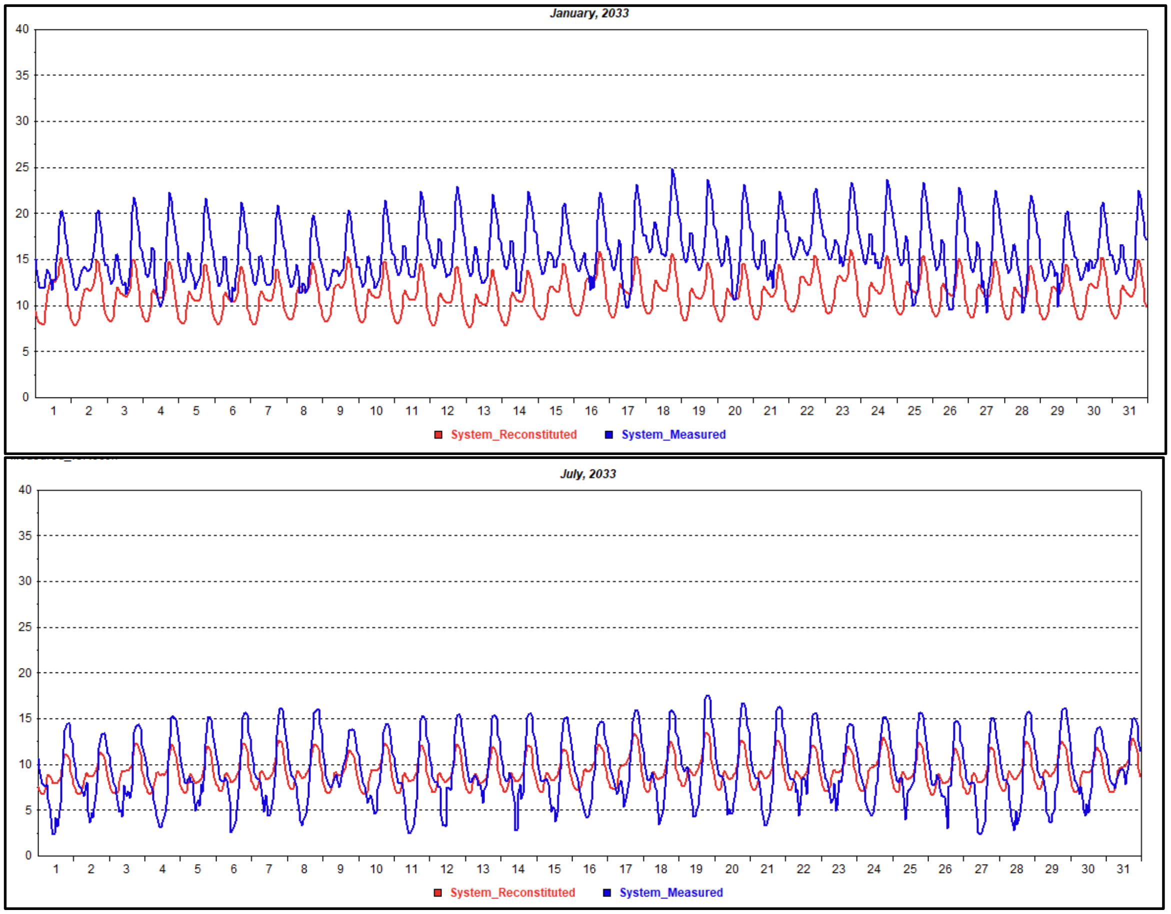
TABLE 3: EV, PV, AND CCHP FORECAST

Incremental New Tech Usage (MWh)			
Year	Electric Vehicles	BTM Solar	Heat Pumps
2023	1,348	965	4,695
2024	1,796	1,618	5,492
2025	2,382	2,008	6,282
2026	3,144	2,424	7,070
2027	4,128	2,958	7,863
2028	5,379	3,097	8,658
2029	6,942	3,217	9,457
2030	8,853	3,351	10,259
2031	11,128	3,398	11,065
2032	13,743	3,521	11,873
2033	16,629	3,549	12,684
2034	19,670	3,652	13,499
2035	22,709	3,696	14,169
2036	25,583	3,813	14,861
2037	28,149	3,838	15,455
2038	30,322	3,934	16,052
2039	32,077	3,974	16,575
2040	33,441	4,084	17,023
2041	34,473	4,086	17,396
2042	35,238	4,086	17,693
2043	35,802	4,086	17,914

Technology annual energy forecasts are estimated by combining technology characteristics such as average historical load profile, heating and cooling unit energy consumption, average miles driven, and technology efficiency trends with unit forecasts. Hourly (8,760) technology forecasts are then generated by combining technology annual energy forecast with technology hourly profiles that reflect seasonality, solar load patterns, and expected HDD and CDD.

The system adjusted hourly load forecast is calculated by subtracting PV hourly load forecast and adding EV and CCHP load forecasts to the baseline hourly load forecast. Figure 3 shows the baseline and adjusted hourly load forecast for January and July 2033.

FIGURE 3: BASELINE AND ADJUSTED HOURLY LOAD FORECAST



By 2033, EVs and CCHP add significant load. EV and CCHP add 9.2 MW to baseline demand forecast and in the summer 4.2 MW. The winter load adjustments are much higher than summer adjustments as both EV charging and CCHP have a much larger impact on winter peak demand than summer peak demand. Adjusted energy is calculated by adding the hourly adjusted load forecasts and winter and summer peak demands are derived by finding the highest hourly load in each season and year. TABLE 4 shows the adjusted energy and demand forecasts.

TABLE 4: WEC ENERGY AND DEMAND FORECAST

Energy and Peak								
Year	Energy (MWh)	Chg	Summer Peak (MW)	Chg	Peak Time	Winter Peak (MW)	Chg	Peak Time
2023	73,305		13.66		7/18/23 7:00 PM	16.57		1/22/23 5:00 PM
2024	74,124	1.1%	13.78	0.9%	7/16/24 7:00 PM	16.87	1.8%	1/21/24 5:00 PM
2025	75,184	1.4%	13.98	1.5%	7/15/25 7:00 PM	17.26	2.3%	1/21/25 6:00 PM
2026	76,568	1.8%	14.39	2.9%	7/21/26 7:00 PM	18.15	5.2%	1/20/26 6:00 PM
2027	77,931	1.8%	14.65	1.8%	7/20/27 7:00 PM	18.84	3.8%	1/19/27 6:00 PM
2028	80,174	2.9%	14.87	1.5%	7/18/28 7:00 PM	19.43	3.1%	1/18/28 6:00 PM
2029	82,254	2.6%	15.29	2.8%	7/17/29 7:00 PM	20.22	4.1%	1/23/29 6:00 PM
2030	84,918	3.2%	15.76	3.1%	7/16/30 7:00 PM	21.19	4.8%	1/22/30 6:00 PM
2031	87,989	3.6%	16.25	3.1%	7/15/31 7:00 PM	22.24	5.0%	1/21/31 6:00 PM
2032	91,568	4.1%	16.99	4.6%	7/20/32 7:00 PM	23.61	6.2%	1/20/32 6:00 PM
2033	95,099	3.9%	17.60	3.6%	7/19/33 7:00 PM	24.83	5.2%	1/18/33 6:00 PM
2034	98,896	4.0%	18.14	3.1%	7/18/34 7:00 PM	25.75	3.7%	1/24/34 6:00 PM
2035	102,688	3.8%	18.84	3.9%	7/17/35 7:00 PM	27.06	5.1%	1/23/35 6:00 PM
2036	106,584	3.8%	19.51	3.6%	7/15/36 7:00 PM	28.24	4.4%	1/22/36 6:00 PM
2037	109,755	3.0%	20.21	3.6%	7/21/37 7:00 PM	29.54	4.6%	1/20/37 6:00 PM
2038	112,704	2.7%	20.70	2.4%	7/20/38 7:00 PM	30.48	3.2%	1/19/38 6:00 PM
2039	115,218	2.2%	21.17	2.3%	7/19/39 9:00 PM	31.27	2.6%	1/18/39 6:00 PM
2040	117,375	1.9%	21.50	1.6%	7/17/40 9:00 PM	31.63	1.2%	1/24/40 6:00 PM
2041	118,758	1.2%	21.79	1.3%	7/16/41 9:00 PM	32.16	1.7%	1/22/41 6:00 PM
2042	120,052	1.1%	22.01	1.0%	7/15/42 9:00 PM	32.53	1.2%	1/21/42 6:00 PM
2043	121,107	0.9%	22.24	1.0%	7/21/43 9:00 PM	33.02	1.5%	1/20/43 6:00 PM
23-43		**2.5%**		**2.5%**			**3.5%**	

Projected EV, CCHP, and PVs have a significant impact on load; over the next twenty years, energy requirements are expected to average 2.5% annual growth. This compares with a baseline annual sales increase of 0.1%. Winter adjusted peak averages 3.5% annual demand growth and summer 2.5% average annual growth. WEC remains a winter peaking utility throughout the forecast period.

TABLE 5 and TABLE 6 summarizes the demand forecast by base load and technologies.

TABLE 5: WEC SUMMER PEAK FORECAST (MW)

Summer Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2023	13.49		0.06	0.00	0.11	13.66	
2024	13.43	-0.4%	0.15	-0.02	0.22	13.78	0.9%
2025	13.41	-0.1%	0.26	-0.02	0.33	13.98	1.5%
2026	13.55	1.0%	0.40	-0.01	0.45	14.39	2.9%
2027	13.52	-0.2%	0.59	-0.01	0.56	14.65	1.8%
2028	13.39	-1.0%	0.82	-0.01	0.67	14.87	1.5%
2029	13.41	0.1%	1.12	-0.03	0.79	15.29	2.8%
2030	13.38	-0.2%	1.48	-0.01	0.90	15.76	3.1%
2031	13.35	-0.2%	1.91	-0.02	1.02	16.25	3.1%
2032	13.48	1.0%	2.40	-0.01	1.13	16.99	4.6%
2033	13.42	-0.4%	2.95	-0.01	1.25	17.60	3.6%
2034	13.25	-1.3%	3.52	0.00	1.36	18.14	3.1%
2035	13.31	0.5%	4.10	-0.03	1.46	18.84	3.9%
2036	13.33	0.2%	4.63	-0.01	1.56	19.51	3.6%
2037	13.45	0.9%	5.13	-0.01	1.64	20.21	3.6%
2038	13.45	0.0%	5.54	-0.02	1.72	20.70	2.4%
2039	12.49	-7.1%	7.06	0.00	1.61	21.17	2.3%
2040	12.48	-0.1%	7.35	0.00	1.67	21.50	1.6%
2041	12.46	-0.2%	7.61	0.00	1.72	21.79	1.3%
2042	12.47	0.1%	7.78	0.00	1.75	22.01	1.0%
2043	12.56	0.7%	7.91	0.00	1.78	22.24	1.0%
23-43		**-0.3%**					**2.5%**

TABLE 6: WEC WINTER PEAK FORECAST (MW)

Winter Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2023	16.25		0.06	0.00	0.26	16.57	
2024	16.20	-0.3%	0.14	0.00	0.53	16.87	1.8%
2025	15.56	-4.0%	0.38	0.00	1.31	17.26	2.3%
2026	15.80	1.5%	0.59	0.00	1.76	18.15	5.2%
2027	15.78	-0.1%	0.86	0.00	2.20	18.84	3.8%
2028	15.59	-1.2%	1.21	0.00	2.63	19.43	3.1%
2029	15.49	-0.6%	1.64	0.00	3.09	20.22	4.1%
2030	15.47	-0.1%	2.18	0.00	3.54	21.19	4.8%
2031	15.45	-0.1%	2.81	0.00	3.98	22.24	5.0%
2032	15.68	1.5%	3.52	0.00	4.41	23.61	6.2%
2033	15.61	-0.4%	4.34	0.00	4.89	24.83	5.2%
2034	15.23	-2.4%	5.18	0.00	5.34	25.75	3.7%
2035	15.33	0.7%	6.02	0.00	5.71	27.06	5.1%
2036	15.38	0.3%	6.80	0.00	6.06	28.24	4.4%
2037	15.58	1.3%	7.54	0.00	6.42	29.54	4.6%
2038	15.59	0.1%	8.14	0.00	6.75	30.48	3.2%
2039	15.60	0.1%	8.63	0.00	7.04	31.27	2.6%
2040	15.41	-1.2%	8.98	0.00	7.24	31.63	1.2%
2041	15.37	-0.3%	9.29	0.00	7.50	32.16	1.7%
2042	15.38	0.1%	9.50	0.00	7.65	32.53	1.2%
2043	15.60	1.4%	9.66	0.00	7.76	33.02	1.5%
23-43		**-0.2%**					**3.5%**

Baseline summer system peak is largely flat in line with the baseline energy. Expected PV adoption negatively impacts energy growth but has a limited to no impact on peak demand as the system peak has moved out to later hours from past solar adoption. Most of the load growth is driven by EV charging and CCHP.

2023 LONG-TERM FORECAST MODEL OVERVIEW

INTRODUCTION

Long-term sales, energy, and demand forecasts have been developed for Washington Electric Cooperative (WEC).

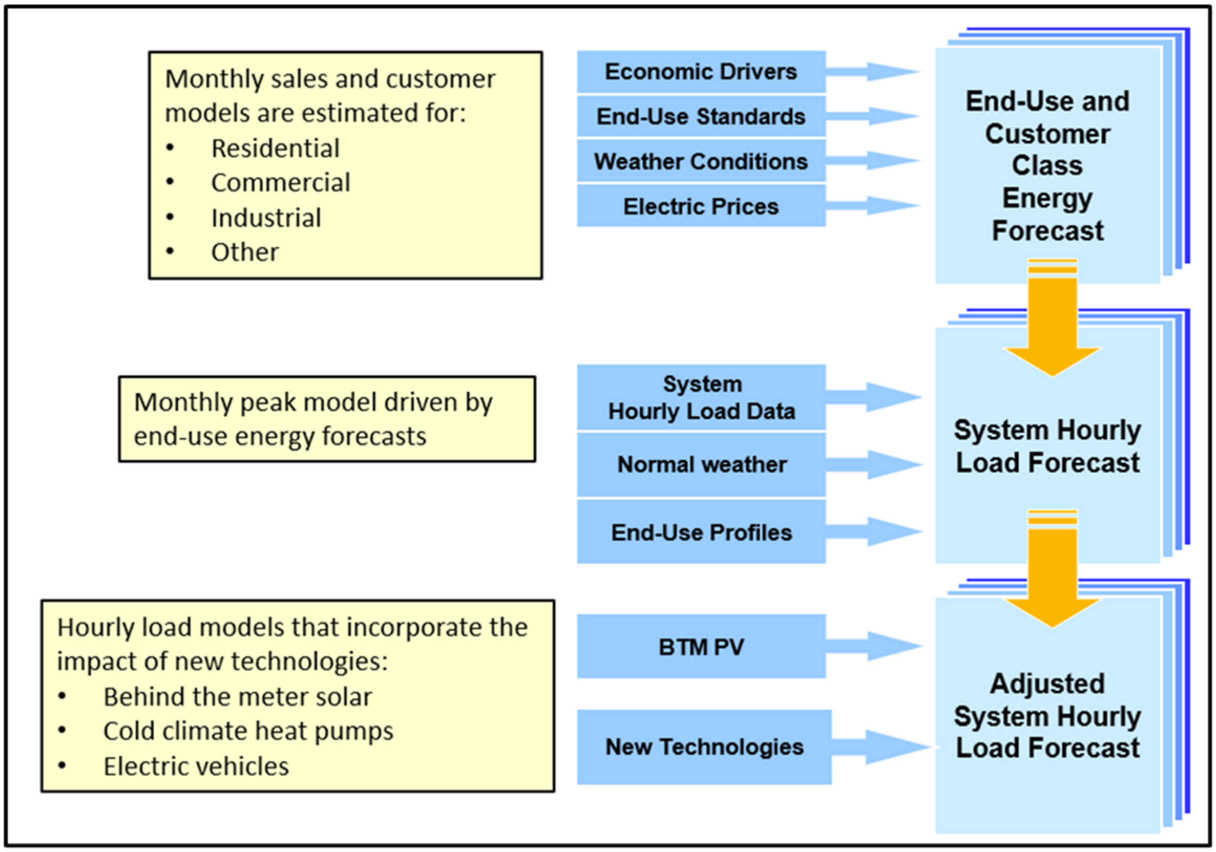
Forecast includes:

- Residential, small, and large commercial sales and customers
- Baseline energy and peak demand
- Energy and peak demand adjusted for the impacts of new technologies including electric vehicles, photovoltaic solar, and cold-climate heat pumps.

FORECAST METHOD

The long-term forecasts are based on a bottom-up approach where baseline energy, demand, and hourly load is first developed from underlying customer class heating, cooling, and base-use energy requirements. The baseline hourly load forecast is then adjusted for the long-term load impacts of electric vehicles (EV's), solar (PV's), and cold-climate heat pumps (CCHP). Figure 4 shows the general forecasting approach.

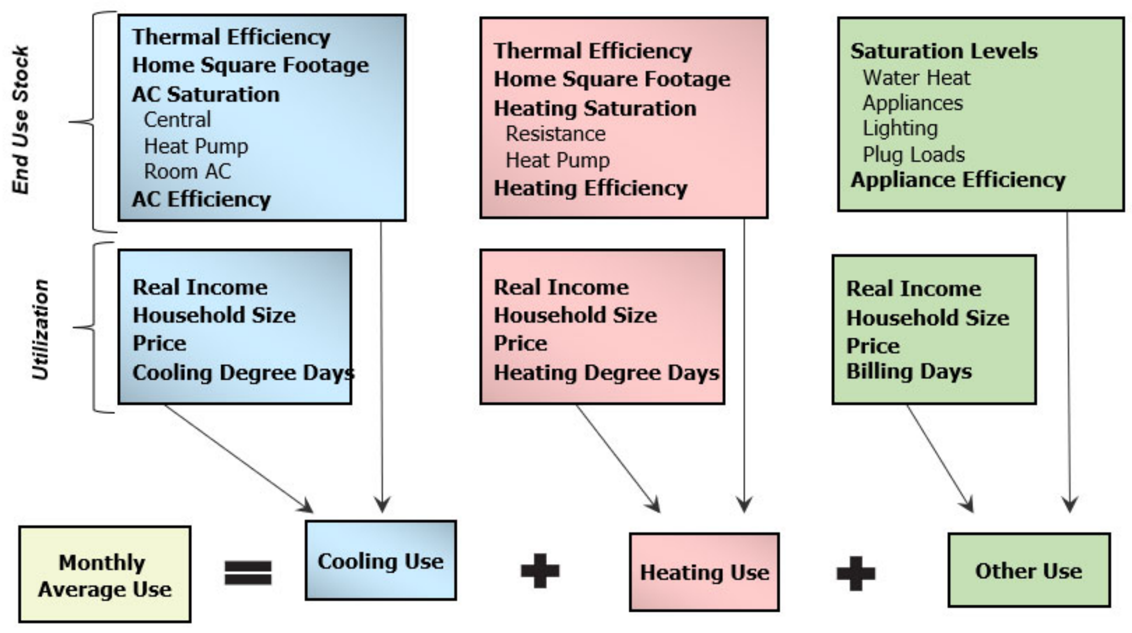
FIGURE 4: FORECASTING FRAMEWORK



Customer Class Sales Forecast

The forecast process starts with estimating sales models for residential, small commercial, and large commercial revenue classes. The residential forecast is derived as the product of the residential average use and customer forecast. Commercial classes are estimated as total sales models. Models are estimated with monthly billed sales data from January 2011 through December 2022 using linear regression. Models are used to forecast sales and customers based on projected demographic and economic growth, end-use intensity trends (reflecting both change in end-use ownership and efficiency improvement), and trended normal heating degree-days (HDD) and cooling degree-days (CDD). Where supported by the data, models are estimated using a modeling structure called a Statistically Adjusted End-Use (SAE) model. The SAE model specification integrates the forecast drivers into three primary model variables that include heating (XHeat), cooling (XCool), and other uses (XOther) variables.
Figure 5 shows the SAE model specification.

FIGURE 5: RESIDENTIAL STATISTICALLY ADJUSTED END-USE (SAE) MODEL



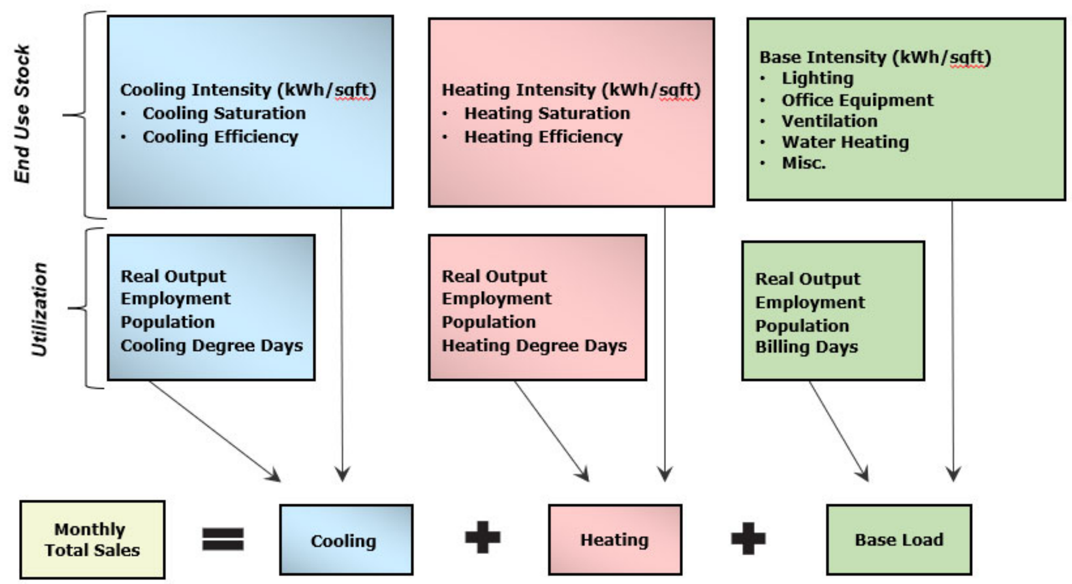
$$AvgUse_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_e \times EE_m$$

Residential forecast is the product of the customer forecast and average use forecast. Average use is defined as the sum of average monthly cooling (XCool), heating (XHeat), and other non-weather energy use (XOther). Historical EE estimates are also sometimes included in the model to account for any state efficiency savings that are not captured on the primary end-use variables. In most models the variable proved to be statistically insignificant largely as the number of customers and noise in the billing data proved to be too few to pick up much of an impact. Instead, residential and commercial energy intensities were adjusted based on efficiency programs in the state of Vermont.

A monthly average use regression model is used to estimate the coefficients a, b_c, b_h, and b_o,, and b_e which effectively *statistically adjust* the end-use model variables to actual customer usage. End-use sales estimates are then derived by combining the estimated model coefficients with the model variables (XCool, XHeat, and XOther) for normal weather conditions. The specification is theoretically strong and appropriately captures the impact and interaction of structural model variables (e.g., end-use saturation, efficiency, and thermal shell integrity) with monthly utilization variables – weather conditions, household size, and household income.

A similar SAE model specification is used for the commercial customer classes. Figure 6 shows the commercial model specification.

FIGURE 6: COMMERCIAL SAE MODEL



$$kWh_m = \quad a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_d$$

In the commercial model end-use energy intensities are expressed on a kWh per square foot basis. Intensities for cooling, heating, and base-use are derived from EIA's Annual Energy Outlook for the New England Census Division. Annual end-use intensities are combined with monthly utilization variables that include monthly HDD and CDD, and constructed economic driver based that incorporates state economic output, employment, and population. Model variables are used in estimating monthly sales models. Commercial end-use energy requirements are derived as the product of the estimated model coefficient and initial end-use energy estimates (XCool, XHeat, and XOther).

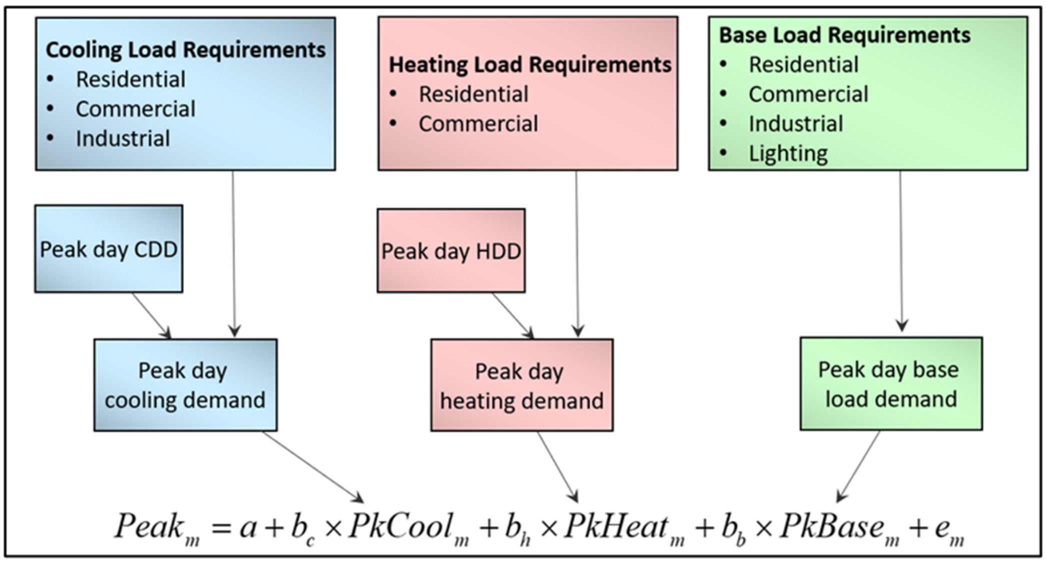
The large commercial customer class is dominated by a few companies. There is often significant variation in month-to-month sales making it difficult to fit with an SAE model specification. In this case a generalized econometric was used.

Baseline Energy, Peak, and Hourly Load Forecast

The baseline energy forecast is derived from the customer-class sales forecasts. For most members, the energy forecast is derived by aggregating the customer class sales forecasts and adjusting for line losses. In some cases where billed sales data (used in estimating class sales) are too noisy due to the billing process, separate monthly energy regression models are estimated where the total sales forecast is the primary driver.

Monthly peak regression models are estimated based on underlying heating, cooling, and base-use loads derived from the customer class sales models. Heating and cooling load requirements are combined with peak-producing weather to generate peak-day heating and cooling variables; the impact of peak-day temperatures changes over time with changes in heating and cooling load requirements. In general baseline heating requirements are declining as traditional resistant heat saturation falls and cooling requirements are increasing with increasing air conditioning saturation. The expected growth due to the CCHP program turns around the baseline decline in heating load and adds to cooling demand growth. Figure 7 shows the baseline peak demand model.

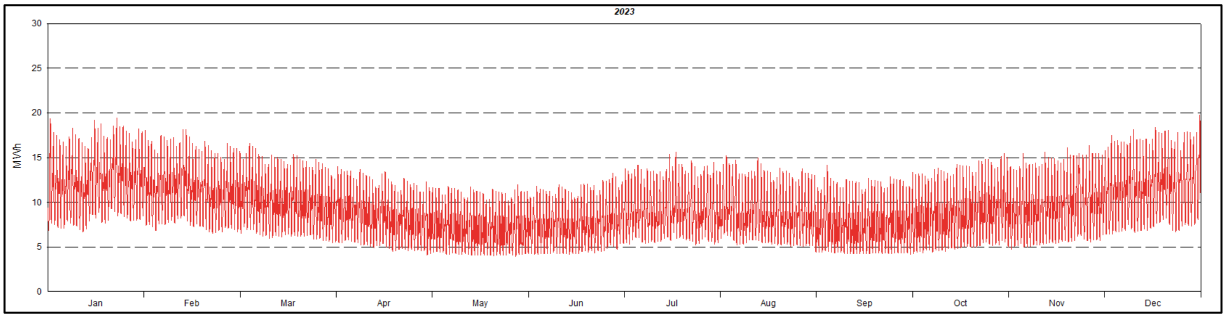
FIGURE 7: BASELINE PEAK MODEL



The peak model is estimated using linear regression that relates the monthly peak to peak-day CDD and HDD, combined with cooling, heating, and base load requirements at time of peak.

A baseline hourly load profile is derived from historical hourly system loads. Models are designed to capture expected hourly loads for typical weather conditions, day of the week, season, and holidays. Figure 8 shows the baseline profile.

FIGURE 8: HOURLY BASELINE PROFILE



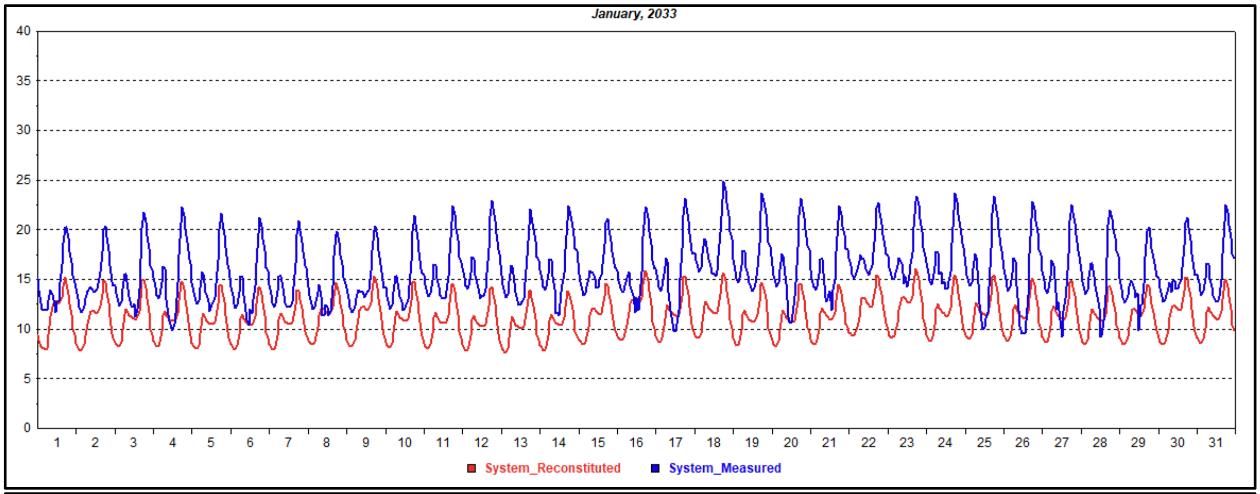
The baseline profile is constant over the estimation period. The baseline hourly load forecast is then derived by combining the baseline energy and peak forecast with the profile. Increase in energy requirements and peak demand lift the baseline profile over time. The baseline hourly load forecast reflects customer projections, economic impacts, weather conditions, and energy efficiency impacts.

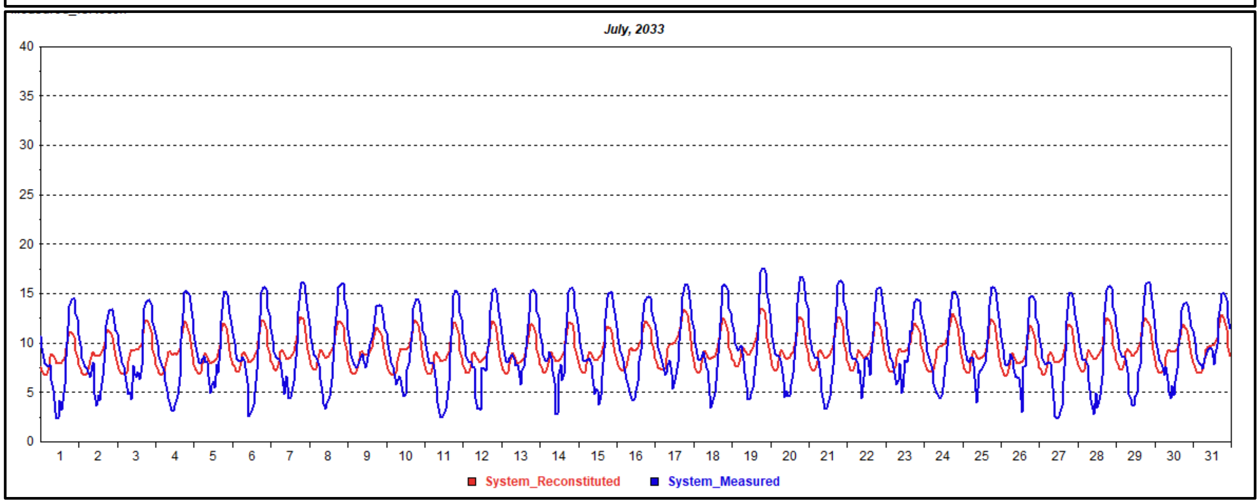
Adjusted Load Forecast

For the most part, baseline loads are either flat or declining as efficiency gains have outweighed customer and economic growth. The long-term peak demand drivers are expected market penetration of CCHP and EV purchases. Both incentivized CCHP and EVs are expected to play a significant role in achieving state greenhouse gas reduction. While PV market penetration is projected to continue to increase, capacity projections slow from current pace and have minimum impact on peak demand; PV capacity has already shifted peaks into the later summer hours and has no impact on winter peak demand.

The expected increase in PV adoption, CCHP, and EVs reshape system load over time and as a result the timing and level of peak demand. Incremental PV energy savings, and new heat pump and EV sales are combined with associated technology hourly load profiles and layered on the baseline hourly load forecast.
Figure 9 compares the baseline and hourly load forecast for 2033.

FIGURE 9: SYSTEM HOURLY LOAD COMPARISON





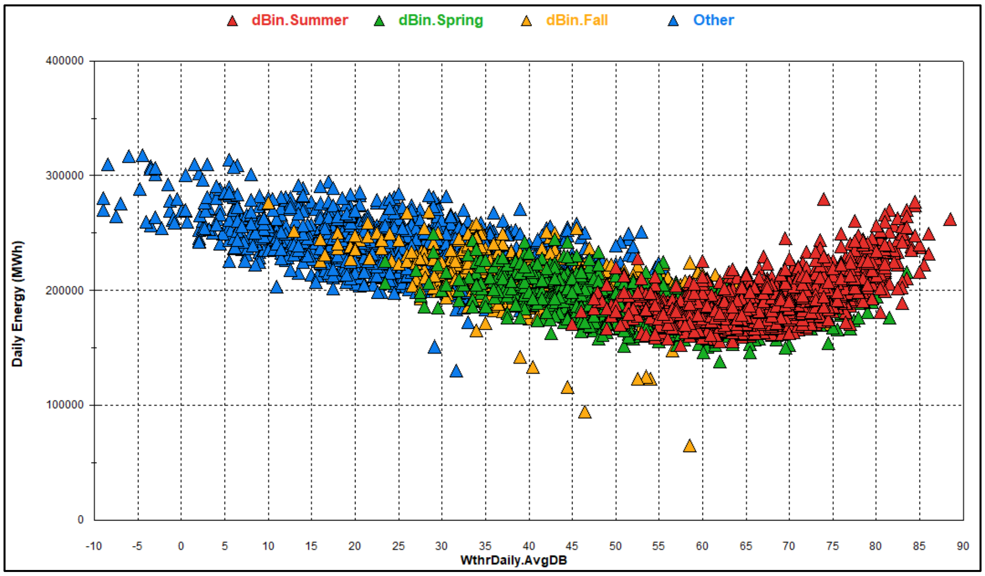
The initial baseline forecast is shown in red and the forecasted adjusted PV, EV, and heat pumps in blue. Solar adoption combined with EV charging shifts the summer peak into the evening hours while heat pumps and EV charging have a much larger impact on winter peaks than summer peaks.

FORECAST ASSUMPTIONS

Weather

Member forecasts use weather from either Burlington or Rutland depending on location. Burlington airport weather data is used for eight VPPSA members that are clustered in north-central Vermont and Rutland weather data for the three large municipals in the central and southern regions of the state. The temperature/load relationship is evaluated at the system level. Figure 10 illustrates what this relationship looks like at the system level for WEC.

FIGURE 10: LOAD-TEMPERATURE RELATIONSHIP



Each point represents the daily average use (in kWh) and the average temperature for that day. The curve shows us a long heating curve with heating starting at 55 degrees, and a short cooling curve with cooling starting at around 60 degrees.

Historical temperature data is used to generate daily and monthly heating-degree days (HDD) and cooling degree-days (CDD). HDD are derived using a base temperature of 55 degrees; this is the temperature point where we begin to see heating load. HDD are positive when the average daily temperature falls below 55 degrees and 0 when temperatures exceed 55 degrees. CDD are defined for a 60 degree-day. CDD are positive when temperatures are above 60 degrees and 0 when average daily temperature falls below 60 degrees.

Normal or expected degree-days are used to drive the forecast. The general approach is to calculate normal degree-days as an average of past temperature or degree-days over a historical time; most utilities will use a 30-year or 20-year period. The implied assumption is that future temperatures is best represented by the average of the past. Given climate change, however, this is probably not the best assumption. Our analysis and that of others shows that average temperatures are increasing. An analysis of the last 50 years of weather data for Burlington airport shows average temperatures are increasing roughly .08 degrees per year or 0.8 degrees per decade. This is consistent with temperature trends we found in New York. Temperature trend studies have shown average temperatures increasing from 0.4 degrees to over 1.0 degrees per decade depending on geographic location. Temperature trends tend to be the lowest in cities near the ocean.

Increasing temperatures result in fewer HDD and increasing number of CDD. This is illustrated in Figure 11 and Figure 12 that show 20-year degree-day moving average against actual degree days.

FIGURE 11: HEATING TREND

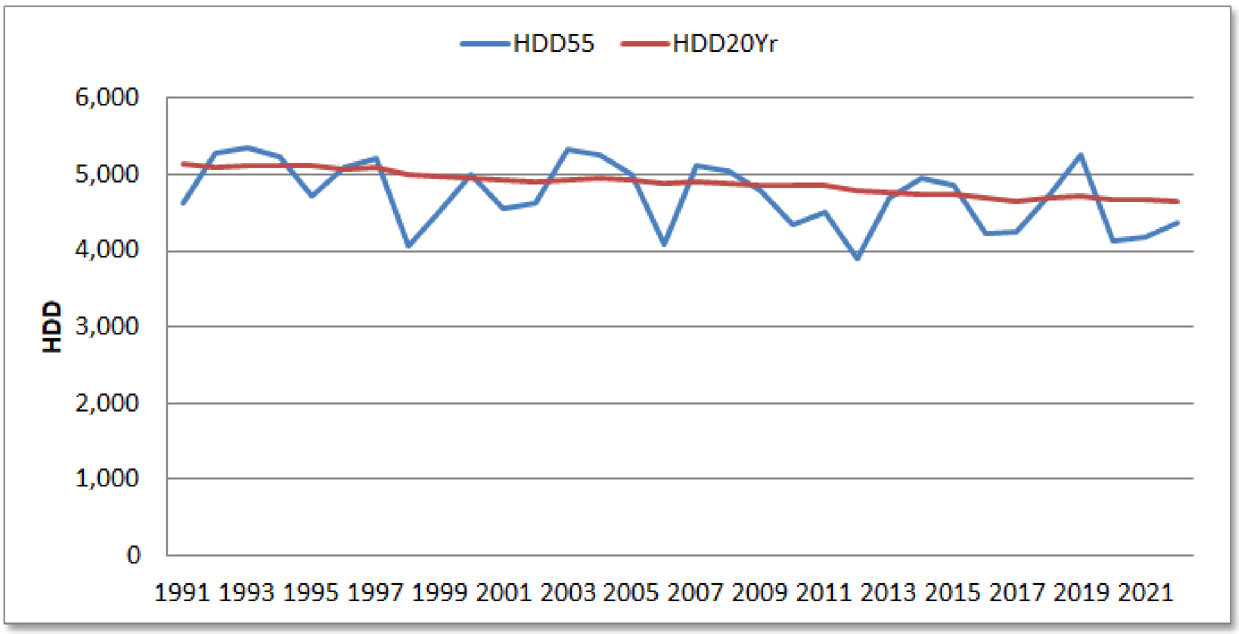
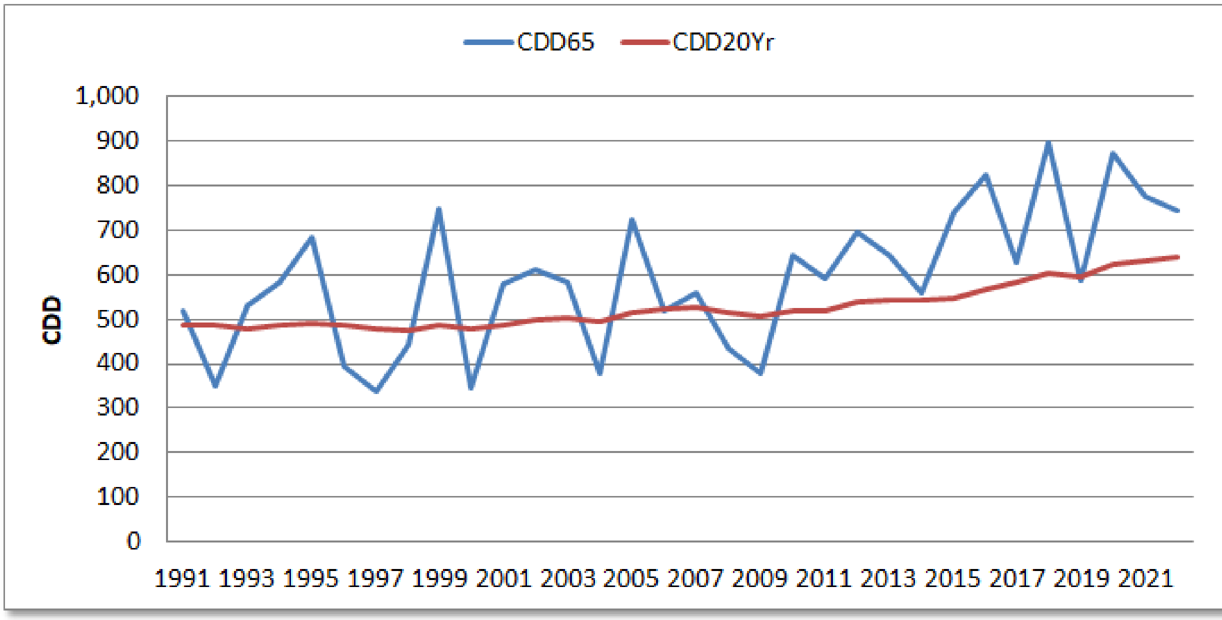


FIGURE 12: COOLING TREND



Recent climate studies show that we can expect temperatures to continue to increase. We assume HDD and CDD trends to persist through the forecast period.

FIGURE 13 and FIGURE 14 compare actual, 20-year normal, and trended HDD and CDD.

FIGURE 13: NORMAL AND TRENDED NORMAL HDD

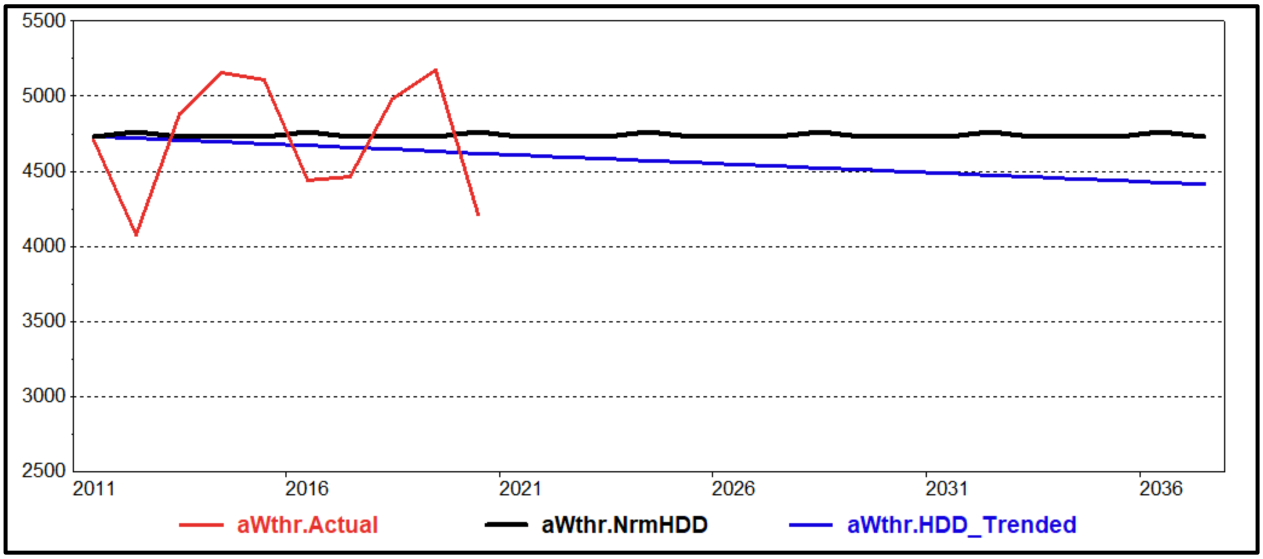
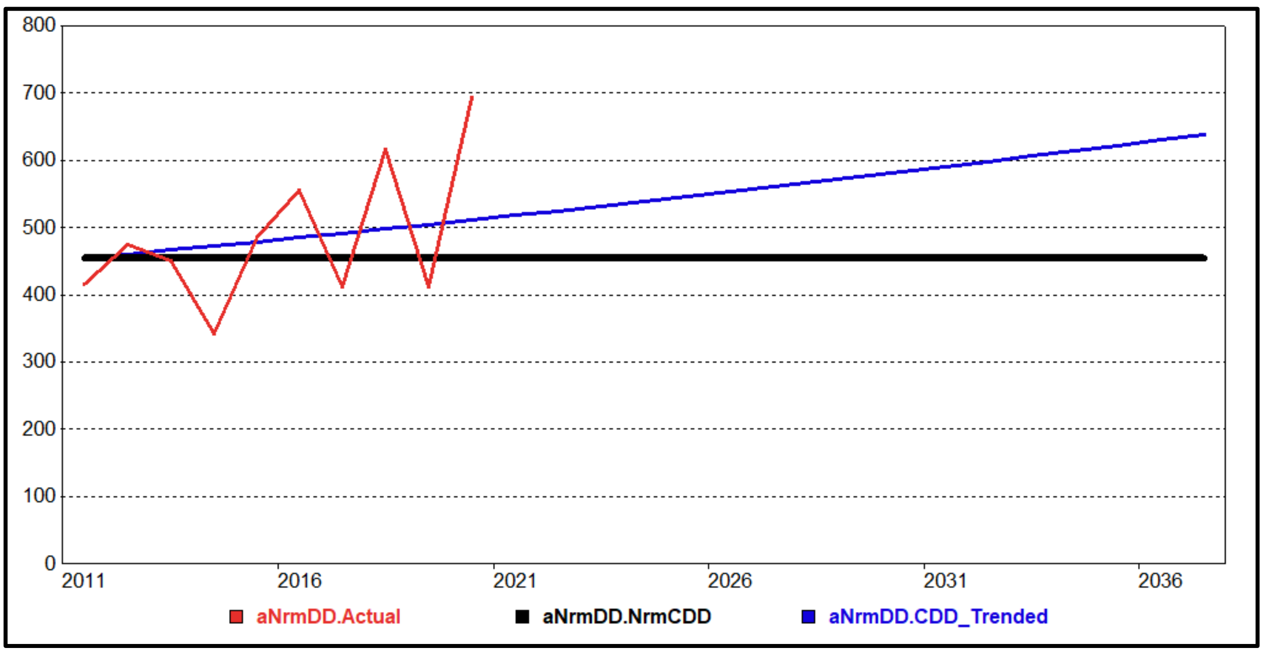


FIGURE 14: NORMAL AND TRENDED NORMAL CDD



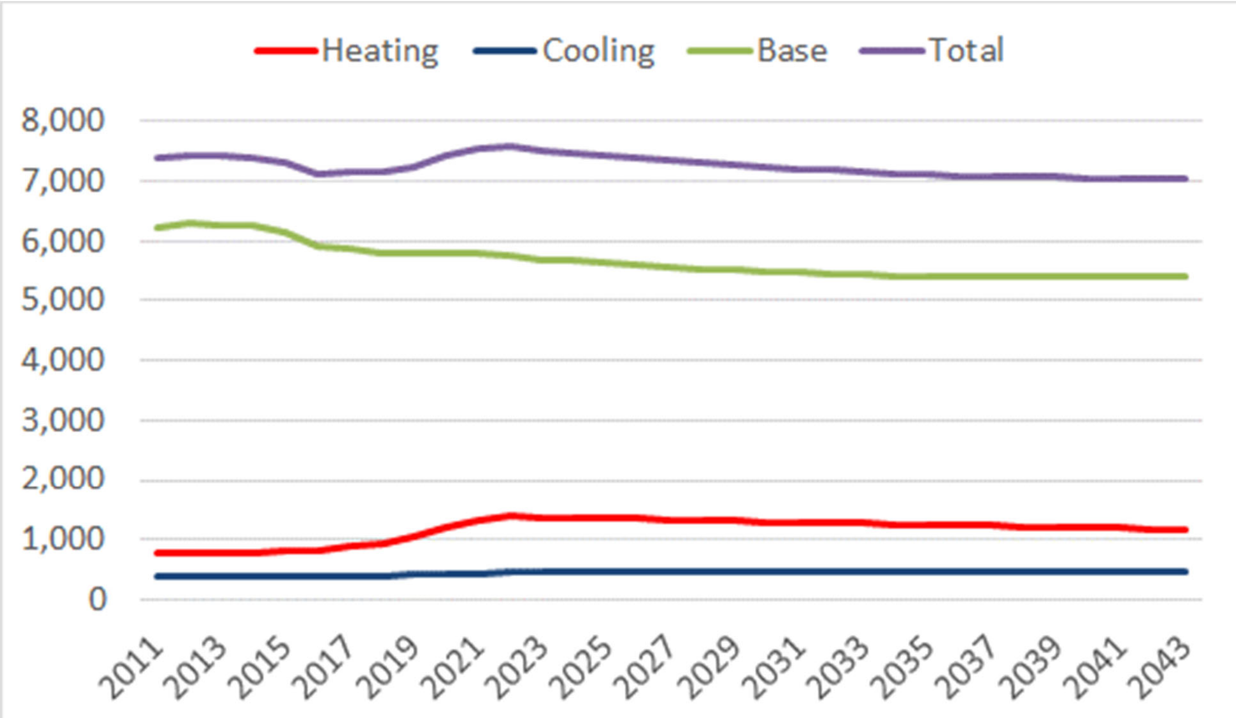
Based on historical data, CDD are expected to increase 1.2% per year and the number of HDD decline 0.3% per year.

End-Use Intensities

Overall, sales have been flat to declining across the state. The decline is largely attributable to behind-the-meter solar adoption and end-use and efficiency gains resulting from new standards and state-incentivized energy efficiency programs. The impact of efficiency improvements is captured in the end-use intensities that reflect both changes in end-use ownership (saturation) and end-use efficiency. End-use intensities are derived for ten residential and nine C&I end-uses by combining saturation and efficiency projections. In the residential sector, intensities are measured on a kWh per household basis and in the commercial sector on a kWh per square-foot basis. End-use intensities are based on EIA 2022 Annual Energy Outlook for New England. Residential end-use saturations are calibrated to Vermont-specific end-use saturations where this data is available.

For most end-uses, increasing efficiency outweighs increase in saturation contributing to declining customer average use. The exception is miscellaneous use (e.g., plug loads, appliances, electric equipment) and residential cooling; in residential cooling saturation continues to trend positive at a rate faster than improvements in air conditioning stock efficiency. Increasing CDD and incentivized heat-pumps are also expected to contribute to additional cooling-related sales. Still, aggregate cooling consumption is relatively small given temperate summer weather conditions. Figure 15 shows efficiency-adjusted residential end-use intensities aggregated into heating, cooling, base, and total intensity.

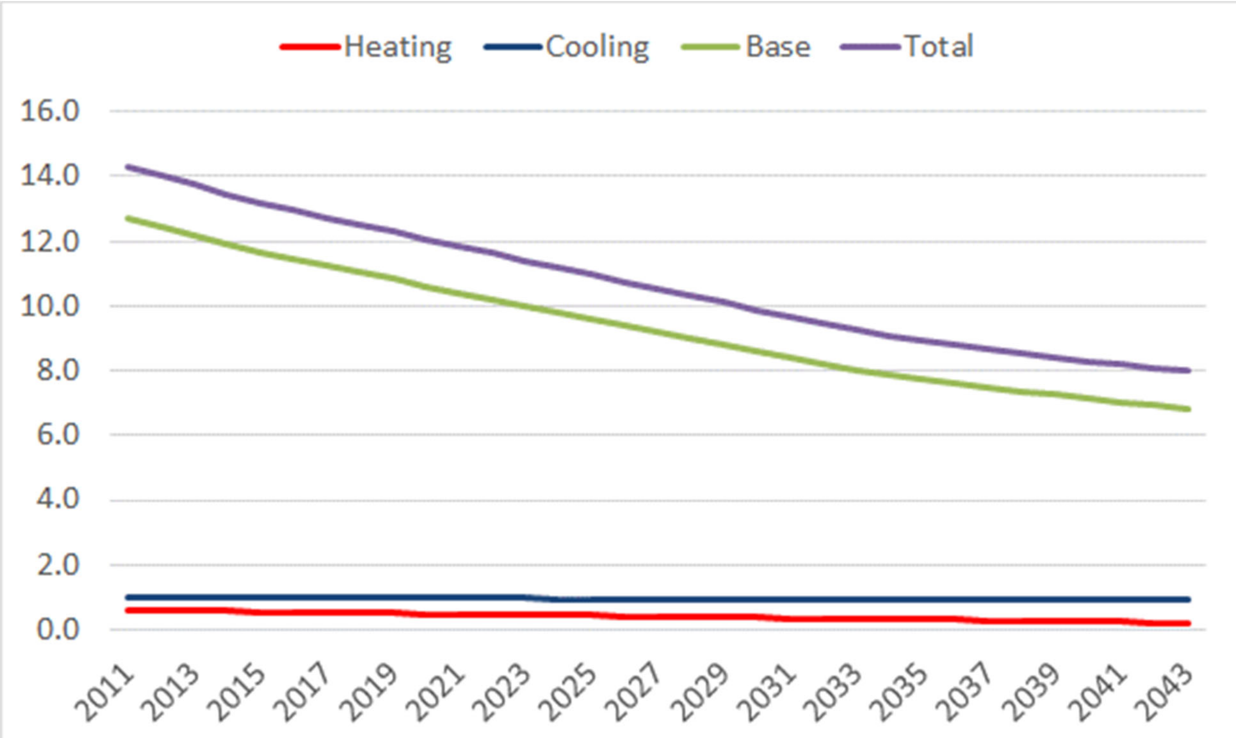
FIGURE 15: RESIDENTIAL SAE INDICES (KWH/HOUSEHOLD)



Since 2012, total residential intensity has been largely flat with efficiency improvements largely cancelling out saturation increases. The energy intensity declines over the forecast period (-0.3% per year) as the lighting savings have been realized and the impact of new appliance standards begins to slow.

Commercial energy intensities are measured on a kWh per Sq. ft. basis. Figure 16 shows efficiency-adjusted commercial heating, cooling, and other use intensity trends. Heating and cooling are a relatively small part of commercial energy use. The non-weather sensitive use (Other) is composed of seven end-uses where the largest end-uses include ventilation, lighting, refrigeration, and miscellaneous use.

FIGURE 16: COMMERCIAL SAE INDICES (KWH/HOUSEHOLD)



In general, there has been a long-term decline in commercial sales largely driven by efficiency gains. Commercial intensity has averaged 1.8% decline over the last ten years and is projected to continue over the forecast period.

EE Program Impacts

State efficiency programs have also had a significant impact on sales. At the state level, most of the impact is captured in the end-use intensities. EIA adjusts end-use efficiencies to reflect New England EE program savings. Forecasts are further adjusted for Vermont-specific savings by incorporating VEIC measured and projected savings as an additional model variable. Where the variable is statistically insignificant, sales are adjusted based on allocated state EE savings projections. State savings projections are allocated to utilities based on customer class sales.

Economic Outlook

The forecast is based on Moody's December 2022 state economic projections. The primary economic drivers include number of state households, population, real personal income, employment, and real economic output (GDP). TABLE 7 shows historical and projected economic outlook.

Itron

TABLE 7: ECONOMIC FORECAST

Year	Households (Thou)	Chg	RPI (Mil $)	Chg	GDP (Mil $)	Chg	Emp (Thou)	Chg
2011	259.2		28,119		28,981		300.9	
2012	260.8	0.6%	28,505	1.4%	29,281	1.0%	304.5	1.2%
2013	263.2	0.9%	28,624	0.4%	28,671	-2.1%	306.7	0.7%
2014	264.7	0.6%	29,295	2.3%	28,868	0.7%	309.6	0.9%
2015	265.6	0.3%	30,129	2.8%	29,172	1.1%	312.1	0.8%
2016	265.7	0.0%	30,327	0.7%	29,378	0.7%	313.3	0.4%
2017	266.0	0.1%	30,559	0.8%	29,499	0.4%	315.0	0.5%
2018	266.2	0.1%	31,072	1.7%	29,630	0.4%	316.1	0.3%
2019	264.3	-0.7%	32,330	4.0%	29,831	0.7%	315.4	-0.2%
2020	259.0	-2.0%	34,415	6.4%	29,174	-2.2%	289.3	-8.3%
2021	256.2	-1.1%	34,266	-0.4%	30,491	4.5%	293.4	1.4%
2022	258.8	1.0%	33,163	-3.2%	31,328	2.7%	300.5	2.4%
2023	259.1	0.1%	33,265	0.3%	31,575	0.8%	303.6	1.0%
2024	260.0	0.4%	33,693	1.3%	32,083	1.6%	305.4	0.6%
2025	260.9	0.3%	34,366	2.0%	32,884	2.5%	307.0	0.5%
2026	261.7	0.3%	35,070	2.0%	33,726	2.6%	307.6	0.2%
2027	262.2	0.2%	35,736	1.9%	34,527	2.4%	308.0	0.1%
2028	262.7	0.2%	36,386	1.8%	35,311	2.3%	308.6	0.2%
2029	263.1	0.2%	36,997	1.7%	36,053	2.1%	309.2	0.2%
2030	263.5	0.2%	37,535	1.5%	36,708	1.8%	309.5	0.1%
2031	263.9	0.2%	38,030	1.3%	37,313	1.6%	309.6	0.0%
2032	264.3	0.2%	38,534	1.3%	37,932	1.7%	309.6	0.0%
2033	264.7	0.2%	39,064	1.4%	38,584	1.7%	309.7	0.0%
2034	265.1	0.2%	39,591	1.3%	39,234	1.7%	309.7	0.0%
2035	265.5	0.2%	40,102	1.3%	39,867	1.6%	309.6	0.0%
2036	265.9	0.2%	40,601	1.2%	40,488	1.6%	309.4	-0.1%
2037	266.3	0.2%	41,089	1.2%	41,095	1.5%	309.1	-0.1%
2038	266.7	0.2%	41,561	1.1%	41,686	1.4%	308.8	-0.1%
2039	267.1	0.2%	42,034	1.1%	42,279	1.4%	308.5	-0.1%
2040	267.5	0.1%	42,504	1.1%	42,870	1.4%	308.2	-0.1%
2041	267.9	0.2%	42,973	1.1%	43,461	1.4%	308.0	-0.1%
2042	268.3	0.1%	43,447	1.1%	44,060	1.4%	307.8	-0.1%
2043	268.7	0.3%	43,932	2.2%	44,675	2.8%	307.6	-0.1%
11-22		0.0%		1.5%		0.7%		0.0%
23-33		0.2%		1.6%		2.0%		0.2%
23-43		0.2%		1.5%		1.8%		0.1%

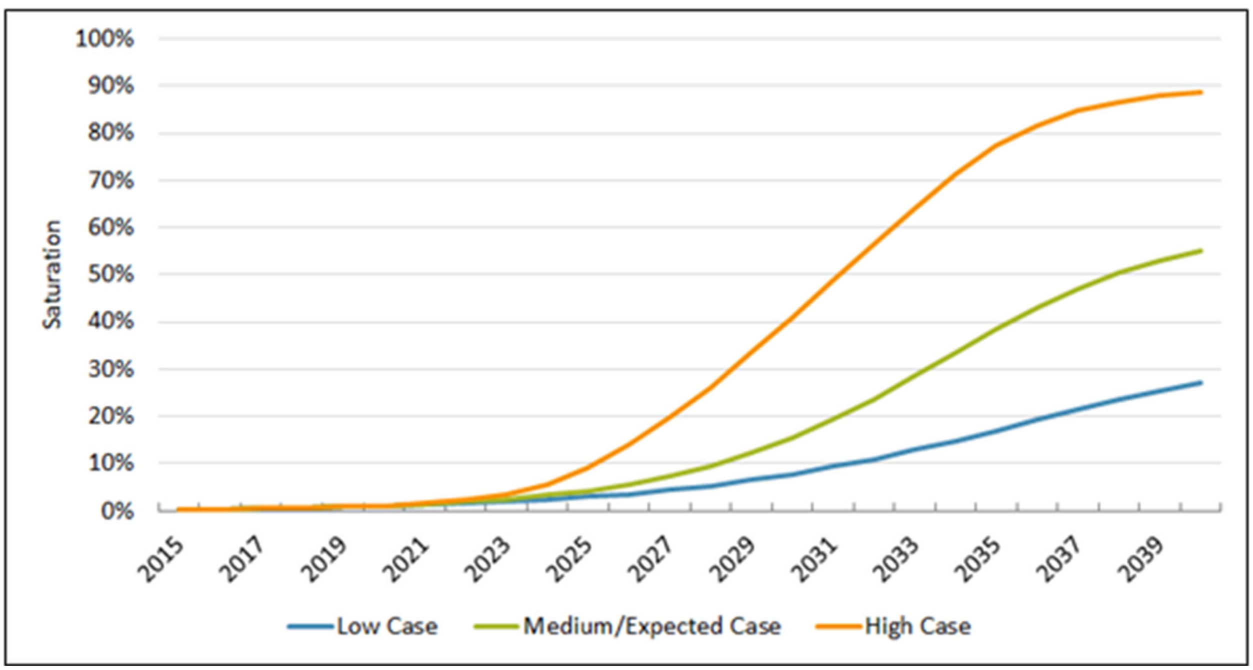
In 2020, state output (GDP) dropped 2.2% and employment declined 8.3% while personal income increased 6.4%. The large increase in real income is a result of government financial stimulus designed to counter the COVID employment impact. Moody's projects economic recovery to pre-pandemic levels by 2022 with strong economic growth coming out of the COVID-driven recession.

Over the long term, the number of households is expected to average 0.2% with employment increasing at roughly the same rate. GDP averages 1.8% per year largely driven by improvements in productivity and a jump in GDP coming out of the pandemic.

Electric Vehicles

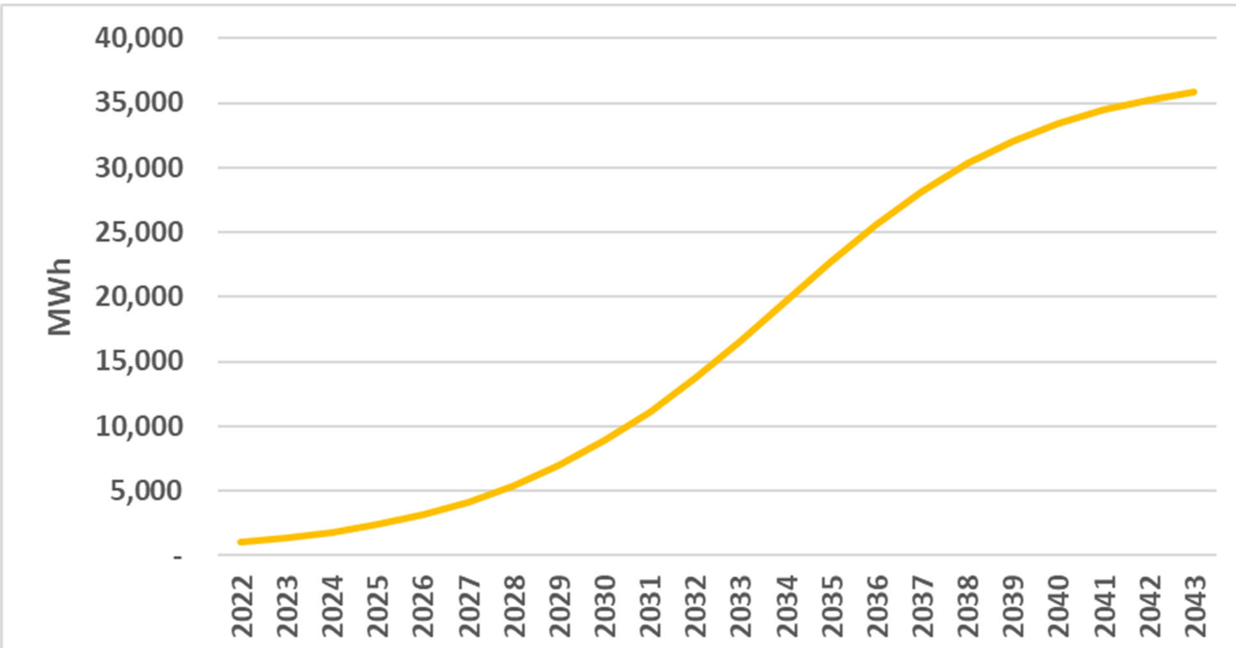
The electric vehicle (EV) forecast was developed by the VEIC as part of VELCO 2023 Long-Range Transmission Plan. VEIC provided three forecast scenarios; low, medium, and high, based on saturation targets for light-duty registered vehicles. The forecast assumes the high case path as this is most consistent with state mandates that all new registered vehicles are electric starting in 2035. In the high case, 90% of all vehicles are electric by 2050 with a 50% market share by 2030.

FIGURE 17: ELECTRIC VEHICLE PROJECTIONS



EV saturations are translated into number of vehicles and then total charging energy requirements based on estimated annual miles driven and kWh per mile driven. Figure 18 shows EV electric consumption. By the end of the forecast period, there is over 35,000 MWh of EV charging load.

FIGURE 18: EV ELECTRICITY FORECAST

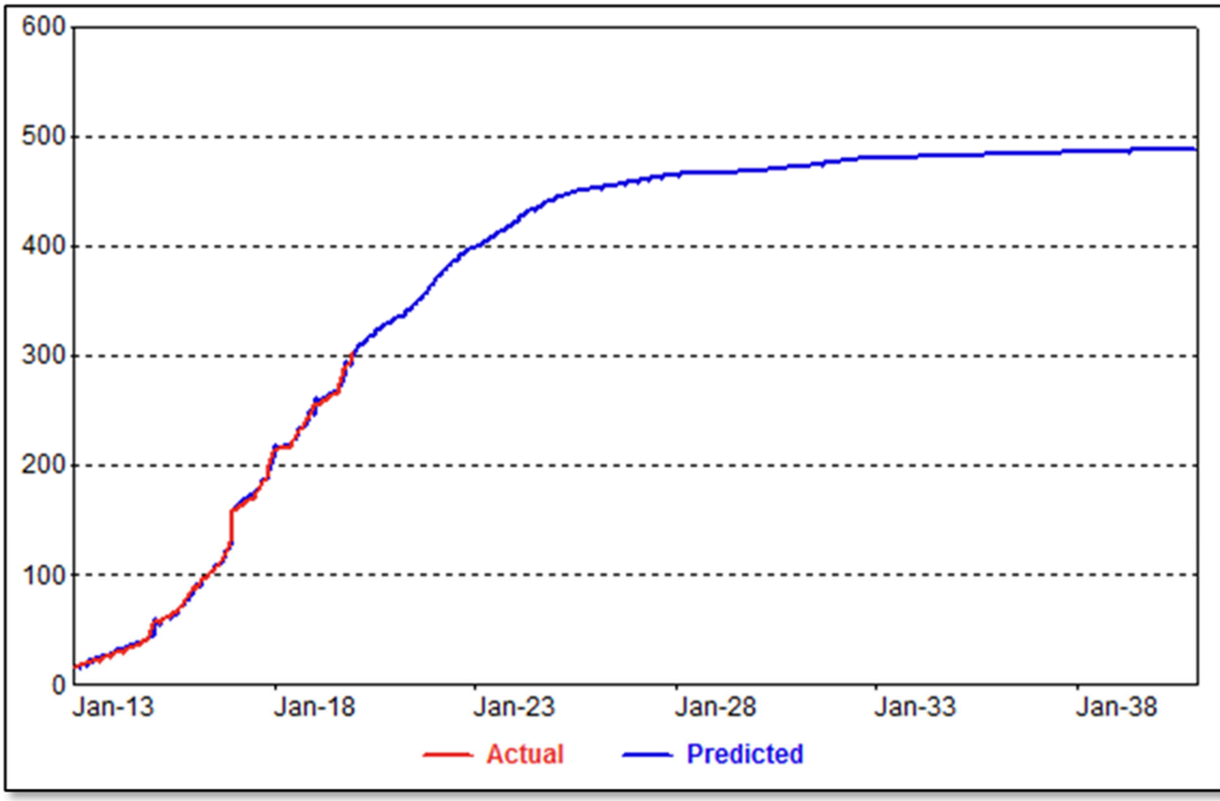


State EV sales are allocated using the WEC share of statewide number of residential customers.

Solar

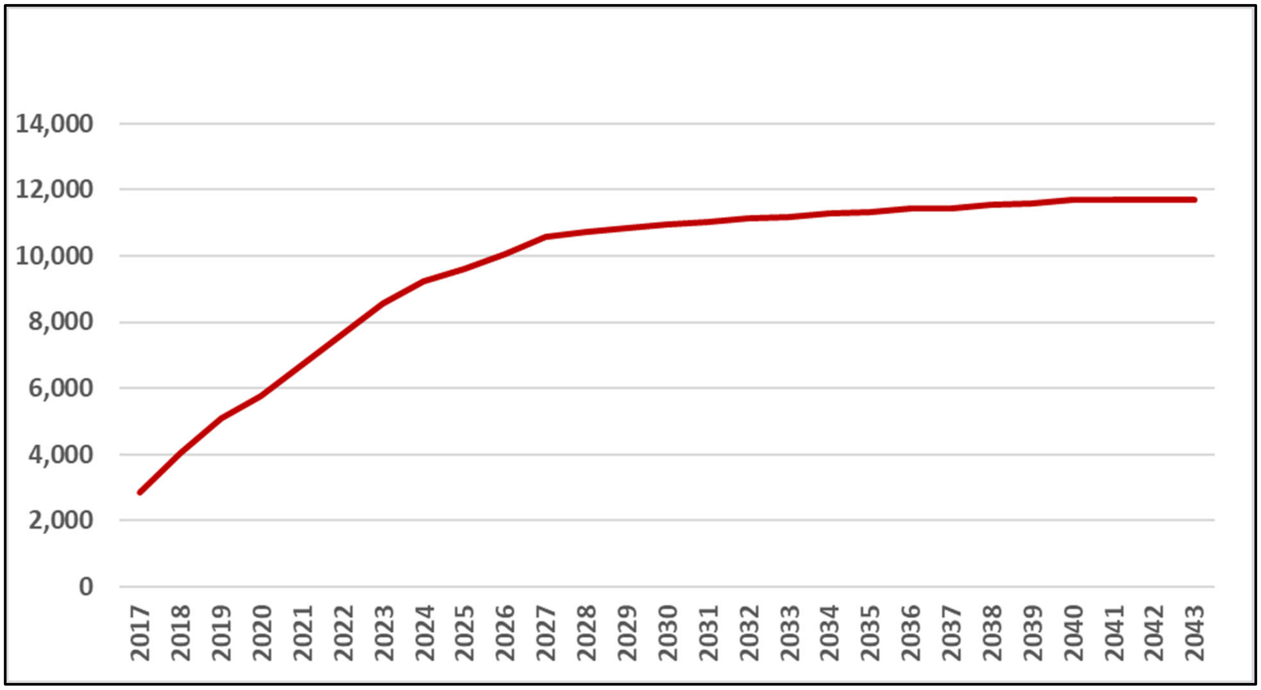
The solar forecast is based on Itron's behind-the-meter (BTM) solar forecast developed also as part of the 2023 VELCO long-term forecast. BTM solar capacity is derived from an investment return-based model that relates installed capacity to average system payback (number of years before investment costs are recovered). Figure 19 shows state capacity forecast.

FIGURE 19: STATE SOLAR CAPACITY FORECAST (MW)



We expect the growth of BTM solar adoption to begin to slow by 2025 as system costs begin to flatten out. We project over 450 MW of installed solar capacity by 2032. This translates into nearly 650,000 MWh based on monthly load factors derived from Vermont solar generation profile data. In 2022, WEC had roughly 7,600 MWh of solar generation. Our default assumption is WEC BTM solar generation continues to increase at the same rate as state generation projections. Like the state, solar generation is expected to slow significantly after 2025. FIGURE 20 shows the WEC solar generation forecast.

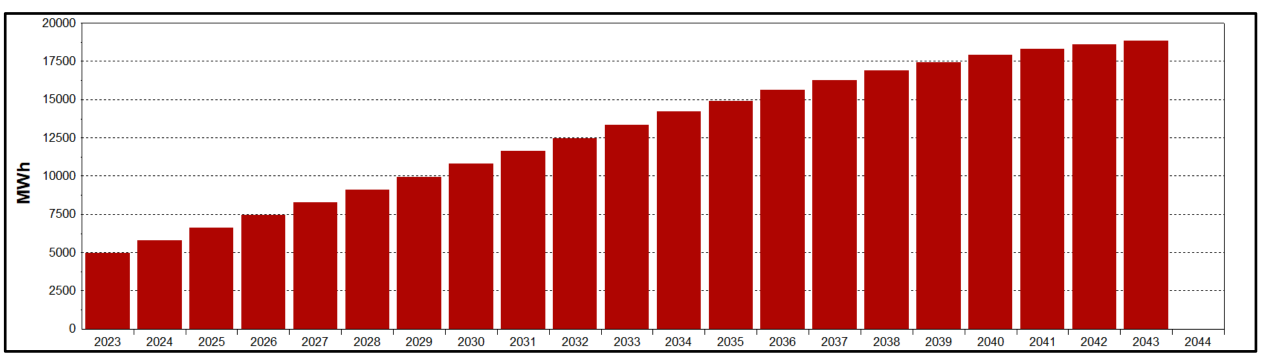
FIGURE 20: EXPECTED WEC SOLAR GENERATION (MWH)



Cold Climate Heat Pumps

As part of state efforts to reduce CO_2 emissions, the state has launched a program to promote CCHP by offering financial incentives including rebates and 0 interest financing. The primary target are homes that heat with oil, propane, and wood. Over the last four years, the state has seen aggressive heat pump adoption with over 50,000 units installed. We expect to see continued strong heat pump adoption with WEC heat pump adoption increasing proportionally to state projection based on WEC residential customers relative to state residential electric customers. FIGURE 21 shows WEC heat pump sales projections.

FIGURE 21: PROJECTED HEAT PUMP SALES



APPENDIX A – MODEL RESULTS

Residential Average Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRes.XHeat	0.317	0.042	7.546	0.00%
mStructRes.LagXHeat	0.365	0.043	8.502	0.00%
mStructRes.XCool	0.23	0.065	3.521	0.06%
mStructRes.LagXCool	0.636	0.064	9.869	0.00%
mStructRes.XOther	0.092	0.074	1.255	21.16%
mStructRes.LagXOther	0.767	0.075	10.21	0.00%
mBin.Bef15	-20.733	4.383	-4.73	0.00%
mBin.Yr17	23.222	6.655	3.489	0.07%

Model Statistics	
Iterations	1
Adjusted Observations	136
Deg. of Freedom for Error	128
R-Squared	0.834
Adjusted R-Squared	0.825
AIC	6.165
BIC	6.337
Log-Likelihood	-604.23
Model Sum of Squares	288,791.09
Sum of Squared Errors	57,551.76
Mean Squared Error	449.62
Std. Error of Regression	21.2
Mean Abs. Dev. (MAD)	16.71
Mean Abs. % Err. (MAPE)	3.30%
Durbin-Watson Statistic	1.695

Residential Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.Mar18Plus	446.011	20.04	22.256	0.00%
mEcon.CustVar	10367.627	9.449	1097.237	0.00%
mBin.Yr2016Plus	393.925	22.724	17.335	0.00%
MA(1)	0.678	0.063	10.776	0.00%

Model Statistics	
Iterations	16
Adjusted Observations	144
Deg. of Freedom for Error	140
R-Squared	0.978
Adjusted R-Squared	0.978
AIC	7.954
BIC	8.037
Log-Likelihood	-773.02
Model Sum of Squares	17,405,308.60
Sum of Squared Errors	387,843.38
Mean Squared Error	2,770.31
Std. Error of Regression	52.63
Mean Abs. Dev. (MAD)	31.69
Mean Abs. % Err. (MAPE)	0.30%
Durbin-Watson Statistic	1.638

Small Commercial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructCom.XOther	6572.011	3084.749	2.13	3.54%
mStructCom.LagXOther	27161.869	3111.441	8.73	0.00%
mStructCom.XHeat	-70738.148	84678.84	-0.835	40.53%
mStructCom.LagXHeat	969408.926	83674.64	11.585	0.00%
mStructCom.XCool	14435.741	28851.54	0.5	61.79%
mStructCom.LagXCool	117734.377	28782.05	4.091	0.01%
mBin.Bef15	-40674.833	7470.14	-5.445	0.00%
mBin.Yr2016Plus	19928.013	5064.147	3.935	0.02%
mBin.Trend_Bef2016	-3893.16	647.708	-6.011	0.00%
MA(1)	0.199	0.097	2.065	4.13%

Model Statistics	
Iterations	8
Adjusted Observations	118
Deg. of Freedom for Error	108
R-Squared	0.793
Adjusted R-Squared	0.776
AIC	19.859
BIC	20.094
Log-Likelihood	-1,329.12
Model Sum of Squares	160,948,372,367.16
Sum of Squared Errors	41,969,688,251.12
Mean Squared Error	388,608,224.55
Std. Error of Regression	19,713.15
Mean Abs. Dev. (MAD)	14,641.08
Mean Abs. % Err. (MAPE)	3.59%
Durbin-Watson Statistic	1.887

Large Commercial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mEcon.IndVar	298372.505	4484.173	66.539	0.00%
mCovid.NResIndex	-12870.181	6811.551	-1.889	6.10%
mBin.Jan	25616.185	7585.836	3.377	0.10%
mBin.Feb	40134.867	7012.152	5.724	0.00%
mBin.Jun	10923.057	6827.828	1.6	11.21%
mBin.Sep	12493.566	6490.948	1.925	5.64%
mBin.Nov	12247.93	7008.927	1.747	8.29%
mBin.Dec	36511.978	7596.089	4.807	0.00%
mBin.Bef16	-31935.963	5571.185	-5.732	0.00%
MA(1)	0.321	0.085	3.792	0.02%

Model Statistics	
Iterations	8
Adjusted Observations	141
Deg. of Freedom for Error	131
R-Squared	0.454
Adjusted R-Squared	0.417
AIC	20.161
BIC	20.37
Log-Likelihood	-1,611.40
Model Sum of Squares	57,994,880,414.18
Sum of Squared Errors	69,710,397,753.58
Mean Squared Error	532,140,440.87
Std. Error of Regression	23,068.17
Mean Abs. Dev. (MAD)	17,079.93
Mean Abs. % Err. (MAPE)	5.92%
Durbin-Watson Statistic	1.799

Peak Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mCPkEndUses.BaseVar	2234.736	28.062	79.635	0.00%
mWthr.HeatVar55	0.019	0.003	5.621	0.00%
mWthr.CoolVar60	0.123	0.008	16.015	0.00%
mBin.Mar	1.815	0.197	9.235	0.00%
mBin.Apr	1.15	0.196	5.861	0.00%
mBin.Jun	-0.606	0.193	-3.135	0.23%
mBin.Oct	1.398	0.177	7.919	0.00%
MA(1)	0.41	0.099	4.145	0.01%

Model Statistics	
Iterations	18
Adjusted Observations	101
Deg. of Freedom for Error	93
R-Squared	0.862
Adjusted R-Squared	0.852
AIC	-1.071
BIC	-0.864
Log-Likelihood	-81.24
Model Sum of Squares	184.4
Sum of Squared Errors	29.54
Mean Squared Error	0.32
Std. Error of Regression	0.56
Mean Abs. Dev. (MAD)	0.43
Mean Abs. % Err. (MAPE)	3.19%
Durbin-Watson Statistic	1.708

2023 Vermont Energy Burden Report

August 2023

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Efficiency Vermont

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Executive Summary

Energy burden, which examines energy usage in context of income, is an important lens for understanding the impacts of energy costs on Vermont households and communities. It can also help us understand if Vermont's energy transformation programs[1] are reaching the customers who can most benefit from them.

This new analysis of data through 2021 indicates that energy burdens have remained relatively constant over the last decade, with households on average spending 11% of their income on energy costs—including electricity, transportation fuels, and home heating (thermal) fuels. Spending on transportation energy makes up the largest portion of these costs (45%). This report is somewhat unique in that it includes transportation fuel costs in the determination of energy burden, which can make it challenging to understand where Vermont stands in a national context. However, a combined electric and thermal burden of greater than 6% is generally considered high;[2] when transportation costs are removed from our calculation, the average electric and thermal burden for Vermont is 5%, indicating that there are many households in our state with high energy burden. Consistent with the last iteration of this report, published in 2019 (and based on data from 2013-2017), we find that adoption of clean energy technologies, which can lower costs and decrease energy burden, is lagging in highly energy-burdened communities where they can provide the most benefits to residents.

Meeting Vermont's aggressive energy and equity goals will require widespread adoption of technologies that reduce energy costs and climate impact. This means designing and implementing energy programs that explicitly address energy burden and make significant resource investments to address the barriers faced by residents with limited means or historic disadvantages. Energy efficiency and electric distribution utility programs are just one part of the solution to these challenges, but they will likely need the flexibility to place a greater focus on addressing energy burden in the context of their overall performance requirements.

[1] Programs intended to help Vermont residents reduce their energy costs and/or fossil fuel consumption.

[2] Affordable levels of spending or burden vary by category. Generally, a combined electricity and thermal energy spending burden less than 6% of household income is considered affordable (see ACEEE: https://www.aceee.org/sites/default/files/energy-affordability.pdf; NYSERDA: https://www.nyserda.ny.gov//media/Files/Publications/PPSER/Program-Evaluation/2017ContractorReports/LMI-Special-Topic-Rpt---Energy-Burden.pdf; Connecticut PUC: https://portal.ct.gov/-/media/PURA/electric/FAQs-Docket-No-17-12-03RE11.pdf). A combined transportation and housing burden of 45% of household income is used by the Housing and Transportation Affordability Index (see https://htaindex.cnt.org/about/#methodology). The combined 45% affordability threshold is inclusive of total shelter costs (rent/mortgage, insurance, utility costs, etc.) and all associated transportation costs (vehicle maintenance, fuel, insurance, public transit costs). For the purposes of this report, we only considered transportation energy (fuel) costs.

Introduction

This is the third iteration of the Vermont Energy Burden Report, which presents an analysis of geographic patterns and trends across the three major components of household energy costs: Electricity, Thermal[3], and Transportation.

For this study update, we leveraged electric usage data and other publicly-available data sets to estimate the average dollars spent annually on energy, as a percentage of annual income, at the town level, and at the census block group level[4] for towns with larger populations[5]. While this report discusses our town-level findings, we created a companion resource (available at efficiencyvermont.com/energyburden) that enables readers to examine census block group data. We also examined customer participation data for the subset of Efficiency Vermont's programs most likely to help reduce household energy burden.

Our primary goals in conducting this analysis were to:

1. Provide a data-driven assessment of the impact of energy costs on Vermonters, in order to support equitable program design and more effective engagement with residents who can most benefit from clean and affordable energy technologies.
2. Explore whether there have been any notable changes or shifts in the basic patterns we identified in the first two Vermont Energy Burden Reports, published in 2016 and 2019.
3. Assess the extent to which Efficiency Vermont's programs are reaching energy-burdened residents, within the limitations of available data on customer participation.

While there are some limitations in the data that are currently available – particularly in terms of customer demographics[6] – we hope that this report will help provide context for ongoing conversations around how best to advance progress on Vermont's energy, climate, and equity[7] goals.

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[3] Thermal costs are primarily driven by home heating but may also include cooking and water heating.
[4] A census block group is the smallest geographic unit for which the U.S. Census Bureau provides basic demographic data: https://www.census.gov/newsroom/blogs/random-samplings/2011/07/what-are-census-blocks.html.
[5] Defined as 3,000 or more residents.
[6] Efficiency Vermont does not routinely capture demographic data for customers who participate in its programs; doing so can be particularly difficult for programs that are offered at point of sale.
[7] Leveraging the American Council for an Energy-Efficient Economy's (ACEEE) Energy Equity project as our guide, Efficiency Vermont defines "Equity" as working to address the embedding of Diversity, Equity and Inclusionary considerations into our programs, policies, and investments, such that we can improve and expand determination of, access to, and utilization of impactful clean energy services and technologies for underserved groups while creating more just processes, outcomes, and systems. More information is available at: https://www.aceee.org/topic/energy-equity.

Background

The pattern of total energy burden in Vermont remains largely unchanged since our 2016 analysis, with relatively low burden in Chittenden County and relative high burden in the Northeast Kingdom.[8] However, there have been some changes in our methodology for each iteration of this report.

Census Block Group Data

Analyzing energy burden exclusively at the town level can obscure significant variations within Vermont's larger communitiies.

In 2016, we explored energy burden through census block group and zip code. We opted to report energy burden by town in 2019, because that unit is more accessible and relatable. However, analyzing energy burden exclusively at the town level can obscure significant variations within Vermont's larger communities. While easy to understand, this approach risks giving an impression that only relatively small rural communities must contend with high energy burden. For example, there are 28 census block groups in Burlington, including one of the most energy-burdened block group in Vermont; however, our town-level analysis places Burlington in the "lowest" energy burden category. In order to provide a more accurate characterization of energy burden across Vermont, we have created an interactive online resource as a companion to this report that allows readers to explore census block group-level estimates of energy burden for all of Vermont's larger communities. Each census block group contains between 600 and 3,000 people. In rural areas of Vermont, many towns only have one block group, meaning a block-group level analysis provides no additional information.

In the previous two versions of the report, we used data from a variety of sources to estimate thermal energy spending. We relied heavily on the American Community Survey (ACS) which provides primary heating fuel source(s) for each census block group and town in Vermont. We combined these estimates with cost data from the Vermont Public Service Department to estimate household-level spending. In this year's report, we opted to use the US Department of Energy's Low Income Energy Affordability Data (LEAD) Tool.[9] The LEAD Tool is a rigorously tested and sophisticated model that provides estimates of spending on household heating by census tract.[10]

Image 1. Total Energy Burden, 2016–2023.

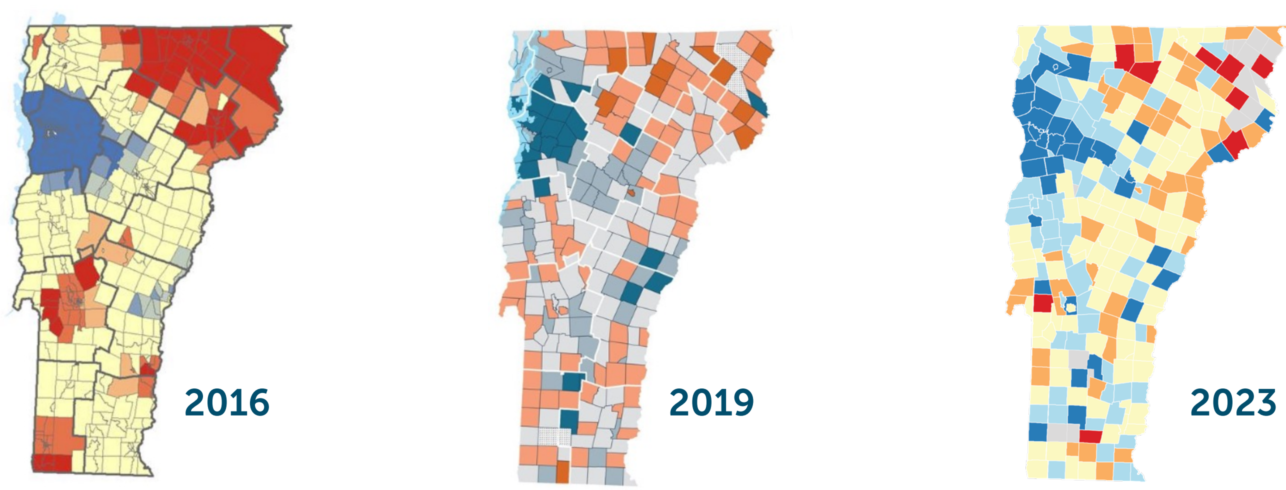

Image 1: Total Energy Burden maps from the 2016 (left), 2019 (center), and 2023 (right) Vermont Energy Burden Reports demonstrate the same basic pattern. Red areas indicate high burden and blue areas indicate low burden.

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[8] Caledonia, Essex, and Orleans counties.

[9] https://www.energy.gov/scep/slsc/lead-tool

[10] Per the U.S Census Bureau, census tracts are "small relatively permanent statistical subdivisions of a County, averaging about 4,000 residents:" https://www2.census.gov/geo/pdfs/education/CensusTracts.pdf

Since the first report was published in 2016, Efficiency Vermont has increased its consideration of energy burden in the design of programs, but is still working to understand how to best track and measure the impact of this work. Among many changes and improvements, there are now bonus incentives and zero interest loans available for low- and moderate-income Vermonters to help them complete weatherization projects and install cold climate heat pumps. We have also leveraged new flexibility made possible by the passage of the Energy Efficiency Modernization Act (Act 151 of 2020) to introduce a pilot program, in partnership with Vermont's electric utilities, which pairs income-eligible Weatherization Assistance Program customers with Efficiency Excellence Network contractors to install cold climate heat pumps at no cost. This program and other programs supporting efficiency measures for low-income households are largely driven by policy preferences of legislators and regulators and made possible by Efficiency Vermont balancing the overall budget impact of these programs against other programs that generate much higher energy savings at a significantly lower cost.

Programs such as these will likely need to be scaled up dramatically over the next decade if Vermont is to meet its aggressive climate goals and ensure that a larger share of low- and moderate-income Vermonters can adopt and benefit from energy-saving technologies. However, there is a limit to how much additional investment can be made from Vermont's energy efficiency programs, which are generally focused on maximizing electricity and thermal savings at the lowest possible cost. While the current focus is important for reducing costs for all Vermont residents, it drives a different set of program priorities than would a focus on reducing energy burden, or reducing greenhouse gas emissions.

Improving Programs

Since the first report was published in 2016, Efficiency Vermont has increased its consideration of energy burden in the design of programs.

Methodology

We used a combination of residential electric usage data, U.S. Census data, and modeling from the LEAD Tool to estimate total energy spending and burden in Vermont communities. Energy burden is provided at the town level for all communities with more than 50 households.[11] For communities with more than 3,000 residents,[12] we have also estimated energy burden at the census block group level (representing 60 towns and 313 block groups).

Energy Spending ÷ **Household Income** = **Total Energy Burden**

Total energy spending is the sum of annual costs for three categories: Electricity, Thermal, and Transportation.[13] Energy burden is defined as annual energy spending expressed as a percentage of household income.

[11] Towns with fewer than 50 households were excluded from this analysis due to small sample sizes and high variability. These towns include: Avery's Gore, Averill, Brunswick, Ferdinand, Glastenbury, Granby, Lemington, Lewis, Somerset, Victory, Warner's Grant, Warren's Gore.

[12] Many communities with fewer than 3,000 households include only one census block group, and thus their energy burden data can be easily expressed at the town level.

[13] Estimates of spending do not account for fuel assistance that qualifying households may receive, since that data is not available at the community level.

To estimate energy spending and burden at the community level for each of the three energy categories we used the following data sources:

- **Electricity:** Through Efficiency Vermont's ongoing partnership with Vermont's electric utilities, we obtained average electricity usage per residential account for the 246 (of 253) towns in Vermont for which it was available from 2019 to 2021. To the extent that the homes in a community are using electricity for heating, it would impact our estimate of electric burden; we anticipate revisiting this methodology in future iterations of this report to account for increasing usage of efficient electric heating systems.

- **Thermal:** Estimates of spending on heating are available through the LEAD tool. The LEAD tool provides detailed estimates of spending on heating by a variety of demographic variables and building characteristics. The LEAD tool also reports spending by census tract. There are 180 census tracts in Vermont. Each census tract contains approximately 4,000 people. Most tracts contain more than one town and some cities contain more than one tract. We converted tract-based estimates of thermal energy spending to town-based estimates. The LEAD tool estimates are based largely on 2016 American Community Survey data.[14] We updated the tool's estimates with fuel-specific inflation factors available for Vermont through the Energy Information Administration to capture average prices over the 2017-2021 period.[15] As efficient electric heating systems become more widespread, we anticipate adjusting our methodology in future iterations of this report to more effectively account for their impact and costs. We converted tract-level estimates of spending from the LEAD Tool to town and block group level and calculated burden using town and block group-level median household income.

- **Transportation:** To estimate spending on transportation energy we used estimates of vehicle miles traveled (VMT) available by census block group through the Housing and Transportation Affordability Index (H&T Index), from the Center for Neighborhood Technology. We averaged these estimates by town and used them to calculate town-level transportation energy spending. These estimates were merged at the town level to create town-level VMT estimates. They were then combined with statewide average fuel efficiency (23.4 miles per gallon)[17] and average gasoline prices ($2.91 in 2022)[18] to estimate fuel usage and spending. As the number of electric vehicles increases, we anticipate adjusting our methodology in future iterations of this report to more effectively account for their impact and costs. We included transportation energy costs in this analysis because transportation energy costs are consistently the largest portion of household energy spending and burden.

- **Median Household Income:** Estimates of median household income are available through the American Community Survey in five-year blocks by both town[19] and census block group. For this analysis we used the most current five year estimates available: 2017-2021. Estimates of spending and income are expressed in constant dollars and not adjusted for inflation unless noted.

Towns with fewer than 50 households were excluded from all burden categories due to high margins of error.

The COVID-19 pandemic had wide ranging impacts, which are still being analyzed and are far beyond the scope of this report. However, where it is plausible to assume an impact on this analysis and/or the data sets we used, we have made specific reference to it.

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[14] A new version of the LEAD Tool was released in June of 2023, after analysis for this report had already been completed.
[15] https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_prices/res/pr_res_VT.html&sid=VT – this time period was chosen in order to mirror the most recently-available income and energy usage data leveraged in this analysis.
[16] See: https://htaindex.cnt.org/
[17] Vermont Transportation Energy Profile: https://vtrans.vermont.gov/sites/aot/files/planning/documents/planning/2021%20Vermont%20Transportation%20Energy%20Profile.pdf
[18] https://vtrans.vermont.gov/contract-admin/resources/construction-contracting/fuel-price-adjustment-historical. At the time this report was published (August 2023), the Vermont average gasoline price was more than $3.50/gallon.
[19] The American Community Survey did not provide median household income data for Mount Tabor or Landgrove – for that reason, we were unable to estimate energy burden for those communities in this report.

Results

We estimate that, on average, Vermont households are spending $7,071 annually on electricity, thermal, and transportation fuels. This represents approximately 11% of statewide household median income, which is generally consistent with our prior two reports. However, it represents an increase of $1,239 over average annual energy costs estimated in our 2019 report. Thermal energy and transportation fuel costs varied considerably across towns, with electricity costs being significantly less variable.

Table 1. Average spending by energy category +/- standard deviation for the current report and the previous version of the report released in 2019.

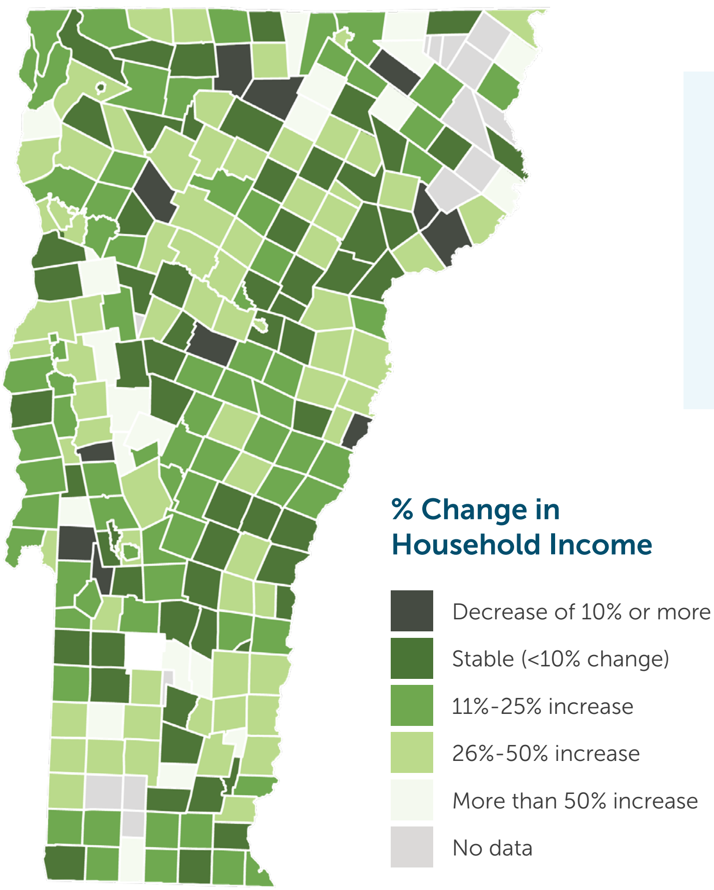
Energy Type	Average Expenditure (2019)	Range of expenditures (2019)	Proportion of total energy cost (2019)	Average Expenditure (2023)	Range of expenditures (2023)	Proportion of total energy cost (2023)
Electricity	$1,150 ±$199	$302 - $1,777	20%	$1,417 ±$209	$619 - $2,073	20%
Thermal	$2,050 ±$290	$1,041 - $2,916	35%	$2,447 ±$390	$1,050 - $4,340	35%
Transportation	$2,638 ± $126	$2,047 - $2,874	45%	$3,217 ±$417	$1,682 - $4,196	45%
Total	$5,837 ± $471	$3,859 - $6,949	-	$7,071 ±$741	$3,498 - $9,100	-

Chart 1. Graph of average spending by energy category +/- standard error.

Chart 1: The full range of town-level burden estimates for each energy category is represented by dots. The box and lines represent the majority of all burden estimates, showing that thermal and transportation burdens are much more variable across communities than is electric burden.

There is generally greater variation in energy burden than energy spending. Spending on energy is relatively inelastic (meaning consumers do not have a lot of control immediate over the amount of energy they use on an ongoing basis), relative to non-essential household expenses, and there is substantial variation in median household income across towns. Median income can vary significantly from year to year – particularly in communities with a small number of households. While we updated our methodology this year by excluding towns with fewer than 50 households to help account for that variability, there are some trends that have impacted our estimates of town-level energy burden. Between 2017 and 2021, statewide median household income increased 26%, from about $57,500 to over $72,000.[20] These increases were not restricted to specific regions, occurred in communities throughout the state, and occurred relatively consistently each year (meaning the increase in median income over that five-year period cannot be attributed solely to the COVID-19 pandemic in 2020-2021).

Image 2. Change in town level median income 2017-2021.



> **Income & Burden**
>
> There were 37 towns that experienced significant declines in median income from 2017-2021. Where there was a decrease in median income, we generally observed a corresponding increase in energy burden.

Image 2: Percent change in median household income by town, 2017 ACS vs. 2021 ACS.

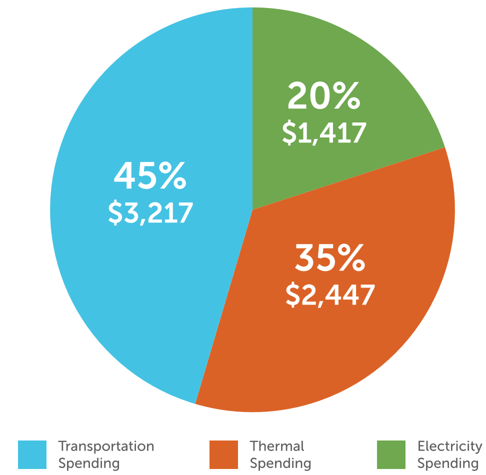
There were 31 towns where median household income increased by over 40% between 2017 and 2021, including Troy, Hancock, Hinesburg, St. George, Irasburg, and Ripton. There were 37 towns that experienced significant declines in median income; these were also dispersed throughout the state and included Underhill, Fairlee, Lowell, and Castleton. There do not appear to be any discernible trends or shared characteristics in terms of which towns experienced significant increases, or decreases, in annual median income. However, in towns where there was a decrease in median income, we generally observed a corresponding increase in energy burden.

[20] Nationally, median household income increased 15.5% between 2017 and 2021 (see American Community Survey Table S1901).

Total Energy Spending & Burden

Total energy spending across towns ranged from more than $8,000 to less than $4,000, meaning that households in the lowest-spending communities spent roughly half as much as those in the highest-spending communities. Consistent with the 2019 report, transportation is the highest cost category, representing nearly half (45%) of annual household spending on energy, followed by thermal (35%), with electricity representing the smallest share (20%).

Figure 2. Statewide household total energy spending by category.



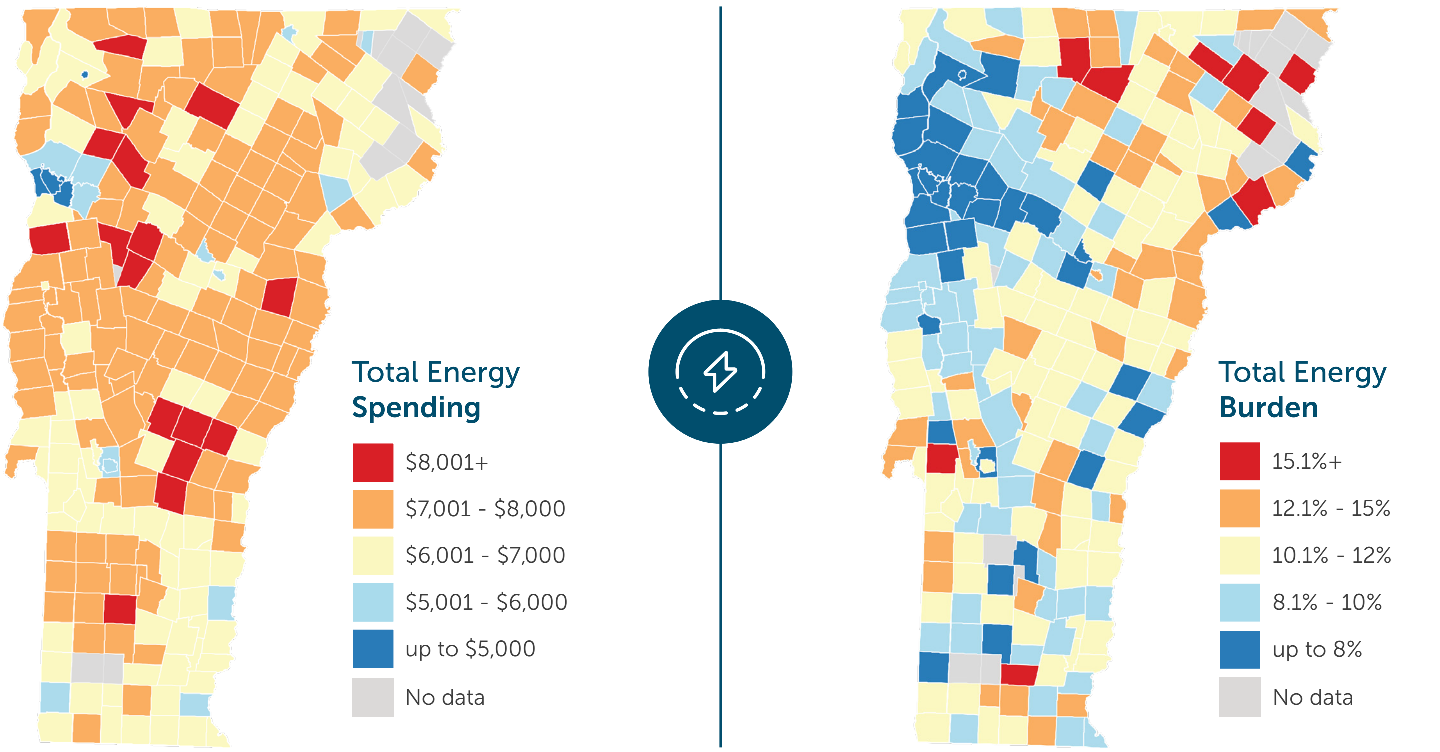
Similar to our previous reports, we observe town-level total energy burden to be highest in the Northeast Kingdom and pockets of southern Vermont, and the lowest in Chittenden County and the greater Champlain Valley region. We attribute this pattern to higher household incomes in the Champlain Valley region, along with access to natural gas (a relatively low-cost heating fuel), and the prevalence of more compact settlement patterns, which reduce vehicle miles traveled and enable access to lower-cost transportation options. The addition of census block group data in this analysis shows that despite energy burdens being lower in the Champlain Valley on a regional basis, there is still significant variation and pockets of high energy burden within Vermont's most populous communities. More than variation in spending, what an analysis by block group reveals is variation in household income, which can vary substantially within a given town. This variation is masked when burden is only examined at the town-level. For instance, Rutland City overall has a moderate total energy burden of 10%. By block group however, that total burden varies from 5.6% in the eastern part of the city to nearly 30% in the western part, and includes three of the most highly burdened block groups that we studied.

Table 2. Ten Highly Burdened Census Block Groups.

Block Group Location (U.S. Census ID#)	Town	Median Household Income	Electricity Burden	Thermal Burden	Transportation Burden	Total Energy Burden
Southeastern Barre City (500239552002)	Barre	$13,550	9.6	16.9	17.5	44.%
Northwestern Rutland City (500219632004)	Rutland	$16,366	6.8	12.9	9.0	29%
Southern St. Johnsbury (500059574002)	St. Johnsbury	$16,602	5.1	13.7	9.4	28%
Central/Southern Manchester (500039704011)	Manchester	$23,636	6.1	11.5	9.3	27%
UVM campus dorms (500070039004)	Burlington	$11,417	5.5	9.9	8.3	24%
Western Windsor (500279660003)	Windsor	$29,018	4.1	8.2	7.0	19%
Central Barre City (500239551004)	Barre	$22,381	3.8	9.3	6.0	19%
Central Springfield (500279666002)	Springfield	$28,750	4.0	7.7	6.3	18%
Western Rutland City (500219633004)	Rutland	$22,454	5.2	8.1	4.5	18%
Southwestern Rutland City (500219633005)	Rutland	$26,708	3.7	6.8	6.1	17%

Census block group analysis isn't necessary for Vermont's smaller communities, since many are comprised of a single block group. Town-level data gives us a good understanding of energy burden in such areas. Again, we find the most burdened communities tend to be in rural areas, like the Northeast Kingdom, and in areas with lower median incomes. Despite the fact that many Northeast Kingdom towns have a high energy burden, we estimate that annual energy usage and spending in these communities is often at or below the statewide average. Household incomes in this region of the state are relatively low, which is the single biggest driver of energy burden. In addition, this region of the state is largely rural, with little or no access to low-cost public transit. Many homes in this region are older[21] and likely cost more to keep warm in the winter, despite a higher prevalence of wood heat, which is typically a more affordable fuel source.

Image 2. Total energy spending and burden by town.



There are nine towns with an estimated total energy burden of greater than 15%, the majority of which are located in the Northeast Kingdom. Only three of these communities (Montgomery, Dover and Castleton) are located outside of the Northeast Kingdom. All of the towns have relatively low populations and are characterized by lower household median income and near average spending on energy.

Only two of these towns (Brighton and Montgomery) were highlighted in our 2019 report, which listed the ten communities with the highest total energy burden. In the case of Montgomery, estimated energy burden has increased significantly (from 15% to 23%), which can be attributed to a decrease in median household income from $41,513 to $30,500. We estimate that in Brighton, total energy burden has held steady at 15%, despite the fact that median household income has increased by approximately 22%. While Granby and Lemington both appeared on the list of highly burdened communities in our 2019 report, we did not estimate energy burden for those towns this year, due to an updated methodology which limited our analysis to communities with 50 or more households in order to control for the significant variability that is inherent in small sample sizes.

[21] https://vtdigger.org/2023/04/09/vermonts-aging-homes-put-extra-strain-on-states-housing-crisis/

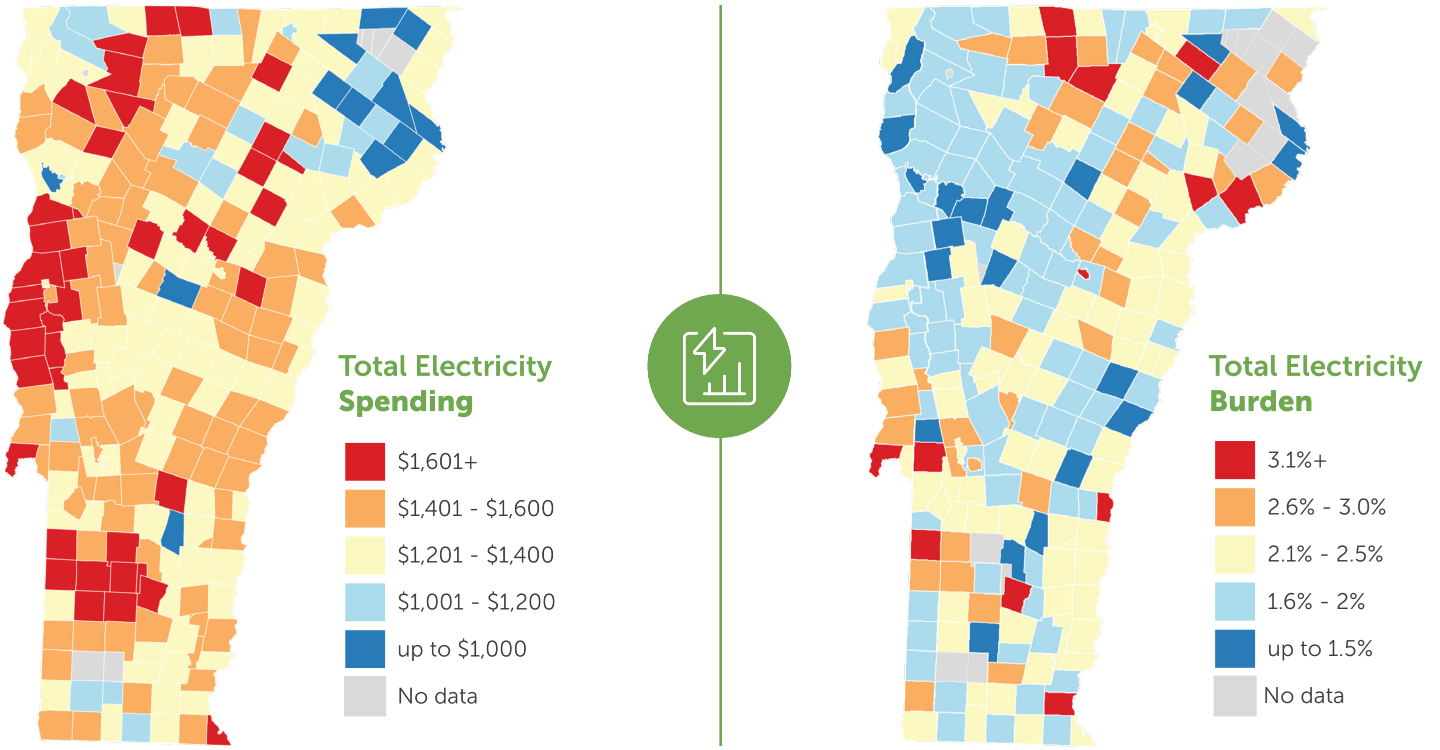
Table 3. Towns with total energy burdens greater than 15%

Town	Total Households	Median Income (2017-21)	Thermal Burden	Electricity Burden	Transportation Burden	Total Energy Burden
Montgomery	522	$30,500	7%	4%	12%	23%
Charleston	441	$37,798	6%	3%	10%	19%
East Haven	132	$36,250	6%	3%	10%	19%
Lowell	326	$42,000	5%	3%	9%	17%
Concord	478	$41,667	5%	3%	8%	16%
Brighton	558	$42,431	5%	3%	8%	16%
Castleton	1,685	$43,257	5%	3%	7%	15%
Dover	570	$45,625	6%	2%	6%	15%
Bloomfield	115	$46,563	5%	3%	8%	15%
Statewide	256,514	$67,674	4%	2%	5%	11%

Electricity: Spending, Burden, & Trends

Consistent with our 2019 report, there is a pattern of relatively high electricity spending along the western side of the state, particularly in Addison County and northern Bennington County.

Image 3. Electricity spending and burden by town.



There is not a stark pattern for the distribution of town-level electricity burden, but generally there is a lower burden in Chittenden County, consistent with our other energy usage categories. There is a pocket of high electricity burden in eastern Franklin and western Orleans Counties, though there are other highly burdened communities distributed throughout the state.

Table 4. Towns with electricity burdens of 3% or greater

Town	Total Households	Median Income (2017-21)	Electricity Spending	Electricity Burden
Montgomery	522	$30,500	$1,342	4%
Pawlet	537	$50,096	$1,715	3%
Lowell	326	$42,000	$1,416	3%
Castleton	1,685	$43,257	$1,405	3%
Charleston	441	$37,798	$1,216	3%
Windsor	1,621	$44,761	$1,374	3%
Richford	958	$52,946	$1,606	3%
St. Johnsbury	3,188	$43,190	$1,309	3%
Brattleboro	5,533	$41,001	$1,240	3%
Barre city	3,880	$44,298	$1,322	3%
Londonderry	792	$55,465	$1,646	3%
Statewide	256,514	$67,674	$1,417	2%

Table 5. Three-year growth in residential electric consumption by county.

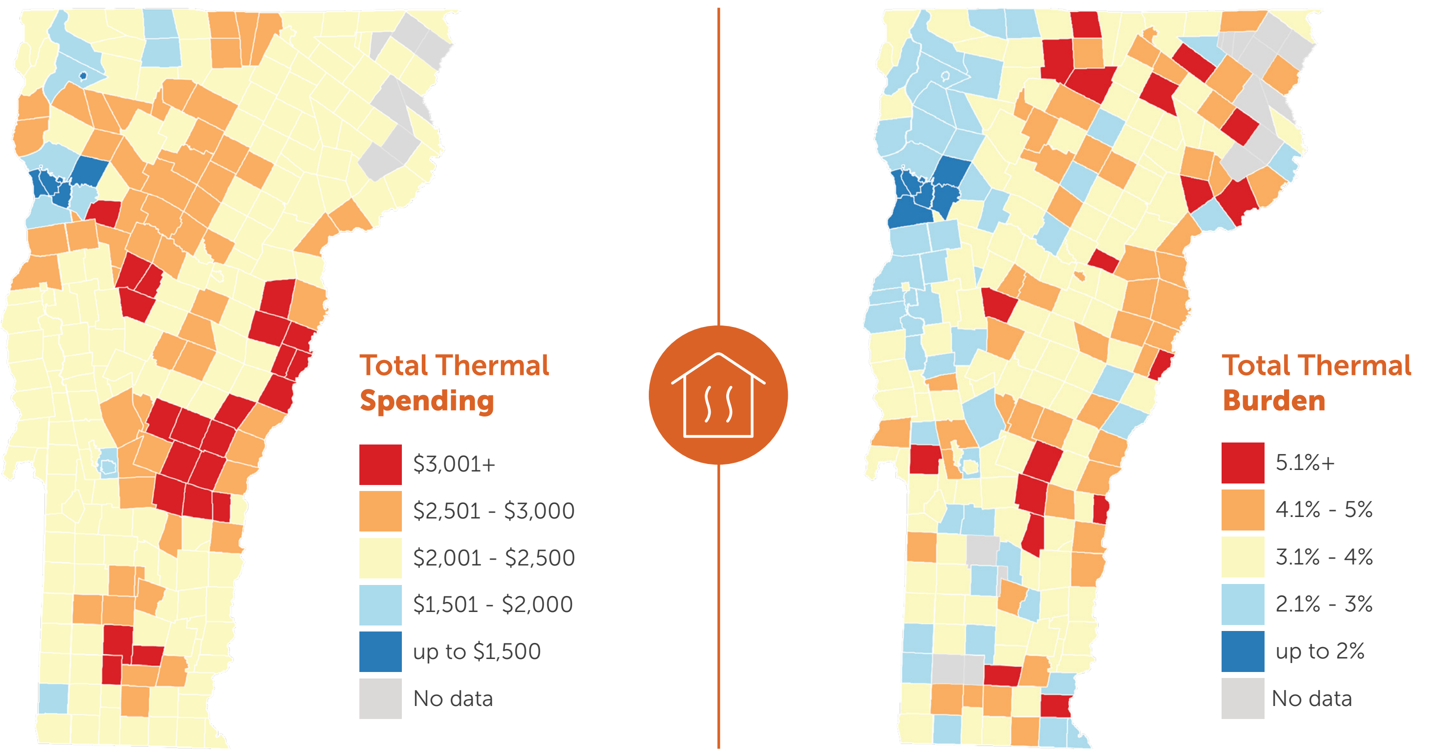
County	Change in annual residential electric usage (2019-21)
Addison	12%
Bennington	8%
Caledonia	10%
Chittenden	11%
Essex	8%
Franklin	7%
Grand Isle	6%
Lamoille	2%
Orange	8%
Orleans	4%
Rutland	7%
Washington	8%
Windham	9%
Windsor	8%

In contrast with our 2019 report, which showed a downward trend in residential electric usage, we observed an increase in every county from 2019-2021. This is generally consistent with national trends that began to emerge during the COVID-19 pandemic, and which may continue as more consumers begin to electrify their heating and transportation, and with a continued higher prevalence of "work from home" jobs.

Thermal: Spending, Burden, & Trends

We estimate that on average Vermont households spend $2,447 on thermal energy annually, which equates to a thermal energy burden of 3.6%. Our analysis indicates that there is a concentration of communities in the Upper Valley region where households are spending more than $3,000 annually on thermal costs. However, as many of these towns are at or above statewide average median income, this does not translate to a high thermal energy burden. Towns with a high thermal burden are generally located in the Northeast Kingdom and along the Green Mountains. There is a notable pattern of low thermal energy burden in the Champlain Valley region in Franklin, Chittenden, and Addison Counties, which we attribute to higher median household incomes, and lower spending on thermal energy, likely due to the accessibility of natural gas, which is a relatively affordable heating fuel.

Image 4. Thermal spending and burden by town.



The towns that were identified as having thermal energy burdens of greater than 5% (our highest thermal energy burden category) are located throughout the state, excluding the Champlain Valley, and all have median incomes below the statewide average. Only three (Fairlee, Bridgewater, and Warren) of 17 have annual thermal spending exceeding $3,000; we do not have sufficient information to speculate on why this is the case.

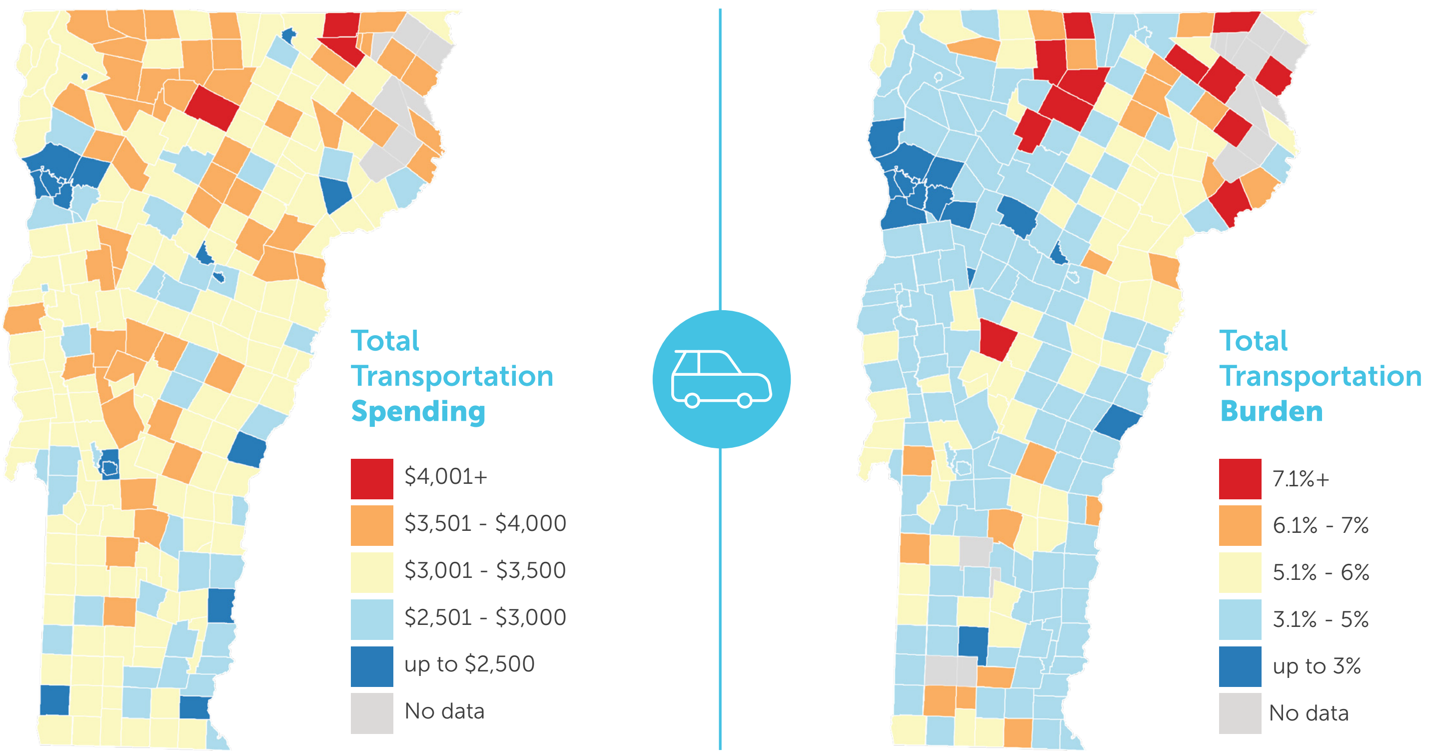
Table 6. Towns with thermal burdens greater than 5%.

Town	Total Households	Median Income (2017-21)	Thermal Spending (est.)	Thermal Burden
Montgomery	522	$30,500	$2,024	7%
Dover	570	$45,625	$2,833	6%
East Haven	132	$36,250	$2,209	6%
Ludlow	822	$46,928	$2,837	6%
Fairlee	516	$53,767	$3,129	6%
Charleston	441	$37,798	$2,170	6%
Brattleboro	5,533	$41,001	$2,265	6%
St. Johnsbury	3,188	$43,190	$2,373	6%
Bridgewater	481	$60,218	$3,210	5%
Concord	478	$41,667	$2,209	5%
Jay	244	$48,750	$2,580	5%
Windsor	1,621	$44,761	$2,367	5%
Plymouth	180	$60,714	$3,210	5%
Castleton	1,685	$43,257	$2,275	5%
Plainfield	534	$47,500	$2,483	5%
Warren	702	$66,136	$3,422	5%
Lowell	326	$42,000	$2,133	5%
Statewide	256,514	$67,674	$2,447	3.6%

Transportation: Spending, Burden, & Trends

Transportation energy burden has remained relatively constant, at 4% statewide, but spending on transportation energy shows more variability than in our 2019 report. This variability appears to have come from declines in vehicle miles traveled (VMT) in denser areas of the state including in South Burlington, Burlington, Winooski, Barre, Rutland, and Newport. We attribute this to changes in travel patterns due to the COVID-19 pandemic.

Image 5. Transportation spending and burden by town.

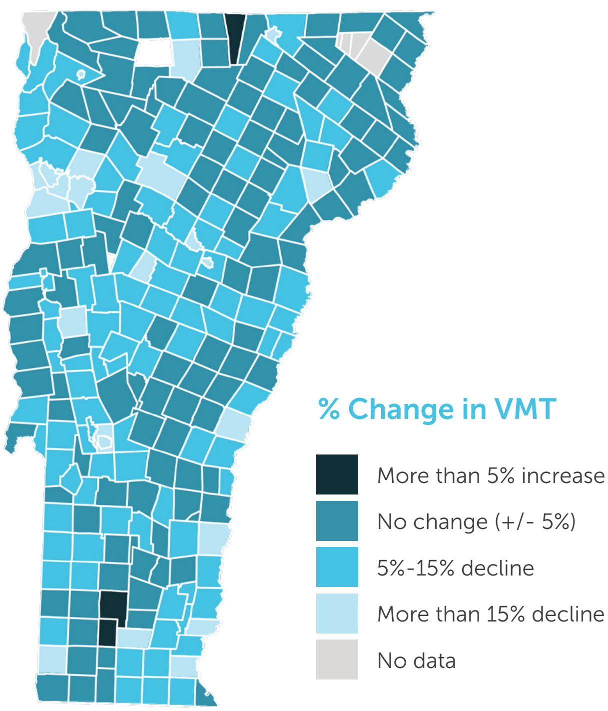


While there are communities throughout the state with relatively high spending on transportation energy, the towns with the highest transportation energy burden are concentrated in the Northeast Kingdom, and adjacent communities in northern Lamoille and eastern Franklin Counties. Granville is the only town in the highest transportation burden category that is not located in these regions. Unsurprisingly, the greater Burlington region is characterized by both low transportation energy spending and burden, being the only area of the state with relatively easy access to public transit and the widespread opportunity for shorter commuting distances as well as easier access to health care and education facilities.

Table 7. Towns with transportation burdens greater than 7%.

Town	Total Households	Median Income (2017-21)	Transportation Spending (est.)	Transportation Burden
Montgomery	522	$30,500	$3,666	12%
Charleston	441	$37,798	$3,822	10%
East Haven	132	$36,250	$3,623	10%
Lowell	326	$42,000	$3,640	9%
Brighton	558	$42,431	$3,640	8%
Bloomfield	115	$46,563	$3,699	8%
Norton	56	$48,000	$3,699	8%
Concord	478	$41,667	$,194	8%
Eden	571	$54,861	$4,196	8%
Granville	156	$51,250	$3,705	7%
Jay	244	$48,750	$3,502	7%
Johnson	1.284	$47,717	$3,347	7%
Statewide	256,514	$67,674	$3,217	4%

Image 6. Changes in Vehicle Miles Traveled (VMT) by town, 2017-2021.



For the majority of Vermont towns, we have seen VMT hold steady or decline over the last five years. However, there were some areas of the state that experienced significant shifts in recent years. Unfortunately, these changes did not help address existing inequities, since we saw the largest declines in VMT in the greater Burlington region, where transportation energy burdens were already the lowest in the state.

Changes in Travel

We saw the largest declines in vehicles miles traveled (VMT) in the greater Burlington region, where transportation energy burdens were already the lowest in the state.

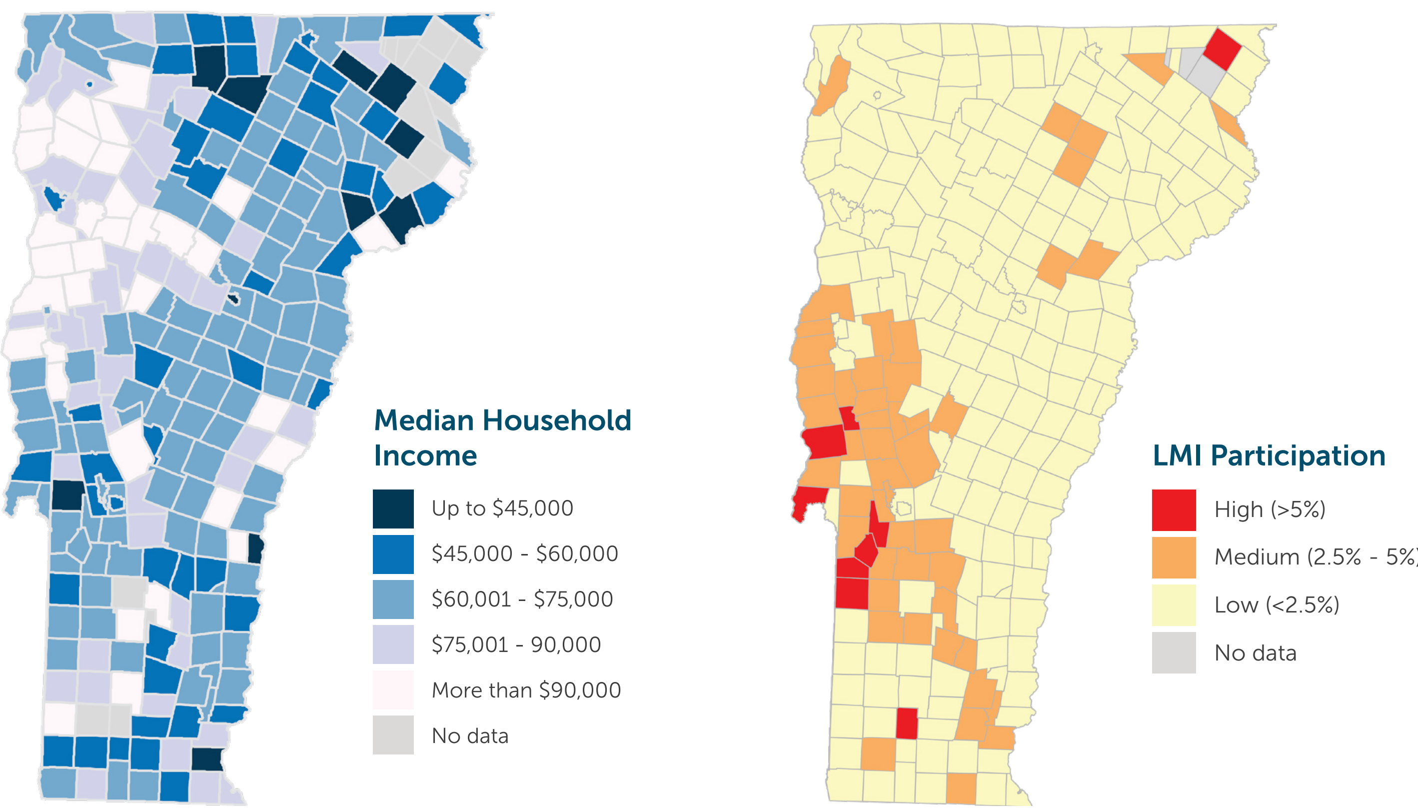
Ultimately energy burden is still a relatively narrow lens for understanding equity in the transportation sector. While residents of Burlington, Winooski, and other communities served by Vermont's public transit system may spend less of their income paying to get from one place to another, they may still invest a significant amount of time in doing so – and their options for employment and recreation may be limited by proximity to transit. In addition, the higher cost of housing in these areas may outstrip their transportation savings.

Discussion

While this analysis can help provide critical context for the work of Vermont's Energy Efficiency Utilities (EEUs),[22] it is important to note that it does not provide household level estimates of energy burden, since the data necessary for that approach is not readily available. Instead, we have generated estimates of energy burden aggregated at the community level. While this is a common practice, the limitation of this approach is that it can falsely lower the average energy burden calculated in communities with more significant income variation, since energy spending does not increase proportionally with income. For this reason, Efficiency Vermont uses energy burden to help guide the focus of our community-level programs and engagement – but when implementing programs specifically designed to alleviate energy burden, we will (where practicable) carry out an additional process to calculate household-level burden and tailor our proposed project recommendations.

Since this analysis does not consider household level energy burden, we have sought to leverage community level data on program uptake in order to understand the extent to which highly energy burdened Vermont residents are accessing programs that might help lower their ongoing costs. Efficiency Vermont does not collect demographic information from customers for most programs – though we do have participation data by income level for low- and moderate-income bonus incentives for cold climate heat pumps and weatherization, which is based on self-verification via a signed attestation.[23]

Image 7. Town-level median income and per-household participation in Efficiency Vermont low- and moderate-income (LMI) bonuses (2017-2021).



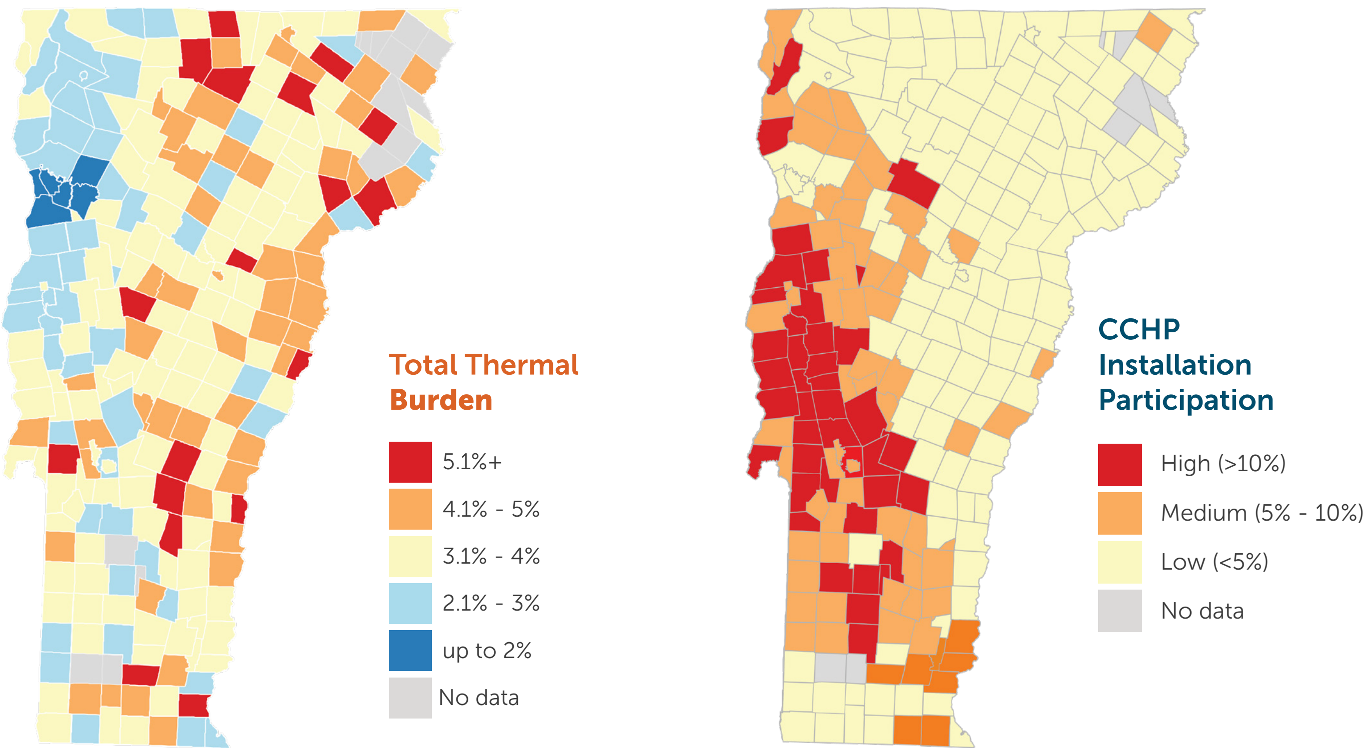
[22] Efficiency Vermont, Burlington Electric Department, and Vermont Gas Systems serve as Energy Efficiency Utilities, under Orders of Appointment from the Vermont Public Utility Commission.

[23] As of 2022, Efficiency Vermont contracts with a financial institution to conduct document-based income verification for the Home Performance with ENERGY STAR® program, in accordance with requirements for administration of American Rescue Plan Act funding.

A comparison of per capita town-level participation data for these bonus incentive programs with town level median income indicates that they may not yet be reaching the customers who could most benefit from energy and cost savings. Where incomes are notably lower in the Northeast Kingdom, participation in low- and moderate-income bonuses is also relatively low. Participation is highest in Rutland and Addison counties.[24]

We were particularly interested to understand whether Vermonters with a high thermal energy burden have been able to access heating technologies that could help alleviate it, such as cold climate heat pumps. A comparison of thermal energy burden against the per capita uptake[25] of this technology at the town level indicates that there is a much higher prevalence of heat pumps in communities with a relatively low energy burden – with more than 20% of homes in some Champlain Valley towns having installed this technology.[26] Installations of heat pumps appear to be much lower in the Northeast Kingdom and high-burden communities.

Image 8. Thermal energy burden by town and per capita installations of cold climate heat pumps by town (2017-2021).



As we did in our 2019 report, we looked at which towns in Vermont had the highest per capita adoption of several clean energy technologies, and found an even starker pattern, with only two communities in our high and highest energy burden categories appearing on the lists. This provides another indication that the Vermonters who could most benefit from the energy and cost savings of these technologies are not currently accessing them, presumably as a result of the high upfront investment they require.

[24] We estimate overall rates of participation in our LMI programs to be over 3% of the general population and even 5% in many communities. A 2017 review by ACEEE noted that the median rate of participation among eligible customers (not the general population) in electric utility EE programs nationally was 1% (see 'Making a Difference: Strategies for Successful Low-Income Energy Efficiency Programs' https://www.aceee.org/research-report/u1713)

[25] Efficiency Vermont has comprehensive sales and installation data for heat pump technologies through management of a statewide point-of-sale rebate program, in partnership with Vermont's electric utilities.

[26] Installation data does not indicate how customers are using cold climate heat pumps – whether as a primary or secondary heating source, or primarily as an air conditioner. Efficiency Vermont generally recommends that customers maintain a supplemental heat source even after installing a cold climate heat pump.

Table 8. Top ten towns by per capita adoption of clean energy technology (2021).[27]

Rank	Cold Climate Heat Pumps & Thermal Burden	Electric Vehicles & Transportation Burden	Weatherized Homes & Thermal Burden
1	Stratton	Charlotte	Winhall
2	Winhall	Norwich	Dover
3	Mendon	Strafford	Landgrove*
4	Ripton	Montpelier	Shrewsbury
5	Killington	Cornwall	Stratton
6	Peru	Plainfield	Mount Holly
7	Cornwall	Shelburne	Jamaica
8	St. George	Waitsfield	Peru
9	Sudbury	Huntington	Averill*
10	Orwell	Thetford	Dorset

*Energy burden was not calculated for communities with fewer than 50 households, or where median income data was not available.

Burden category:

Highest	High	Moderate	Low	Lowest

We anticipate that the next iteration of this analysis will need to be significantly adapted to account for the increasing electrification of thermal and transportation energy. This trend is aligned with Vermont's climate goals because our state's electric sector produces very little greenhouse gas emissions. It is also the sector for which household level usage data is most readily available – however, it is not possible, as of yet, to disaggregate this data and understand what end uses are being electrified in a given home. We cannot, therefore, have a complete understanding of the extent to which an individual household is reducing its energy burden. This is significant because electrification will not always lead to reductions in energy burden; for example, if a customer installs a heat pump but uses it primarily for air conditioning in summer (increasingly a necessity as our climate continues to warm) and does not leverage it to offset higher cost fossil fuels in the winter, they will see an increase in their annual energy costs. And, importantly, any heating or air conditioning system installed in a home that is not weatherized will lead to higher costs.

Conclusion

How might we help alleviate energy burden for Vermont's most vulnerable residents? There are a range of programs from utilities and state agencies that lower the upfront cost of technologies with the potential to reduce energy burden, from cold climate heat pumps, to weatherization, to electric vehicles. Vermont's EEUs lead and partner on a number of these programs and have historically maintained minimum spending requirements for programs that serve income-eligible residents as their primary approach to addressing energy burden. It is easy to measure progress against such spending goals, but there is an ongoing national conversation about whether they are the most effective way to advance equity in the energy sector.[28]

[27] Sources: Energy Action Network Vermont Energy Dashboard: www.vtenergydashboard.org, and Drive Electric Vermont EV registration data.

[28] https://energyequityproject.com/wp-content/uploads/2022/08/220174_EEP_Report_8302022.pdf

Low-income spending requirements have increased over time, and are generally a major component of EEU services, though the majority of savings achieved from EEU programs continues to be generated by lower-cost savings through market-generated projects. As an example, within Efficiency Vermont's current programs, a project to install pipe insulation for a large business customer might cost $10 per unit of energy saved, while helping a moderate-income customer complete a home weatherization project can cost in excess of $300 per unit of energy saved. It is quite common to see cost disparities between residential and business projects, since homes generally use much less energy than businesses, so the impact of any single efficiency project is much smaller. These same disparities often also exist between small and large business customers, with much greater savings opportunities present in large energy-intensive facilities.

Equity & Cost

Within Efficiency Vermont's current programs, a project to install pipe insulation for a large business customer might cost $10 per unit of energy saved, while helping a moderate-income customer complete a home weatherization project can cost more than $300 per unit of energy saved.

However, the relative impact of energy savings – and their attendant cost reduction – may be more significant in relieving energy burden for the customer whose home has been weatherized, or for the corner store that upgrades its refrigeration, than for a large business. In addition to energy cost savings, the residential customer likely will experience the benefits of a home that is more resilient to a changing climate, holding heat for longer in the winter and maintaining cooler temperatures in the summer. Many customers who weatherize their homes also experience other health and safety benefits including a reduction in pests, improved indoor air quality, noise reduction, and greater comfort throughout the year. A corner store with new refrigerators may be better able to meet the needs of its community, see savings from reduced food spoilage, and create a better working environment for employees in addition to the electric bill savings its owners experience.

Low- and moderate-income customers, renters (both residential and commercial), rural, Black, Indigenous, and people of color (BIPOC) and many others face higher barriers in completing clean energy projects.[29] Beyond a lack of access to upfront capital, which is often the case for low- and moderate-income residents, they may lack the authority to make decisions about the features and quality of their home or business (in the case of renters); they may have been forced to live far from their place of work due to a lack of access to affordable housing (residents of rural communities); or they may have been historically denied access to homeownership and capital, which severely limits the ability to build generational wealth (BIPOC Vermonters). Finding solutions to these challenges takes sustained commitment, significant resources, and time – and is critical to do, because the Vermonters who will most feel the effects of our changing climate in the coming years will often be those who cannot access clean energy technologies.

Ultimately, these considerations of equity, cost to generate energy savings, and the metrics we use to measure the success of energy-saving programs have an impact on who these programs serve – and how we serve them – every day. We hope this report will serve as a resource for Vermont policymakers as they continue seeking the appropriate balance between greenhouse gas reductions, cost savings, and accessibility in our rapidly-evolving energy system.

[29] https://www.aceee.org/energy-burden

Appendix A

Reducing Energy Burden

The table below provides an estimate of how various measures and projects would impact energy burden for a household of median income, living in a baseline Vermont home.[30]

Category	Action	Annual $ Savings	Lifetime $ Savings	Reduction in Total Annual Energy Burden
Low-Cost Measures	Replace a standard programmable thermostat with a smart thermostat	$158	$1,577	2.2%
	Replace a standard showerhead with a low flow showerhead	$72	$646	1.0%
	Replace a standard high flow faucet aerator with a low flow faucet aerator	$18	$158	0.2%
	Replace an incandescent light bulb with an LED	$11	$166	0.2%
Appliances	Replace an oil water heater with a heat pump water heater	$449	$5,832	4.3%
	Replace a standard electric water heater with a heat pump water heater	$299	$3,884	4.2%
	Replace a pre-1993 refrigerator with a high efficiency refrigerator[31]	$138	$2,343	1.9%
	Replace a 1993-2001 refrigerator with a high efficiency refrigerator	$49	$840	0.7%
	Replace a standard dehumidifier with an ENERGY STAR dehumidifier	$46	$550	0.6%
	Replace an inefficient fossil fuel furnace/boiler with a high efficiency fossil fuel furnace/boiler	$190	$4,268	2.7%
Comprehensive Weatherization	Comprehensive weatherization (including air sealing, whole building insulation, window improvements, and attic/ceiling/wall insulation).	$467	$11,680	6.6%
Ductless Heat Pumps	Install a single zone heat pump in a home heated by fossil fuels	$215	$3,223	3.0%
	Install a multi zone heat pump in a home heated by fossil fuels	$560	$8,402	7.9%
Electric and Plug-in Hybrid Vehicles	Change from a fossil fuel powered vehicle to a new all electric vehicle	$835	$6,683	11.8%
	Change from a fossil fuel powered vehicle to a used all electric vehicle	$835	$3,341	11.8%
	Change from a fossil fuel powered vehicle to a new plug-in hybrid electric vehicle	$695	$5,559	9.8%
	Change from a fossil fuel powered vehicle to a used plug-in hybrid electric vehicle	$695	$2,780	9.8%

[30] Assumptions are derived from the Efficiency Vermont and Renewable Energy Standard Technical Reference Manuals. MMBtu cost savings are calculated using fuel oil as the existing fuel. It is assumed that each measure is installed on its own, and rather than in combination with other measures, which is the most common practice for customers, particularly with higher cost projects.
[31] Consortium for Energy Efficiency (CEE) Tier 2

Appendix B

Energy Burden by Town[32]

Town	Total # of Households	Median Household Income	Thermal	Electricity	Transportation	Total Energy	Total Energy Burden Bin
Addison	546	$93,438	3%	2%	4%	8.4%	Low
Albany	400	$60,938	3%	2%	5%	11.0%	Moderate
Alburgh	764	$63,462	4%	2%	5%	11.4%	Moderate
Andover	193	$75,139	3%	2%	4%	9.3%	Low
Arlington	1,045	$75,750	3%	2%	3%	8.3%	Low
Athens	181	$67,656	3%	2%	5%	10.1%	Moderate
Bakersfield	605	$80,223	3%	2%	5%	9.6%	Low
Baltimore	128	$69,545	3%	2%	5%	10.0%	Low
Barnard	472	$73,621	4%	2%	5%	11.0%	Moderate
Barnet	574	$55,000	5%	2%	6%	12.4%	High
Barre	3,492	$74,977	3%	2%	4%	9.0%	Low
Barre city	3,880	$44,298	5%	3%	4%	12.2%	High
Barton	1,215	$47,841	5%	3%	7%	14.2%	High
Belvidere	179	$80,547	3%	2%	4%	9.3%	Low
Bennington	5,931	$51,851	4%	3%	4%	10.8%	Moderate
Benson	337	$54,766	4%	3%	6%	12.6%	High
Berkshire	499	$71,806	3%	2%	5%	10.5%	Moderate
Berlin	1,100	$80,789	3%	2%	3%	7.9%	Lowest
Bethel	817	$65,768	4%	2%	4%	10.3%	Moderate
Bloomfield	115	$46,563	4%	3%	8%	15.1%	Highest
Bolton	440	$100,208	3%	1%	3%	7.6%	Lowest
Bradford	1,194	$66,100	5%	2%	4%	11.1%	Moderate
Braintree	435	$66,319	4%	2%	6%	11.4%	Moderate
Brandon	1,721	$61,653	3%	2%	5%	10.7%	Moderate
Brattleboro	5,533	$41,001	6%	3%	5%	13.5%	High
Bridgewater	481	$60,218	5%	2%	6%	13.9%	High
Bridport	499	$65,156	4%	3%	5%	11.5%	Moderate
Brighton	558	$42,431	5%	3%	8%	15.5%	Highest
Bristol	1,624	$77,500	3%	2%	4%	9.1%	Low
Brookfield	615	$67,212	4%	2%	5%	10.7%	Moderate
Brookline	197	$65,139	3%	2%	5%	10.4%	Moderate
Brownington	388	$53,690	4%	3%	6%	13.4%	High
Buels Gore	60	$125,833	2%	-	3%	-	
Burke	546	$62,857	4%	2%	5%	10.4%	Moderate
Burlington	17,174	$59,331	2%	1%	3%	5.9%	Lowest

[32] As noted in the Methodology section of this report towns with less than 50 households, and those for which median income data was not available have not been included in his analysis. Towns with less than 50 households are Avery's Gore, Averill, Brunswick, Ferdinand, Glastenbury, Granby, Lemington, Lewis, Somerset, Victory, Warner's grant, Warren's gore. Towns for which income data is not available are Mount Tabor and Landgrove.

Town	Total # of Households	Median Household Income	Thermal	Electricity	Transportation	Total Energy	Total Energy Burden Bin
Cabot	630	$62,671	4%	3%	5%	11.7%	Moderate
Calais	707	$76,875	3%	2%	4%	9.5%	Low
Cambridge	1,376	$78,816	3%	2%	4%	9.3%	Low
Canaan	367	$52,560	4%	2%	6%	12.1%	High
Castleton	1,685	$43,257	5%	3%	7%	15.2%	Highest
Cavendish	469	$59,485	4%	2%	6%	11.6%	Moderate
Charleston	441	$37,798	6%	3%	10%	19.1%	Highest
Charlotte	1,717	$111,535	3%	2%	3%	7.3%	Lowest
Chelsea	509	$59,821	4%	3%	6%	12.3%	High
Chester	1,268	$61,397	4%	2%	5%	10.8%	Moderate
Chittenden	527	$90,313	3%	2%	4%	8.3%	Low
Clarendon	944	$61,974	4%	2%	5%	11.4%	Moderate
Colchester	6,868	$83,869	2%	2%	3%	6.6%	Lowest
Concord	478	$41,667	5%	3%	8%	15.9%	Highest
Corinth	683	$67,434	4%	2%	5%	11.7%	Moderate
Cornwall	436	$90,417	3%	2%	4%	8.2%	Low
Coventry	428	$51,827	4%	3%	6%	13.0%	High
Craftsbury	419	$72,670	3%	2%	4%	8.9%	Low
Danby	447	$60,739	4%	3%	6%	11.8%	Moderate
Danville	981	$62,617	4%	2%	5%	11.3%	Moderate
Derby	2,036	$64,096	4%	2%	5%	10.4%	Moderate
Dorset	848	$68,333	4%	3%	5%	11.0%	Moderate
Dover	570	$45,625	6%	3%	6%	15.2%	Highest
Dummerston	890	$85,357	3%	2%	3%	8.1%	Low
Duxbury	583	$79,276	4%	2%	4%	10.1%	Moderate
East Haven	132	$36,250	6%	3%	10%	18.9%	Highest
East Montpelier	1,098	$70,119	4%	3%	4%	10.6%	Moderate
Eden	571	$54,861	5%	3%	8%	14.8%	High
Elmore	464	$96,364	3%	1%	4%	7.6%	Lowest
Enosburgh	999	$59,856	3%	3%	5%	11.3%	Moderate
Essex	9,315	$88,136	2%	2%	3%	5.9%	Lowest
Fair Haven	989	$64,618	4%	2%	4%	10.4%	Moderate
Fairfax	1,967	$92,536	3%	2%	4%	8.3%	Low
Fairfield	697	$98,942	2%	2%	4%	7.9%	Lowest
Fairlee	516	$53,767	6%	2%	6%	14.1%	High
Fayston	383	$109,432	4%	1%	3%	8.3%	Low
Ferrisburgh	1,117	$95,625	3%	2%	4%	8.3%	Low
Fletcher	481	$80,625	3%	2%	5%	10.2%	Moderate
Franklin	519	$83,229	3%	2%	5%	9.1%	Low
Georgia	1,728	$91,456	3%	2%	4%	8.6%	Low
Glover	393	$61,806	4%	2%	6%	11.8%	Moderate
Goshen	79	$75,750	3%	2%	5%	9.5%	Low
Grafton	249	$68,125	3%	2%	5%	10.0%	Low

Town	Total # of Households	Median Household Income	Thermal	Electricity	Transportation	Total Energy	Total Energy Burden Bin
Grand Isle	867	$97,361	3%	2%	3%	7.7%	Lowest
Granville	156	$51,250	5%	3%	7%	14.3%	High
Greensboro	323	$57,917	4%	3%	5%	12.2%	High
Groton	435	$61,458	4%	2%	6%	12.3%	High
Guildhall	144	$103,333	2%	1%	4%	7.0%	Lowest
Guilford	959	$77,431	3%	2%	4%	8.9%	Low
Halifax	290	$50,357	5%	2%	6%	13.7%	High
Hancock	234	$64,449	4%	2%	6%	11.5%	Moderate
Hardwick	1,224	$61,116	4%	3%	5%	12.0%	Moderate
Hartford	4,765	$61,678	5%	2%	4%	10.8%	Moderate
Hartland	1,501	$66,356	4%	2%	5%	11.1%	Moderate
Highgate	1,313	$64,974	4%	2%	5%	11.1%	Moderate
Hinesburg	2,024	$103,750	3%	1%	3%	7.4%	Lowest
Holland	256	$65,536	3%	2%	6%	11.4%	Moderate
Hubbardton	288	$89,167	3%	1%	4%	7.4%	Lowest
Huntington	728	$82,118	3%	2%	4%	9.8%	Low
Hyde Park	1,241	$69,323	4%	2%	5%	10.8%	Moderate
Ira	143	$62,679	3%	2%	6%	11.1%	Moderate
Irasburg	469	$65,781	3%	2%	5%	10.5%	Moderate
Isle La Motte	213	$60,417	4%	2%	6%	11.6%	Moderate
Jamaica	418	$57,800	4%	2%	5%	11.8%	Moderate
Jay	244	$48,750	5%	2%	7%	14.7%	High
Jericho	2,084	$96,442	2%	2%	3%	7.4%	Lowest
Johnson	1,284	$47,717	5%	3%	7%	14.3%	High
Killington	364	$68,333	4%	2%	4%	10.2%	Moderate
Kirby	283	$51,250	4%	3%	7%	13.5%	High
Leicester	452	$55,357	4%	2%	6%	12.8%	High
Lincoln	553	$66,985	4%	2%	5%	10.8%	Moderate
Londonderry	792	$55,465	5%	3%	5%	13.3%	High
Lowell	326	$42,000	5%	3%	9%	17.1%	Highest
Ludlow	822	$46,928	6%	1%	6%	13.2%	High
Lunenburg	573	$45,792	5%	3%	6%	13.5%	High
Lyndon	2,227	$53,536	4%	2%	5%	11.5%	Moderate
Maidstone	108	$65,500	3%	1%	6%	10.3%	Moderate
Manchester	1,956	$81,885	3%	2%	4%	9.0%	Low
Marlboro	365	$80,250	3%	2%	4%	8.6%	Low
Marshfield	653	$62,131	4%	2%	6%	11.9%	Moderate
Mendon	399	$82,417	3%	2%	4%	9.1%	Low
Middle Springs	283	$63,558	3%	2%	5%	10.6%	Moderate
Middlebury	2,875	$68,239	4%	2%	4%	9.3%	Low
Middlesex	714	$96,250	3%	2%	4%	8.2%	Low
Milton	3,997	$97,813	2%	2%	3%	6.8%	Lowest
Monkton	752	$112,500	2%	1%	3%	6.7%	Lowest
Montgomery	522	$30,500	7%	4%	12%	23.1%	Highest

Town	Total # of Households	Median Household Income	Thermal	Electricity	Transportation	Total Energy	Total Energy Burden Bin
Montpelier city	3,939	$71,163	3%	2%	3%	7.9%	Lowest
More	696	$87,109	3%	2%	4%	8.7%	Low
Morgan	352	$78,611	3%	1%	5%	9.1%	Low
Morris	2,429	$58,621	5%	2%	5%	11.4%	Moderate
Mount Holly	565	$59,395	4%	2%	6%	11.8%	Moderate
New Haven	746	$84,375	3%	2%	4%	9.0%	Low
Newark	240	$51,667	5%	2%	7%	13.1%	High
Newbury	880	$60,867	5%	2%	6%	12.5%	High
Newfane	826	$59,792	4%	2%	5%	11.5%	Moderate
Newport	681	$68,616	4%	2%	5%	10.4%	Moderate
Newport City	1,910	$52,283	4%	2%	4%	10.3%	Moderate
North Hero	528	$84,375	3%	1%	4%	8.1%	Low
Northfield	1,873	$60,819	4%	2%	5%	10.3%	Moderate
Norton	56	$48,000	4%	2%	8%	14.0%	High
Norwich	1,273	$121,509	2%	1%	2%	5.9%	Lowest
Orange	392	$63,021	4%	3%	5%	12.0%	Moderate
Orwell	416	$63,333	4%	3%	5%	11.6%	Moderate
Panton	266	$83,594	3%	2%	4%	9.5%	Low
Pawlet	537	$50,096	5%	3%	6%	14.7%	High
Peacham	358	$68,571	4%	2%	6%	11.0%	Moderate
Peru	172	$108,182	3%	2%	3%	7.2%	Lowest
Pittsfield	236	$58,382	4%	3%	6%	12.4%	High
Pittsford	1,205	$58,118	4%	3%	6%	12.2%	High
Plainfield	534	$47,500	5%	3%	7%	14.3%	High
Plymouth	180	$60,714	5%	3%	5%	13.3%	High
Pomfret	383	$86,250	4%	2%	4%	9.5%	Low
Poultney	1,039	$60,750	4%	2%	5%	10.8%	Moderate
Pownal	1,224	$63,654	3%	2%	5%	10.8%	Moderate
Proctor	671	$66,635	3%	2%	4%	9.8%	Low
Putney	856	$57,500	4%	2%	5%	11.0%	Moderate
Randolph	1,946	$70,000	4%	2%	4%	10.0%	Low
Reading	230	$66,500	5%	2%	5%	11.7%	Moderate
Readsboro	300	$60,833	4%	2%	5%	11.3%	Moderate
Richford	958	$52,946	4%	3%	6%	13.2%	High
Richmond	1,833	$105,625	3%	1%	3%	7.5%	Lowest
Ripton	243	$88,393	3%	2%	4%	8.3%	Low
Rochester	684	$62,941	4%	2%	6%	11.5%	Moderate
Rockingham	2,161	$61,514	4%	2%	4%	9.7%	Low
Roxbury	429	$66,250	4%	2%	5%	10.8%	Moderate
Royalton	1,054	$67,000	4%	2%	4%	9.9%	Low
Rupert	282	$61,471	4%	3%	6%	12.1%	High
Rutland	1,646	$74,107	3%	2%	3%	7.8%	Lowest
Rutland City	7,536	$51,868	4%	3%	4%	10.0%	Low

Town	Total # of Households	Median Household Income	Thermal	Electricity	Transportation	Total Energy	Total Energy Burden Bin
Ryegate	464	$60,833	4%	2%	6%	12.4%	High
Salisbury	462	$87,083	3%	2%	4%	8.7%	Low
Sandgate	212	$63,032	4%	2%	6%	11.3%	Moderate
Searsburg	52	$52,500	4%	2%	7%	13.3%	High
Shaftsbury	1,248	$91,198	2%	2%	4%	7.6%	Lowest
Sharon	580	$76,293	4%	2%	4%	10.2%	Moderate
Sheffield	270	$70,000	3%	2%	5%	10.4%	Moderate
Shelburne	3,180	$104,796	2%	2%	3%	5.9%	Lowest
Sheldon	851	$64,602	4%	3%	6%	12.5%	High
Shoreham	499	$73,393	3%	2%	5%	10.2%	Moderate
Shrewsbury	474	$81,136	3%	2%	4%	9.3%	Low
South Burlington	8,727	$83,750	1%	2%	2%	5.1%	Lowest
South Hero	553	$107,750	3%	1%	3%	7.0%	Lowest
Springfield	3,955	$57,160	4%	2%	5%	11.1%	Moderate
St. Albans	2,647	$82,913	2%	2%	4%	7.5%	Lowest
St. Albans City	2,747	$49,063	3%	0%	5%	7.4%	Lowest
St. George	254	$88,750	3%	2%	3%	8.6%	Low
St. Johnsbury	3,188	$43,190	5%	3%	5%	13.7%	High
Stamford	365	$78,250	3%	2%	4%	9.1%	Low
Stannard	91	$60,795	4%	3%	6%	12.3%	High
Starksboro	701	$77,188	3%	2%	5%	10.0%	Low
Stockbridge	332	$71,250	4%	2%	5%	11.4%	Moderate
Stowe	2,401	$74,065	4%	2%	4%	9.7%	Low
Strafford	554	$98,083	3%	1%	3%	7.3%	Lowest
Stratton	118	$107,500	3%	1%	3%	7.0%	Lowest
Sudbury	219	$72,375	3%	2%	5%	9.7%	Low
Sunderland	379	$75,673	3%	2%	5%	9.7%	Low
Sutton	385	$61,406	4%	2%	6%	11.7%	Moderate
Swanton	2,540	$68,294	3%	2%	5%	9.3%	Low
Thetford	1,198	$81,750	4%	2%	4%	9.7%	Low
Tinmouth	320	$68,750	3%	2%	5%	9.7%	Low
Townshend	641	$73,068	3%	2%	4%	8.7%	Low
Topsham	415	$67,557	4%	2%	5%	12.0%	Moderate
Troy	637	$78,490	3%	2%	4%	9.2%	Low
Tunbridge	538	$68,929	4%	2%	5%	10.6%	Moderate
Underhill	1,285	$87,227	3%	2%	4%	9.3%	Low
Vergennes	1,101	$65,750	4%	2%	4%	9.7%	Low
Vernon	876	$78,393	3%	2%	4%	8.8%	Low
Vershire	350	$62,333	4%	2%	6%	11.9%	Moderate
Waitsfield	878	$72,692	5%	2%	4%	10.9%	Moderate
Walden	437	$67,768	3%	2%	5%	10.7%	Moderate
Wallingford	779	$72,689	3%	2%	4%	9.2%	Low
Waltham	191	$85,208	3%	2%	4%	8.8%	Low

Town	Total # of Households	Median Household Income	Thermal	Electricity	Transportation	Total Energy	Total Energy Burden Bin
Wardsboro	336	$78,500	4%	2%	4%	9.6%	Low
Warren	702	$66,136	5%	2%	5%	11.9%	Moderate
Washington	489	$63,417	4%	2%	5%	11.5%	Moderate
Waterbury	2,104	$92,231	3%	2%	3%	7.5%	Lowest
Waterford	518	$96,136	3%	2%	4%	7.7%	Lowest
Waterville	183	$61,250	4%	2%	6%	12.3%	High
Weathersfield	1,101	$67,236	4%	2%	5%	11.0%	Moderate
Wells	386	$66,364	3%	2%	5%	10.0%	Low
West Fairlee	320	$69,821	4%	2%	5%	11.1%	Moderate
West Haven	115	$61,607	4%	3%	5%	12.1%	High
West Rutland	1,016	$50,909	4%	3%	6%	12.9%	High
West Windsor	470	$94,300	3%	2%	3%	8.3%	Low
Westfield	252	$54,375	5%	3%	6%	13.7%	High
Westford	842	$99,464	3%	2%	4%	8.2%	Low
Westminster	1,210	$64,297	4%	2%	4%	10.4%	Moderate
Westmore	168	$70,333	3%	1%	5%	9.3%	Low
Weston	288	$110,000	2%	1%	3%	6.4%	Lowest
Weybridge	310	$100,185	2%	2%	3%	7.4%	Lowest
Wheelock	304	$62,308	4%	2%	6%	11.2%	Moderate
Whiting	210	$68,125	3%	3%	5%	11.2%	Moderate
Whitingham	560	$62,167	4%	2%	5%	10.8%	Moderate
Williams	1,349	$70,813	4%	2%	5%	10.7%	Moderate
Williston	4,114	$99,071	2%	1%	3%	5.6%	Lowest
Wilmington	873	$59,821	5%	2%	5%	12.1%	High
Windham	184	$78,750	3%	2%	4%	8.5%	Low
Windsor	1,621	$44,761	5%	3%	6%	14.4%	High
Winhall	272	$69,375	4%	3%	5%	11.8%	Moderate
Winooski city	3,504	$61,033	2%	2%	3%	6.5%	Lowest
Wolcott	702	$62,931	4%	2%	6%	12.0%	Moderate

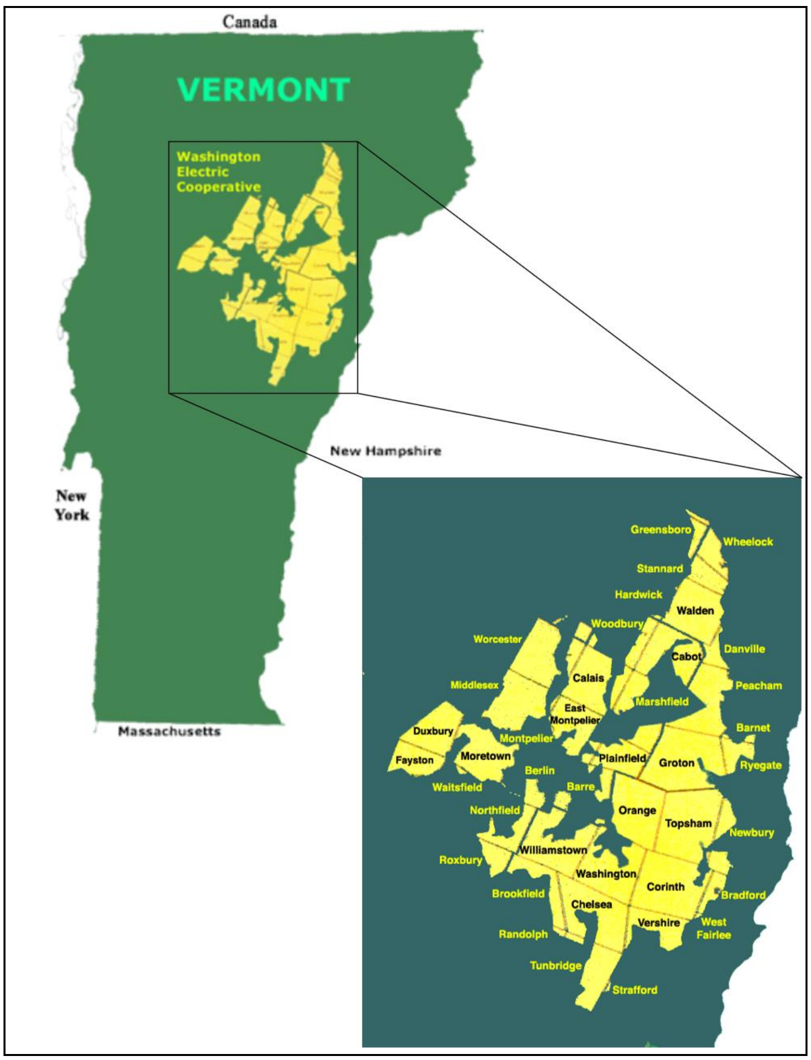
WASHINGTON ELECTRIC COOPERATIVE, INC.

2023 SYSTEM RELIABILITY REPORT

Table of Contents

1. Background

Washington Electric Cooperative served an average of 11,527 members in 2023 via an electrical distribution system that includes 26 miles of WEC-owned transmission line and 1,266 miles of distribution line. The system includes eight distribution substations, seven of which depend on third-party transmission provider Green Mountain Power for service. The remaining substation is served via a WEC owned transmission line interconnected to Vermont Electric Power Company's (VELCO) high voltage substation in Chelsea, VT. WEC's distribution lines are located throughout 41 towns in Central Vermont, covering approximately 2,728 square miles and serve remote locations composed of rural homes, small farms and small businesses. There are approximately 8 service locations per mile of line, many of which are located on unpaved roads in small valleys within the 41 towns.

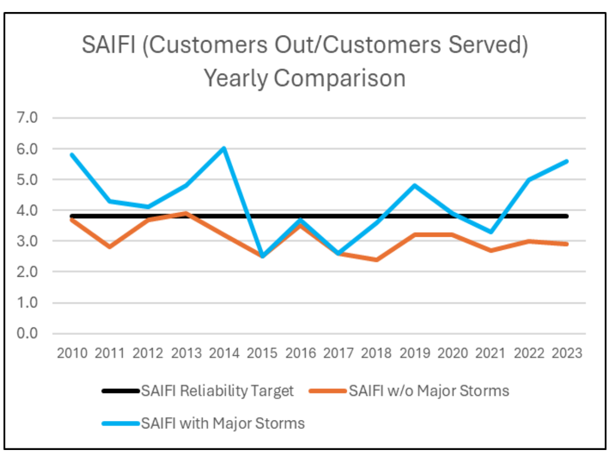


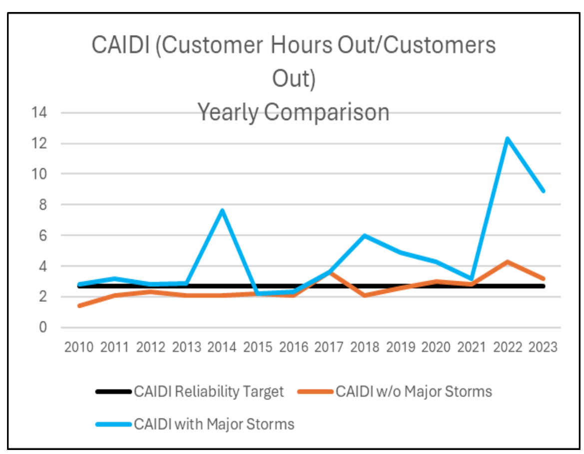
The distribution system was constructed during a time when much of the land in Vermont was open fields and pasture that has since grown in. Vermont lies within a biological transition zone between the northern boreal forest to the southern deciduous forests. The northern hardwood mix of beech, birch, and maple dominates Vermont's forests, accounting for 71% of the forest cover. The remote location of the lines and abundance of fast-growing species such as red maple, poplar and white birch coupled with severe weather events, significantly increases the exposure of the lines to tree-related outages which can only be combated through hardening of the lines and increased maintenance clearing.

WEC records data associated with all power outages occurring over the calendar year and provides a year end Service Reliability Report to the Vermont Public Utilities Commission as required by Rule 4.900. To compare trends more effectively in WEC's reliability performance and associated efforts to make improvements in those performance areas, this report generally excludes those outages associated with severe weather events determined to be "Major Storms" as defined in WEC's Successor Service Quality and Reliability Performance Plan. However, a distinctive increase in frequency and severity of these weather events is significantly contributing to a decline in service reliability across most of WEC's service territory and therefore must be taken into consideration when analyzing service reliability and planning for improvements. While it is true that severe weather events do create conditions that exceed the design capability of the electrical delivery system, it remains obvious that design criteria and maintenance schedules must be improved to counteract the increased severity of these events.

2. Reliability Summary:

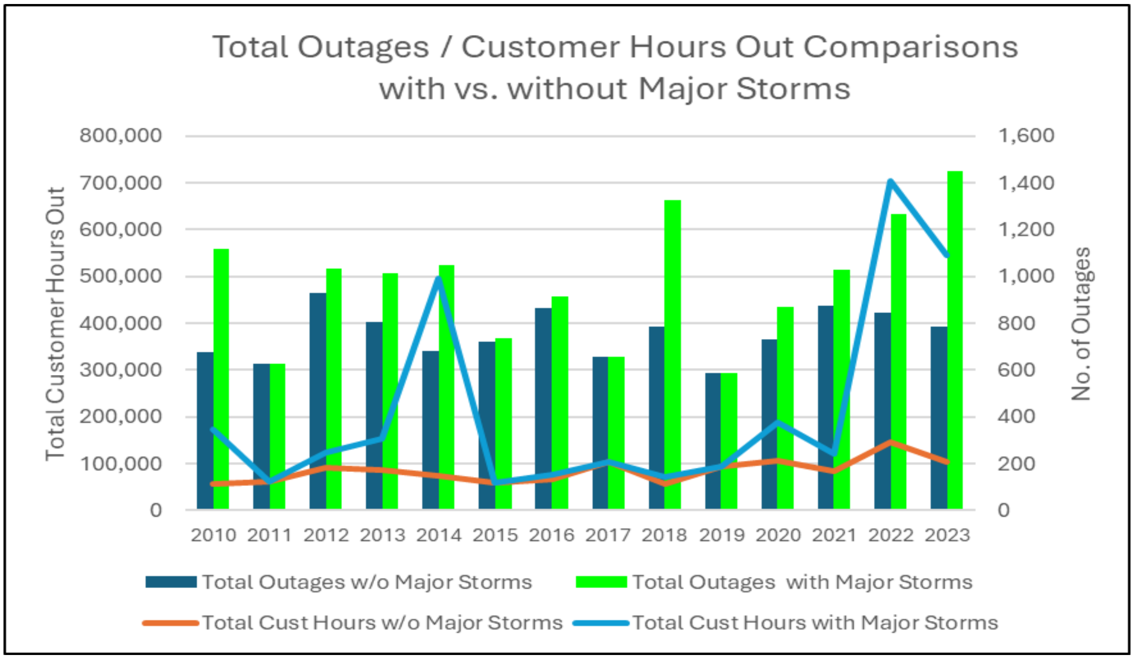
The SAIFI and CAIDI performance measure targets established in WEC's Successor Service Quality and Reliability Plan are **3.8** and **2.7** respectively. The SAIFI and CAIDI indices for 2023**,** exclusive of major storms, were **2.8** and **3.2** respectively. The SAIFI and CAIDI indices**,** exclusive of major storms, have averaged 2.8 and 3.4 over the last three years and the 10-year averages are 2.9 and 2.8 respectively.





3. Outage Totals/Customer Hours Out Summary:

In 2023 WEC experienced 787 separate outages, exclusive of major storms, on the distribution system compared to 843 in 2022. The rolling 3-year average for total number of outages, exclusive of major storms, is 835, and the rolling 10-year average is 753. The total number of consumer-hours-out in 2023, exclusive of major storms, was 103,876 compared to 145,304 in 2022. The rolling 3-year average of consumer-hours-out, exclusive of major storms, is 111,220 and the 10-year rolling average is 89,264.

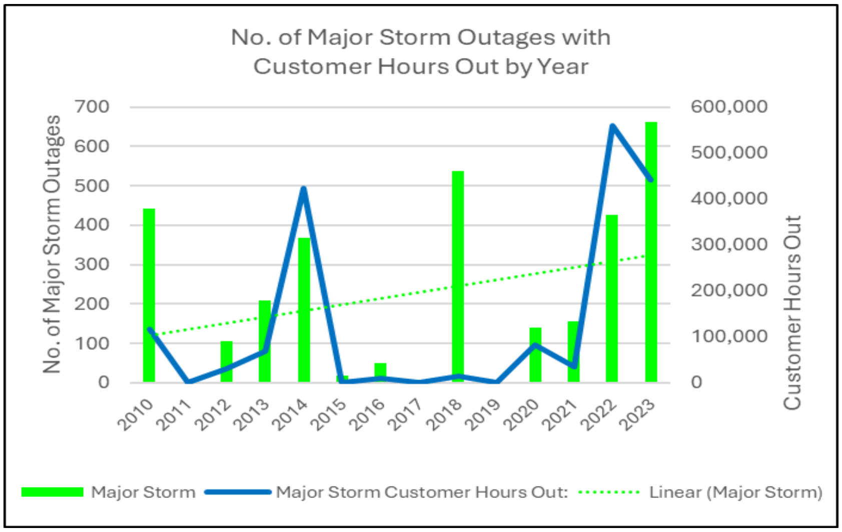


4. Impact of Major Weather Events:

During 2023, WEC experienced four severe weather events that met the criteria for Major Storm. Major Storms are defined in WEC's Successor Service Quality and Reliability Performance Plan as:

1. Extensive mechanical damage to the utility infrastructure has occurred;
2. More than 10% of the customers in a service territory are out of service due to the storm or the storm effects; and
3. At least 1% of the customers in the service territory are out of service for at least 24 hours.

In total, these four major storms almost doubled the number of regular outages WEC experienced in 2023 with an additional 662 outage events involving 29,294 customers out and 441,839 customer-hours-out.



Major Storm Details:

March 14, 2023: This severe weather event produced 8” to 14” of wet heavy snow in much of WEC’s territory and snow totals approaching 40” in southern Vermont. Damages included broken poles and wires downed due to heavy snow loading, winds and falling trees.

Duration: 3/14/23 at 04:00 through 3/16/23 at 18:00
Peak: 3,370 out
Broken poles: 2

July 9, 2023: This severe weather event featured 3” to 9” of prolonged heavy rainfall across Vermont resulting in catastrophic flooding in several parts of WEC’s service territory including several areas where poles, wires and secondary roads were washed away. Several outage locations were not accessible for days due to washed out roads and bridges.

Duration: 7/9/23 at 16:40 through 7/14/23 at 13:00
Peak: 2,135 out
Broken poles: 13

November 27, 2023: Over 8” of heavy wet snow brought down trees which brought down wires and broke poles across WEC’s territory. WEC requested mutual aid for 24 additional line crews and ROW crews to help with outage restoration.

Duration: 11/27/23 at 01:30 through 11/30/23 at 16:00
Peak: 7,260 out
Broken poles: 5

December 3, 2023: This severe weather event seemed to be concentrated over WEC's territory and central Vermont with 4" to 6" of heavy wet snow and winds damaging poles and wires. WEC received restoration help from 15 additional Mutual Aid line crews and ROW crews for this event.

Duration: 12/3/23 at 19:00 through 12/6/23 at 14:00
Peak: 4,824 out
Broken poles: 5

NOTE: Although they did not qualify as Major Storms in 2023 WEC territory would experience two more events in December that damaged WEC's infrastructure including an additional seven broken poles. In total, WEC replaced 32 broken poles in 2023 due to the increased severity of weather events Vermont is experiencing.

December 10, 2023: This severe weather event, for the second weekend in a row, seemed to be concentrated over WEC's territory and central Vermont with an additional 4" to 6" of heavy wet snow and winds. WEC received restoration help from one additional Mutual Aid line crew.

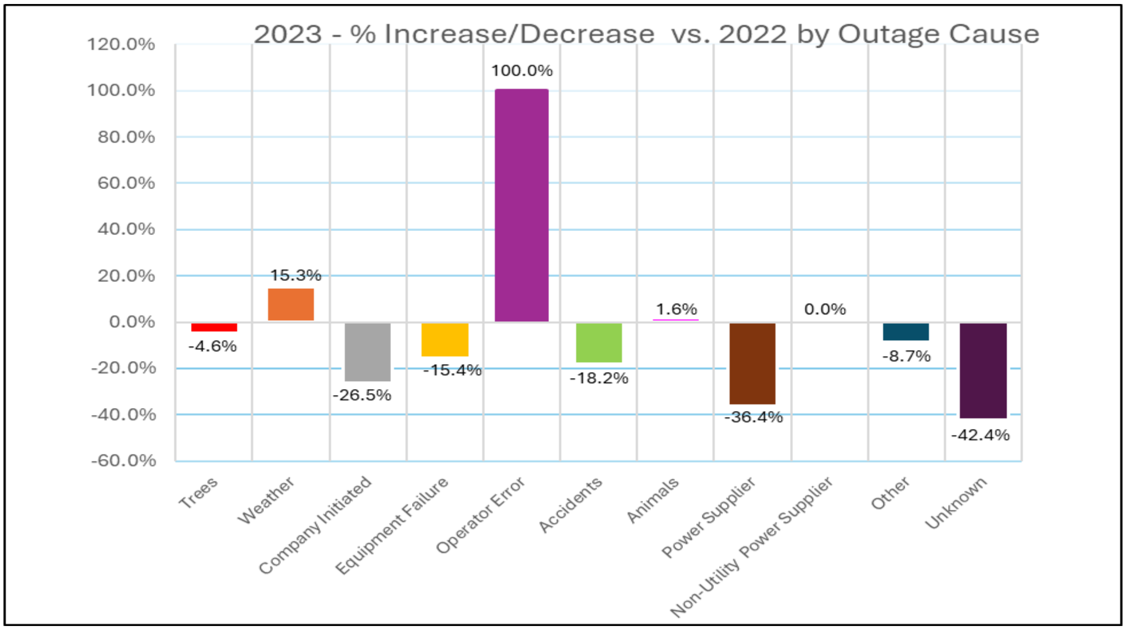
Duration: 12/10/23 at 16:00 through 12/12/23 at 01:00
Peak: 1,166 out
Broken poles: 3

December 18, 2023: This severe weather event brought heavy rains and high winds gusts between 35-55 MPH to Vermont and parts of WEC's territory.

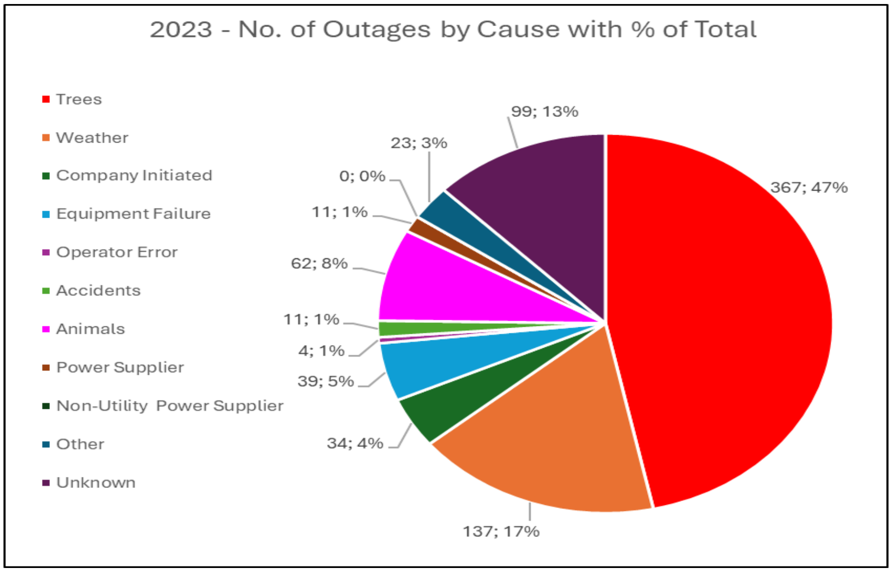
Duration: 12/18/23 at 07:00 through 12/19/23 at 12:00
Peak: 1,552 out
Broken poles: 4

5. Outage causes and assessments:

Most outage categories in 2023 had either slight increases or decreases over 2022 with seven categories having decreases, three having slight increases, and one category, Operator Error, increasing with four outages in 2023 over zero in 2022.



The top three outage categories that WEC experienced most during 2023 are: Trees = 367 outages; Weather = 137 outages; and Unknown = 99 outages. These categories were also the top three in 2022.



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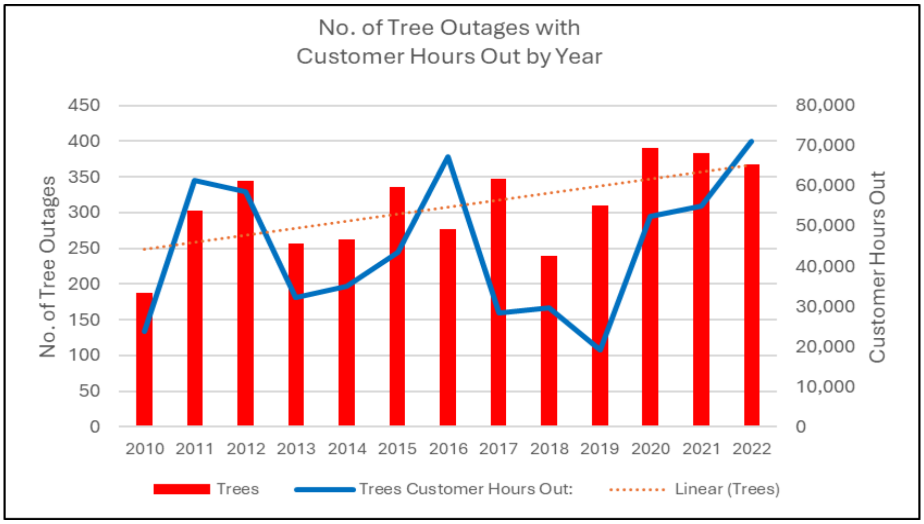
6. Outage Category Assessment

6.1 Tree Outages

At 47% of total outages, trees continue to be the largest cause of outage events on WEC's distribution system. In 2023, WEC experienced 367 tree outages with 71,139 member hours out compared to 384 and 55,033 member hours out in 2022. The three-year average for tree outages is 380 and 59,519 member hours out and the 10-year average is 317 and 43,328 member hours out.



In 2023, WEC completed a study of tree outages that occurred on the distribution system over a six-year period from 2017 through 2022 to determine the worse performing substations and circuits.

Sub-Feeder	Miles of Line	No. of Meters	Sub-Feeder	# of Outages
EM-CA	193	277	**1-1**	128
EM-PL	222	610	**1-2**	325
EM-MC	124	888	**1-3**	227
JB	8	80	**2-1**	48
MK-PE	77	1443	**3-1**	172
MK-CO	202	557	**3-2**	512
WD-HV, WD, PE	56	465	**4-1**	94
WAL-GRE	67	507	**5-1**	127
WAL-ECA	64	459	**5-2**	150
WAL-WHP	49	314	**5-3**	123
JC-TO	56	351	**8-1**	113
JC-CH	67	1378	**8-2**	204
JC-NO	163	453	**8-3**	368
MO-MI	62	878	**9-1**	192
MO-MOCO	25	163	**9-2**	81
MO-FA	96	504	**9-3**	216
MC-NCS	42	298	**10-1**	93
MC-MI	72	607	**10-2**	217
TU-CO	109	267	**11-1**	320
TU-ST	40	705	**11-2**	121
TU-BR	49	240	**11-3**	140
21 Feeders	1843	11444	**Grand Total**	**3971**

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Results of the study identified the top four worst performing substation/feeders are:

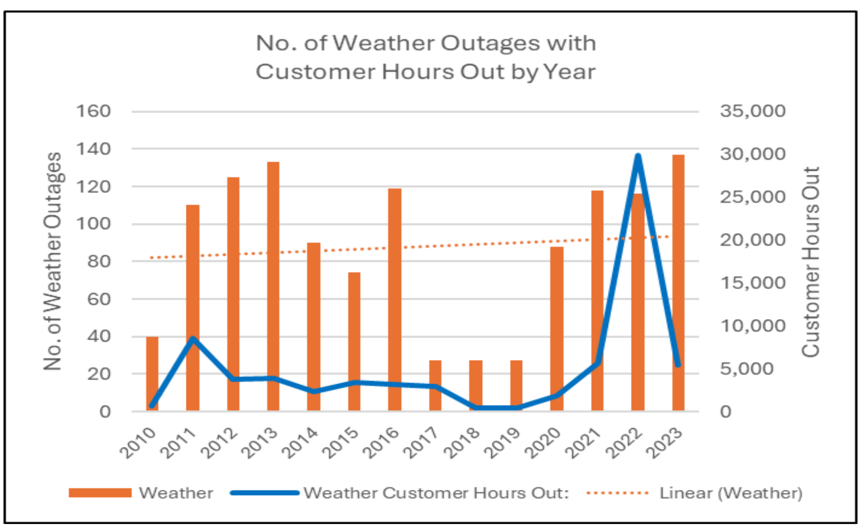
1. Mt. Knox substation, #3 Corinth Feeder
2. Jackson Corners substation, #3 Northfield Feeder
3. East Montpelier substation, 2 Plainfield Feeder
4. So. Tunbridge substation, #1 Corinth Feeder

Note: The Jackson Corners, Mt. Knox and East Montpelier substations also rank as the top three in terms of total number of outages, number of meters served and miles of line.

Sub	Total No. of Outages	Outage Rank	Total Miles of Line	Miles Rank	Total Meters	Rank Meters
EM	680	3	539	1	1775	3
JB	48	9	8	9	80	9
MK	684	2	279	3	2000	2
WD	94	8	56	8	465	8
WAL	400	6	180	6	1280	5
JC	685	1	286	2	2182	1
MO	489	5	183	5	1545	4
MC	310	7	114	7	905	7
TU	581	4	198	4	1212	6

6.2 Weather Outages

At 17% of total outages, weather was the second highest cause of outage events on WEC's distribution system in 2023. WEC experienced 137 weather related outages with 5,474 member hours out compared to 116 and 29,842 member hours out in 2022. The three-year average for weather outages is 124 and 13,645 member hours out and the 10-year average is 82 and 5,536 member hours out.



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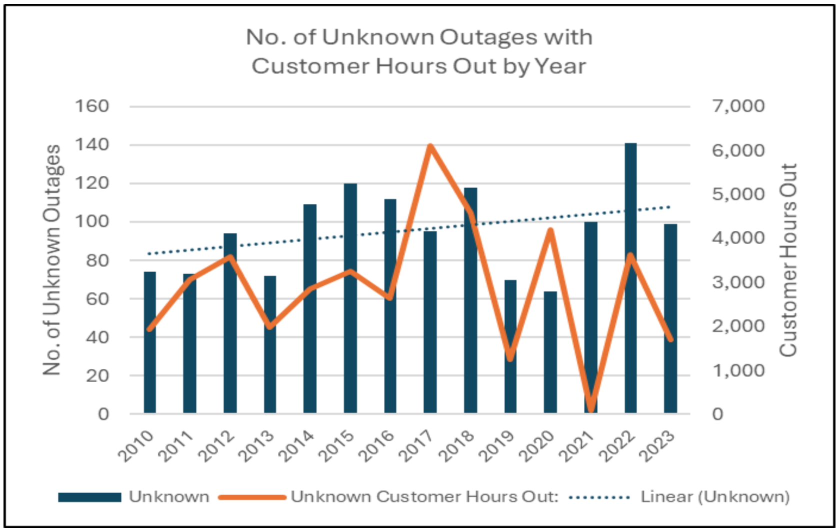
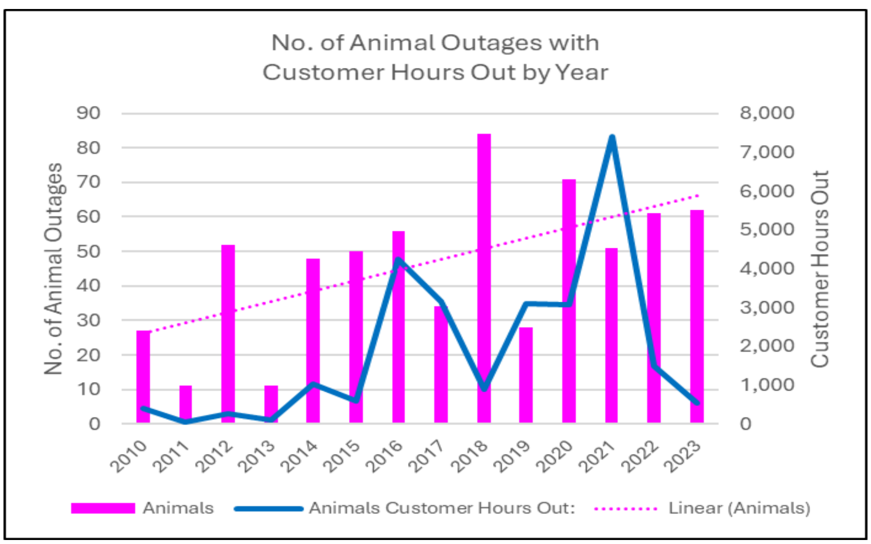
6.3 Unknown Outages

Unknown outages ranked 3rd in 2023 at 17% of total outages. In 2023, WEC experienced 99 unknown outages with 1,705 member hours out compared to 144 and 3,623 member hours out in 2022. The three-year average for unknown outages is 113 and 1,806 member hours out and the 10-year average is 103 and 3,029 member hours out.



6.4 Animal Outages

Ranked 4th, animal outages were 8% of total outages. In 2023, WEC experienced 62 animal outages with 525 member hours out compared to 61 outages and 1,499 member hours out in 2022. The three-year average for animal outages is 58 and 3,140 member hours out and the 10-year average is 55 and 2,549 member hours out.



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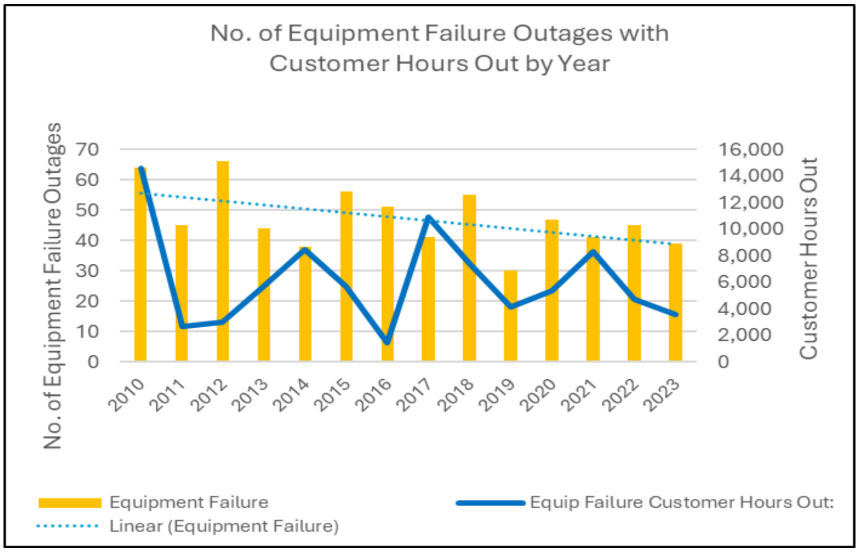
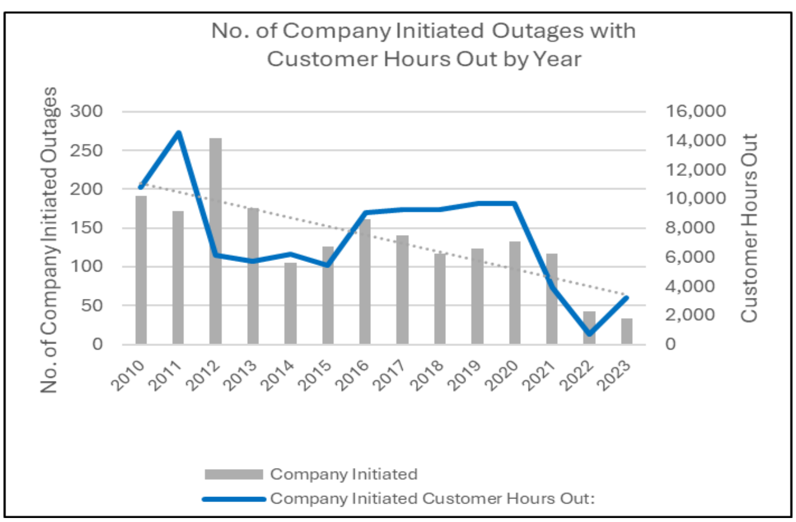
6.5 Equipment Failure

At 5% of total outages, equipment failure outages ranked 5th in terms of number of outages. WEC experienced 39 equipment failure outages with 3,574 member hours out compared to 45 and 4,743 member hours out in 2022. The three-year average for equipment failure outages is 42 and 5,545 member hours out and the 10-year average is 44 and 6,000 member hours out.



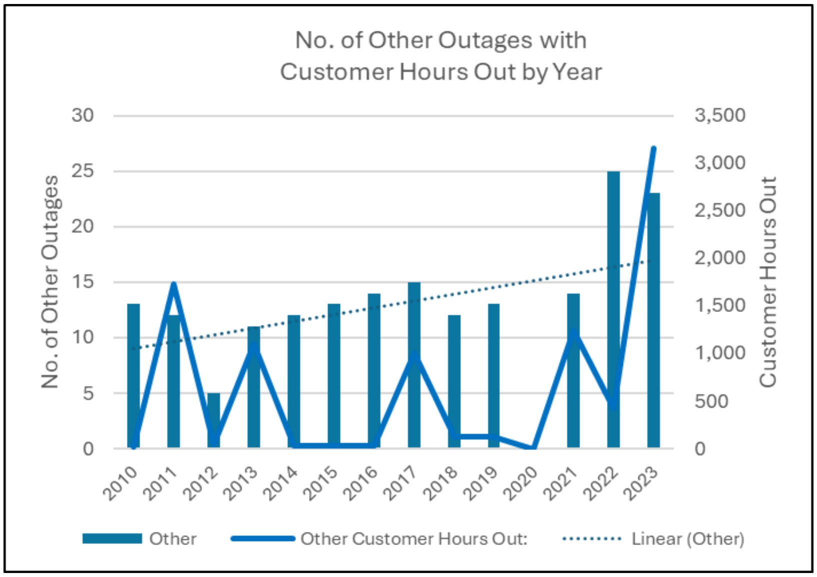
6.6 Company Initiated Outages

Ranked at 6th, company initiated outages made up 4% of the total outages in 2023. WEC experienced 34 company initiated outages with 3,574 member hours out compared to 43 outages and 712 member hours out in 2022. The three-year average for company-initiated outages is 65 and 2,614 member hours out and the 10-year average is 110 and 6,641 member hours out.



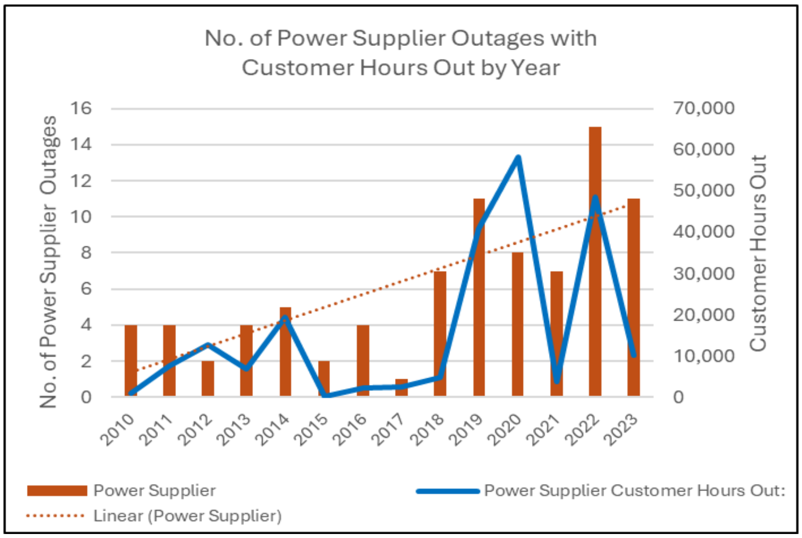
6.1 Other Outages

At 3% of total outages, other outages ranked 7th. In 2023, WEC experienced 23 Other outages with 3,159 member hours out compared to 25 and 418 member hours out in 2022. The three-year average for other outages is 21 and 1,606 member hours out and the 10-year average is 14 and 616 member hours out.



6.1 Power Supplier Outages

At 1% of total outages, power supplier outages ranked 8th. In 2023, WEC experienced 11 outages caused by the GMP transmission system with 10,113 member hours out compared to 15 and 48,517 member hours out in 2022. The three-year average for power supplier outages is 11 and 20,838 member hours out and the 10-year average is 7 and 19,105 member hours out.



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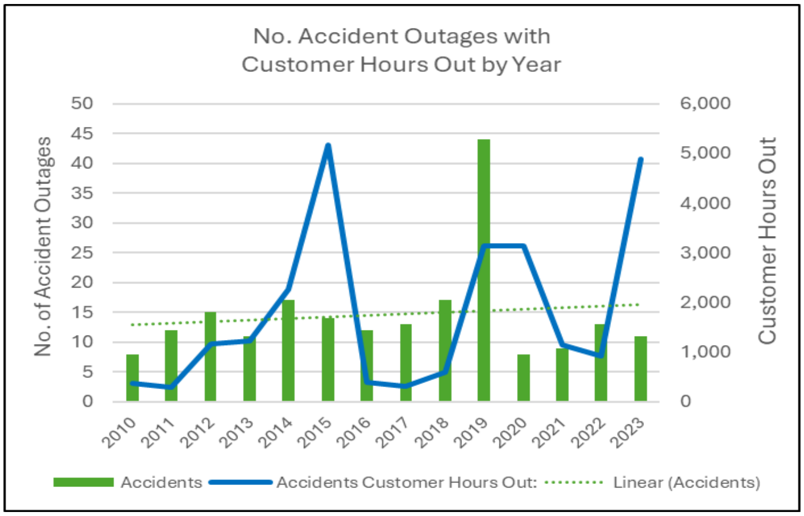
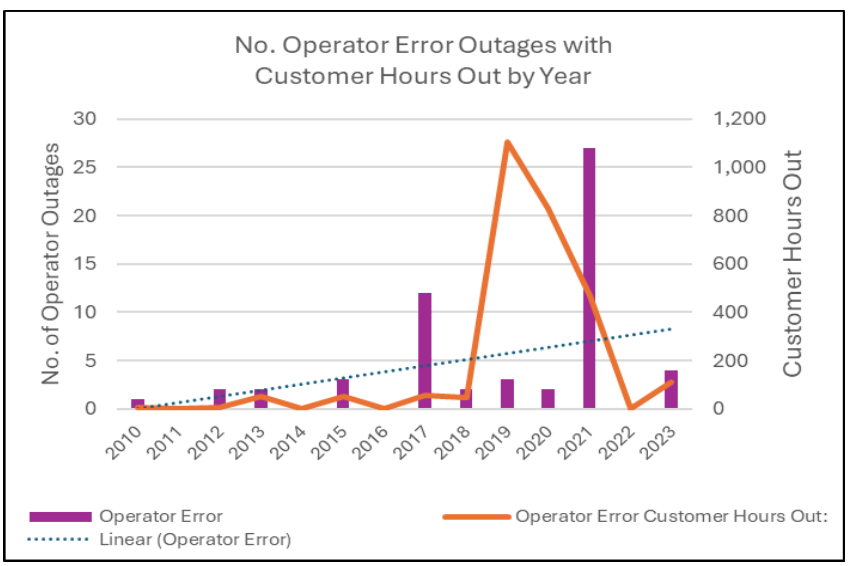
6.1 Accidents

At 1% of total outages, Accident outages ranked 9th with 11 outages and 4,879 member hours out compared to 13 Accident outages and 917 member hours out in 2022. The three-year average for Accident outages is 11 and 2,314 member hours out and the 10-year average is 16 and 2,193 member hours out.



6.9 Operator Error

At 1% of total outages and ranked 10th (last), Operator Error outages accounted for 4 outages in 2023 with 110 member hours out compared to no outages in 2022. The three-year average for Operator Error outages is 10 and 193 member hours out and the 10-year average is 5 and 267 member hours out.



7. Action Plan:

Over the last 25 years WEC has been adhering to USDA Rural Utility Services (RUS) construction standards that help harden the distribution system from the effects of increased storm severity. These practices are funded through the RUS approved Construction Work Plan (CWP) process. The four-year CWP is focused on continued improvement and enhanced reliability of WEC's transmission and distribution system.

Over the last ten years 100% of WEC's pole plant has been inspected and WEC continues to inspect 10% of the plant each year as required by RUS standards. WEC has also recently conducted an inspection of all primary underground installations to ensure they meet RUS and NESC requirements and present no inherent safety or reliability issues. The results of these inspections are used to assess the current condition of WEC's pole plant to maximize their life cycle value. The inspection data is crucial in determining pole condition and the results are fully integrated into the WEC's four-year CWP. During the 2019-22 CWP work period, WEC replaced and/or installed a total of 1,071 poles. Also in 2022, WEC moved away from using Class 3 pole sizes and started replacing poles with a stronger, thicker Class 2 pole to provide added protection against falling trees.

In 2023, WEC's consulting engineering group completed a system wide study to develop a ten-year long-range plan (LRP) to determine the immediate and long-term distribution system requirements through the year 2033. The study reviewed all of WEC's distribution substations, distribution lines and transmission lines and evaluations included thermal, voltage, reverse power, reactive compensation, short circuit, asset condition, reliability and operational considerations based on historical load and load growth projections over the next ten years. The evaluations determined a list of short and long-term recommendations that WEC will incorporate into its new 2024-2027 CWP and subsequent CWPs through 2034.

The new 2024-2027 CWP calls for approximately 75% of the dollars being spent on reconstruction and upgrades on circuits in WEC's service territory. The CWP also outlines system-hardening improvements including, but not limited to, the following: replacement of small and aged conductors, installation of capacitors to reduce line loss, the replacement of deteriorated poles, the addition of mid-span poles to reduce conductor span lengths and the reconstruction of approximately 14 miles of line.

Upgrades and system enhancements in the new 2024-2027 CWP include a complete AMI system replacement, installation of Transmission Ground Fault Over Voltage (TGFOV) protection at six substations, installation and/or upgrades of 24 new reclosers, installation and/or replacement of approximately 750 distribution transformers, installation of new voltage regulators and capacitors, upgrades at two substations and the complete replacement of two other substations.

In addition to the above CWP projects, fourteen line rehabilitation projects were identified and added to the new plan, two of which will extend three-phase conductors on two feeders beyond their current end points to help with phase balancing, voltage control and outage management by further segmenting long, single-phase lines. A third three-phase project was created from the December 2022 winter storm that was eligible as a FEMA event. FEMA will provide mitigation funding for this project, where an off-road section of this three-phase line was heavily damaged during that storm.

The mitigation plan will replace 46 old class 4, 5, and 6 poles with taller class 2 poles, relocate an off-road section of the line to the road and replaces the older, smaller conductors with the stronger Cable Spacer System. The Cable Spacer System's compact design shrinks the strike zone from falling trees and uses a support messenger to support the insulated conductors. This system is better suited to keeping the conductors in the air and energized when struck by a falling tree. It will be used for all applicable three-phase upgrade projects in the future for added reliability. WEC also reviews all single-phase upgrade projects to determine if they should be upgraded in place or moved to the road or if it should be converted to underground.

WEC continues the practice of conducting annual inspections of its entire 34.5 kV and 46 kV transmission lines in the spring and fall of each year. An infrared hot spot scan of equipment and equipment connections within the substations is also completed. During the 2019-22 CWP period, WEC completed upgrades on the Graniteville to Jackson Corners 34.5 kV transmission line and installed a new 34.5 kV switch at the Mt. Knox substation. WEC also completed 65% of the upgrades on the South Walden 34.5 kV transmission line during the last CWP work period. In the upcoming 2024-2027 CWP, WEC plans on completing the upgrades on the South Walden 34.5 kV line and adding a new recloser at the GMP/WEC tap location.

For the last five years and again for 2024, WEC's Board of Directors has approved significant funding for ROW clearing. The funding will be used to target clearing those lines directly affected by wet snow loading and danger trees. During 2023, ROW clearing crews maintained approximately 67 miles of distribution line and 1.16 miles of transmission line. A total of 4,326 danger trees were cut during ROW operations.

In 2023, WEC also conducted a study of tree outages over the 2017-2022 six-year period to determine which substations and distribution circuits were the worst performers. Individual circuits were evaluated down to the fuse level to identify those sections of line with a higher frequency of outages. WEC plans on utilizing the results of this study and combining this information with new emerging technologies and other system information to develop a new cutting plan in 2024.

Emerald Ash Borer (a continued threat to service reliability): In 2018, the Emerald Ash Borer (EAB) was detected in Orange County which is the heart of WEC's service territory. The EAB is an insect of Asiatic origin that bores into the Ash tree and lays eggs. The resulting larvae feed off the soft tissue of the tree below the bark effectively girdling the tree and cutting off the flow of water and nutrients to the tree's canopy, killing the tree. Based on experience in other states, the EAB is expected to devastate most Ash trees located within any infected area. Historically, utilities have purposely left the Ash tree to populate along and adjacent to electric line corridors as it was a hardy and resilient species. Unfortunately, the Ash trees once infected with the EAB are expected to be dead within 2 to 4 years and hence become a significant threat to electric lines and therefore service reliability. Ash trees are prioritized by WEC ROW clearing crews while performing maintenance cutting in WEC rights-of-way.

The 2024 ROW clearing budget will fund a targeted distribution system trim cycle of just over eight years and a transmission trim cycle of approximately six years. The additional funding provided over the last 4 budget years was mostly allocated to WEC's three phase main line feeders and danger tree removal on transmission, three phase and single phase main - line circuits. The additional trimming did provide significantly improved reliability to those lines.

Outage Management: In 2023 WEC made several changes internally to the way outages are managed. Working with our OMS software vendor WEC changed the way our online outage map displays outage information. Members can now see if their general location is affected by an outage or is part of a larger outage. By hovering over the outage point on the map, information regarding the outage i.e., when reported, when crews are assigned, cause and estimated restoration time, can be displayed. Also in 2023, WEC deployed tablets to our line crews who now have the ability to view all outage information including any information regarding the outage called in by members.

Storm Response: WEC monitors the weather on a daily basis and when notification of an approaching severe weather event is received from the VELCO weather forecasters, WEC participates in the VELCO emergency prep conference calls for these events. WEC personnel are then put on alert ahead of the pending situation and preparations are made ahead of the event to coordinate deployment of resources and restoration. WEC also utilizes the NEPPA Mutual Aid program for Major Storm restoration and depending on the type and amount of damage that occurs, WEC will request any needed resources from NEPPA, WEC Line Contractors and other Vermont utilities to expedite restoration.

The 2023 Reliability Report is being submitted to the Board via ePUC.

Respectfully submitted,

Dave Kresock
Director of Operations & Engineering

Washington Electric Cooperative, Inc.

This report is pursuant to PSB Rule 4.903B. It is to be submitted to the Public Service Board and the Department of Public Service no later than 30 days after the end of the calendar year.

Electricity Outage Report -- PSB Rule 4.900

Name of company	Washington Electric Cooperative, Inc.
Calendar year report covers	2023
Contact person	Dave Kresock
Phone number	802-223-5245
Number of customers	11,527

Reliability Targets:
SAIFI: 3.8
CAIDI: 2.7

System average interruption frequency index (SAIFI) =	**5.3**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**8.9**
Customer Hours Out / Customers Out	

		Number of Outages	Total customer hours out
1	**Trees**	367	71,139
2	**Weather**	137	5,474
3	**Company initiated outage**	34	3,198
4	**Equipment failure**	39	3,574
5	**Operator error**	4	110
6	**Accidents**	11	4,879
7	**Animals**	62	525
8	**Power supplier**	11	10,113
9	**Non-utility power supplier**	0	0
10	**Other**	23	3,159
11	**Unknown**	99	1,705
12	**Storm**	662	441,839
	Total	1,449	545,714

Washington Electric Cooperative, Inc.

This report is pursuant to PSB Rule 4.903B. It is to be submitted to the Public Service Board and the Department of Public Service no later than 30 days after the end of the calendar year.

Electricity Outage Report -- PSB Rule 4.900

Name of company	Washington Electric Cooperative, Inc.
Calendar year report covers	2023
Contact person	Dave Kresock
Phone number	802-223-5245
Number of customers	11,527

Reliability Targets:
SAIFI: 3.8
CAIDI: 2.7

System average interruption frequency index (SAIFI) =	**2.8**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**3.2**
Customer Hours Out / Customers Out	

		Number of Outages	Total customer hours out
1	**Trees**	367	71,139
2	**Weather**	137	5,474
3	**Company initiated outage**	34	3,198
4	**Equipment failure**	39	3,574
5	**Operator error**	4	110
6	**Accidents**	11	4,879
7	**Animals**	62	525
8	**Power supplier**	11	10,113
9	**Non-utility power supplier**	0	0
10	**Other**	23	3,159
11	**Unknown**	99	1,705
	Total	787	103,875

Washington Electric Cooperative, Inc.
Construction Work Plan
2024-2027

Prepared by:

i. Engineering Certification

Respectfully Submitted By

Signature____________________________
Pamela Allen, PE of ControlPoint Technologies

Date___3/20/24___

STATE OF VERMONT
PAMELA ALLEN
NO. 062955
ELECTRICAL
LICENSED
PROFESSIONAL ENGINEER

ii. Table of Contents

I. EXECUTIVE SUMMARY

Washington Electric Cooperative (WEC) is a rural distribution utility operating in the state of Vermont with 11,454 members. WEC owns eight distribution substations, one 12.47 kV metering point and five sub-transmission lines, four of which are radial and feed the distribution circuits and the Coventry sub-transmission line that feeds the Coventry Landfill Gas Generating Station.

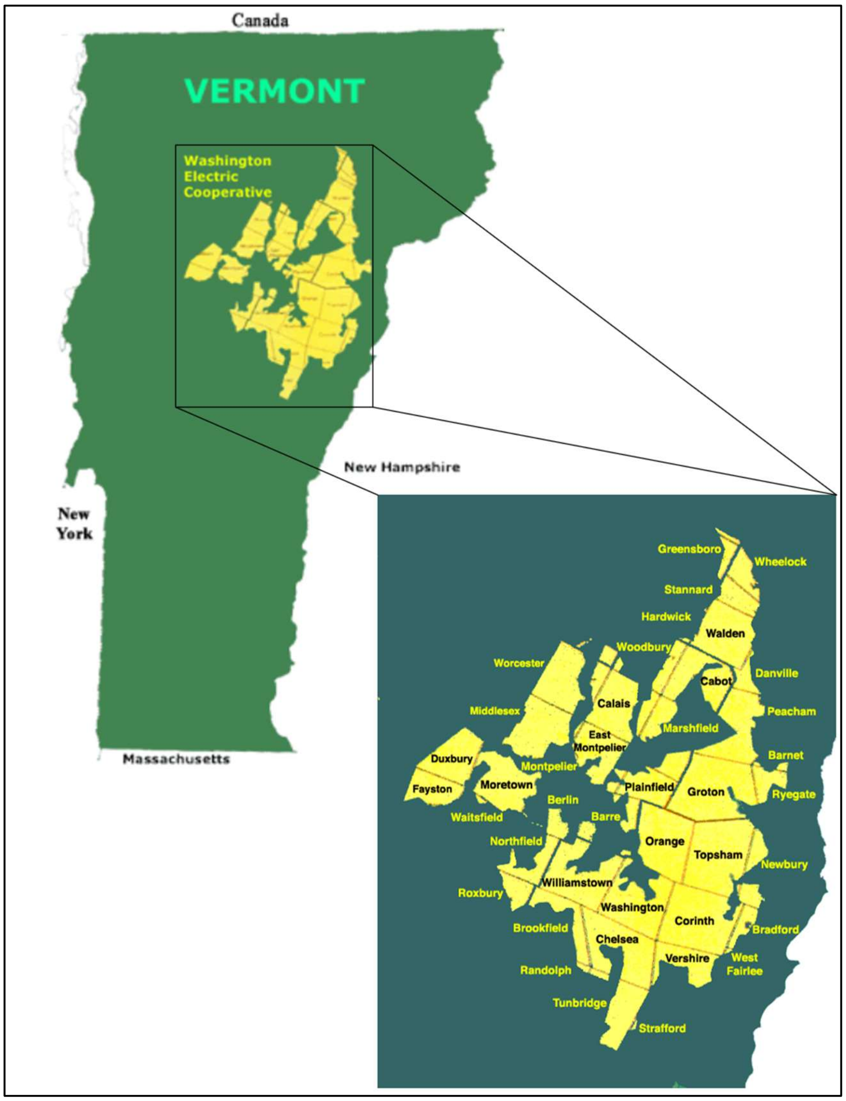


Figure 1: WEC Service Territory

A. Purpose of CWP

Washington Electric Cooperative (WEC) receives financing from the Rural Utilities Service (RUS) for its electrical system improvements. One of the requirements for RUS borrowers is the periodic development of a Construction Work Plan (CWP) in accordance with RUS Bulletin 1724D-101B guidelines. This report fulfills the RUS requirement.

WEC is committed to providing its members with safe, reliable, efficient and economical power and periodically prepares a construction work plan to improve the performance of its electrical system. However, there are financial considerations and the WEC Board makes difficult decisions to allocate the limited resources available to the areas that will provide the most benefit for the dollars spent.

ControlPoint Technologies (CPT) has prepared this CWP based on the 2023 Long Range Plan (LRP) which was also recently completed by CPT. The 2023 LRP included a load forecast which projects out ten years to 2033 based off historical WEC loads that incorporated Vermont specific Beneficial Electrification factors publicly available from ISO-NE.

A CWP is used to prepare a four-year work plan that will then be submitted to the RUS for approval in order to acquire funding to carry out the work. The work contained within the CWP is what was determined to be the most feasible, environmentally acceptable and economical means to continue to provide WEC’s existing and future members with adequate and reliable electric service. Note, the CWP will list all work regardless of whether the RUS will be financing it.

The analysis for the development of project recommendations for the 2024-2027 CWP is supported by WEC’s design criteria, distribution line and equipment costs, past system studies and the review of various historical system data.

The work identified in the proposed CWP will help support the Comprehensive Energy Plan 2022 issued by the Vermont Department of Public Service. Due to the increasing load from Beneficial Electrification the system must be strengthened to not only enable that additional load, but greater connectivity and reliability is required as members rely more on electricity for their basic needs. In addition to traditional load (forward power), WEC also needs to harden and strengthen its system to continue to interconnect Distributed Energy Resources (DER) or reverse power. Reverse power can create transmission protection issues such as “Transmission Ground Fault Overvoltages” TGFOV that must be protected against. Currently all the WEC owned distribution substations require TGFOV protection but only on some of its circuits has it been deployed.

B. Service Area, Existing System & Power Supply

1. Service Area

Washington Electric Cooperative, Inc. (WEC) is a member owned rural electric company established in 1939. WEC serves over 11,467 meters, 99.8% of which are residential (including regular and seasonal consumers). The WEC service area covers approximately 2,728 square miles in north-central Vermont including portions of 41 towns in Washington, Orange, Caledonia and Orleans counties. It operates approximately 1,266 miles of distribution line, with eight substations. The balance of customers is a mix of small commercial and larger commercial customers. The largest commercial customer is Harwood Union High School in Duxbury.

2. Distribution Facilities

The existing WEC distribution system has approximately 1,233 miles of overhead distribution line and 33 miles of underground primary distribution, for a total of 1,266 miles[1]. The distribution system operates at 12.47/7.2 kV.

The distribution system consists of eight substations and one primary metering point. *Table 1* below provides a list of the substations and the approximate length of primary overhead and underground on each. Existing distribution line equipment is tabulated in Appendix D, *Table 35*, *Table 36*, and *Table 37*.

[1] Per GIS data, 1/23/2024.

Circuit Conductor & Meter Counts				
Substation	**Circuit**	**Overhead** *(Approximate Miles)*	**Underground** *(Approximate Miles)*	**Total # of Meters**
#1 East Montpelier	#1 Cabot	44.2	1.6	280
	#2 Orange	87.9	2.0	890
	#3 County Rd	57.1	2.7	612
#2 Jones Brook ***Metering Point***	#1 Jones Brook	10.0	0.0	80
#3 Mt. Knox	#1 Peacham	63.9	0.9	555
	#2 Corinth	155.5	2.1	1447
#4 West Danville	#1 Hookerville (AØ) #2 West Danville (BØ) #3 Peacham (CØ)	42.6	2.6	461
#5 South Walden	#1 Greensboro	59.8	0.5	455
	#2 East Cabot	54.8	0.7	498
	#3 West Hill Pond	40.9	0.3	324
#8 Jackson Corners	#1 Topsham	42.7	0.9	455
	#2 Chelsea	60.8	0.6	352
	#3 Northfield	123.3	4.2	1385
#9 Moretown	#1 Middlesex	45.6	1.7	503
	#2 Moretown Common	17.7	1.4	164
	#3 Fayston	67.9	5.7	892
#10 Maple Corners	#1 North Calais	35.3	1.0	298
	#2 Middlesex	58.0	0.7	603
#11 North Tunbridge	#1 Corinth	86.6	1.9	705
	#2 South Tunbridge	38.8	0.6	241
	#3 Brookfield	39.5	0.6	267
Totals	23	1,233	32.6	11,467

Table 1: WEC Substations & Circuits

The primary conductor size on the system ranges from 3/12 copperweld to 4/0 aluminum on the overhead portion of the line. The primary underground line, which accounts for approximately 2.68% of the total system, consists of 1/0 Al, 15 kV cable.

Four of the eight substations and the #7 Graniteville Switch were originally built as wood pole structures with timber crossarms, varying in age. Four substations, Moretown, South Walden, Maple Corners, and East Montpelier have been completely rebuilt with modern metal frame construction and increased clearances to meet present requirements. West Danville Substation, while a wood pole structure, was rebuilt in 1986 while major equipment was replaced in 2002.

3. Transmission Facilities

The majority of the power distributed to WEC's customers is generated outside of WEC's service area. Therefore, WEC depends on transmission facilities owned by VELCO and GMP to transmit power to its electrical facilities. The Vermont transmission facilities relative to WEC's service territory are shown in Appendix B, *Figure 8*.

WEC owns five sub-transmission lines, four of which are radial and feed the distribution circuits and the Coventry sub-transmission line that feeds the Coventry Landfill Gas Generating Station, see Table 2 below. The 2023 LRP only evaluated the four lines that feed the distribution substations. All WEC owned sub-transmission lines are in Vermont.

Line	Station Served	Operating Voltage	Line Miles
East Montpelier to Maple Corners Line	Maple Corners	34.5 kV	8.99
Graniteville to Jackson Corners Line	Jackson Corners	34.5 kV	4.45
GMP 3319 Tap to Walden Feed	South Walden	34.5 kV	2.26
VELCO Chelsea to Tunbridge Line	North Tunbridge	46 kV	2.6
Coventry	Coventry Landfill Gas Generating Station	46 kV	7.3

Table 2: WEC Owned Sub-Transmission Lines

The ratings of the sub-transmission lines that feed the WEC distribution substations are listed in Table 3 below. In the analysis, each of the listed lines is evaluated for thermal loading over the next 10 years.

Line	Limiting Element		
	Description	Rating (Amps)	MVA
East Montpelier to Maple Corners Line	4/0 ACSR Conductor	357	21.31
Graniteville to Jackson Corners Line	4/0 ACSR Conductor	357	21.31
GMP 3319 Tap to Walden Feed	2/0 ACSR[2]	276	16.48
VELCO Chelsea to Tunbridge Line	4/0 ACSR Conductor	357	21.31

Table 3: WEC Owned Sub-Transmission Line ratings that supply Distribution Substations

[2] This line has approximately 10,953 feet of 2/0ACSR and approximately 1,006 feet of 4/0AAAC.

4. Power Supply[3]

WEC is a leader in renewable energy and one of only a few utilities in the nation that can boast a 100% renewable power supply mix, per the WEC 2022 Financial Statement. Below is a chart depicting WEC's various power sources, these are described in greater detail later in this CWP.

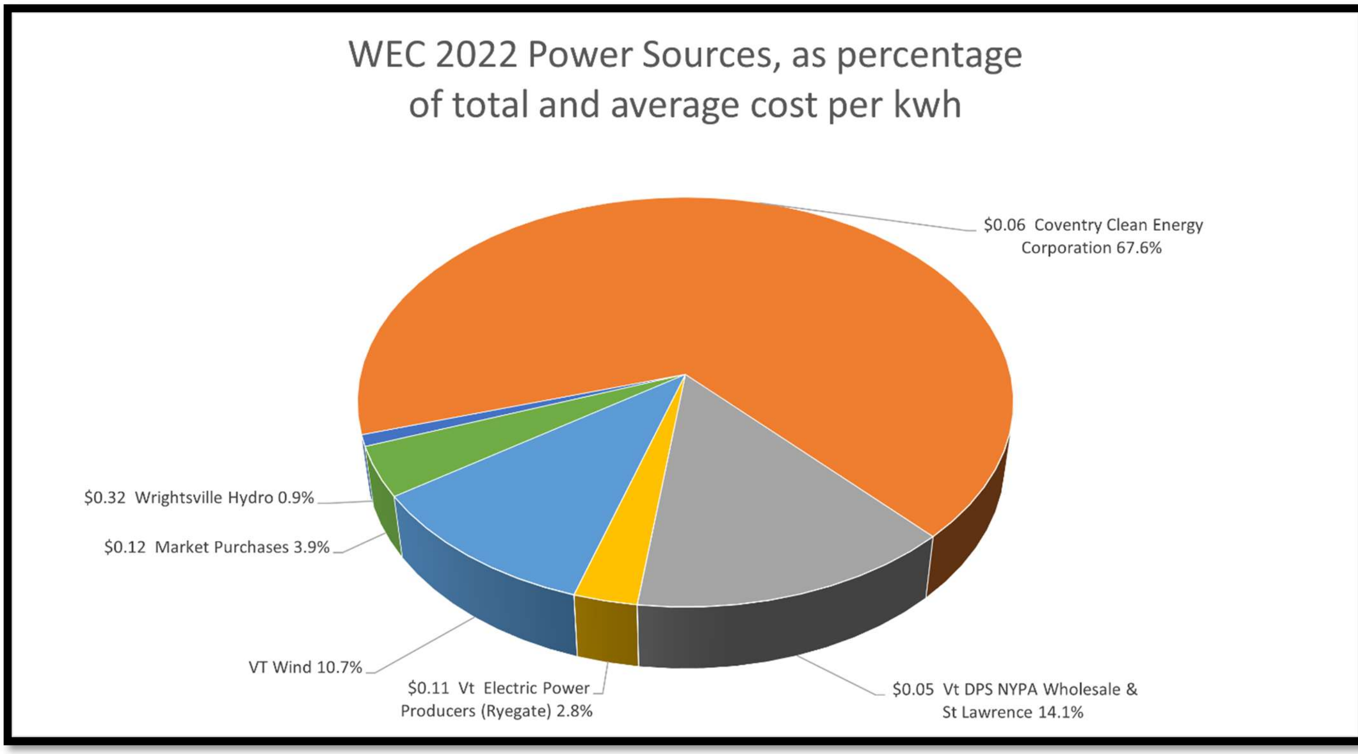


Figure 2: WEC 2022 Power Sources

WEC maintains a portfolio that is 100% renewable and therefore exceeds the Vermont Renewable Energy Standard 30 V.S.A. § 8002-8005 (RES) requirements that utilities must receive 75% of their power from renewable sources by 2032.

In March 2016, WEC petitioned the PUC in Docket 8550 for a determination that it qualifies as a retail electricity provider meeting the conditions in 30 VSA 8005 (b)(1)(A) which allows it to satisfy the distributed generation requirement of Tier 2 by accepting net metering systems within its service territory. The PUC approved this petition and WEC was granted the determination that it qualified as a 100% renewable retail electric provider (Docket 8714). WEC files annually for approval of its renewable status and

[3] Language in this section is from WEC's "Consolidated Financial Statements, December 31, 2022", https://www.washingtonelectric.coop/wp-content/uploads/2023/03/wec-2022-Audited-Financials.pdf

expects that later this year the PUC will approve its filing indicating that it was a 100% renewable utility in 2022 although that determination has not been finalized yet. As noted above, Tier 2 requires electric providers to have distributed renewable generation comprising at least one percent of its annual retail sales for the year beginning January 1, 2017, and thereafter increasing by two-thirds percent each year for 10 years. For 2022 the Tier 2 requirement is equivalent to 6% of retail sales. WEC's renewable determination by the PUC enables WEC to satisfy Tier 2 requirements by accepting net metering systems within its service territory. Therefore, WEC is not exempt from offering net metering as a renewable energy provider. Rather, it must offer net metering, but its members are not required to achieve the annual energy targets set forth in Tier 2; WEC is relieved of the requirement to provide 2.8% of its annual sales from new net metering due to its 100% renewable status.

The Vermont RES Tier 3, or what has been referred to as the energy transformation Tier, focuses on efforts that switch members away from fossil fuels in transportation and heating use to non-fossil fuel. All utilities were required to create a plan to meet their Tier 3 obligations. WEC's Annual Plan addresses its strategy to meet Tier 3 compliance obligation for 2023 and was filed with the PUC in November 2022. WEC offered a suite of energy transformation measures that have been screened and vetted through the Technical Advisory Group (TAG) screening process. A fundamental component of WEC's plan is to emphasize and match TAG screened measures with heightened weatherization efforts.

Coventry Methane Generation Project

The Cooperative owns and CCEC operates a generating facility powered by landfill gas at the Coventry Landfill in northern Vermont. The plant first began generating in July 2005 and was subsequently expanded in 2007 and 2009, to a present generating nameplate capacity of 8 MW. A set of contractual agreements was executed in 2003 between CCEC and New England Waste Services of Vermont, Inc. (NEWSVT), a wholly owned subsidiary of Casella Waste Systems, Inc. which owns the Coventry Landfill. These agreements codify the relationship of the parties.

The initial project was financed by an RUS loan. The 2007 expansion was financed by CFC under their implementation of the Clean Renewable Energy Bond Program (CREB). The 2009 expansion was financed by an RUS-guaranteed FFB loan and by reallocating funds in the 2008- 2011 CWP from distribution projects to generation assets.

	Plant Cost	Note Balance
Phase 1 - Initial Construction, Engines 1-3	$ 7,136,054	$ 2,984,121
Phase 2 - Engine 4	1,238,397	75,385
Phase 3 - Engine 5 plus building modifications	4,133,419	1,499,348
Siloxane Removal System (SRS)	2,182,483	1,080,366
Systems Upgrades financed with general funds	522,846	-
	$ 15,213,199	$ 5,639,220

Table 4: WEC Power Supply Energy from "WEC Consolidated Financial Statements, December 31, 2022"

Costs for each phase have been capitalized to both generation and transmission plant, with the majority in generation.

Of the $15,213,199 plant cost, $13,300,449 is capitalized to generation plant with the balance included in transmission plant.

In 2016, WEC added a new gas scrubbing system and related upgrades at the plant, referred to as a Siloxane Removal System (SRS). WEC filed for a Certificate of Public Good (CPG) for this work with the PUC pursuant to 30 V.S.A. § 248(j). The PUC issued an order in Docket 8721 approving the project in May 2016. Subsequent to receiving permission to build the project, WEC filed with the PUC for permission pursuant to 30 V.S.A. § 108 for approval to finance the project in the amount of $1,712,366 using United States Department of Treasury's New Clean Renewable Energy Bonds (NCREB). The PUC approved financing in August 2016. The SRS is intended to remove siloxanes, which reduces the concentration of contaminates in the landfill gas. The buildup of siloxane compounds within the engines causes destructive detonation and inefficient operation of the engines requiring additional maintenance and engine downtime. The removal of the siloxane compounds has improved engine availability and increased electricity production. The project was successfully completed and began operating in January 2017.

In 2022 the Coventry Project provided 67.6% of the Cooperative's total power supply output.

CCEC has a Landfill Gas Project Agreement with Innovative Energy Systems, Inc. (IES), IES had been a subsidiary of Aria Energy with corporate headquarters in Novi, Michigan, but has since merged with Archaea Energy which has since been purchased by BP. Services provided by Aria/Archaea/BP include day-to-day management, operation, maintenance, plant repair, monitoring and adjustment of the gas collection system. WEC and IES entered a revised O&M contract which was signed in December 2016. The new contract assures continuity of operations at the plant. The contract term is for 15 years, from May 2015 through May 2030. On December 31, 2022, and 2021 the contract amount included in expense was $1,234,666 and $1,303,606, respectively.

On June 14, 2021, the Civil Division of the Orleans Superior Court approved, and entered as an order, WEC's settlement with the Town of Coventry for the tax valuation of the Coventry Clean Energy Corporation Landfill Gas to Energy Plant. Coventry valued the Plant at $14,030,000 and was attempting to increase this valuation through WEC's appeal of this valuation. WEC's initial position was that the valuation should be $8.9M. The settlement value adopted by the Court is $10.2M for the six tax years 2021 through 2026. Coventry was allowed to keep the over-payment (difference between $14.03M and $10.2M) for the 2019 and 2020 tax years.

Wrightsville Hydro

The Cooperative also owns and operates the Wrightsville Hydroelectric Generation Station in Montpelier, Vermont, a largely run-of-the-river project that has a nameplate capacity of 933 kW, though it provides significantly less average output because it is dependent on precipitation and weather conditions during the year. Operating costs were $118,948 and $125,396 on December 31, 2022, and 2021, respectively. Fixed costs were $88,602 and $95,369 over that same period, respectively. All debt associated with this station has been paid in full as of December 31, 2014.

In March 2016, WEC successfully converted the hydro unit's status at the ISO-NE from a generator to a load reducer. As a load reducer the production from Wrightsville goes directly toward lowering WEC's load with the ISO-NE. This change saves WEC in ancillary market costs, capacity costs, reserves and many other expenses assessed to load by the ISO-NE. We continue to record generation monthly for internal tracking and adjust load internally as if the generator were not a load reducer. This allows WEC to measure and track total member load for planning purposes.

The Wrightsville Hydro facility was issued a 40-year license by the Federal Energy Regulatory Commission (FERC) on November 23, 1982 (FERC No. 5124 also known as North Branch No. 3 Hydroelectric Project). At the time of the license, the Project was owned by the Montpelier Hydroelectric Company; it was later transferred to the Washington Electric Cooperative, Inc. (WEC) on June 30, 1983.

The current license was due to expire on October 31, 2022. As a result, WEC filed a Notice of Intent (NOI) and Pre-Application Document (PAD) on October 31, 2017. WEC has been working with FERC and state agencies to address various water and aquatic study requirements as well as power plant improvements that may be needed to continue the facility's operation. FERC held public scoping meetings on January 24 and 25, 2019. No members from the public attended but various state agencies and WEC staff were in attendance at both meetings.

WEC has worked with the Vermont Agency of Natural Resources (VANR) to review the options to renew the license. As of January 2020, WEC and VANR came to an agreement as to how the Wrightsville facility shall be operated going forward.

In accordance with FERC regulations, WEC filed a final license application (FLA) for a new license with FERC before October 31, 2020. The Project consists of three fixed flow turbines. The proposed action described in the FLA is to relicense the Project but use flow from a minimum flow gate to fill the flow gap between the fixed flow turbines so as to maintain a more stable flow regime below the powerhouse. WEC made public portions of the FLA available to resource agencies, Indian Tribes, local governments, non-government organizations, and the public on the Project's distribution list. An electronic copy of the FLA is available on FERC's website using the following https://elibrary.ferc.gov/eLibrary/search, enter P-5124 in the docket number. A paper copy of the FLA can also be viewed during normal business hours at the Kellogg-Hubbard Library at 135 Main Street, Montpelier, VT 05602.

WEC continues to work on the license renewal process with both FERC and the State of Vermont. On October 13, 2021, WEC received the Draft Environmental Assessment from FERC and filed comments on November 12, 2021. On November 10, 2021, FERC issued a Draft Programmatic Agreement and WEC filed comments on December 12, 2021. On February 4, 2022, the Vermont Department of Environmental Conservation issued a draft 401 Water Quality Certificate for the Wrightsville Hydroelectric Project.

The FERC license ended on October 1, 2022. However, since FERC has not yet issued the final license order, the FERC issued WEC a notice that it can continue operating under the existing license until October 31, 2023, or until a new license is issued.

Similarly, WEC's operating agreement with the state DEC (which operates the dam) has expired, but the state has authorized the continued operation of the project under the old license agreement until a new agreement is completed.

Due to weather conditions, a several month period when the plant was offline due to ice, and equipment issues at the plant, Wrightsville production in 2022 was far below expectations. In addition, the new permit requirements will likely result in less power being produced by the Wrightsville project going forward. WEC's consultant estimates that all other conditions being equal, the new operating conditions will result in a 6 percent reduction in output.

In 2022, Wrightsville produced 0.89% of WEC's total power and 0.82% of WEC's Total Real Time Load Obligation.

Sheffield Wind Project

In May 2005, the Cooperative executed an Advance Purchase Fee Agreement with wind developer UPC Wind Vermont, LLC (UPC), which subsequently became Vermont Wind, LLC ("Vermont Wind") and was part of SunEdison, for up to a 4 MW share of the output of its proposed 40 MW project in Sheffield. The PUC awarded UPC the required Certificate of Public Good for the project in August 2007. In January 2009, the Vermont Supreme Court unequivocally upheld the PUC Order. The contract was filed by Vermont Wind with the PUC in June 2009 and the PUC approved it, in Docket No. 7156, in August 2009. The Cooperative finalized a long-term Purchased Power Agreement with Vermont Wind in September 2009. Vermont Wind began construction in 2010 and the project reached its commercial operation date on October 19, 2011. WEC began receiving power generated from the wind project at that time on a contract that is set to expire October 2031. Sheffield Wind accounted for 10.69% of WEC's total power supply in 2022 and 9.85% of WEC's Total Real Time Load Obligation.

NYPA

The Cooperative receives power from the Franklin D. Roosevelt-St. Lawrence and Niagara hydroelectric projects in New York, through the DPS, which contracts with the New York Power Authority (NYPA). NYPA power is currently being provided through the DPS under a long-term contract. The contract for St. Lawrence has been extended through April 30, 2032. The Niagara Contract has been extended through September 1, 2025. The Cooperative anticipates no reductions in NYPA power supply going forward under the latest agreements, except when low water conditions exist. When low water conditions do exist, NYPA makes available replacement energy at a higher cost, but purchase of such replacement power is optional. The Niagara project, the largest provider of NYPA power to the Cooperative, was recently relicensed. This relatively low-cost resource is expected to continue to be available to the Cooperative's residential customers far into the future, though some related costs have increased in recent years, particularly transmission. NYPA accounted for 14.09% of WEC's total power supply in 2022 and served 12.99% of WEC's Total Real Time Load Obligation.

Hydro-Quebec

On January 7, 1991, the PUC approved the Cooperative's purchase of 2.589 MW of Hydro-Quebec (HQ) Schedule B power for a term from September 23, 1995, through October 31, 2015. With the end of the HQ Vermont Joint Owners contract, WEC replaced the power with a new contract from HQ.

WEC, along with other Vermont utilities, petitioned the Vermont Public Service Board in 2010 in Docket 7670 to approve various agreements related to obtaining power from H.Q. Energy Services (US) Inc. through a Purchase Power Agreement (HQUS PPA). WEC is participating as a buyer of power under the Vermont Public Power Supply Authority (VPPSA), through a sub-allocation arrangement. WEC will be allocated energy products from the HQUS PPA through VPPSA in the amount of 4 MW from November 1, 2016, through October 31, 2038.

The energy from this contract is delivered 7 days a week from hour ending 08:00 to hour ending 23:00 on a firm basis through an Internal Bilateral Transaction (IBT) settled through the ISO-NE markets. There is no capacity accompanying the energy, but environmental attributes will be delivered with a minimum guarantee that 90% of the power will come from hydro or other renewable resources.

WEC has a contract entitlement from this resource of up to 4 MW. Currently WEC assigns this power to Vermont Electric Cooperative (VEC) through a sleeve arrangement. Starting on November 1, 2016, WEC is contractually required to take back this power to meet its load if its other committed resources are insufficient. The amount of power WEC must take is specified by a formulaic process in the sleeve agreement. This agreement states:

- WEC must begin to take power back from VEC with a one-year notice period if its coverage ratio falls below 97% over the preceding 12-month period.
- The amount of power WEC takes back is defined by formula which includes a coverage band tied to the amount of power needed to bring WEC's coverage ratio to 100%.
- Once WEC takes power back, it must retain that power through the end of the contract term in 2038.
- WEC can temporarily take back power in the event of an unplanned outage from an existing resource.

Twelve months after the month the coverage ratio falls below 97%, WEC will begin to take back power up to the amount of the energy deficit for the current month, provided the desired amount of energy falls between the coverage ratio limits. If it falls outside these limits, then the amount WEC will take reflects the coverage band lower or upper bound. Once WEC takes back a certain amount of power, that amount will remain in the WEC resource portfolio.

WEC began this process in May of 2022, and expects that its coverage ratio will be below 97% for the year and that it will pursue the possibility of taking back up to 2 MW of power under the HQ contract.

Ryegate

In an Order dated October 29, 2012, the PUC established a standard-offer price schedule for baseload renewable power (Ryegate biomass facility) that is represented by a levelized price of $0.10 per kWh and that included a fuel pass-through mechanism by which the price will be adjusted to reflect changes in Ryegate's fuel costs. The new contract began November 2012 at the termination of Ryegate's Rule 4.100 contract. The new contract for Ryegate is in effect from November 2012 through October 2023. WEC is currently being allocated roughly 1.35% of the power from the Ryegate facility. In 2022, the Vermont Legislature extended the Ryegate contract, despite WEC's objections, meaning WEC will continue in the near term to be obligated to take power from that source. In 2022, Ryegate represented 2.77% of WEC's power supply and 2.56% of WEC's Total Real Time Load Obligation

Standard Offer Resources

Standard Offer is a feed-in like tariff program for developers, available under the auspices of the PUC, and authorized by the Vermont legislature, through various PUC dockets (#7523 and #7533). The Cooperative has two Standard Offer facilities on its distribution system, a 2.1 MW photovoltaic (PV) project in Williamstown, and a 1.5 MW PV system which is also in Williamstown. WEC does not take power from these facilities due to an exemption as a 100% renewable electric utility. Another 2.2 MW photovoltaic project was approved by the PUC and is interconnected to the Cooperative's sub-transmission line in Coventry.

Net Meter

There are 8,917 kW of small net metering (mostly solar arrays) proposed or connected to the WEC distribution system as of February 2023, as shown in *Table 5* below.

Many of the projects are smaller than 20 kW, which does not trigger a detailed review. However, small projects in aggregate can create issues over time. The analysis considered aggregate impacts of the existing and proposed DER on the sub-transmission for thermal limits, fault current and voltage.

Substation	Feeder	Existing (kW)	Proposed (kW)	Total (kW)
#1 East Montpelier	#1 Cabot	319	0	319
	#2 Orange	519	36	555
	#3 County Rd	1,462	80	1,542
	Total	*2,300*	*116*	*2,416*
GMP Mountain View #27	#2 Jones Brook Metering Point	47	-	47
#3 Mount Knox	#1 Peacham	215	15	230
	#2 Corinth	457	50	507
	Total	*672*	*65*	*737*
#4 West Danville *(3 - 1Ø Circuits)*	#1 Hookerville	168	24	192
	#2 W. Danville	-	-	-
	#3 Peacham	-	-	-
	Total	*168*	*24*	*192*
#5 South Walden	#1 Greensboro	153	30	183
	#2 Cabot	204	20	224
	#3 West Hill Pond	117	15	132
	Total	*474*	*65*	*539*
#8 Jackson Corners (Served by #7 Graniteville)	#1 Topsham	357	15	372
	#2 Chelsea	175	20	194
	#3 Northfield	725	68	793
	Total	*1,257*	*103*	*1,359*
#9 Moretown	#1 Middlesex	371	197	568
	#2 Moretown Common	258	46	304
	#3 Fayston	1,107	125	1,232
	Total	*1,736*	*367*	*2,104*
#10 Maple Corners	#1 North Calais	209	30	239
	#2 Middlesex	452	75	527
	Total	*661*	*106*	*766*
#11 North Tunbridge	#1 Corinth	298	116	414
	#2 South Tunbridge	100	34	134
	#3 Brookfield	162	49	210
	Total	*560*	*198*	*758*

Table 5: Aggregate Net Meter DER on each Substation and Circuit

<u>VELCO</u>

The Cooperative has entered into contracts with the Vermont Electric Power Company, Inc. (VELCO), which operates Vermont's bulk transmission system, to participate in Phase I of the Hydro-Quebec Interconnection, a 450 kV HVDC transmission line directly connecting the HQ electric system with the New England Power Pool. Under these agreements, the Cooperative provided capital for the cost of construction through purchase of VELCO Class C preferred stock and will provide support for the operation of its 0.1133% (.782 MW) interest in the line. Vermont Transco LLC was officially established on June 30, 2006. Vermont Transco LLC is a limited liability company formed by VELCO and Vermont's distribution company owners, including the Cooperative. Vermont Transco LLC is now the owner of Vermont's high-voltage electric transmission system. VELCO is the manager of the LLC and, in that capacity, operates and maintains Vermont's electric transmission system, as it has for over fifty years.

Under collateral call arrangements associated with the Cooperative's ownership in VELCO and Vermont Transco LLC, the Cooperative purchased $16,540 and $655,060 in Vermont Transco equity units in 2022 and 2021, respectively. Over the next four years, Vermont Transco LLC anticipates additional collateral calls. The Cooperative's estimated investment would be nearly $1,685,000 over this period.

ISO-NE

The Cooperative, like all other electric utilities in New England, relies upon the ISO-NE, operator of the New England regional bulk transmission system, to dispatch generation and settle load obligations in the New England power markets. The Cooperative relies upon the ISO-NE to maintain reliability of the bulk power system and to administer the electricity markets within New England.

Through its joint ownership in VELCO and under the Cooperative's participation in the Central Dispatch Agreement (CDA) with the Vermont Public Power Supply Authority (VPPSA), the Cooperative is a member of the New England Power Pool (NEPOOL). The Cooperative's power supply resources are combined in the CDA with other VPPSA participants, and settled as one entity with ISO-NE. The CDA is intended to provide savings to its members by taking advantage of economies of scale through sharing staff resources through VPPSA, where under the CDA supply sources and loads of all of its participants are aggregated into a single entity for the purpose of ISO-NE settlement calculations. The Cooperative became a member of the CDA effective July 1, 1998. The Cooperative can withdraw from the arrangement on a short-term notice (30 days including any additional time required by ISO-NE to reflect such a change).

Over the past decade, the ISO-NE market structure has continued to evolve. Spot markets for energy, capacity and ancillary power products were developed, upon which New England utilities such as the Cooperative depend to achieve reliability of the bulk power system. In recent years, significant investments in transmission in the ISO-NE region have contributed to increased transmission costs for the Cooperative and other utilities.

Transmission congestion in the Sheffield-Highgate Export Interface or SHEI area of Vermont restricts the ability for power from Sheffield Wind and Coventry to be exported to areas of power demand in the rest of Vermont and New England. Congestion charges cost WEC $73,325 in 2021 and $140,949 in 2022. This is expected to be ongoing and even exacerbated by additional generation being added in the SHEI area.

In 2022 the Cooperative's energy settlement load obligation with the ISO-NE plus internal generation was 78,287 MWH (this value represents the Cooperative's retail sales, distribution and transmission losses, unbilled accounts, and internal generation). To hedge its load obligation, the Cooperative's power sources in 2022 totaled 72,163 MWH. The following table summarizes the Cooperative's sources of power:

	2022			2021		
	MWH	Percentage		MWH	Percentage	
VDPS - NYPA	9,893	13.70	%	12,274	15.67	%
Small Power Producers & Ryegate	2,278	3.16	%	2,432	3.10	%
Wrightsville	641	0.89	%	1,844	2.35	%
Coventry Clean Energy Corporation	48,801	67.63	%	53,511	68.32	%
Sheffield Wind	7,712	10.69	%	6,066	7.74	%
Market Purchases	2,838	3.93	%	2,200	2.81	%
Total Resources	72,163	100.00	%	78,327	100.00	%
Load Obligation	78,287			79,340		
ISO Exchange	(6,124)	-7.80	%	(1,013)	-1.29	%

Table 6: WEC Power Supply Energy from "WEC Consolidated Financial Statements, December 31, 2022"

C. Summary of Construction Program & Costs

The results indicate that a total budget of $11,028,292 will be required for the proposed CWP, see the complete 2024-2027 budget in *Table 7* below. It is anticipated that there will be approximately $621,001 of Customer-In-Aid-Contributions (CIAC) so that the total CWP that WEC will finance from the RUS is $10,407,291. The 2019-2022 CWP received $8,081,840 in funding. The increase in requested funding is due to the rise in equipment costs and AMI initiatives. A complete status of the 2019-2022 CWP items is located on page 26.

The following is a list of the larger Projects included in 2024-2027 CWP including recommendations from the 2023 LRP:

a. Finish upgrading the 3319, 34.5kV Transmission Line that feeds the #5 South Walden Substation, line was previously upgraded for VELCO fiber make ready, $234,000.
b. Addressing Transmission Ground Fault Over Voltage “TGFOV” issues at all the distribution substations, due to increasing “DER” is $450,000.
c. There are two circuits that require three phase extension projects to address increasing loads and one circuit mitigation project designed to reduce outages which combined are approximately $714,056, see Appendix B, *Figure 9*, *Figure 10* and *Figure 11*.
d. Recloser work due to increasing load and fault current is approximately $594,000 of this total.
e. Regulator upgrades and setting changes account for another $236,300.
f. Overloaded distribution transformer upgrades is approximately $266,988.
g. Replace a failing chiller unit at the Coventry generation plant estimated at $250,000.
h. Replace the obsolete control system at the Wrightsville hydro plant estimated at $75,000.
i. A new 34.5 kV recloser to improve reliability and work clearances at the #5 South Walden substation is estimated to be $75,000.

2024-2027 CWP Costs

		2019-2022 CWP		2024-2027 CWP				
		Total Budgeted	Total (Actual)	2024	2025	2026	2027	Total
100	**Line Extn (OH & URD)**							**$828,001**
	101 Underground	$138,747	$301,746	$39,890	$39,890	$39,890	$39,890	$159,559
	102 Overhead	$581,254	$734,839	$167,111	$167,111	$167,111	$167,111	$668,442
300	**Line Conversions**	$5,194,245	$1,393,996	$730,041	$499,341	$457,453	$350,847	**$2,037,682**
500	**Sub changes**	$12,500	$0	$167,500	$150,000	$150,000	$150,000	**$617,500**
600								**$6,008,359**
	601 Transformers OH	$363,947	$1,111,022	$1,091,533	$625,017	$0	$0	$1,716,549
	Transformers UG	$52,371	$277,359	$375,636	$64,422	$0	$0	$440,058
	601 Meters-AMI	$168,000	$166,012	$340,813	$340,813	$340,813	$340,813	$1,363,252
	602 Misc Service Improvements	$22,000	$1,242	$6,050	$6,050	$6,050	$6,050	$24,200
	603 Line Reclosers	$23,250	$24,450	$48,000	$48,000	$48,000	$450,000	$594,000
	604 Voltage Regulators	$21,030	$23,980	$39,650	$39,650	$0	$0	$79,300
	605 Capacitors	$9,892	$21,348	$39,000	$0	$0	$0	$39,000
	606 Misc Pole Replacement	$450,001	$2,842,111	$120,000	$120,000	$120,000	$120,000	$480,000
	607 Misc Distr Replacement	$800,002	$333,419	$220,000	$220,000	$220,000	$220,000	$880,000
	608 Misc Conductor Replacement	$400,001	$23,316	$98,000	$98,000	$98,000	$98,000	$392,000
	610 Fault Indicators	$5,000	$0					
700								**$902,750**
	702 Security/Street Lighting	$15,000	$27,402	$4,000	$4,000	$4,000	$4,000	$16,000
	705 AMI Line Equip/Repeaters	$0	$0	$886,750	$0	$0	$0	$886,750
1001	Jackson Corners - Insulators	$110,000	$199,351					
1002	Jackson Corners - GOAB	$31,000	$0					
1001	So. Walden Tap – Insulators/Poles			$0	$0	$234,000	$0	**$234,000**
1002	So. Walden Tap – Recloser			$0	$0	$75,000	$0	**$75,000**
1201	Coventry Pipe Upgrade - Outside	$351,600	$393,264					
1203	Coventry Pipe Upgrade Amendment	$380,000	$554,099					
1201	**Coventry Chiller Replacement**			$250,000	$0	$0	$0	**$250,000**
1202	**Wrightsville Andover Upgrade**			$75,000	$0	$0	$0	**$75,000**
	Sub Total	$9,129,840	$8,428,955	$4,698,973	$2,422,293	$1,960,316	$1,946,710	**$11,028,292**
	CIAC	-$620,000						**-$621,001**
	Total Budget (Proposed)	$8,509,840						**$10,407,291**
			$8,428,955					

Table 7: CWP 2024-2027 – Budget

D. Load Data

This section provides load data from the LRP that is forecasted out to ten years. The first load Forecast in *Table 19*, located in Appendix A along with the rest of the tables referenced in this section, indicates the load growth for the WEC system from 2023 to 2033 based off historical WEC loads. *Table 20* is a load forecast based off historical data that also incorporates Vermont specific Beneficial Electrification factors publicly available from ISO-NE. In the past two years the WEC system has been firmly winter peaking with peaks occurring after the sun has gone down. This means that DER will not be able to further offset increases in loads. The WEC system has documented continued growth in Member counts as shown in *Figure 7* in Appendix A. It should also be noted that WEC has seen a significant increase in requests to upgrade services and replace overloaded distribution transformers due to Beneficial Electrification.

Some load flow results from the LRP, which covers the system present and four-year forecasted loads, pre- and post-Recommendations, are shown in Appendix C and show the following conditions:

- Present Conditions
    - Prior to Recommendations
        - Peak, No DER Output
        - Minimum, No DER Output
        - Minimum, Full 100% DER Output
    - Post Recommendations
        - Peak, No DER Output
        - Minimum, Full 100% DER Output

- Four Year Peak
    - Prior to Recommendations
        - Peak, No DER Output
        - Minimum, Full 100% DER Output
    - Post Recommendations
        - Peak, No DER Output
        - Minimum, Full 100% DER Output

All calculations and analysis done in the LRP followed industry best practices and are documented for future reference.

The WEC infrastructure that feeds distribution categories were reviewed in the following categories:

1. Sub-transmission Lines
   No sub-transmission lines were shown to be overloaded in the most recent LRP.

2. Distribution Substations
   Substation limiting elements and their present and projected four year loads are shown in *Table 21* through *Table 23*.

3. Distribution Circuit Equipment at the substation
   Circuit limiting elements, at the substation, their present and projected four year loads were are shown in *Table 24* through *Table 27*.

4. Circuit line devices that require upgrades that are included in the CWP are shown below in *Table 8*. These upgrades are included in the Recloser and Regulator upgrades listed in the above Section C. No additional line devices required upgrades due to loads at the forecasted four-year loads.

Substation	Circuit	Device #	Device Description	Rating	Current Peak Load No DER	Recommendation		
				Amps	Peak Amps	#	New Device Description	Rating
#1 East Montpelier	#1 Cabot	RC13306	50H Line Recloser	50	54.6	135	70 V4H	140A
#3 Mount Knox	#2 Corinth	RC24581	50L Line Recloser	50	63.1	256	Triple-Single	400A
#8 Jackson Corners	#3 Northfield	REG24076	(3) - 150A Line Regulators	150	101.2	31	219	219A
#10 Maple Corners	#2 Middlesex	RC09580	35 H Line Recloser	35	38.6	172	Upgrade 172 to a 50 V4H at minimum	50A
#11 North Tunbridge	#3 Brookfield	RC30229	50 H Line Recloser	50	65	133	100 4H	100A

Table 8: Line Devices – Current Peak Load – No DER

II. BASIS OF STUDY AND PROPOSED CONSTRUCTION

A. Planning Criteria

The following Planning Criteria, used for the LRP analysis for normal and N-1 conditions is based off RUS requirements and industry best practices:

- Thermal Criteria:
  - Substation Transformers ≤ 100% of Top Nameplate Rating
  - Fuses, Reclosers, Switches ≤ 100% of Top Nameplate Rating
  - Voltage Regulators ≤ 100% of Top Nameplate Rating (without load bonus)
  - Overhead & Underground Conductors ≤ 90% of Nominal Rating
- Protection Criteria:
  - Device pickups shall be 150% of the maximum current flow through the device.
  - Device Reach shall be ≥ 3 for bolted LLL and SLG faults.
- Voltage Criteria:
  - Within ANSI Range A (0.95 – 1.05 per-unit) [4]
  - Phase Imbalance < 3% between all phases
- Transmission Ground Fault Overvoltage (TGFOV) Criteria:
  - Load-to-Generation Ratio < 2 on applicable transformer winding configurations
- Power factor correction in the form of capacitors can reduce losses and improve voltage, provided that the capacitor is sized and placed judiciously. The criteria for installing a capacitor bank to reduce losses is for circuits with a power factor less than 95%.
- Asset Conditions
  - Sub-transmission Poles >50 years of age will be considered near end-of-life[5].
  - Condition to be based on field information, testing, and WEC Operations consultation.

B. Distribution Line and Equipment Costs

The basic cost estimates and parameters, shown in *Table 9* were used to develop high level budgetary planning grade estimates for the 2023 LRP. It should be noted that in the few cases where options presented themselves in the LRP that comparison analysis

[4] ANSI C84.1 is the national standard for utilization voltage. ANSI Range A is the normal operating voltage which spans from 105% to 95% of nominal. ANSI Range B is the acceptable range for contingency conditions and spans from 106% to 91% of nominal.
[5] USDA RUS Bulletin 1724D-101A RD-GD-2017-85

will be deferred until the upgrade is more imminent due to the recent volatility of equipment costs:

Construction Type	High Level Planning Grade Estimate
Phase Balancing Tap / Fuse Change	$1,600
Setting Change	$1,600
Recloser – Single Ø	$7,411
Recloser – Three Ø	$75,000
Capacitor Install - Three Ø	$12,907
Regulator Install – Single Ø	$39,650
Dist Transformer – Replace - Single Ø – 37.5 kVA	$3,513
Three Ø – 1/0AAAC OH Per Foot	$28.61
Three Ø – 4/0AAAC OH Per Foot	$49.88
Three Ø – 477ACSR OH Per Foot	$99.76
Substation Getaway Cable RC Per Foot	$24.63
TGFOV 3V0 (Add Circuit Recloser Upgrade for each substation)	$75,000
Substation Rebuild	$8,000,000
Coordination Study	$6,000
Strategic Study	$50,000

Table 9: High Level Planning Grade Estimates

C. Status of Previous CWP Items

During the previous 2019-2022 CWP construction period, WEC experienced a significant shift in the type of work from what the 2019-2022 CWP started out as. Due to COVID at the beginning of 2019, many Vermont residents were ordered to work from home increasing energy use across WEC's mostly residential territory. Additionally, Vermont saw an increase in the number of people moving to the State desiring isolation and minimal contact with COVID positive people in higher populated areas prompting an increase in requests for new services at WEC.

Vermont's new 2022 Comprehensive Energy Plan significantly increases the installation and use of Distributed Energy Resources, particularly residential solar and promotes the transition away from fossil fuels for heating and transportation with the installation of residential heat pumps and use of EV's (Beneficial Electrification). Because of these measures, WEC also saw a significant increase in transformer upgrades for members having to upgrade their existing services to accommodate heat pumps and EVs.

In the fall of 2021, because of Beneficial Electrification across the entire Country, WEC became aware that the availability of materials and distribution equipment, particularly distribution transformers, was becoming a problem forcing WEC to place large blanket orders at increased costs to compensate for the long lead times. With transformer costs now two to three times more in 2021 and WEC experiencing low inventory levels on some transformer sizes, the need to delay some transformer upgrades to maintain a safe level of inventory for new services and emergencies became a reality.

Also in 2020, due to the many residents now working from home, Vermont also recognized the need for expanded broadband services and created Communications Union Districts (CUDs) who would be tasked with deploying fiber to all unserved and underserved communities in Vermont. WEC then experienced a very large increase in make ready work, including pole replacements, to accommodate the CUD's fiber attachments to WEC poles. WEC was then faced with increased pole costs and very long lead times for poles.

Because of the above factors, WEC's construction work force was diverted away from Category 300 projects throughout the four-year period to concentrate on new services, service upgrades and make ready work for the fiber buildout by the CUDs.

The status of each item contained in the 2019-2022 CWP plan is provided below.

- Category 100 – Service Connection for New Members
  WEC saw a significant increase during the 2019-2022 CWP and exceeded the anticipated amount of completed new Service Connections.

- Category 200 – Tie Lines
  No new tie lines were proposed in the 2019-2022 CWP.

- Category 300 – Conversions and Line Changes
  WEC completed 30% of the projects targeted for this category due to the unanticipated effects from COVID, broadband and beneficial electrification explained above. Of the remaining 48 projects originally proposed, five projects will be carried over into the new 2024-2027 CWP and the balance will be re-evaluated and added to subsequent CWPs.

- Category 400 – New Substations, Switching Stations and Metering Points
  No new Substations, Switching Stations and Metering Points were proposed in the 2019-2022 CWP.

- Category 500 – Substation Rebuilds
  A new air break switch was installed at the Mt. Knox substation in the 2019-2022 CWP.

- Category 600 – Miscellaneous Distribution Equipment
  - 601 – Transformers
    A total of 543 energy efficient transformers were purchased during the 2019-2022 CWP period.

  - 601 – Meters
    The 2019-2022 CWP estimated total requirement of $168,000 with $166,012 actually spent.

  - 602 – Service Improvements
    Only $2,055 was spent of the $22,000 budgeted due to the increase in contribution in aid from members upgraded their services for new heat pumps and EV chargers.

  - 603 – Sectionalizing Equipment
    One new recloser was installed under the 2019-2022 CWP as well as cutout upgrades completed. Of the $23,250 budgeted for the category, $24,450 was actually spent.

  - 604 – Voltage Regulators
    The 2019-2022 CWP estimated total requirement of $21,030 with $23,980 actually spent.

  - 605 – Capacitors
    The 2019-2022 CWP estimated total requirement of $9,892 with $21,348 actually spent.

  - 606 – System Improvement Pole Changes
    A total of 1,071 poles were changed as part of this category. Of the $450,001 budgeted, $1.6M was used during the 2019-2022 CWP construction period.

  - 607 – Miscellaneous Distribution Replacements
    $321,561 was spent of the $800,002 in this category due to the increase in contribution in aid from the CUDs for make ready work to attach their fiber to WEC poles.

- Category 700 – Other Distribution Items
  - 702 – Security Lights

    A total of 22 security lights were installed during the CWP period at a cost of $27,402.

- Category 1000 – Line and Station Change

  The Jackson Corners insulator changeout program was completed in 2019-2022 CWP at $199,350. This category was originally budgeted at $141,000 which, in August 2022, WEC filed an amendment for additional funds increasing the total assigned to this category to $240,364.

- Category 1203 – Coventry LFGTE Pipe Upgrade Project

  The pipe upgrade outside the plant was completed in 2019 at $393,264, slightly above the budgeted $351,600. In 2022, WEC filed amendment #2 for additional pipe upgrades inside the plant budgeted at $380,000. The total amount spent for that project completed in October 2022 was $554,099.

D. Analysis of Current System Studies

The following studies and information were reviewed for the purposes of developing 2024-2027 CWP:

1. 2023 Long Range Plan

This CWP is based on the recent 2023 LRP analysis and Recommendations. There were only three projects that had more than one solution, two of the projects will be reviewed closer to implementation to determine the least cost option while the third will require a Study to determine the best solution.

The following is a list of the larger Projects from the 2023 LRP included in the 2024-2027 CWP:

a) Finish upgrading the 3319, 34.5kV Transmission Line that feeds the #5 South Walden Substation, line was previously upgraded for VELCO fiber make ready, $234,000.
b) Addressing Transmission Ground Fault Over Voltage “TGFOV” issues at all the distribution substations, due to increasing “DER” is $450,000.

c) There are two circuits that require three phase extension projects to address increasing loads which combined are approximately $714,056, Appendix B, Figure 9 and Figure 11.
d) Recloser work due to increasing load and fault current is approximately $594,000 of this total.
e) Regulator upgrades and setting changes account for another $236,000.
f) Overloaded distribution transformers are approximately $266,988.
g) Replace a failing chiller unit at the Coventry generation plant estimated at $250,000.
h) Replace the obsolete control system at the Wrightsville hydro plant estimated at $75,000.
i) A new 34.5 kV recloser to improve reliability and work clearances at the #5 South Walden substation is estimated to be $75,000.

Current O & M Survey (RUS Form 300)

The RUS Form 300 documents the periodic review of an electric borrowers Operations and Maintenance (O&M) practices. WEC's most recent RUS Form 300 O&M review was completed in August of 2022 and shown below in *Figure 3* and *Figure 4*.

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

REVIEW RATING SUMMARY

BORROWER DESIGNATION	DATE PREPARED
VT0008	August 10, 2022

Ratings on form are:	0: Unsatisfactory – No Records	2: Acceptable, but Should be Improved – See Attached Recommendations
NA: Not Applicable	1: Corrective Action Needed	3: Satisfactory – No Additional Action Required at this Time

PART I. TRANSMISSION and DISTRIBUTION FACILITIES

1. Substations (Transmission and Distribution)	*(Rating)*
a. Safety, Clearance, Code Compliance	3
b. Physical Conditions: Structure, Major Equipment, Appearance	3
c. Inspection Records - Each Substation	3
d. Oil Spill Prevention	3
2. Transmission Lines	
a. Vegetation and Line Maintenance	3
b. Right-of-Way: Clearing, Erosion, Appearance, Intrusions	3
c. Physical Condition: Structure, Conductor, Guying	3
d. Line Patrol Program and Records:	3
e. Pole Inspection Program and Records	3
3. Distribution Lines - Overhead	
a. Pole Inspection - Program and Records	3
b. Line Patrol Program and Records	2
c. Compliance with Safety Codes: Clearances	3
Foreign Structures	3
Attachments	3

3. Distribution Lines - Overhead	*(Rating)*
d. Observed Physical Condition: Right-of-Way	3
Other	3
4. Distribution - Underground Cable	
a. Grounding and Corrosion Control	3
b. Surface Grading, Appearance	3
c. Riser Pole: Hazards, Guying, Condition	3
5. Distribution Line Equipment: Conditions and Records	
a. Voltage Regulators	3
b. Sectionalizing Equipment	3
c. Distribution Transformers	3
d. Pad Mounted Equip: Safety - Locking, Dead Front, Barriers	3
e. Pad Mounted Equip: Appearance - Settlement, Condition	3
f. Kilowatt-hour and Demand Meter Reading and Testing	3

PART II. OPERATIONS and MAINTENANCE

6. Line Maintenance and Work Order Procedures	*(Rating)*
a. Work Planning & Scheduling	3
b. Work Backlogs: Right-of-Way Maintenance	3
c. Work Backlogs: Poles	3
d. Work Backlogs: Retirement of Idle Services	3
e. Work Backlogs: Other	N/A

7. Service Interruptions

a. Average Annual Minutes/Consumer by Cause (Complete for each of the previous 5 years)

PREVIOUS 5 YEARS	POWER SUPPLIER	MAJOR EVENT	PLANNED	ALL OTHER	TOTAL	*(Rating)*
(Year)	a.	b.	c.	d.	e.	
2021	20.50	178.90	20.60	392.30	612.30	1
2020	85.00	192.40	37.10	269.80	584.30	2
2019	207.60	879.60	51.80	247.70	1,386.70	2
2018	25.50	2,134.20	49.30	342.00	2,551.00	1
2017	7.30	6,274.90	51.00	5.60	6,338.80	3

	(Rating)
a. Service Interruptions - outage reporting	2
b. Emergency Restoration Plan	3

8. Power Quality	*(Rating)*
a. General Freedom from Complaints	3
9. Loading and Load Balance	
a. Distribution Transformer Loading	3
b. Load Control Apparatus	N/A
c. Substation and Feeder Loading	3
10. Maps and Plant Records	
a. Operating Maps: Accurate and Up-to-Date	3
b. Circuit Diagrams	3
c. Staking Sheets	3
11. Oil Storage & Handling	
a. Spill prevention containment and control (SPCC) plan	3
12. Avian Protection and Response Plan	
a. Avian Protection Plan	N/A

PART III. ENGINEERING

13. System Load Conditions and Losses		*(Rating)*
a. Annual System Losses	6.58%	3
b. Annual Load Factor	56.9%	3
c. Power Factor at Monthly Peak		3
14. Voltage Conditions		
Substation Transformer Output Voltage Spread		3

15. Load Studies and Planning	*(Rating)*
a. Long Range Engineering Plan	3
b. Construction Work Plan	3
c. Sectionalizing Study	3
d. Load Data for Engineering Studies	3
e. Power Requirements Study	3
f. Energy Efficiency and Conservation Program QA	N/A

Rating Summary a/k/a Form **300:** This form has been modified to include Bulletin and CFR updates through 2018. PAGE 1 OF 2 PAGES

Figure 3: WEC RUS Form 300 Pg. 1

PART IV. OPERATION AND MAINTENANCE BUDGETS

YEAR	For Previous 2 Years		For Present Year	For Future 3 Years		
	2020	2021	2022	2023	2024	2025
	Actual $ Thousands	Actual $ Thousands	Budget $ Thousands	Budget $ Thousands	Budget $ Thousands	Budget $ Thousands
Normal Operation	2,289	2,330	2,610	2,714	2,823	2,936
Normal Maintenance	2,772	3,061	3,055	3,177	3,304	3,436
Additional (Deferred) Maintenance				0	0	0
Total	5,061	5,391	5,665	5,892	6,127	6,372

16. Budgeting: Adequacy of Budgets for Needed Work 3 *(Rating)*

17. Date budget discussed with Board of Directors 10/15/2021 *(Date)*

EXPLANATORY NOTES

ITEM NO.	COMMENTS
	Washington Electric Cooperative (WEC) complies with the conditions normally needed to justify a rating of 3 in the Bulletin 1730-1, Electric System, Operation and Maintenance, for all items that received a ration of a 3 on the RUS Form 300.
Part 1.1.b	1. East Montpelier Substation: WEC should correct large gaps in gate / fencing which exceed 3 inches.
	2. Maple Corners Substation: WEC should continue it's vegitation management in substation.
	3. Walden Substation: WEC should correct gap under fencing which is greater than 3 inches.
	4. West Danville Substation: WEC should store equipment in storage facilites unless for use in near future.
	5. Mt. Knox Substation: WEC should continue it's vegitation management in and around substation.
Part 1.3.b	WEC currently performs line patrol on a 10 year cycle. WEC should perfom the line patrol cycle in accordance with Bulletin 1730-1.
Part 1.3.d and Part 2.6.b	WEC currently performs Distribution ROW clearing on a 9 year cycle. WEC has a 5 year service interruption average of over 2000 minutes/yr. WEC may want to consider increasing the frequency of the ROW clearing cycle. WEC experiences financial pressures due to the unusually high penetration of solar in their service territory and net metering. WEC has increased it's investment in ROW Clearing.
Part II.7.a	WEC records "Major Events" based on the definition established by the Vermont PSB. WEC should consider following the recommendations in Bulletin 1730A-119, Part 3, Interruption Analysis.
Part 3.15.a	WEC's long range plan is out of date. Although RUS does not approve these plans, RUS requires that the cooperative have an up to date LRP.

	NAME	TITLE	DATE
RATED BY:		Director of Engineering	8/10/22
REVIEWED BY:		General Manger	Aug 10 '22
REVIEWED BY:	Dana R. Mattera	RUS GFR	8-10-22

RUS Form 300 (This form has been modified to include Bulletin and CFR updates through 2020.) PAGE 2 OF 2 PAGES

Figure 4 - WEC RUS Form 300 Pg. 2

Sectionalizing Studies

The 2023 LRP included a high level assessment of the existing feeder backup ties (see Appendix B, Figure 12 and Figure 13) and evaluated strategic improvements to facilitate and strengthen feeder ties. WEC members are increasingly relying on electricity for their critical needs, so this flexibility is becoming more important. Strengthening a system for feeder backup also makes it resilient for accommodating load growth.

Existing tie circuit's limiting element at the substation was evaluated for present peak loads and forecasted out to ten years, with no DER, see results in Table 10.

In addition to the existing feeder backup ties, several locations were identified as being prime locations to create or strengthen ties details are given in (see Appendix B, Figure 14 and Figure 15). Several substations such as #3 Mount Knox, #4 West Danville, #5 South Walden, and #9 Moretown do not have existing three phase distribution ties to other substations. The #11 Tunbridge substation already has a tie with #8 Jackson Corners, but it is very limited given the small and fragile conductor between the substations. Table 11 shows the suggested Recommendations to increase feeder backup capability. None of these are included in this CWP but will be addressed in subsequent CWPs. An expanded list of all the feeder backup ties and their thermal impacts to the circuit limiting elements for current and ten-year peak loads is shown in Table 12 [6]. The substation upgrades necessary to address the thermal issues for existing and proposed feeder backup ties are shown in Table 13. Some of the substation upgrades can be factored into other work that will be performed at the substations in the coming years.

Another factor in feeder backup is substation transformer capacity, recommended substation transformer sizes based on feeder backup are shown in Table 14. Note, Table 14 is a suggested size based on Feeder Backup for all the substation transformers regardless of whether they are slated to be replaced or not in the next ten years for other reasons such as thermal or asset concerns.

Circuit recloser settings were reviewed for their Cold Load Pickup capability as well (Table 15). Cold Load Pickup refers to increased current demand that occurs when a line, that has been de-energized for a significant period, is re-energized. This increased current is due to inrush current and loss of load diversity and can be up to 150% of the peak load for the circuit. Inrush current can last for several seconds but loss of load diversity can be an issue for several minutes to several hours. These increased currents can cause the circuit recloser to trip based on the phase pickup settings. Cold Load Pickup issues are a greater risk during feeder backup due to the abnormally high

[6] Any proposed feeder backup tie is highlighted in light green in this section.

loads. A solution for this is to raise the phase pickup for the circuit recloser. However, this is not possible for the WEC circuits since the substation transformers are small enough that they limit the phase pickups of the circuit reclosers. As the substation capacity increases over time though phase pickups should be evaluated and increased where needed and feasible to address growing loads. Since phase pickups cannot be increased the next option is to re-energize parts of the line over a period of time, this is an added burden to Members and the WEC workforce under what would already be a contingency case. Increased transformer sizes and remote switching of critical switches could reduce the impact.

No load flows were done as part of the feeder backup assessment.

							10 Year Forecasted		
Sub	Circuit Providing Back Up	Circuit Being Backed Up	Limiting Element	Limiting Element Current Loading (Amps)	Combined Peak Amps Loading	Current Load for combined circuits (KW)	Loading for Combined Circuits (kW)	Ratio of combined circuits current to 10 year forecasted load	Peak Load Combined Circuit (Amps)
#1 East Montpelier	#1 Cabot	#1 East Montpelier - #3 County Road	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A	150	116.9	1,754	2,622	1.49	**174.75**
	#2 Orange	#8 Jackson Corners - #1 Topsham	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A	150	**141.3**	2,221	3,293	1.48	**209.50**
	#3 County Rd	#10 Maple Corners - #2 Middlesex	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A 4/0 ACSR- OH Line - Rated 357A	150	120.7	1,755	2,793	1.59	**192.09**
		#1 East Montpelier - #2 Cabot			116.9	1,754	2,165	1.23	**144.29**
#5 South Walden	#1 Greensboro	#5 South Walden - #3 West Hill Pond	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A 1/0AAAC - OH Line - Rated at 256A	150	109	976	1,261	1.29	**140.83**

							10 Year Forecasted		
Sub	Circuit Providing Back Up	Circuit Being Backed Up	Limiting Element	Limiting Element Current Loading (Amps)	Combined Peak Amps Loading	Current Load for combined circuits (KW)	Loading for Combined Circuits (kW)	Ratio of combined circuits current to 10 year forecasted load	Peak Load Combined Circuit (Amps)
	#3 West Hill Pond	#5 South Walden - #1 Greensboro	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A 1/0ACSR - OH Line - Rated 242A	150	109	976	1,261	1.29	**140.83**
#8 Jackson Corners	#1 Topsham	#1 East Montpelier - #2 Orange	Recloser Bypass 2/0 ACSR - OH Line - Rated 276A	150	**141.3**	2,221	3,293	1.48	**209.50**
	#2 Chelsea	#11 North Tunbridge - #1 Corinth	Recloser Bypass 1/0AAAC - OH Line - Rated 256A	150	83.7	1,573	2,084	1.32	**110.89**
#10 Maple Corners	#2 Middlesex	#1 East Montpelier - #3 County Rd	Circuit Regulators Recloser Bypasses - 150A 4/0 ACSR- OH Line - Rated 357A	100	**120.7**	1,755	2,793	1.59	**192.09**
#11 North Tunbridge	#1 Corinth	#8 Jackson Corners - #2 Chelsea	Circuit Regulators 4/0 ACSR- OH Line - Rated 357A	150	83.7	1,573	2,084	1.32	110.89

Table 10: Existing Feeder Backup Ties – Current & Future Thermal Evaluation

Substation	Circuit	Recommendation #	Description	Ties that are Created/Strengthened	From Pole, Road, Town	To Pole, Road, Town	Distance (Feet)
#4 West Danville	#1 Hookerville	275	Extend 3Ø & RC[7] #4HDC	Creates West Danville-S. Walden Tie	Pole #4-1H-1, Woodward Rd, Danville	Pole #5-2-82L45, West Shore Rd, Cabot	6616
#5 S. Walden	#2 Cabot	276	Extend 3Ø & RC #4HDC	Creates West Danville-S. Walden Tie	Pole #5-2-82 Cabot Plains Rd, Cabot	Pole #5-2-82L45, West Shore Rd, Cabot	10017
#8 Jackson Corners	#2 Chelsea	98	RC #2ACSR	Jackson Corners - Tunbridge	Pole #8-2-41, Chelsea Rd, Williamstown	Pole #8-2-68, Williamstown Rd, Washington	9591
		99			Pole #8-2-71, Williamstown Rd, Washington	Pole #8-2-70, Williamstown Rd, Washington	205
		100			Pole #8-2-79 ROW off VT Rte. 110, Chelsea	Pole #8-2-86, VT Rte. 110, Chelsea	1660
		101			Pole #8-2-144, ROW off VT Rte. 110, Chelsea	Pole #8-2-164, Washington Turnpike, Chelsea	7427
#9 Moretown	#1 Middlesex	102	Extend 3Ø	Creates Moretown #1 Middlesex to East Montpelier #3 County Rd circuit tie	Pole #9-1-163, French Road, Middlesex	Pole #9-1-215, Horn of the Moon Rd, Middlesex	17386
#10 Maple Corners	#1 North Calais	277	Extend 3Ø	Creates 2nd tie between #10 Maple Corners and #1 East Montpelier Substations	Pole #11-1-173R17, George Rd, Calais	Pole #1-1-54, Lightening Ridge Rd, Calais	19780

[7] RC = Re-Conductor

Substation	Circuit	Recommendation #	Description	Ties that are Created/Strengthened	From Pole, Road, Town	To Pole, Road, Town	Distance (Feet)
#11 North Tunbridge	#1 Corinth	104	RC 6/8CWC	Jackson Corners - Tunbridge	Pole #11-1-110, ROW off Blackhawk Road, Chelsea	Pole #11-1-110L27, Upper Village Road, Chelsea	6526
#3 Mount Knox	#2 Corinth	64	Extend 3Ø	Creates three phase tie to #8 Jackson Corners #1 Topsham circuit	Mount Knox Pole #3-2-33 William Scott Memorial Hwy US Rte. 302, Topsham, VT	Pole #3-2-33R13 William Scott Memorial Hwy US Rte. 302, Orange, VT	3696
#8 Jackson Corners	#1 Topsham	74	Extend 3Ø	Creates a three-phase tie to #3 Mount Knox #2 Corinth circuit	Pole #8-1-131, Rte. 302, Orange, VT	Pole #3-2-33R13, William Scott Memorial Hwy US Rte. 302, Orange, VT	21089

Table 11: Strategic Feeder Backup Upgrades[8]

[8] Any proposed feeder backup tie is highlighted in light green in this section.

							10 Year Forecasted		
Sub	Circuit Providing Back Up	Circuit Being Backed Up	Limiting Element	Limiting Element Current Loading (Amps)	Combined Peak Amps Loading	Current Load for combined circuits (KW)	Loading for Combined Circuits (kW)	Ratio of combined circuits current to 10 year forecasted load	Peak Load Combined Circuit (Amps)
#1 East Montpelier	#1 Cabot	#1 East Montpelier - #3 County Road	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A	150	116.9	1,754	2,622	1.49	**174.75**
		#10 Maple Corners - #1 North Calais		150	**141**	989	1,605	1.62	**228.82**
	#2 Orange	#8 Jackson Corners - #1 Topsham	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A	150	**141.3**	2,221	3,293	1.48	**209.50**
	#3 County Rd	#1 East Montpelier - #2 Cabot	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A 4/0 ACSR- OH Line - Rated 357A	150	116.9	1754.00	2,165	1.23	**144.29**
		#9 Moretown - #1 Middlesex			115	2,305	3,780	1.64	**188.59**
		#10 Maple Corners - #2 Middlesex			120.7	1,755	2,793	1.59	**192.09**
#3 Mount Knox	#2 Corinth	#8 Jackson Corners - #1 Topsham	Recloser Bypass 2/0 ACSR - OH Line - Rated 276A	150	**159**	2,701	3,775	1.40	**222.22**
#4 West Danville	#1 Hookerville	#5 South Walden - #2 Cabot	Voltage Regulators 100A	100	81	813	991	1.22	**98.73**

							10 Year Forecasted		
Sub	Circuit Providing Back Up	Circuit Being Backed Up	Limiting Element	Limiting Element Current Loading (Amps)	Combined Peak Amps Loading	Current Load for combined circuits (KW)	Loading for Combined Circuits (kW)	Ratio of combined circuits current to 10 year forecasted load	Peak Load Combined Circuit (Amps)
#5 South Walden	#1 Greensboro	#5 South Walden - #3 West Hill Pond	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A 1/0AAAC - OH Line - Rated at 256A	150	109	976	1,261	1.29	**140.83**
	#2 Cabot	#4 West Danville - #1 Hookerville	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A	150	81	813	991	1.22	98.73
	#3 West Hill Pond	#5 South Walden - #1 Greensboro	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A 1/0ACSR - OH Line - Rated 242A	150	109	976	1,261	1.29	**140.83**
#8 Jackson Corners	#1 Topsham	#1 East Montpelier - #2 Orange	Recloser Bypass 2/0 ACSR - OH Line - Rated 276A	150	**141.3**	2,221	3,293	1.48	**209.50**
		#3 Mount Knox - #2 Corinth		150	**159**	2,701	3,775	1.40	**222.22**
	#2 Chelsea	#11 North Tunbridge - #1 Corinth	Recloser Bypass 1/0AAAC - OH Line - Rated 256A	150	83.7	1,573	2,084	1.32	**110.89**

							10 Year Forecasted		
Sub	Circuit Providing Back Up	Circuit Being Backed Up	Limiting Element	Limiting Element Current Loading (Amps)	Combined Peak Amps Loading	Current Load for combined circuits (KW)	Loading for Combined Circuits (kW)	Ratio of combined circuits current to 10 year forecasted load	Peak Load Combined Circuit (Amps)
#9 Moretown	#1 Middlesex	#1 East Montpelier - #3 County Rd	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A	150	115	2,305	3,780	1.64	**188.59**
#10 Maple Corners	#1 North Calais	#1 East Montpelier - #1 Cabot	Circuit Regulators Recloser Bypasses - 150A 1/0 AL UG Getaway - Rated 155A 1/0ACSR - OH Line - Rated 242A	100	141	989	1,605	1.62	**228.82**
	#2 Middlesex	#1 East Montpelier - #3 County Rd	Circuit Regulators Recloser Bypasses - 150A 4/0 ACSR- OH Line - Rated 357A	100	**120.7**	1,755	2,793	1.59	**192.09**
#11 North Tunbridge	#1 Corinth	#8 Jackson Corners - #2 Chelsea	Circuit Regulators 4/0 ACSR- OH Line - Rated 357A	150	83.7	1,573	2,084	1.32	110.89

Table 12: Existing & Proposed Feeder Backup Ties – Current & Future Thermal Evaluation[9]

[9] Items in bold **red** lettering are over the thermal limits or very close.

		Recommendation	
Sub	Circuit Providing Back Up	#	Feeder Backup Upgrades
#1 East Montpelier	#1 Cabot	264	Upgrade Recloser Bypass to 150K, Voltage Regulators 328A, & UG Getaway Cable to 350 MCM CU 412A
	#2 Orange	265	Upgrade Recloser Bypass to 150K, Voltage Regulators 328A, & UG Getaway Cable to 350 MCM CU 412A
	#3 County Rd	266	Upgrade Recloser Bypass to 150K, Voltage Regulators 328A, & UG Getaway Cable to 350 MCM CU 412A
#3 Mount Knox	#2 Corinth	267	Upgrade Recloser Bypass to 150K
#4 West Danville	#1 Hookerville	268	Upgrade circuit regulators to 219A
#5 South Walden	#1 Greensboro	269	Upgrade Recloser Bypass to 150K, Voltage Regulators 219A, & UG Getaway Cable to 4/0 AL UG Cable 260A
	#3 West Hill Pond	270	Upgrade Recloser Bypass to 150K, Voltage Regulators 219A, & UG Getaway Cable to 4/0 AL UG Cable 260A
#8 Jackson Corners	#1 Topsham	271	Upgrade Recloser Bypass to 150K
	#2 Chelsea	272	Upgrade Recloser Bypass to 150K
#10 Maple Corners	#1 North Calais	273	Upgrade Recloser Bypass to 150K, Voltage Regulators 328A, & UG Getaway Cable to 350 MCM CU 412A
	#2 Middlesex	274	Upgrade Circuit Regulator to 328A & Recloser Bypass to 150K

Table 13: Circuit Upgrades at the Substation for Feeder Backup

Feeder Backup Source		Substation Being Backed up						
Substation Name	**10 YR Forecasted Load MVA with Electrification**	**Substation Name**	**10 YR Forecasted Load MVA with Electrification**	**Total MVA**	**Existing Transformation Capacity MVA**	**Delta between Transformation Capacity & Feeder Backup Total** ***(Negative indicates that there is insufficient capacity)***	**Min Suggested Transformer Size MVA**	**Notes**
#1 East Montpelier	4.995	#8 Jackson Corners	5.048	10.043	5	-5.043		Jackson Corners has other stronger and potential ties that are closer, load would be split during feeder backup.
	4.995	#10 Maple Corners	1.776	6.771	5	-1.771		
	4.995	#9 Moretown	5.213	10.208	5	-5.208	**7.5/10.5**	There is a 17,386' gap on the Middlesex circuit that is currently single phase and mostly 3/12CWC, note most of the Middlesex main line is 1/0ACSR which needs to be re-conductored for voltage and load support reasons. Moretown doesn't have any potential feeder backup options
	4.995	#5 S. Walden	2.035	7.03	5	-2.03		There will be a 7-mile gap even with the all the upgrades planned for the next 10 years
#2 Jones Brook	0.18	No Ties		0.18	N/A			No Ties

Feeder Backup Source		Substation Being Backed up						
Substation Name	**10 YR Forecasted Load MVA with Electrification**	**Substation Name**	**10 YR Forecasted Load MVA with Electrification**	**Total MVA**	**Existing Transformation Capacity MVA**	**Delta between Transformation Capacity & Feeder Backup Total *(Negative indicates that there is insufficient capacity)***	**Min Suggested Transformer Size MVA**	**Notes**
#3 Mount Knox	3.857	#8 Jackson Corners	5.048	8.905	3.75	-5.155	**7.5/10.5**	Jackson Corners substation load would be at minimum split between Mount Knox and Tunbridge
#4 West Danville	0.875	#5 S. Walden	2.035	2.91	1.5	-1.41	**5**	Three phase tie would need to be built, ~3.15 miles
#5 South Walden	2.035	#1 East Montpelier	4.995	7.03	3.75	-3.28	**5**	There will be a 7-mile gap even with the all the upgrades planned for the next 10 years. Jackson Corners and potentially Moretown would split up this load.
	2.035	#4 West Danville	0.875	2.91	3.75	0.84	**5**	Three phase tie would need to be built ~3.15 miles
#8 Jackson Corners	5.048	#1 East Montpelier	4.995	10.043	3.75	-6.293	**7.5/10.5**	East Montpelier substation load would be split between Jackson Corners and Maple Corners at minimum. Recommend 219A circuit regulators, or 546A bus regulators (non-standard item).
	5.048	#3 Mount Knox	3.857	8.905	3.75	-5.155		
	5.048	#11 Tunbridge	2.553	7.601	3.75	-3.851		

Feeder Backup Source		Substation Being Backed up						
Substation Name	10 YR Forecasted Load MVA with Electrification	Substation Name	10 YR Forecasted Load MVA with Electrification	Total MVA	Existing Transformation Capacity MVA	Delta between Transformation Capacity & Feeder Backup Total *(Negative indicates that there is insufficient capacity)*	Min Suggested Transformer Size MVA	Notes
#9 Moretown	5.213	#1 East Montpelier	4.995	10.208	3.75	-6.458	**7.5/10.5**	There is a 17,386' gap on the Middlesex circuit that is currently single phase and mostly 3/12CWC, note most of the Middlesex main line is 1/0ACSR which needs to be re-conductored for voltage and load support reasons. East Montpelier substation load would likely be split between Moretown, Maple Corners and Jackson Corners
#10 Maple Corners	1.776	#1 East Montpelier	4.995	6.771	2.5	-4.271	**7.5/10.5**	East Montpelier substation load would likely be split between Moretown, Maple Corners and Jackson Corners
#11 Tunbridge	2.553	#8 Jackson Corners	5.048	7.601	3.24	-4.361	**7.5/10.5**	

Table 14: Recommended Substation Transformer Sizes Based on Feeder Backup

Sub	Circuit Providing Back Up	Circuit Being Backed Up	Phase Pickup (Amps)	Cold Load Pickup (Phase/1.5)	Combined Peak Amps Loading	Combined Cold Load Amps	Is Cold Load Pickup Setting sufficient?
#1 East Montpelier	#1 Cabot	#1 East Montpelier - #3 County Road	150	100.00	116.9	175.35	**No**
	#2 Orange	#8 Jackson Corners - #1 Topsham	250	166.67	141.3	211.95	**No**
	#3 County Rd	#10 Maple Corners - #2 Middlesex	250	166.67	120.7	181.05	**No**
		#1 East Montpelier - #2 Cabot			116.9	175.35	**No**
#5 South Walden	#1 Greensboro	#5 South Walden - #3 West Hill Pond	175	116.67	109	163.5	**No**
	#3 West Hill Pond	#5 South Walden - #1 Greensboro	150	100.00	109	163.5	**No**
#8 Jackson Corners	#1 Topsham	#1 East Montpelier - #2 Orange	150	100.00	141.3	211.95	**No**
	#2 Chelsea	#11 North Tunbridge - #1 Corinth	150	100.00	83.7	125.55	**No**
#10 Maple Corners	#2 Middlesex	#1 East Montpelier - #3 County Rd	160	106.67	120.7	181.05	**No**
#11 North Tunbridge	#1 Corinth	#8 Jackson Corners - #2 Chelsea	200	133.33	83.7	125.55	Yes

Table 15: Feeder Backup – Cold Load Pickup Review

E. Historical and Projected System Data

1. Annual Energy & Consumer Data

In addition to the Load Growth analysis done by Control Point Technologies in the 2023 LRP, a second 2023 Long-Term Demand Forecast Summary (see separate report attached) was recently completed for WEC by Itron. The analysis will also be used to forecast energy consumption for WEC through the year 2043 (see *Table 16* below) which also includes the impact of Beneficial Electrification.

Year	SystemPk Date	SystemPk	Chg	BaselinePk	HtPmpCPk	EVCPk	SolarCPk	MWh	Chg
2023	1/24/2023 18:00	21.57		19.73	2.66	0.37	-	78,466.95	
2024	1/23/2024 18:00	22.87	6.0%	20.36	3.1	0.5	-	79,301.28	1.1%
2025	1/21/2025 18:00	23.43	2.4%	20.25	3.56	0.66	-	80,372.21	1.4%
2026	1/20/2026 18:00	24.42	4.2%	20.21	4.01	0.87	-	81,767.69	1.7%
2027	1/19/2027 18:00	25.08	2.7%	20.15	4.46	1.15	-	83,146.12	1.7%
2028	1/18/2028 18:00	25.51	1.7%	20.13	4.88	1.49	-	85,405.24	2.7%
2029	1/23/2029 18:00	26.25	2.9%	20.01	5.36	1.93	-	87,501.91	2.5%
2030	1/22/2030 18:00	27.18	3.5%	19.9	5.83	2.46	-	90,185.26	3.1%
2031	1/21/2031 18:00	28.18	3.7%	19.8	6.27	3.1	-	93,275.72	3.4%
2032	1/20/2032 18:00	29.61	5.1%	19.75	6.69	3.81	-	96,873.65	3.9%
2033	1/18/2033 18:00	30.78	4.0%	19.61	7.19	4.63	-	100,424.58	3.7%
2034	1/24/2034 18:00	31.48	2.3%	19.52	7.65	5.47	-	104,241.07	3.8%
2035	1/23/2035 18:00	32.81	4.2%	19.44	8.04	6.32	-	108,052.10	3.7%
2036	1/22/2036 18:00	33.92	3.4%	19.41	8.38	7.09	-	111,968.96	3.6%
2037	1/20/2037 18:00	35.26	4.0%	19.27	8.76	7.83	-	115,160.29	2.9%
2038	1/19/2038 18:00	36.11	2.4%	19.18	9.1	8.43	-	118,129.92	2.6%
2039	1/18/2039 18:00	36.8	1.9%	19.08	9.4	8.92	-	120,665.61	2.1%
2040	1/24/2040 18:00	36.96	0.4%	19.02	9.6	9.27	-	122,843.93	1.8%
2041	1/22/2041 18:00	37.44	1.3%	18.87	9.89	9.59	-	124,248.40	1.1%
2042	1/21/2042 18:00	37.73	0.8%	18.77	10.03	9.8	-	125,563.75	1.1%
2043	1/14/2043 20:00	24.6	-34.9%	18.68	10.16	9.96	-	126,643.75	0.9%

Table 16: Itron Energy 2023 Forecast

2. Substation & Circuit Load Data

The 2023 LRP load forecast was developed based on historical thermal demand ammeter data going back to early 2020 and, where available, VELCO and GMP SCADA data going back to January 1st, 2018 (See tables in Appendix A). Load data was not available for some circuits, so ratios were developed based on connected kVA or SCADA data was approximated to a circuit level using ratios of thermal demand ammeter data between circuits. It should be noted that thermal demand ammeter data is not coincidental.

Historically, the WEC peak loading has occurred in the winter. In 2019/2020 and 2020/2021 some circuits had summer peaks. However, in the past two years 2021/2022 and 2022/2023 all circuits have been firmly winter peaking. Peak loads occurred between 5:45 PM to 11:00 PM when PV would not have been generating, and the majority of WEC's load is residential, so no load masking was assumed due to DER.

WEC's load was forecasted twice out to the ten-year horizon. The first forecast, shown in *Table 19* using purely historical data and the second, shown in *Table 20*, used publicly available data from ISO NE to approximate the forecasted impact from electrification of heating and transportation. Per *Figure 7*, WEC has seen a steady increase in Members since 2010 and in addition to that WEC has already seen firsthand impacts of increasing electrification to individual distribution transformers and services. Most of the load is residential and many members are served by 5 kVA transformers. A single Level 1 car charger can draw 2.3 kW, and a Level 2 charger can draw 3.7 to 22 kW.

The 2023 LRP load forecast was grown out to 10 years to assist WEC in making planned upgrades in response to the aggressive load growth anticipated. This forecast will be used to help WEC plan for infrastructure upgrades large and small. However, the results of this Report should be regularly reviewed.

The load forecast based on historic loading indicates a peak load of 21.53 MW in 10 years while the forecast that factors in electrification efforts (based on ISO NE11 estimates combined with the historical forecast) shows a peak load of 26.493 MW in 10 years, this is based off a current peak load of 17.839 MW. Historically WEC has seen very low load growth, so the historical forecast is already a significant increase of 3.691 MW or 2.06% while the electrification forecast 8.657 MW or 4.85% increase from the current peak load over a ten-year period. This means that several infrastructure upgrades will be required to support WEC's members greater reliance on electricity so that they can reduce their fossil fuel consumption. Due to WEC members increasingly anchoring their fundamental needs on electricity reducing carbon also creates a push for more reliability-based upgrades like feeder backup capability improvements such as reconductoring and extending three phase. These improvements can also strengthen the system for future growth. Since growth is likely to be more uneven than predicted, having greater connectivity across the system and stronger main lines will increase the flexibility of the WEC system to adapt to its member's needs.

Additional load tables that show the impact of present and forecasted loads are located in Appendix V Section A.

3. Load Data Measurements

WEC load data was based on thermal demand ammeter data, which is collected at each substation monthly. Historical data for use in this study goes back to January 1st, 2018. Most of the WEC circuits have thermal demand ammeter data but at some substations only bus load data is available, in those cases the connected aggregate distribution transformer kVA ratings were used to determine the percentage loading for each circuit. Green Mountain Power "GMP" was able to provide some 15-minute interval SCADA data for some 34.5 kV substation feeds, and Vermont Electric Power Company "VELCO" was also able to supply hourly interval data for the 46 kV sub-transmission line that feeds the WEC #11 North Tunbridge substation. Interval data was used with the thermal demand ammeter data to determine peak loading for each substation and circuit. WEC's kWH AMI data was also incorporated into the load flows which added another layer of granularity to loading across the system.

The WEC system has historically been a winter peaking system, but in some places in the past five years was starting to shift to summer peaking. However, as DER has increased the system has shifted back to winter peaking across the board for the past two years. Where recorded loads had a time-of-day it was shown that these winter peaking loads occurred outside daylight hours. This means that we can assume that there is no load masking due to photovoltaic "PV" generators, which are most of the DER resource deployed on the WEC system.

A 96% Power Factor was assumed for all circuit loads, except the #11 Tunbridge loads, which was based off one of the few locations where we had VAR data available from VELCO. In aggregate the 96% load Power Factor matched the peak VAR demand recorded by the GMP feed to #1 East Montpelier and #10 Maple Corners.

The #11 Tunbridge load Power Factors were assumed to be 99.8%, which is not atypical for mostly residential circuits. This load Power Factor created a VAR demand at the head of the 46 kV sub-transmission line from VELCO Chelsea that matched VELCO's recorded peak loading for the line.

Minimum daytime loading was assumed to be 30% of peak load, this is standard practice for the industry and is fairly accurate provided that the circuit is not a dedicated industrial feed. Since this percentage is based on a peak load after the sun has gone down it is assumed that these are good “true” minimum loads to use since the loads do not include any inadvertent masking from DER which could make the minimum load appear even lower.

In order to more accurately monitor the load and generation across the WEC system, SCADA monitoring is recommended on each circuit. More accurate data could determine if a circuit needs to be de-energized for an extreme regional loading event, it can determine when an upgrade is needed more accurately and can be used to determine if feeder backup is a viable option without risking other members being taken out of service.

4. System Outage & Reliability Data

Included in the 2023 LRP was a review of the WEC reliability data, which included the SAIFI and CAIDI indices for the past 12 years, see *Figure 5* and *Figure 6*. A general downward trend can be seen in the SAIFI, but an upward trend in CADI is indicated. A number of coordination improvements were suggested in the 2023 LRP which will help improve the number of Members out. Then the ten most operated devices from 2016 to 2022 were reviewed to determine what recommendations could be made to improve reliability.

In addition to these frequently operated devices WEC has several locations where outages are of a long duration due to access or adding a new device could reduce the number of Members exposed to an outage, these suggestions were also added to the 2023 LRP. WEC’s 2023 System Reliability Report is included in Appendix E and WEC’s Vegetation Management Plan is included in Appendix F.

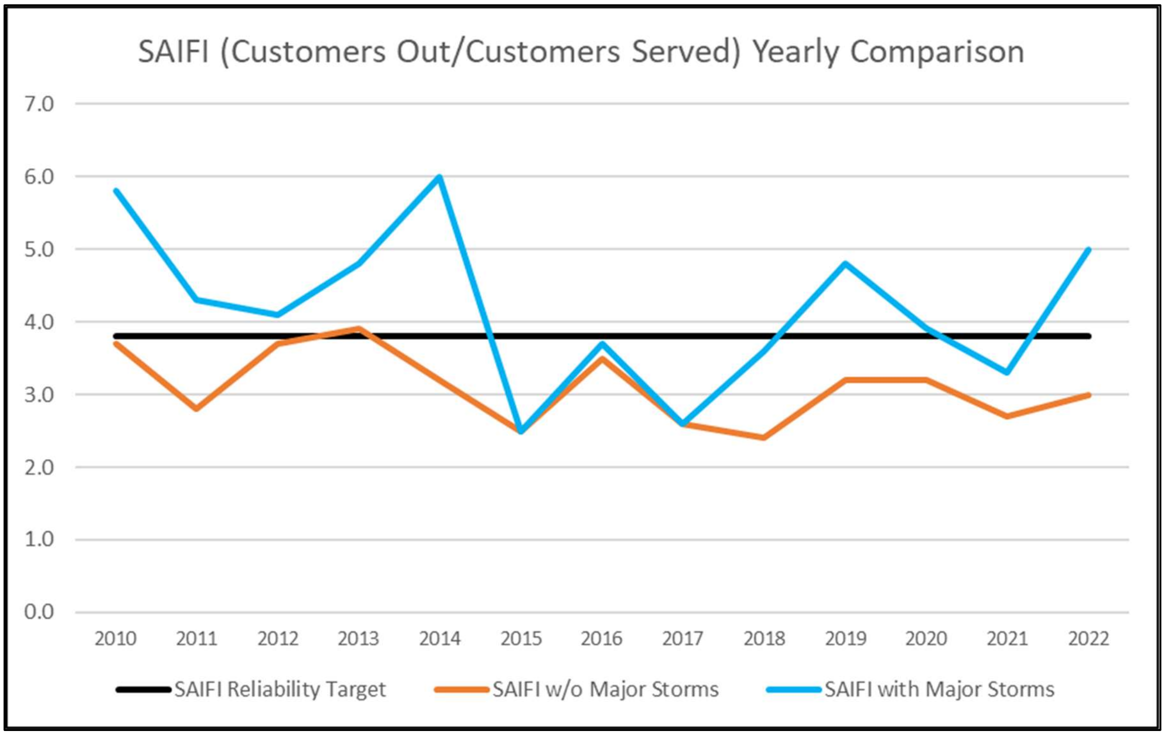


Figure 5: WEC SAIFI 2010-2022

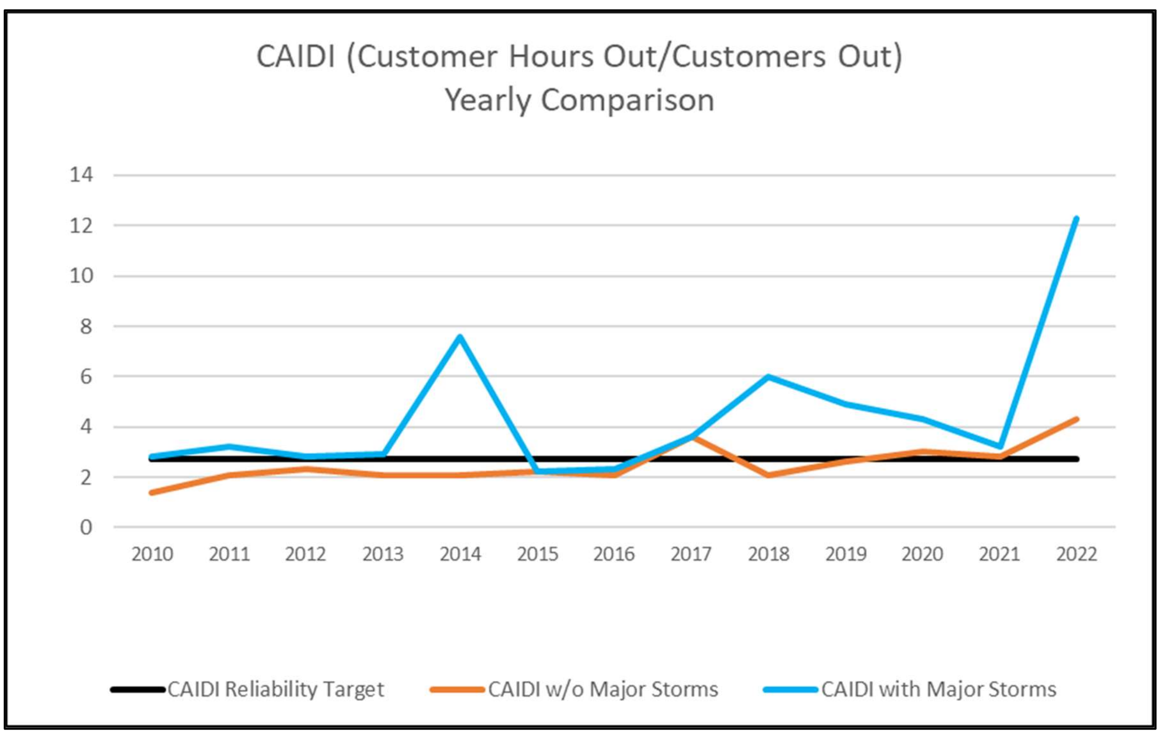


Figure 6: WEC CAIDI 2010-2022

III. 2024-2027 CWP RECOMMEND PROJECTS

Summary

This section of the report summarizes the recommend projects that are included in this 2024-2027 CWP. Projects are listed in categories that include system improvements, capacitor installations, equipment additions/replacements and system reliability. The 2024-2027 CWP budget *Table 18* is included below for reference. Smart Grid Facilities are identified in *Table 18A* below.

A. Service to New Members

Category 100 – The 2024-2027 CWP anticipates a 15% increase in new services for members over the previous CWP for a total of 320 new services and a budgeted amount of $828,000.

B. Service Changes to Existing Customers

Category 602 – Service Improvements – The 2024-2027 CWP has budgeted $24,200 for Service Changes and Upgrades to 71 existing services.

C. Distribution Lines

Category 300 – Overall, 14.22 miles of line will be rehabilitated at an estimated cost of $2,037,683. Of the 14 projects, all but one were carried over from the 2019-2022 CWP and five projects were combined with projects from the 2023 LRP to extend three phase lines approximately 6.2 miles. One new project, #301-44, is a mitigation project to replace a 2.3-mile section of line that was badly damaged during the December 2023 winter storm Elliot with the Hendrix Cable Spacer system. See *Table 17* below for individual project descriptions.

Code	Description/Scope of Work	Carryover From Previous CWP	2024-27 CWP	Sub	Circuit	Total Miles
301-44	Replace Poles / Wires; P#1-3-14L72 to County Rd P#1-3-14L123	No	$196,100	EM	3	2.31
302-01	Replace Poles / Wire 35-7, # 4ACSR from Pole #2 to BE 5	Yes	$175,729	JB	1	0.87
303-44	Replace Poles / Wire; 30-7; 6ACSR; from CO 180- A to BF 36	Yes	$74,508	MK	2	0.38
305-34	SINGLE PHASE to THREE PHASE; 1/0 AAAC Wire; CROSS from SUB to SW06459	Yes	$128,449	WAL	1	1.09
305-35	SINGLE PHASE to THREE PHASE; 1/0 AAAC Wire; CROSS from SW06459 to F06403	Yes	$112,767	WAL	1	0.96
305-36	SINGLE PHASE to THREE PHASE; 1/0 AAAC Wire; CROSS from F06403 TO F06426	Yes	$124,389	WAL	1	1.06
305-38	Replace Poles / Wire; 35-/7; #8CWC Wire, from F08853 to CA 125	Yes	$121,467	WAL	2	1.03
305-41	Replace Poles / Wire; 35-/7; #6SCG Wire; from F08851 to WAL 95	Yes	$12,269	WAL	2	0.10
308-69	Replace Poles / Wire; 35-/7; & 6's #4ACSR* 8CWC Wire; from SW25803 to F25951	Yes	$252,356	JC	2	1.25
308-70	Replace Poles / Wire; 35-/7; & 6's #4ACSR* 8CWC Wire; from F25951 to RC27632	Yes	$130,589	JC	2	0.64
309-20	Replace Poles / Wire; 35-7; 3/12 Wire; from F13001 to MI 114-B	Yes	$61,347	MO	1	0.52
310-36	Replace Poles / Wire; 35-/7; #3/12CWC Wire; from F13228 to SW11477	Yes	$113,771	MC	2	0.96
311-53	SINGLE PHASE to THREE PHASE; Replace Poles/Wire; 35-7; 8CWC Wire; from RC30229 to CH 133	Yes	$348,450	TU	3	1.48
311-54	SINGLE PHASE to THREE PHASE; Replace Poles/Wire; 35-7; 8CWC Wire; from SW28952 to RC28828	Yes	$185,491	TU	3	1.57

Table 17: CWP 2024-2027 Project Code 300 Projects

D. Substations & Metering Points

Category 501 – TGFOV - Budget amount: $450,000. Six of the WEC distribution substations; #1-East Montpelier, #3-Mount Knox, #4-West Danville, #5-South Walden, #8-Jackson Corners, #9-Moretown, #10-Maple Corners and #11-South Tunbridge, require Transmission Ground Fault Over Voltage (TGFOV) protection installed due to the significant increase in Distributed Energy Resources on WEC distribution circuits. TGFOV solutions include new relays that will provide DTT signals via fiber from sub-transmission breaker relays to the new relays in the substation when a fault is present on the sub-transmission system. The DTT signal will open the substation reclosers so that generation from the DERs will not feed into the fault and damage substation transformers and equipment.

Category 502 – High Side Fuse Upgrades – The 2023 LRP determined that new reclosers will be required on WEC distribution feeders as well as reclosers that require upgrading due to the anticipated load increases over the 2024-2027 CWP period. In order for the new and upgraded devices to coordinate with the sub-transmission system protective devices, the High Side Substation Fuses require upgrades. The budget amount for this is estimated at $10,500.

Category 503 – Voltage Regulator Upgrades – The 2023 LRP determined that the Moretown substation regulators need to be increased in size due to the anticipated load increases. The budget amount for this is estimated at $157,000.

E. Sectionalizing Equipment
Category 603 – Line Reclosers – The 2023 LRP recommends the installation and/or upgrade of 18 single-phase and six three-phase line reclosers on distribution feeders to accommodate increase loads and coordinate with substation reclosers. The budgeted amount for these new reclosers is $594,000.

F. Line Regulators
Category 604 – Voltage Regulators – The 2023 LRP includes two new line regulators for the 2024-2027 CWP at a budgeted amount of $79,300.

G. Capacitors
Category 605 – Capacitors – Three new capacitors will be installed in the 2024-2027 CWP at the budgeted amount of $39,000.

H. Ordinary Replacements
Category 601 – Transformers – WEC anticipates purchasing 652 overhead and 94 underground energy efficient transformers at the budgeted amount of $2,156,607.

Category 601 – AMI Meters - During the 2024-2027 CWP, WEC will upgrade our AMI system from the existing Power Line Carrier system to a new RF Mesh network system and take advantage of newly install fiber to our substations and future field fiber installed by the CUDs on our distribution feeders to transmit meter data. The new AMI meters will include: 11,500 residential RF meters, 500 Wi-Fi/RF residential meters and 54 commercial and industrial meters and the budgeted amount for this category will be $1,363,250.

Category 606 – Miscellaneous Pole Replacements – The 2024-2027 CWP has budgeted $480,000 for Pole Replacements.

Category 607 – Miscellaneous Distribution Replacements - The 2024-2027 CWP has budgeted $880,000 for Distribution Replacements.

Category 608 – Miscellaneous Conductor Replacements - The 2024-2027 CWP has budgeted $392,000 for Conductor Replacements.

I. Other Distribution Items

Category 702 – Security/Street Lighting – The 2024-2027 CWP budgets 24 new Security/Street light installations at the budgeted amount of $16,000.

Category 705 – AMI System Upgrade – During the 2024-2027 CWP, WEC will upgrade our AMI system from the existing Power Line Carrier system to a new RF Mesh network system and take advantage of newly install fiber to our substations and future field fiber installed by the CUDs on our distribution feeders to transmit meter data. The new AMI field equipment will include approximately 27 new Gateways, 775 new Relays, 2 Metering Tools and the new Headend System and the budgeted amount for this category will be $886,750. (Note: the new AMI meters are included in Category 601).

J. Transmission Lines

Category 1001 – South Walden 34.5kV Tap – A budgeted amount of $234,000 will be used to complete pole, crossarm and insulator replacements on a section of this transmission line. Approximately two-thirds of this work was completed as make ready work in 2022-2023 for VELCO to install fiber to WEC's South Walden substation for their fiber reliability project.

Category 1002 – South Walden 34.5kV Tap Recloser – In addition to the above work, WEC will install a new 34.5kV Recloser for monitoring the feed from GMP's 3319 34.5kV sub-transmission line. The budgeted amount for the new recloser is $75,000.

K. Generation

Category 1201 – Coventry – The Coventry LFGTE plant requires replacement of a failing chiller unit. The chiller is required to cool the five engine-generator packages in the plant when on line and producing power. The estimated budget for this project is $250,000.

Category 1202 – Wrightsville – The Wrightsville hydroelectric project requires the replacement of an aging Andover controls system used to control the turbines and generators and regulate the flow of water at the inlet structure at the dam. The budgeted amount for this project is $75,000.

2024-2027 CWP Costs

		2019-2022 CWP		2024-2027 CWP				
		Total Budgeted	**Total (Actual)**	**2024**	**2025**	**2026**	**2027**	**Total**
100	**Line Extn (OH & URD)**							**$828,001**
	101 Underground	$138,747	$301,746	$39,890	$39,890	$39,890	$39,890	$159,559
	102 Overhead	$581,254	$734,839	$167,111	$167,111	$167,111	$167,111	$668,442
300	**Line Conversions**	$5,194,245	$1,393,996	$730,041	$499,341	$457,453	$350,847	**$2,037,682**
500	**Sub changes**	$12,500	$0	$167,500	$150,000	$150,000	$150,000	**$617,500**
600								**$6,008,359**
	601 Transformers OH	$363,947	$1,111,022	$1,091,533	$625,017	$0	$0	$1,716,549
	Transformers UG	$52,371	$277,359	$375,636	$64,422	$0	$0	$440,058
	601 Meters-AMI	$168,000	$166,012	$340,813	$340,813	$340,813	$340,813	$1,363,252
	602 Misc Service Improvements	$22,000	$1,242	$6,050	$6,050	$6,050	$6,050	$24,200
	603 Line Reclosers	$23,250	$24,450	$48,000	$48,000	$48,000	$450,000	$594,000
	604 Voltage Regulators	$21,030	$23,980	$39,650	$39,650	$0	$0	$79,300
	605 Capacitors	$9,892	$21,348	$39,000	$0	$0	$0	$39,000
	606 Misc Pole Replacement	$450,001	$2,842,111	$120,000	$120,000	$120,000	$120,000	$480,000
	607 Misc Distr Replacement	$800,002	$333,419	$220,000	$220,000	$220,000	$220,000	$880,000
	608 Misc Conductor Replacement	$400,001	$23,316	$98,000	$98,000	$98,000	$98,000	$392,000
	610 Fault Indicators	$5,000	$0					
700								**$902,750**
	702 Security/Street Lighting	$15,000	$27,402	$4,000	$4,000	$4,000	$4,000	$16,000
	705 AMI Line Equip/Repeaters	$0	$0	$886,750	$0	$0	$0	$886,750
1001	Jackson Corners - Insulators	$110,000	$199,351					
1002	Jackson Corners - GOAB	$31,000	$0					
1001	So. Walden Tap – Insulators/Poles			$0	$0	$234,000	$0	**$234,000**
1002	So. Walden Tap – Recloser			$0	$0	$75,000	$0	**$75,000**
1201	Coventry Pipe Upgrade - Outside	$351,600	$393,264					
1203	Coventry Pipe Upgrade Amendment	$380,000	$554,099					
1201	**Coventry Chiller Replacement**			$250,000	$0	$0	$0	**$250,000**
1202	**Wrightsville Andover Upgrade**			$75,000	$0	$0	$0	**$75,000**
	Sub Total	$9,129,840	$8,428,955	$4,698,973	$2,422,293	$1,960,316	$1,946,710	**$11,028,292**
	CIAC	-$620,000						**-$621,001**
	Total Budget (Proposed)	$8,509,840						**$10,407,291**
			$8,428,955					

Table 18: 2024-2027 CWP Budget Plan

L. Smart Grid Facilities

The following Projects in the 2024-2027 CWP have been identified as Smart Grid Facilities:

740C Code #	Description	Smart Grid Category	Total
501	TGFOV Substation Relay Protection	D	$450,000
503	Voltage Regulator Upgrades	C	$157,000
601	Meters-AMI	E	$1,363,252
603	Line Reclosers	C	$594,000
604	Voltage Regulators	C	$79,300
705	AMI Automated Meter Reading Equip/Repeaters	F	$886,750
1002	South Walden 34.5 KV tap - Install Recloser	A	$75,000
1202	Replace Control System at Wrightsville Hydro Plant	B	$75,000
		Total	**$3,680,302**

Table 18A: Smart Gird Facilities

APPENDICES

A. LOAD TABLES

Load Forecast Based on Historic Load Only												
Sub/Circuit	LGR[10]	Seasonal Year[11] Loads (kW)										
		2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033
#1 East Montpelier 12 kV Distribution	2.12%	3.314	3.385	3.456	3.530	3.604	3.681	3.759	3.838	3.920	4.003	4.087
#1 Cabot		0.566	0.578	0.590	0.602	0.615	0.628	0.642	0.655	0.669	0.683	0.698
#2 Orange		1.561	1.594	1.627	1.662	1.697	1.733	1.770	1.807	1.846	1.885	1.925
#3 County Rd		1.188	1.213	1.239	1.265	1.292	1.319	1.347	1.376	1.405	1.435	1.465
#2 Jones Brook Metering Point	0.00%	0.143	0.143	0.143	0.143	0.143	0.143	0.143	0.143	0.143	0.143	0.143
#3 Mount Knox	1.12%	2.796	2.827	2.859	2.891	2.923	2.956	2.989	3.023	3.056	3.091	3.125
#1 Peacham		0.755	0.763	0.772	0.781	0.789	0.798	0.807	0.816	0.825	0.834	0.844
#2 Corinth		2.041	2.064	2.087	2.110	2.134	2.158	2.182	2.207	2.231	2.256	2.281
#4 West Danville	1.48%	0.616	0.625	0.634	0.644	0.653	0.663	0.673	0.683	0.693	0.703	0.713
#1 Hookerville A Phase		0.153	0.156	0.158	0.160	0.163	0.165	0.167	0.170	0.172	0.175	0.178
#2 W. Danville B Phase		0.262	0.266	0.270	0.274	0.278	0.282	0.286	0.290	0.294	0.299	0.303
#3 Peacham C Phase		0.201	0.204	0.207	0.210	0.213	0.216	0.219	0.223	0.226	0.229	0.233
#5 S. Walden	0.30%	1.575	1.580	1.585	1.589	1.594	1.599	1.604	1.609	1.613	1.618	1.623

[10] LGR = Load Growth Rate
[11] Seasonal Year is from October 1st to September 31st, this keeps winter peaks of the same season together.

Load Forecast Based on Historic Load Only												
Sub/Circuit	LGR[10]	Seasonal Year[11] Loads (kW)										
		2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033
#1 Greensboro		0.518	0.520	0.521	0.523	0.524	0.526	0.527	0.529	0.531	0.532	0.534
#2 Cabot		0.599	0.601	0.603	0.604	0.606	0.608	0.610	0.612	0.614	0.615	0.617
#3 West Hill Pond		0.458	0.459	0.461	0.462	0.464	0.465	0.466	0.468	0.469	0.471	0.472
#8 Jackson Corners	1.76%	3.476	3.537	3.600	3.663	3.728	3.794	3.861	3.929	3.998	4.069	4.140
#1 Topsham		0.660	0.672	0.684	0.696	0.708	0.721	0.734	0.746	0.760	0.773	0.787
#2 Chelsea		0.521	0.531	0.540	0.549	0.559	0.569	0.579	0.589	0.600	0.610	0.621
#3 Northfield		2.294	2.335	2.376	2.418	2.460	2.504	2.548	2.593	2.639	2.685	2.733
#9 Moretown	4.36%	2.906	3.032	3.165	3.303	3.447	3.597	3.754	3.918	4.089	4.267	4.453
#1 Middlesex		1.117	1.166	1.217	1.270	1.325	1.383	1.443	1.506	1.572	1.640	1.712
#2 Moretown		0.292	0.305	0.318	0.332	0.346	0.361	0.377	0.394	0.411	0.429	0.447
#3 Fayston		1.497	1.562	1.630	1.701	1.775	1.853	1.934	2.018	2.106	2.198	2.294
#10 Maple Corners	2.12%	0.990	1.011	1.032	1.054	1.077	1.099	1.123	1.146	1.171	1.195	1.221
#1 North Calais		0.423	0.432	0.442	0.451	0.460	0.470	0.480	0.490	0.501	0.511	0.522
#2 Middlesex		0.567	0.579	0.591	0.603	0.616	0.629	0.642	0.656	0.670	0.684	0.699
#11 Tunbridge	0.00%	2.023	2.023	2.023	2.023	2.023	2.023	2.023	2.023	2.023	2.023	2.023
#1 Corinth		1.052	1.052	1.052	1.052	1.052	1.052	1.052	1.052	1.052	1.052	1.052
#2 South Tunbridge		0.364	0.364	0.364	0.364	0.364	0.364	0.364	0.364	0.364	0.364	0.364
#3 Brookfield		0.607	0.607	0.607	0.607	0.607	0.607	0.607	0.607	0.607	0.607	0.607

Table 19: Load Forecast Based on Historic Load Only

Load Forecast with Electrification												
Sub/Circuit	LGR[12]	Seasonal Year[13] Loads (kW)										
		2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033
#1 East Montpelier 12 kV Distribution	2.12%	3.314	3.425	3.534	3.662	3.807	3.965	4.137	4.325	4.526	4.733	4.955
#1 Cabot		0.566	0.585	0.604	0.625	0.650	0.677	0.707	0.739	0.773	0.808	0.846
#2 Orange		1.561	1.614	1.665	1.725	1.793	1.868	1.949	2.037	2.132	2.230	2.334
#3 County Rd		1.188	1.228	1.267	1.313	1.365	1.421	1.483	1.550	1.623	1.697	1.776
#2 Jones Brook Metering Point	0.00%	0.143	0.145	0.146	0.149	0.152	0.155	0.159	0.164	0.169	0.175	0.180
#3 Mount Knox	1.12%	2.796	2.862	2.925	3.003	3.094	3.196	3.308	3.434	3.568	3.707	3.857
#1 Peacham		0.755	0.773	0.790	0.811	0.836	0.863	0.893	0.927	0.964	1.001	1.042
#2 Corinth		2.041	2.089	2.135	2.192	2.259	2.333	2.415	2.506	2.605	2.706	2.816
#4 West Danville	1.48%	0.616	0.633	0.649	0.668	0.691	0.716	0.743	0.773	0.806	0.839	0.875
#1 Hookerville A Phase		0.153	0.157	0.161	0.166	0.172	0.178	0.185	0.192	0.200	0.208	0.217
#2 Peacham B Phase		0.262	0.269	0.276	0.284	0.294	0.304	0.316	0.329	0.343	0.357	0.372

[12] LGR = Load Growth Rate
[13] Seasonal Year is from October 1st to September 31st, this keeps winter peaks of the same season together.

Load Forecast with Electrification												
Sub/Circuit	LGR[12]	Seasonal Year[13] Loads (kW)										
		2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033
#3 W. Danville C Phase		0.201	0.206	0.212	0.218	0.225	0.234	0.242	0.252	0.263	0.274	0.285
#5 S. Walden	0.30%	1.575	1.599	1.622	1.652	1.690	1.734	1.783	1.840	1.902	1.965	2.035
#1 Greensboro		0.518	0.526	0.533	0.543	0.556	0.570	0.587	0.605	0.625	0.646	0.669
#2 Cabot		0.599	0.608	0.617	0.628	0.643	0.659	0.678	0.700	0.723	0.747	0.774
#3 West Hill Pond		0.458	0.465	0.472	0.480	0.492	0.504	0.519	0.535	0.553	0.571	0.592
#8 Jackson Corners	1.76%	3.476	3.580	3.681	3.802	3.940	4.091	4.256	4.438	4.633	4.833	5.048
#1 Topsham		0.660	0.680	0.699	0.722	0.748	0.777	0.808	0.843	0.880	0.918	0.959
#2 Chelsea		0.521	0.537	0.552	0.570	0.591	0.613	0.638	0.665	0.694	0.724	0.757
#3 Northfield		2.294	2.363	2.429	2.509	2.600	2.700	2.809	2.929	3.058	3.190	3.332
#9 Moretown	4.36%	2.906	3.069	3.233	3.419	3.625	3.847	4.086	4.345	4.620	4.907	5.213
#1 Middlesex		1.117	1.180	1.243	1.314	1.393	1.479	1.570	1.670	1.776	1.886	2.004
#2 Moretown		0.292	0.308	0.325	0.344	0.364	0.387	0.411	0.437	0.464	0.493	0.524
#3 Fayston		1.497	1.581	1.666	1.761	1.867	1.982	2.105	2.238	2.380	2.528	2.686
#10 Maple Corners	2.12%	0.990	1.045	1.102	1.165	1.235	1.310	1.392	1.480	1.574	1.672	1.776
#1 North Calais		0.423	0.447	0.471	0.498	0.528	0.560	0.595	0.632	0.673	0.714	0.759
#2 Middlesex		0.567	0.599	0.631	0.667	0.707	0.751	0.797	0.848	0.902	0.958	1.017
#11 Tunbridge	0.00%	2.023	2.048	2.071	2.104	2.147	2.197	2.254	2.320	2.393	2.469	2.553
#1 Corinth		1.052	1.065	1.077	1.094	1.116	1.142	1.172	1.207	1.245	1.284	1.327

Load Forecast with Electrification												
Sub/Circuit	LGR[12]	Seasonal Year[13] Loads (kW)										
		2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033
#2 South Tunbridge		0.364	0.369	0.373	0.379	0.386	0.395	0.406	0.417	0.431	0.444	0.459
#3 Brookfield		0.607	0.615	0.621	0.631	0.644	0.659	0.676	0.696	0.718	0.741	0.766

Table 20: WEC Distribution Substation & Circuit Load forecast with Beneficial Electrification

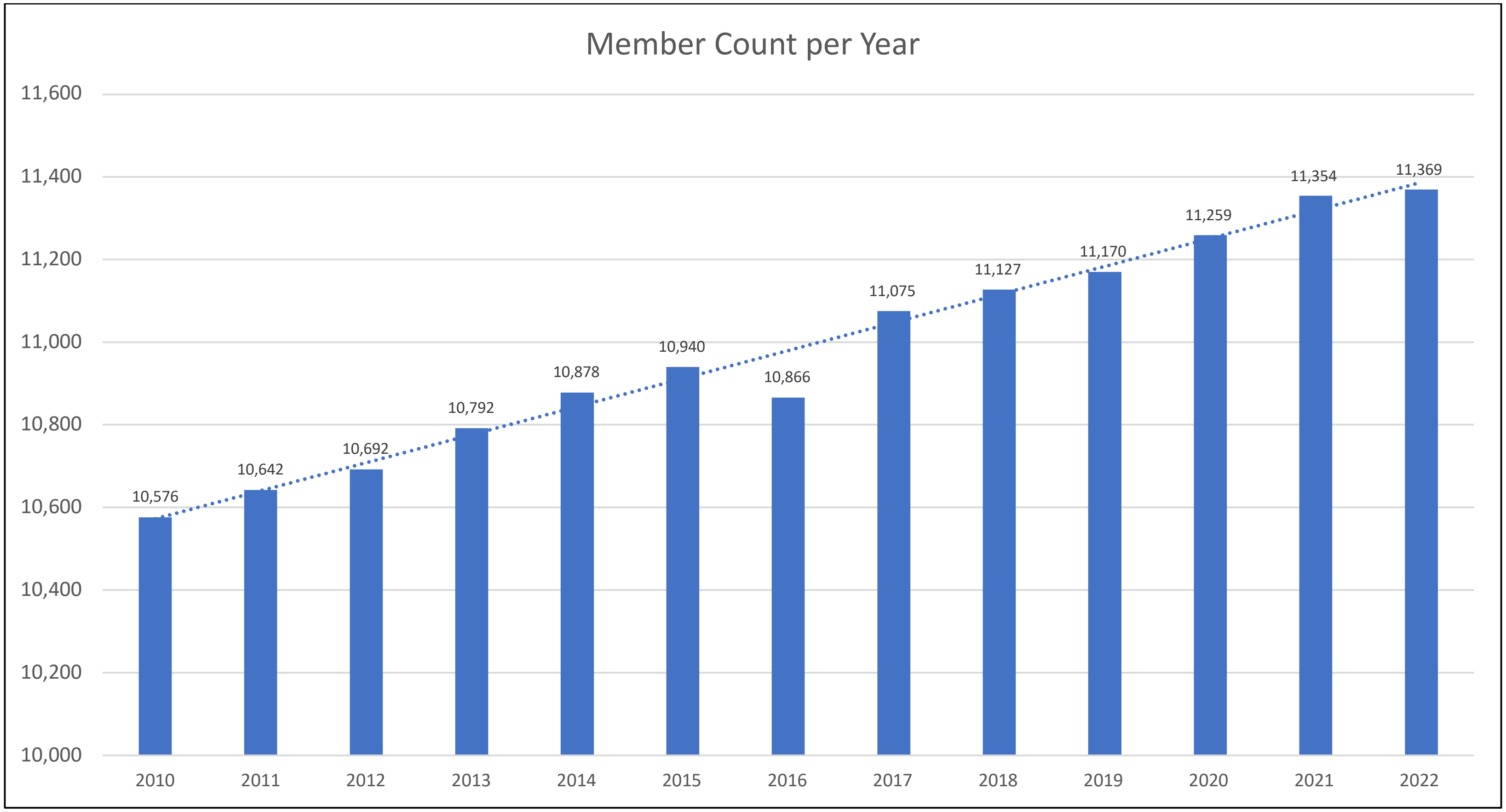


Figure 7: WEC Member Count from 2010 to 2022

Substation	Limiting Element			Current Peak Load, No DER		Remaining 3Ø Capacity	
	Device	Max Amps	MVA	(MVA)	MVA	%	MVA
#1 East Montpelier	Transformer Bank - (3) 1,667 kVA	231.5	5.001	185	3.672	73%	1.328
#2 Jones Brook (Metering Point) ***Single Ø Circuit***	50H Single phase recloser	50	0.360	21	0.149	14%	0.931
#3 Mount Knox	Bus Regulators - 150A[14] *Transformer Bank - (3) 1,250 kVA – 3.75 MVA*	150	3.240	149	2.853	88%	0.387
#4 West Danville	Transformer Bank - (3) 500 kVA	69	1.500	34	0.658	44%	0.842
#5 South Walden	Transformer Bank - (3) 1,250 kVA	174	3.750	114	1.734	46%	2.016
#8 Jackson Corners	Transformer Bank – (1) – 3,750 kVA *Bus Regulators – (3) – 219A*	174	3.750	189	3.483	93%	0.275
#9 Moretown	Transformer Bank – (3) – 1,250 kVA	174	3.750	164	2.997	80%	0.761
#10 Maple Corners	Transformer Bank - (3) 833 kVA	116	2.499	111	1.38	55%	1.119
#11 North Tunbridge	Bus Regulators - (3) 150A *Transformer Bank - (3) 1,250 kVA*	150	3.240	137	1.865	50%	1.893

Table 21: Substation Limiting Element Loading – Current Peak No DER[15]

Substation	Limiting Element			Min Load, Full DER Output		Remaining 3Ø Capacity	
	Device	Max Amps	MVA	%	MVA	%	MVA
#1 East Montpelier	Transformer Bank - (3) 1,667 kVA	231.5	5.001	80	-1.467	29%	3.533
#2 Jones Brook (Metering Point) ***Single Ø Circuit***	50H Single phase recloser	50	0.360	1.59	-0.012	1%	1.069
#3 Mount Knox	Bus Regulators - (3) 150A *Transformer Bank - (3) 1,250 kVA*	150	3.240	63	1.214	37%	2.026
#4 West Danville	Transformer Bank - (3) 500 kVA	69	1.500	8	0.127	8%	1.373
#5 South Walden	Transformer Bank - (3) 1,250 kVA	174	3.750	10	0.111	3%	3.639
#8 Jackson Corners	Transformer Bank – (1) – 3,750 kVA *Bus Regulators – (3) – 219A*	174	3.750	167	-3.489	93%	0.269
#9 Moretown	Transformer Bank – (3) – 1,250 kVA	174	3.750	127	-2.085	55%	1.674
#10 Maple Corners	Transformer Bank - (3) 833 kVA	116	2.499	26	-0.265	11%	2.234
#11 North Tunbridge	Bus Regulators - (3) 150A *Transformer Bank - (3) 1,250 kVA*	150	3.240	8	-405	9%	3.414

Table 22: Substation Limiting Element Loading – Min Load Full DER Output[4]

[14] Two of the bus regulators are rated at 150A, one is 219A.
[15] Items in bold **red** lettering are over the thermal limits or very close.

Substation	Limiting Element			4 Year Peak Load, No DER		Remaining 3Ø Capacity	
	Device	Max Amps	MVA	%	MVA	%	MVA
#1 East Montpelier	Transformer Bank - (3) 1,667 kVA	231.5	5.001	190	3.914	78%	1.086
#2 Jones Brook (Metering Point) ***(Single Ø Circuits)***	50H Single phase recloser	50	0.360	22	0.158	15%	0.922
#3 Mount Knox	Transformer Bank – (1) 7,500/10,500 kVA	486	10.5	143	3.106	30%	7.394
#4 West Danville	Transformer Bank - (3) 500 kVA	69	1.5	37	0.710	47%	0.79
#5 South Walden	Transformer Bank - (3) 1,250 kVA	174	3.750	125	1.776	47%	1.974
#8 Jackson Corners	Transformer Bank – (1) 7,500/10,500 kVA	486	10.5	188	4.013	38%	6.488
#9 Moretown	**Transformer Bank – (3) – 1,250 kVA**	**174**	**3.750**	**209**	**3.813**	**101%**	**-0.054**
#10 Maple Corners	Transformer Bank - (3) 833 kVA	116	2.499	80	1.345	54%	1.154
#11 North Tunbridge	Bus Regulators - (3) 150A *Transformer Bank - (3) 1,250 kVA*	150	3.240	116	2.105	56%	1.654

Table 23: Substation Limiting Element Loading – 4 Year Peak No DER[16]

[16] Items in bold **red** lettering are over the thermal limits or very close.

Substation	Circuit	Device	Limiting Element		Current Peak Loading, No DER		Remaining 3Ø Capacity	
			Amps	MVA	Peak Amps	MVA	%	MVA
#1 East Montpelier	#1 Cabot	Voltage Regulators & Recloser Bypass	150	3.24	58	0.585	18%	2.655
	#2 Orange	Voltage Regulators & Recloser Bypass	150	3.24	100	1.916	59%	1.32
	#3 County Road	Voltage Regulators & Recloser Bypass	150	3.24	59	1.19	37%	2.05
#2 Jones Brook (Metering Point)	#2 Jones Brook *Single Ø Circuit*	50H Single phase recloser	50	0.360	21	0.149	14%	0.93
#3 Mount Knox	#1 Peacham	Recloser Bypass	150	3.24	36	0.763	24%	2.48
	#2 Corinth	Recloser Bypass	150	3.24	118	2.147	66%	1.09
#4 West Danville *(Single Ø Circuits)*	#1 Hookerville *(A Phase)*	Circuit Regulator	100	0.720	26	0.187	26%	0.533
	#2 West Danville *(B Phase)*	Circuit Regulator	100	0.720	33	0.238	33%	0.42
	#3 Peacham *(C Phase)*	Circuit Regulator	100	0.720	34	0.245	34%	0.475
#5 South Walden	#1 Greensboro *Single Ø Circuit*	Voltage Regulators & Recloser Bypass	150	1.08	78	0.589	54%	0.492
	#2 Cabot	Voltage Regulators & Recloser Bypass	150	3.24	47	0.654	20%	2.59
	#3 West Hill Pond	Voltage Regulators & Recloser Bypass	150	3.24	31	0.497	15%	2.74
#8 Jackson Corners	#1 Topsham	Recloser Bypass	150	3.24	41	0.674	21%	2.57
	#2 Chelsea	Recloser Bypass	150	3.24	31	0.522	16%	2.72
	#3 Northfield	Recloser Bypass	150	3.24	118	2.295	71%	0.94
#9 Moretown	#1 Middlesex	Voltage Regulators & Recloser Bypass	150	3.24	56	1.086	34%	2.154
	#2 Moretown Common *Single Ø Circuit*	Circuit Recloser 70 V4L	70	0.504	47	0.326	65%	0.178
	#3 Fayston	**Circuit Regulator**	**75**	**1.620**	**80**	**1.592**	**98%**	**0.028**
#10 Maple Corners	#1 North Calais	Circuit Regulator	100	2.160	48	0.526	9%	5.444
	#2 Middlesex	Circuit Regulator	100	2.160	62	0.855	14%	5.115
#11 North Tunbridge	#1 Corinth	Recloser Bypass	150	3.240	63	1.016	31%	2.224
	#2 South Tunbridge	Overhead Line – 6/8 CWC	100	0.720	43	0.321	45%	0.399
	#3 Brookfield *Single Ø Circuit*	Recloser Bypass	150	1.08	68	0.532	49%	0.548

Table 24: Circuit Limit Element Loading – Current Peak No DER[17]

[17] Items in bold **red** lettering are over the thermal limits or very close.

Substation	Circuit	Device	Limiting Element		Current Min Load, Full DER Output		Remaining 3Ø Capacity	
			Amps	MVA	Peak Amps	MVA	%	MVA
#1 East Montpelier	#1 Cabot	Voltage Regulators & Recloser Bypass	150	3.24	10	-0.149	5%	3.09
	#2 Orange	Voltage Regulators & Recloser Bypass	150	3.24	18	0.353	11%	2.89
	#3 County Road	Voltage Regulators & Recloser Bypass	150	3.24	77	-1.527	47%	1.71
#2 Jones Brook (Metering Point)	#2 Jones Brook *Single Ø Circuit*	50H Single phase recloser	50	0.360	2	-11.44	1%	1.07
#3 Mount Knox	#1 Peacham	Recloser Bypass	150	3.24	6	0.065	2%	3.18
	#2 Corinth	Recloser Bypass	150	3.24	58	1.149	35%	2.09
#4 West Danville *(Single Ø Circuits)*	#1 Hookerville *(A Phase)*	Circuit Regulator	100	0.720	7	0.05	7%	0.67
	#2 West Danville *(B Phase)*	Circuit Regulator	100	0.720	7	0.05	7%	0.67
	#3 Peacham *(C Phase)*	Circuit Regulator	100	0.720	6	0.043	6%	0.677
#5 South Walden	#1 Greensboro *Single Ø Circuit*	Voltage Regulators & Recloser Bypass	150	1.08	10	0.07	6%	1.01
	#2 Cabot	Voltage Regulators & Recloser Bypass	150	3.24	6	0.065	2%	3.17
	#3 West Hill Pond	Voltage Regulators & Recloser Bypass	150	3.24	2	0.037	1%	3.20
#8 Jackson Corners	#1 Topsham	Recloser Bypass	150	3.24	11	0.151	5%	3.09
	#2 Chelsea	Recloser Bypass	150	3.24	7	0.078	2%	3.16
	#3 Northfield	**Recloser Bypass**	**150**	**3.24**	**159**	**3.318**	**102%**	**-0.08**[18]
#9 Moretown	#1 Middlesex	Voltage Regulators & Recloser Bypass	150	3.24	82	1.411	44%	1.83
	#2 Moretown Common *Single Ø Circuit*	Circuit Recloser 70 V4L	70	0.504	22	0.161	32%	0.34
	#3 Fayston	Circuit Regulator	75	1.620	29	0.539	33%	1.08
#10 Maple Corners	#1 North Calais	Circuit Regulator	100	2.160	6	0.063	1%	5.91
	#2 Middlesex	Circuit Regulator	100	2.160	21	0.203	3%	5.77
#11 North Tunbridge	#1 Corinth	Recloser Bypass	150	3.240	20	0.252	8%	2.99
	#2 South Tunbridge	Overhead Line – 6/8 CWC	100	0.720	7	0.052	7%	0.67
	#3 Brookfield *Single Ø Circuit*	Recloser Bypass	150	1.08	6	0.042	4%	1.04

Table 25: Circuit Limiting Element Loading – Current Minimum Full DER[19]

[18] The next limiting device is 4/0AAAC OH conductors are rated at 395A.
[19] Items in bold **red** lettering are over the thermal limits or very close.

Substation	Circuit	Device	Limiting Element		4 Year Peak Loading, No DER		Remaining 3Ø Capacity	
			Amps	MVA	Peak Amps	MVA	%	MVA
#1 East Montpelier	#1 Cabot	Voltage Regulators & Recloser Bypass	150	3.24	56	0.662	20%	2.578
	#2 Orange	Voltage Regulators & Recloser Bypass	150	3.24	79	1.92	59%	1.320
	#3 County Road	Voltage Regulators & Recloser Bypass	150	3.24	61	1.354	42%	1.886
#2 Jones Brook (Metering Point)	#2 Jones Brook *Single Ø Circuit*	50H Single phase recloser	50	0.360	22	0.158	15%	0.922
#3 Mount Knox	#1 Peacham	Recloser Bypass	150	3.24	38	0.85	26%	2.390
	#2 Corinth	Recloser Bypass	150	3.24	107	2.257	70%	0.983
#4 West Danville *(Single Ø Circuits)*	#1 Hookerville *(A Phase)*	Circuit Regulator	100	0.720	28	0.202	28%	0.518
	#2 West Danville *(B Phase)*	Circuit Regulator	100	0.720	35	0.252	35%	0.468
	#3 Peacham *(C Phase)*	Circuit Regulator	100	0.720	38	0.274	38%	0.446
#5 South Walden	#1 Greensboro *Single Ø Circuit*	Voltage Regulators & Recloser Bypass	150	1.08	80	0.606	56%	0.474
	#2 Cabot	Voltage Regulators & Recloser Bypass	150	3.24	37	0.667	21%	2.573
	#3 West Hill Pond	Voltage Regulators & Recloser Bypass	150	3.24	32	0.511	16%	2.729
#8 Jackson Corners	#1 Topsham	Recloser Bypass	150	3.24	35	0.776	24%	2.464
	#2 Chelsea	Recloser Bypass	150	3.24	34	0.613	19%	2.627
	#3 Northfield	Recloser Bypass	150	3.24	123	2.695	55%	2.165
#9 Moretown	#1 Middlesex	Voltage Regulators & Recloser Bypass	150	3.24	71	1.38	43%	1.860
	#2 Moretown Common *Single Ø Circuit*	**Circuit Recloser 70 V4L**	**70**	**0.504**	**56**	**0.410**	**81%**	**0.094**
	#3 Fayston	Recloser Bypass	150	3.24	103	2.026	63%	1.214
#10 Maple Corners	#1 North Calais	Circuit Regulator	100	2.160	41	0.525	9%	5.445
	#2 Middlesex	Circuit Regulator	100	2.160	46	0.825	14%	5.145
#11 North Tunbridge	#1 Corinth	Recloser Bypass	150	3.240	73	1.156	36%	2.084
	#2 South Tunbridge	Overhead Line – 6/8 CWC	100	0.720	49	0.368	51%	0.352
	#3 Brookfield *Single Ø Circuit*	Recloser Bypass	150	1.08	46	0.585	54%	0.495

Table 26: Circuit Limiting Element Loading – 4 Year Peak, No DER – Prior to Fixes

Substation	Circuit	Device	Limiting Element		10 Year Peak Loading, No DER		Remaining 3Ø Capacity	
			Amps	MVA	Peak Amps	MVA	%	MVA
#1 East Montpelier	#1 Cabot	Voltage Regulators & Recloser Bypass	150	3.24	76	0.888	27%	2.35
	#2 Orange	Voltage Regulators & Recloser Bypass	150	3.24	125	2.453	76%	0.79
	#3 County Road	Voltage Regulators & Recloser Bypass	150	3.24	89	1.801	56%	1.44
#2 Jones Brook (Metering Point)	#2 Jones Brook *Single Ø Circuit*	50H Single phase recloser	50	0.360	27	0.189	17%	0.89
#3 Mount Knox	#1 Peacham	Recloser Bypass	150	3.24	50	1.077	33%	2.16
	#2 Corinth	**Recloser Bypass**	**150**	3.24	**138**	**2.879**	**89%**	**0.36**
#4 West Danville *(Single Ø Circuits)*	#1 Hookerville *(A Ø)*	Circuit Regulator	100	0.720	38	0.274	38%	0.446
	#2 West Danville *(B Ø)*	Circuit Regulator	100	0.720	47	0.338	47%	0.382
	#3 Peacham *(C Ø)*	Circuit Regulator	100	0.720	51	0.367	51%	0.353
#5 South Walden	#1 Greensboro *Single Ø Circuit*	Voltage Regulators & Recloser Bypass	150	1.08	101	0.774	72%	0.306
	#2 Cabot	Voltage Regulators & Recloser Bypass	150	3.24	50	0.846	26%	2.394
	#3 West Hill Pond	Voltage Regulators & Recloser Bypass	150	3.24	40	0.646	20%	2.594
#8 Jackson Corners	#1 Topsham	Recloser Bypass	150	3.24	58	1.006	31%	2.234
	#2 Chelsea	Recloser Bypass	150	3.24	44	0.774	24%	2.466
	#3 Northfield	Recloser Bypass	225	4.86	248	3.538	73%	1.322
#9 Moretown	#1 Middlesex	Voltage Regulators & Recloser Bypass	150	3.24	112	2.134	66%	1.106
	#2 Moretown Common *Single Ø Circuit*	**Circuit Recloser 70 V4L**	**70**	**0.504**	**82**	**0.601**	**119%**	**-0.097**
	#3 Fayston	Recloser Bypass	150	3.24	144	2.795	86%	0.445
#10 Maple Corners	#1 North Calais	Circuit Regulator	100	2.160	73	0.805	13%	5.165
	#2 Middlesex	Circuit Regulator	100	2.160	62	1.089	18%	4.881
#11 North Tunbridge	#1 Corinth	Recloser Bypass	150	3.240	84	1.33	41%	1.910
	#2 South Tunbridge	Overhead Line – 6/8 CWC	100	0.720	63	0.473	66%	0.247
	#3 Brookfield *Single Ø Circuit*	Recloser Bypass	150	1.08	62	0.788	73%	0.292

Table 27: Circuit Limiting Element Loading – 10 Year Peak Load No DER – Prior to Fixes[20]

[20] Items in bold **red** lettering are over the thermal limits or very close.

B. MAPS

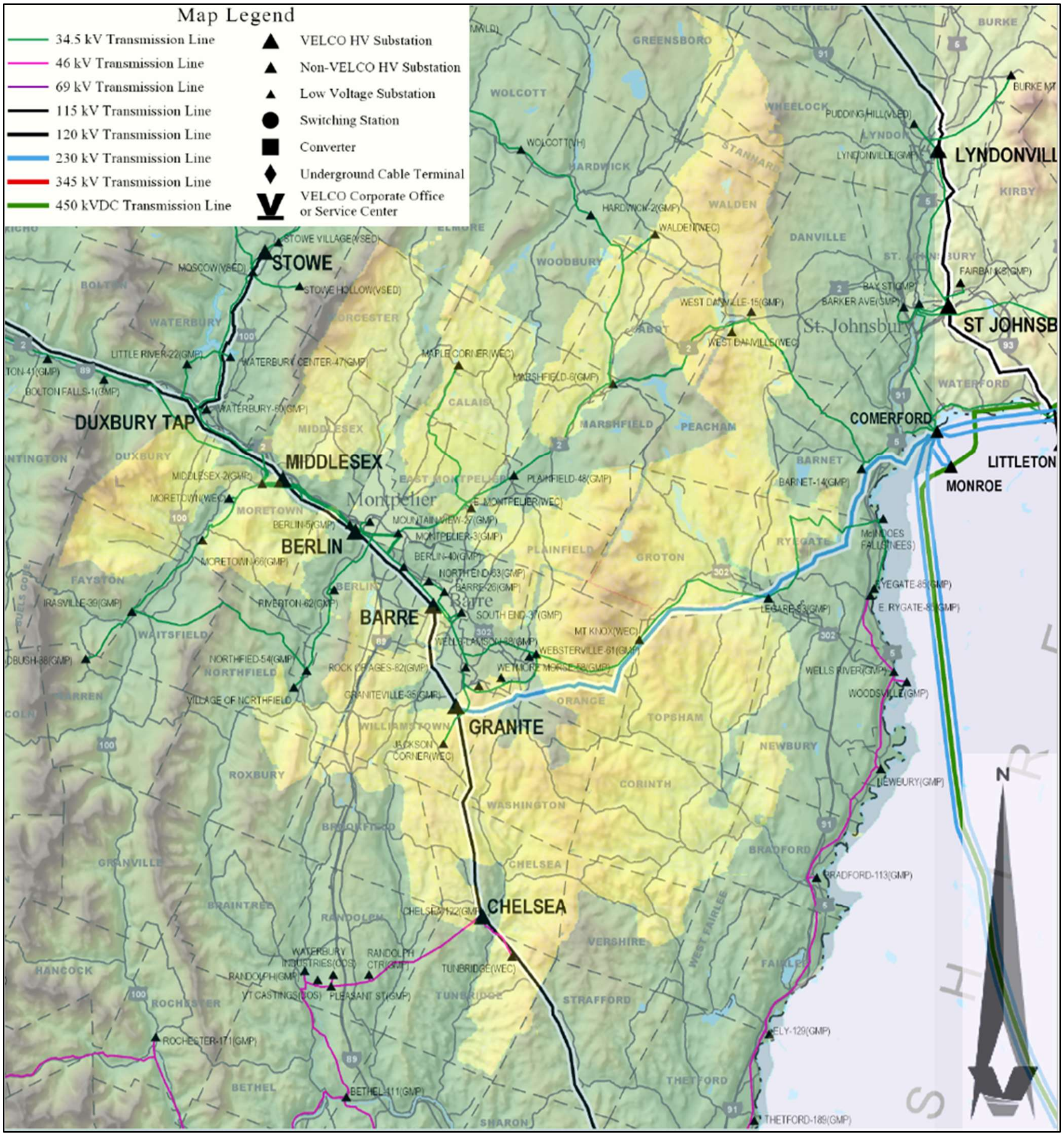


Figure 8: WEC Territory (Yellow) & Transmission Line Crossings

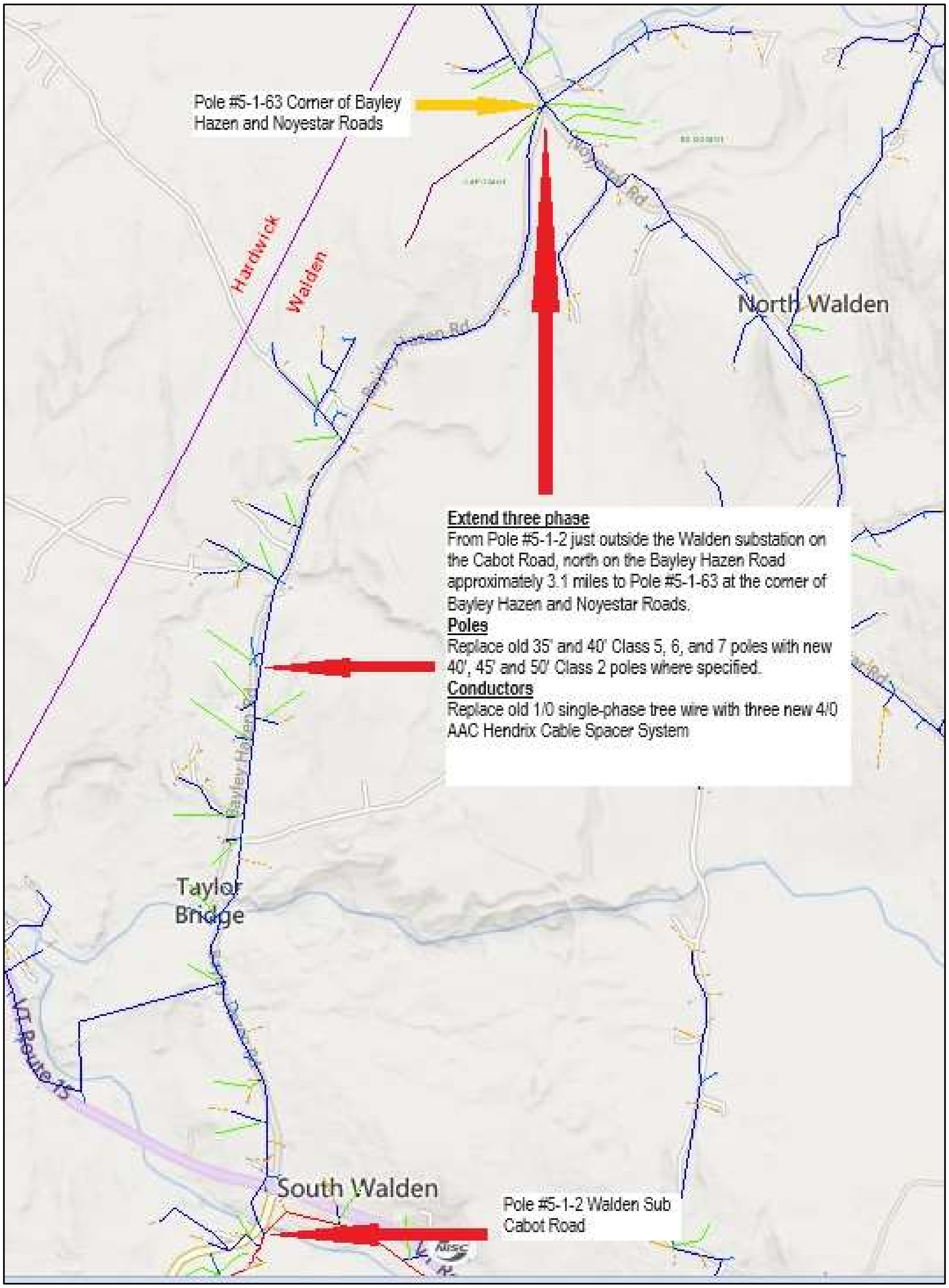


Figure 9: Greensboro Feeder – 3-Phase Extension

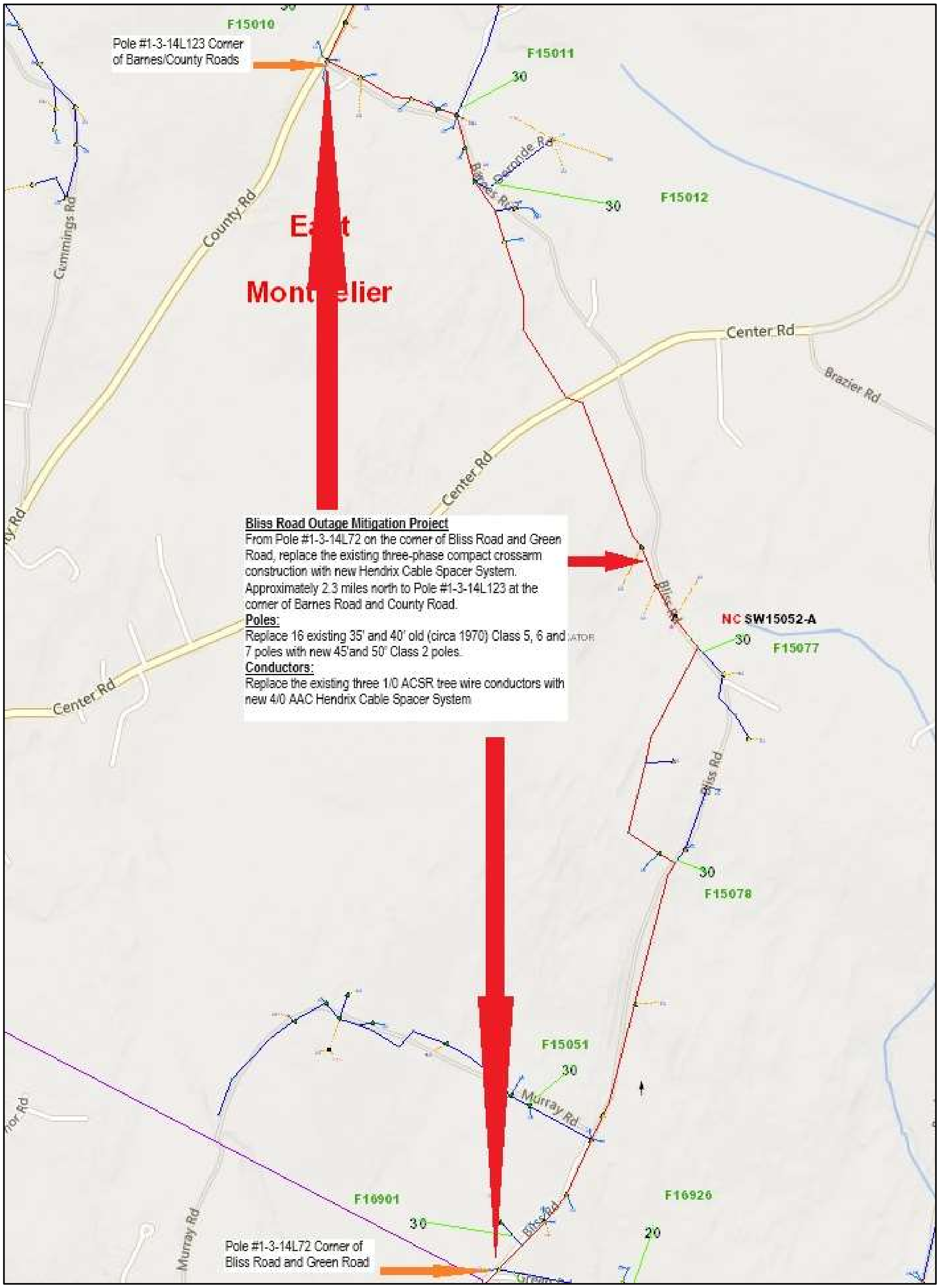


Figure 10: Bliss Road Outage Mitigation Project

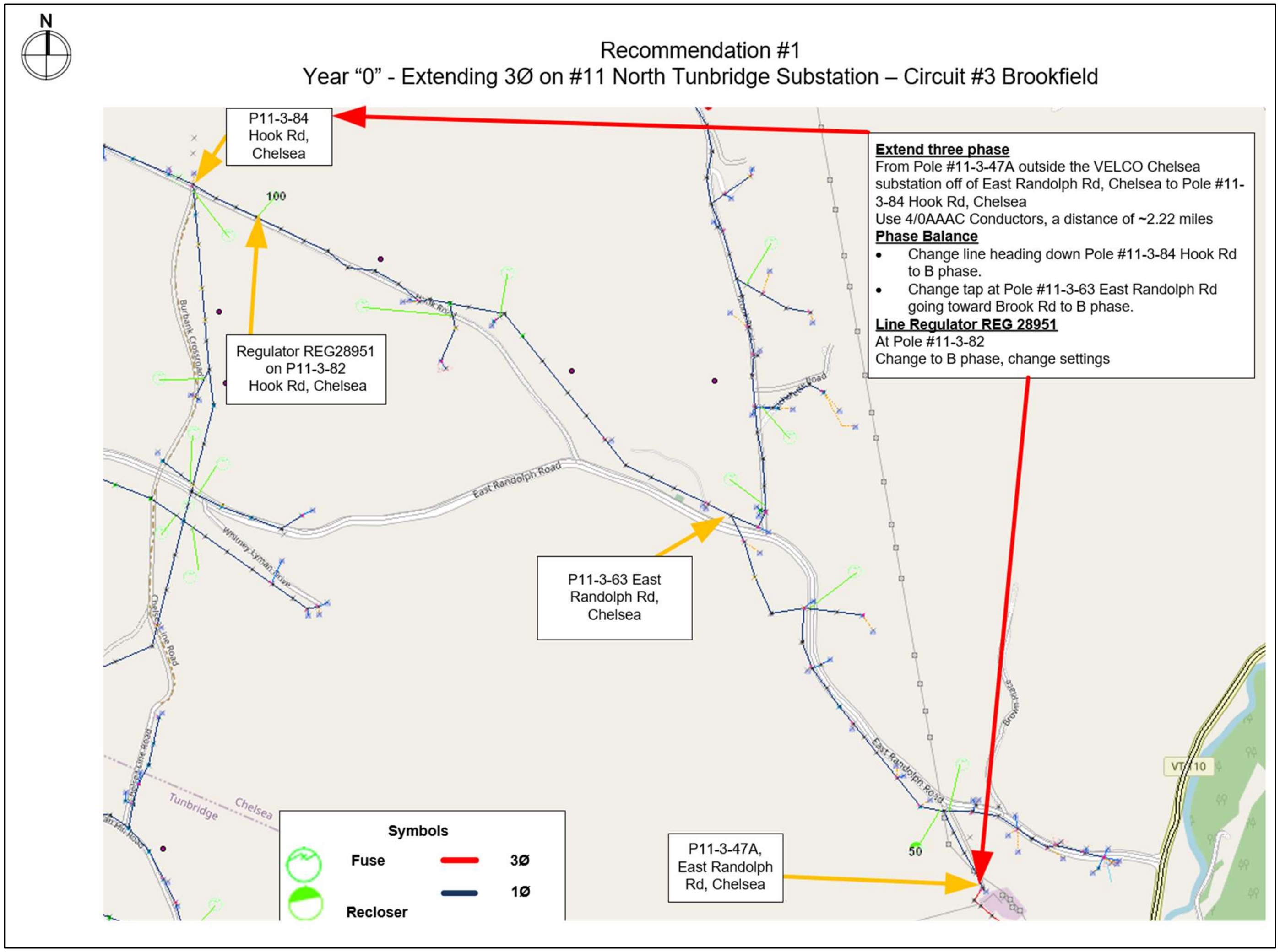


Figure 11: Recommendation #1 - #11 TU - #3 BR – Extend Three Phase – Year 0

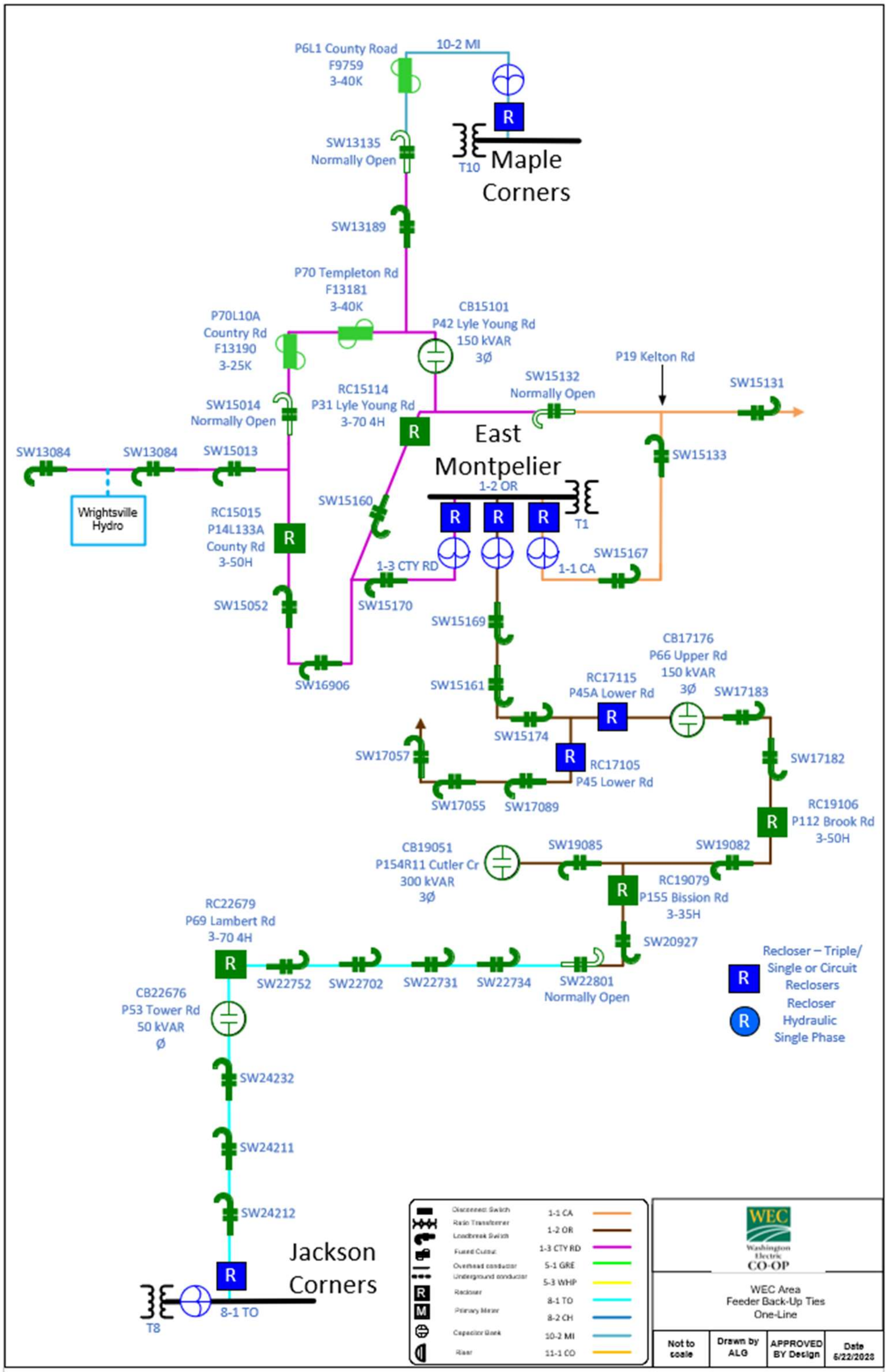


Figure 12 - Existing Feeder Backup Ties – Page 1

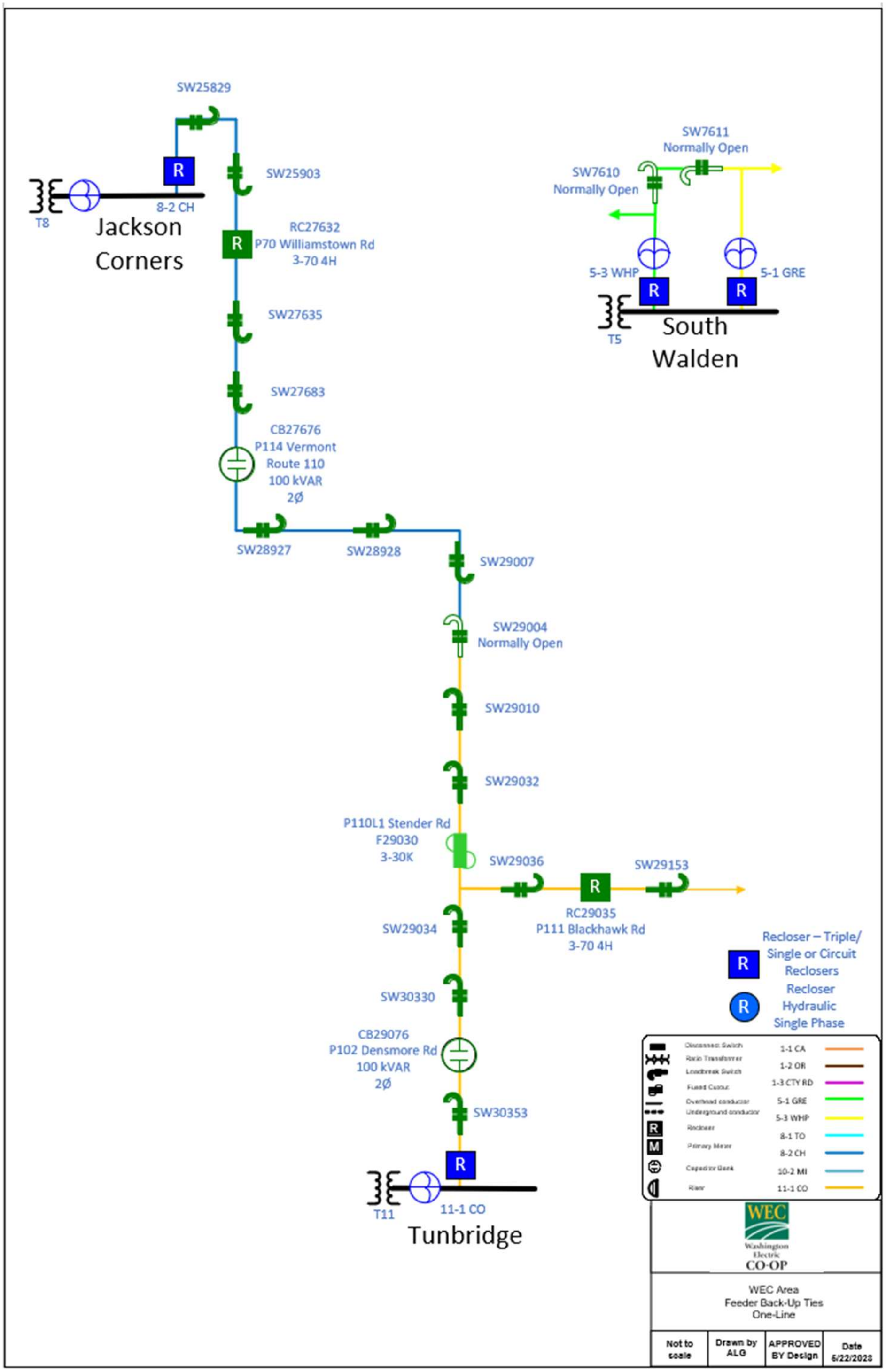


Figure 13: Existing Feeder Backup Ties – Page 2

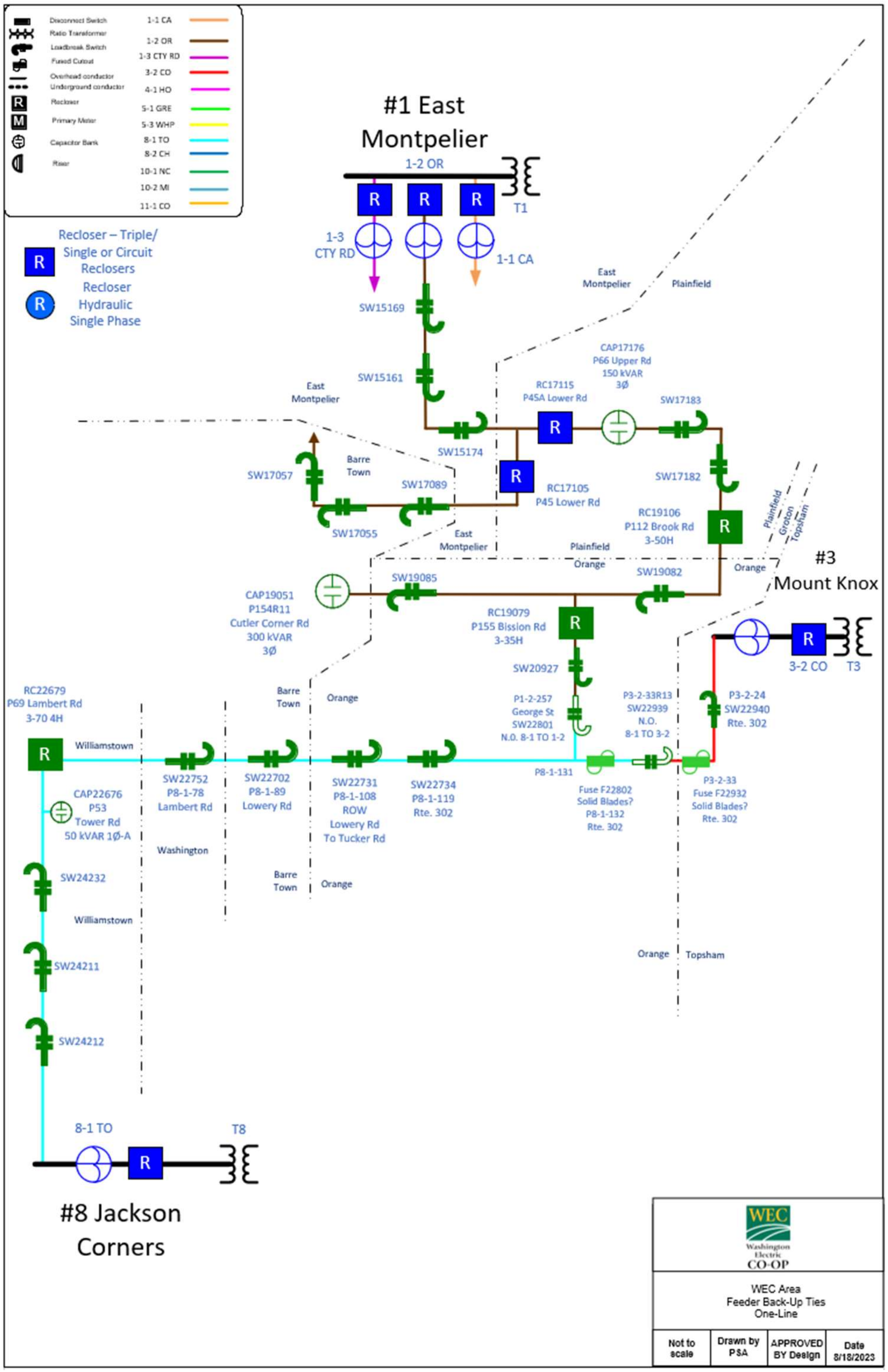


Figure 14: Proposed Feeder Backup Ties – Page 1

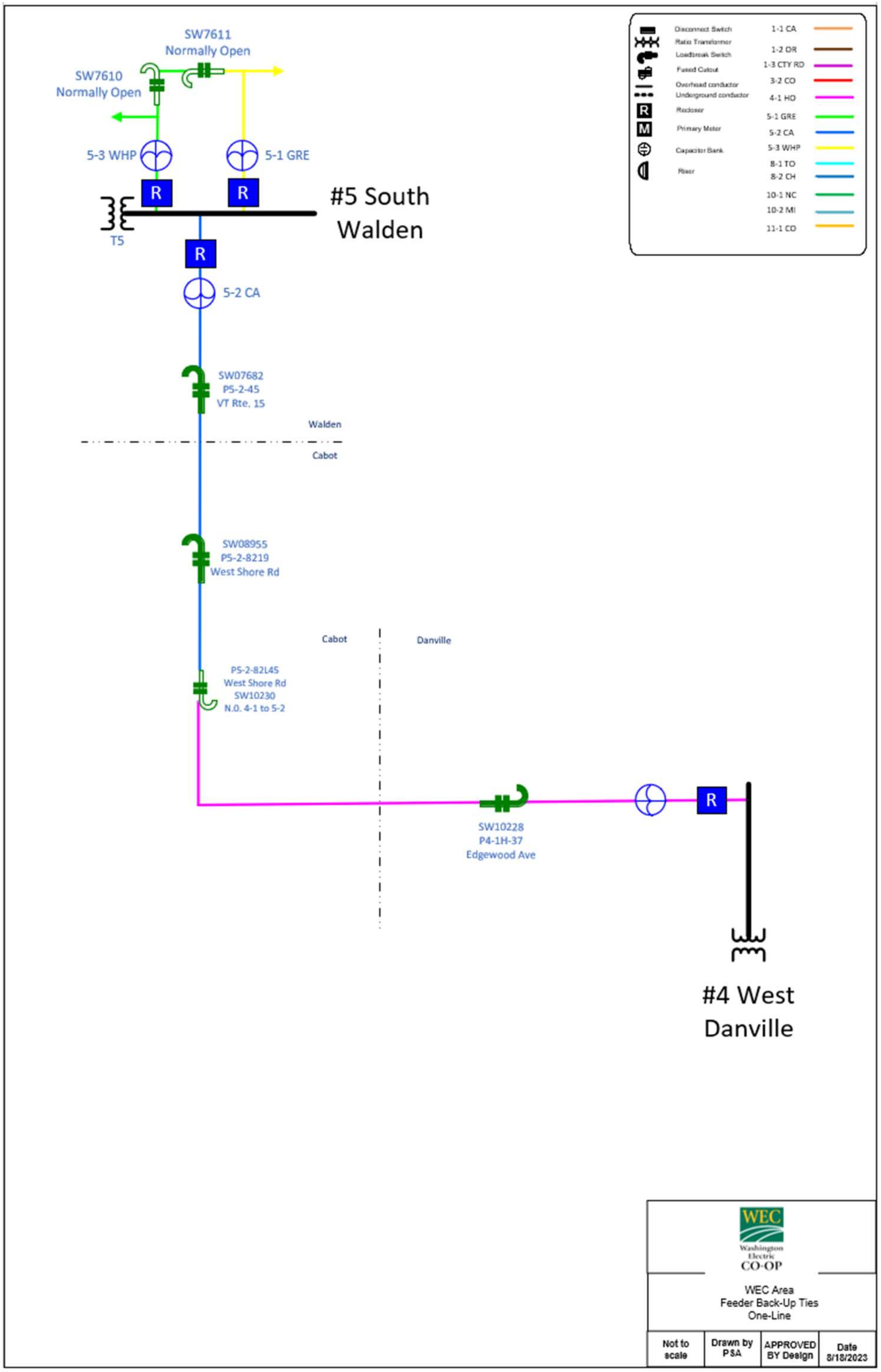


Figure 15: Proposed Feeder Backup Ties – Page 2

C. LRP Load Flow Results

Peak Load Allocation, no DER																			Total kW Losses						
All capacitors Assumed to be on		Cyme Results from load allocation																	258.1356938						
										Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses									
Substation	Circuit	A Amps	B Amps	C Amps	I Neutral	kW	kVAR	kVA	Circuit PF	A	B	C	A	B	C	Phase A	Phase B	Phase C	Total	Low Voltage locations or Overload Location - Distribution transformers in a separate list	Limiting Element	Amp Rating	Limiting Element kVA	% Loading	Remaining MVA
#1 East Montpelier 34.5 kV Feed		80.03	74.94	92.79	0.03	5036.81	626.80	5075.66	99.23%	103.2	103.6	104.5	90.5	94.4	92.3	100.0	57.2	101.0	258.1		HS Fuses 125E	125	7462.5	68%	2.387
34.5 kV feed from EM to Maple Corners		26.67	14.16	29.35	0.03	1347.72	370.46	1397.71	96.42%	103.2	103.6	103.3	92.3	97.1	96.1	36.3	8.3	14.5	59.1	Maybe add 150 kVAR cap bank?	4/0ACSR Conductor	357	21312.9	7%	19.915
#1 East Montpelier 12 kV Distribution	#1 Cabot	5.61	15.10	57.94	49.39	575.56	104.90	585.04	98.38%	102.3	102.1	104.5	98.8	96.5	94.9	0.4	3.6	36.8	40.8	RC13306 50H Recloser 54.6A	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	3240	18%	2.655
	#2 Orange	100.20	79.34	79.74	22.48	1912.75	118.52	1916.42	99.81%	102.2	103.4	102.7	90.5	94.8	92.3	45.8	25.8	32.8	104.3	F17002 6K fuse peak load 6.4 A. Fuses can handle 150% of rating.	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	3240	59%	1.324
	#3 County Rd	59.00	53.47	48.49	10.47	1182.35	-138.81	1190.47	99.32%	102.9	102.8	102.7	94.5	94.4	94.4	11.5	13.9	10.2	35.6	3-112-1 transformer is 112.5 kVA three phase, peak loading per WEC is 208 kVA	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	3240	37%	2.050
	Total	163.36	146.46	184.42	28.17	3670.66	84.61	3671.64	99.97%	102.9	103.4	104.5	90.5	94.4	92.3	57.6	43.3	79.7	180.6		Substation Transformer	231	5000	73%	1.328
GMP Mountain View #27	#2 Jones Brook Metering Point	20.91	0.00	0.00	20.91	143.25	40.26	148.79	96.27%	101.7	0.0	0.0	97.2	0.0	0.0	3.5	0.0	0.0	3.5	To small to add capacitors, good otherwise.	50H Single phase recloser	50	1080	14%	0.931
#3 Mount Knox	#1 Peacham	36.29	34.42	32.65	8.81	755.54	104.81	762.77	99.05%	101.9	102.8	104.0	94.6	97.0	96.6	10.6	9.9	11.3	31.8	None	Recloser Bypass 100	150	3240	24%	2.477
	#2 Corinth	81.83	92.00	118.19	38.00	2041.14	-666.83	2147.30	95.06%	102.2	103.6	104.5	95.7	95.5	95.6	24.6	61.9	78.3	164.8	RC24581 50L Recloser 63A at Peak. Circuit is overcompensated	Recloser Bypass 100	150	3240	66%	1.093
	Total	114.73	123.42	148.64	37.46	2796.68	-562.01	2852.59	98.04%	102.2	103.6	104.5	94.6	95.5	95.6	35.3	71.8	89.6	196.6	150A Bus Regulators, overloaded on C Phase	Bus Regulators	150	3240	88%	0.387
#4 West Danville	#1 Hookerville A Phase	25.48	32.58	33.62	9.41	657.66	14.58	657.82	99.98%	101.9	101.5	104.7	97.1	97.8	98.5	4.5	3.9	7.9	16.3	Small distribution transformers	Substation Transformers 3-500 kVA	69	1500	44%	0.842
	#2 Peacham B Phase	Other "Circuit" info is above																							
	#3 W. Danville C Phase																								

Table 28: LRP – Peak Load, No DER – Load Flows – Pg 1

Peak Load Allocation, no DER																			Total kW Losses						
All capacitors Assumed to be on		Cyme Results from load allocation																	258.1356938						
										Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses									
Substation	Circuit	A Amps	B Amps	C Amps	I Neutral	kW	kVAR	kVA	Circuit PF	A	B	C	A	B	C	Phase A	Phase B	Phase C	Total	Low Voltage locations or Overload Location - Distribution transformers in a separate list	Limiting Element	Amp Rating	Limiting Element kVA	% Loading	Remaining MVA
#5 S. Walden	#1 Greensboro Single Phase Circuit	0.02	78.01	0.02	78.01	583.57	68.49	587.58	99.32%	98.99	104.63	98.42	98.97	98.56	98.38	0.00	28.74	0.00	28.74	None	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	1080	54%	0.492
	#2 Cabot	47.04	4.99	35.99	36.11	649.22	76.39	653.70	99.31%	103.94	100.55	102.69	98.13	98.43	93.93	9.98	0.47	11.16	21.61	low voltage Customer Meter "CA 124- J" fed by 850' secondary conductor	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	3240	20%	2.586
	#3 West Hill Pond	12.00	25.00	31.04	17.57	479.70	128.68	496.66	96.59%	98.99	100.95	102.69	93.35	94.75	96.17	1.80	6.59	5.32	13.71	Low voltage at Customer Meter "CA 93- 5", fed by 950' secondary conductor. Circuit isn't pulling enough VARs to add a	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	3240	15%	2.743
	#5 S. Walden - 12.47 kV Bus	61.33	114.03	69.67	48.29	1712.49	273.55	1734.20	98.75%	103.94	104.63	102.69	93.35	94.75	93.93	11.78	35.80	16.48	64.06		Transformer 3-1,250 kVA transformers	63	3750	46%	2.016
	#5 SOUTH WALDEN 34.5 KV 3319 GMP TAP	32.53	33.45	23.60	0.00	1721.26	334.51	1753.47	98.16%	103.92	104.60	102.67	93.51	94.96	93.91	14.58	39.65	18.67	72.90		2/0ACSR	276	16480	11%	14.727
#7 Graniteville - *Not load allocated*	34.5 kV feed to Jackson Corners	55.18	60.57	65.14	0.00	3527.49	454.58	3556.66	99.18%	104.59	104.08	104.24	97.25	95.93	95.27	59.75	59.74	82.22	201.70		4/0ACSR Conductor	357	21310	17%	17.753
#8 Jackson Corners (Served by #7 Graniteville)	#1 Topsham	38.12	11.97	41.15	34.31	662.15	124.65	673.78	98.27%	104.59	102.13	101.74	99.64	98.44	95.85	4.26	1.23	12.33	17.82		Recloser Bypass 150A Overhead Line - 2/0ACSR 276A	150	3240	21%	2.566
	#2 Chelsea	21.66	19.09	30.53	16.26	521.51	29.51	522.34	99.84%	104.59	101.90	103.83	100.02	95.93	95.28	3.65	5.24	11.44	20.32		Recloser Bypass 150A Overhead Line - 1/0AAAC 256A	150	3240	16%	2.718
	#3 Northfield	102.63	89.74	118.16	31.37	2295.02	21.71	2295.12	100.00%	104.59	104.08	104.24	97.25	96.91	95.27	36.58	40.04	38.13	114.75	25K Fuse F23954 peak load is 28.5A, Fuses can handle 150% of rating.	Recloser Bypass 150A Overhead Line - 4/0AAAC 395A	150	3240	71%	0.945
	Martin Solar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00%	101.52	100.67	100.23	101.52	100.67	100.23	0.00	0.00	0.00	0.00						0.000
	Williamstown Sol	0.03	0.04	0.04	0.00	0.00	-0.77	0.77	0.00%	100.30	101.31	101.53	100.30	101.31	101.53	0.00	0.00	0.00	0.00						-0.001
	12 kV Total	162.13	120.12	189.09	77.17	3478.68	175.87	3483.12	99.87%	104.59	104.08	104.24	97.25	95.93	95.27	44.48	46.51	61.90	152.90		Sub transformer is rated at 174A 3750 MVA	174	3758.4	93%	0.275

Table 28: LRP – Peak Load, No DER – Load Flows – Pg 2

Peak Load Allocation, no DER																			Total kW Losses						
All capacitors Assumed to be on		Cyme Results from load allocation																	258.1356938						
										Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses									
Substation	Circuit	A Amps	B Amps	C Amps	I Neutral	kW	kVAR	kVA	Circuit PF	A	B	C	A	B	C	Phase A	Phase B	Phase C	Total	Low Voltage locations or Overload Location - Distribution transformers in a separate list	Limiting Element	Amp Rating	Limiting Element kVA	% Loading	Remaining MVA
#9 Moretown	#1 Middlesex	36.02	56.00	52.99	18.97	1045.09	295.46	1086.05	96.23%	102.46	104.73	104.77	96.90	95.99	96.62	9.08	24.51	19.44	53.04		& Reclower Bypass *URD Getaway 1/0 AL URD 155A*	150	3240	34%	2.154
#9 Moretown	#2 Moretown Common Single Phase Circuit	0.00	0.00	46.59	46.59	314.94	82.68	325.61	96.72%	0.00	0.00	100.01	0.00	0.00	92.97	0.00	0.00	10.31	10.31		Recloser 70 V4L *Voltage Regulators & Reclower Bypass 150A*	70	504	65%	0.178
#9 Moretown	#3 Fayston	76.00	80.00	56.00	16.42	1576.11	223.05	1591.81	99.01%	104.93	104.73	104.97	97.29	97.23	99.10	35.80	48.46	20.91	105.17	25K Fuses F16404, 26.3A at Peak, Fuses can handle 150% of rating. E5811801 500 kVA transformer bank peak load 581 kVA	75 A regulators outside substation *Recloser Bypass 150A 1/0 AL Cable 155A*	75	1620	98%	0.028
#9 Moretown	Total - 12.47 kV side of Moretown	117.45	145.01	163.76	43.43	2936.14	601.19	2997.05	97.97%	104.93	104.73	104.97	96.90	95.99	92.97	44.89	72.98	50.65	168.51		Substation Transformer 3-1250 kVA 65E Power fuses	174	3758.4	80%	0.761
#9 Moretown	Total - 34.5 kV side of Moretown	49.05	57.13	48.65	0.00	2951.53	787.50	3054.78	96.62%	104.93	104.73	104.97	96.90	95.99	92.97	48.77	78.22	56.92	183.91		65E Power Fuses	65	3880.5	79%	0.826
#10 Maple Corners	#1 North Calais	48.01	0.00	24.09	40.15	507.94	135.24	525.64	96.63%	101.84	102.70	102.27	94.56	102.45	96.08	10.74	0.01	6.10	16.85	Low V due to 800' secondary service to Spot Load CS 129- A	100A Circuit regulators	100	5970	9%	5.444
#10 Maple Corners	#2 Middlesex	61.72	34.90	20.01	37.84	823.50	228.42	854.59	96.36%	100.95	102.02	102.27	92.32	97.10	99.42	17.61	5.80	2.53	25.94	Lots of low voltage beyond many distribution transformers, all on A phase at the north west of the circuit.	100A Circuit regulators	100	5970	14%	5.115
#10 Maple Corners	#10 Maple Corners 12 kV	110.79	34.90	44.10	70.63	1331.44	363.66	1380.21	96.47%	101.84	102.70	102.27	92.32	97.10	96.08	28.35	5.82	8.63	42.80		Sub transformer 3-833 kVA	116	2499	55%	1.119

Table 28: LRP – Peak Load, No DER – Load Flows – Pg 3

Peak Load Allocation, no DER																			Total kW Losses						
All capacitors Assumed to be on		**Cyme Results from load allocation**																	258.1356938						
										Highest Downstream Vpu			**Lowest Downstream Vpu**			**KW Losses**									
Substation	**Circuit**	**A Amps**	**B Amps**	**C Amps**	**I Neutral**	**kW**	**kVAR**	**kVA**	**Circuit PF**	**A**	**B**	**C**	**A**	**B**	**C**	**Phase A**	**Phase B**	**Phase C**	**Total**	**Low Voltage locations or Overload Location - Distribution transformers in a separate list**	**Limiting Element**	**Amp Rating**	**Limiting Element kVA**	**% Loading**	**Remaining MVA**
	#1 Corinth - *Includes 100 kVA of proposed load*	51.76	21.56	63.45	41.27	1003.93	-155.20	1015.85	98.83%	103.73	100.05	104.45	99.48	97.20	96.48	14.03	2.37	40.75	57.14		Recloser Bypass	150	3240	31%	2.224
	#2 South Tunbridge	43.04	0.00	0.00	43.04	319.66	-33.99	321.46	99.44%	103.73	0.00	0.00	95.96	0.00	0.00	13.92	0.00	0.00	13.92	Low voltage at Meter TU 210- 1- A, due to 900' service conductor	6/8CWC - 100A	100	720	45%	0.399
	#3 Brookfield Single Phase Circuit	2.42	0.51	67.84	66.33	531.84	-0.89	531.84	100.00%	104.96	100.05	104.45	101.88	98.12	95.31	0.17	0.07	52.11	52.35	RC30229 50H, 65A at peak, Low V due to the 5 kVA transformer 3549C feeding two Customers	Recloser Bypass	150	1080	49%	0.548
	Includes 100 kVA of proposed load at the Vershire Town Garage	101.32	22.19	137.36	111.35	1855.43	-190.07	1865.14	99.48%	104.96	100.05	104.45	95.96	97.20	95.31	28.12	2.43	92.86	123.42		Substation Transformers 3-1250 kVA	174	3758.4	50%	1.893
#11 Tunbridge	Total - At VELCO Chelsea	18.00	23.57	31.53	0.00	1870.30	-154.41	1876.67	99.66%	104.96	100.13	104.45	95.96	97.20	95.31	32.74	5.61	99.95	138.29		4/0ACSR Conductor	357	21312.9	9%	19.436

Table 28: LRP – Peak Load, No DER – Load Flows – Pg 4

Minimum Load

Total kW Losses 57.97448

All capacitors Assumed to be on

		Min Load Flow 30% of Peak, No DG																		
										Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses				
Substation	**Circuit**	**A Amps**	**B Amps**	**C Amps**	**I Neutral**	**kW**	**kVAR**	**kVA**	**Circuit PF**	**A**	**B**	**C**	**A**	**B**	**C**	**Phase A**	**Phase B**	**Phase C**	**Total**	**Low Voltage locations or Overload Location - Distribution transformers in a separate list**
#1 East Montpelier 34.5 kV Feed	**0**	24.32	25.39	30.10	0.03	1473.57	-744.64	1651.03	0.89	105.44	105.61	105.79	98.63	98.42	99.30	14.36	11.19	14.57	40.13	High V only appeared to be an issue on the distribution bus
34.5 kV feed from EM to Maple Corners	**0**	7.22	4.08	8.36	0.03	394.70	10.60	394.84	1.00	104.32	104.47	104.38	99.26	100.68	100.51	4.02	1.83	2.27	8.12	
#1 East Montpelier 12 kV Distribution	#1 Cabot	1.63	4.41	16.95	15.95	164.11	-24.96	165.99	0.99	101.87	101.65	102.48	100.85	99.95	99.60	0.03	0.34	3.22	3.59	
	#2 Orange	32.26	28.62	28.45	6.00	553.78	-346.65	653.33	0.85	101.63	103.15	102.10	98.63	98.42	99.30	4.72	3.19	3.48	11.39	
	#3 County Rd	25.09	24.56	23.50	3.51	349.17	-404.78	534.57	0.65	101.74	101.88	102.16	99.31	99.48	99.68	1.69	1.93	1.59	5.21	Circuit is overcompensated at minimum
	Total	55.76	53.47	64.39	6.41	1067.05	-776.39	1319.61	0.81	105.44	105.61	105.79	98.63	98.42	99.30	6.45	5.46	8.28	20.19	High V only appeared to be an issue on the distribution bus
GMP Mountain View #27	#2 Jones Brook Metering Point	6.07	0.00	0.00	6.07	42.23	10.61	43.54	0.97	100.85	0.00	0.00	99.40	0.00	0.00	0.30	0.00	0.00	0.30	
#3 Mount Knox	#1 Peacham	11.98	11.22	9.46	7.00	220.56	-64.61	229.83	0.96	101.31	101.43	101.91	99.86	99.34	99.56	1.37	0.96	1.11	3.44	
	#2 Corinth	56.33	61.96	59.83	7.16	617.52	-1140.31	1296.79	0.48	103.03	103.03	102.96	99.32	98.57	99.23	12.47	23.46	18.60	54.53	Circuit is overcompensated at minimum
	Total	66.11	70.95	64.75	11.45	838.08	-1204.93	1467.73	0.57	103.03	103.03	102.96	99.32	98.57	99.23	13.84	24.43	19.71	57.97	

Table 29: LRP – Minimum Load, No DER – Load Flows – Pg 1

Minimum Load																			
																			Total kW Losses
																			57.97448
All capacitors Assumed to be on		Min Load Flow 30% of Peak, No DG																	
										Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses			
Substation	Circuit	A Amps	B Amps	C Amps	I Neutral	kW	kVAR	kVA	Circuit PF	A	B	C	A	B	C	Phase A	Phase B	Phase C	Total	Low Voltage locations or Overload Location - Distribution transformers in a separate list
#4 West Danville	#1 Hookerville A Phase	10.14	10.67	11.34	3.47	194.77	-125.32	231.60	0.84	101.48	101.87	102.56	100.53	100.61	100.67	1.08	0.44	0.79	2.31	
	#2 Peacham B Phase	Other "Circuit" info is above																		
	#3 W. Danville C Phase																			
#5 S. Walden	#1 Greensboro Single Phase Circuit	0.02	25.03	0.02	25.03	169.41	-63.44	180.90	0.94	100.34	100.33	100.14	100.33	98.00	100.13	0.00	2.92	0.00	2.92	
	#2 Cabot	14.77	1.46	11.76	10.53	190.63	-62.07	200.48	0.95	100.34	100.33	100.13	98.93	99.65	98.07	0.97	0.05	1.33	2.35	
	#3 West Hill Pond	3.42	7.24	9.23	5.37	140.98	26.75	143.50	0.98	100.34	100.33	100.13	98.75	98.55	98.24	0.15	0.56	0.48	1.19	
	#5 S. Walden - 12.47 kV Bus	17.99	32.75	20.02	12.79	501.02	-98.76	510.66	0.98	100.34	100.33	100.14	98.75	98.00	98.07	1.12	3.53	1.80	6.45	
	#5 SOUTH WALDEN 34.5 KV	9.47	9.89	6.88	0.00	505.42	-108.20	516.87	0.98	100.34	100.33	100.14	98.80	98.61	98.07	2.57	5.05	3.20	10.82	
#7 Graniteville - *Not load allocated*	34.5 kV feed to Jackson Corners	20.08	19.61	20.87	0.00	1024.70	-637.32	1206.73	0.85	104.27	103.49	103.59	100.00	99.48	98.86	8.86	7.75	10.08	26.68	Circuit is overcompensated at minimum
#8 Jackson Corners (Served by #7 Graniteville)	#1 Topsham	12.45	3.47	11.62	13.97	195.00	-18.14	195.84	1.00	103.12	102.20	102.30	100.62	101.18	99.46	0.49	0.11	1.07	1.67	
	#2 Chelsea	9.26	5.44	10.36	9.27	152.58	-84.19	174.27	0.88	103.32	102.20	102.30	101.95	100.34	99.99	0.43	0.50	1.27	2.20	
	#3 Northfield	41.87	34.54	40.31	14.28	669.21	-536.66	857.81	0.78	103.41	102.99	102.30	100.07	99.48	98.86	5.11	4.89	4.91	14.90	Circuit is overcompensated at minimum
	Martin Solar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	101.83	100.49	100.09	101.83	100.49	100.09	0.00	0.00	0.00	0.00	
	Williamstown Solar	0.04	0.03	0.03	0.00	0.00	-0.76	0.76	0.00	101.35	100.42	100.12	101.35	100.42	100.12	0.00	0.00	0.00	0.00	
	12 kV Total	62.89	41.00	59.89	34.20	1016.78	-638.99	1200.90	0.85	103.41	102.99	102.30	100.07	99.48	98.86	6.02	5.50	7.25	18.77	

Table 29: LRP – Minimum Load, No DER – Load Flows – Pg 2

Minimum Load																				
																			Total kW Losses	
																			57.97448	
All capacitors Assumed to be on		Min Load Flow 30% of Peak, No DG																		
									Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses					
Substation	Circuit	A Amps	B Amps	C Amps	I Neutral	kW	kVAR	kVA	Circuit PF	A	B	C	A	B	C	Phase A	Phase B	Phase C	Total	Low Voltage locations or Overload Location - Distribution transformers in a separate list
#9 Moretown	#1 Middlesex	10.54	16.44	15.44	6.47	302.24	60.74	308.28	0.98	100.78	101.16	101.60	99.17	98.51	98.89	0.79	2.16	1.66	4.61	
	#2 Moretown Common Single Phase Circuit	0.00	0.00	13.00	13.00	92.26	14.63	93.41	0.99	0.00	0.00	99.81	0.00	0.00	97.80	0.00	0.00	0.87	0.87	
	#3 Fayston	27.62	25.21	16.02	14.03	452.63	-178.19	486.45	0.93	101.43	101.85	103.06	99.72	100.13	100.65	4.37	4.82	2.11	11.30	
	Total - 12.47 kV side of Moretown	35.88	40.02	45.03	18.15	847.13	-102.83	853.35	0.99	101.43	101.85	103.06	99.17	98.51	97.80	5.16	6.97	4.64	16.77	Circuit is overcompensated at minimum
	Total - 34.5 kV side of Moretown	14.67	16.62	12.09	0.00	851.93	-87.97	856.46	0.99	101.43	101.85	103.06	99.17	98.51	97.80	6.70	8.58	6.30	21.58	
#10 Maple Corners	#1 North Calais	13.59	0.20	6.90	11.35	148.73	25.85	150.96	0.99	102.26	104.07	102.27	99.85	104.00	100.51	0.90	0.00	0.50	1.40	
	#2 Middlesex	17.56	10.19	5.79	9.98	241.39	50.03	246.52	0.98	101.61	102.11	102.27	99.26	100.68	101.43	1.42	0.50	0.21	2.13	
	#10 Maple Corners 12 kV	30.65	9.95	12.45	18.76	390.11	75.88	397.42	0.98	103.55	104.07	104.23	99.26	100.68	100.51	2.31	0.50	0.72	3.53	
#11 Tunbridge	#1 Corinth - Includes 100 kVA of proposed load at the Vershire Town Garage	22.02	6.45	27.17	21.57	292.42	-260.35	391.53	0.75	101.11	99.71	102.01	99.91	98.29	100.28	1.73	0.40	6.20	8.33	
	#2 South Tunbridge	0.00	0.00	14.89	14.89	93.76	-54.25	108.32	0.87	0.00	0.00	101.05	0.00	0.00	98.62	0.00	0.00	2.03	2.03	
	#3 Brookfield Single Phase Circuit	0.75	0.19	20.92	20.29	149.33	-53.98	158.78	0.94	100.51	99.71	101.95	99.60	98.98	98.58	0.02	0.01	5.37	5.39	
	Total - 12 kV Bus - Includes 100 kVA of proposed load at the Vershire Town Garage	22.62	6.61	61.65	56.25	535.51	-368.58	650.09	0.82	101.11	99.71	102.01	99.60	98.29	98.58	1.75	0.40	13.60	15.75	
	Total - At VELCO Chelsea	4.87	10.40	11.60	0.00	542.00	-417.82	684.35	0.79	101.11	100.21	102.01	99.60	98.29	98.58	3.65	2.36	16.23	22.24	

Table 29: LRP – Minimum Load, No DER – Load Flows – Pg 3

Minimum Load

Total kW Losses 317.9

All capacitors Assumed to be on

Min Load Flow 30% of Peak, with DG

						Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses								Min Load No DER Output		Min Load Full DER Output	
Substation	**Circuit**	**kW**	**kVAR**	**kVA**	**Circuit PF**	**A**	**B**	**C**	**A**	**B**	**C**	**Phase A**	**Phase B**	**Phase C**	**Total**	**Low Voltage locations or Overload Location – Distribution transformers in a separate list**	**Limiting Element**	**Amp Rating**	**Limiting Element kVA**	**% Loading**	**Remaining kVA**	**% Loading**	**Remaining MVA**
#1 East Montpelier 34.5 kV Feed	0	-1631.73	491.64	1704.19	-0.96	113.99	119.78	120.87	96.72	97.89	97.92	81.56	77.28	98.05	256.88		HS Fuses 125E	125	7462.5	22%	5811.47	23%	5.76
34.5 kV feed from EM to Maple Corners	0	-247.14	16.09	247.66	-1.00	109.47	119.78	108.73	99.52	101.32	101.50	14.82	7.24	5.05	27.12		4/0ACSR Conductor	357	21312.9	2%	20918.06	1%	21.07
#1 East Montpelier 12 kV Distribution	#1 Cabot	-147.64	-20.21	149.02	-0.99	106.39	105.25	106.94	101.10	99.38	98.21	2.10	1.96	6.59	10.64	2 locations with high voltage, only on secondaries 121V on 15 kV side of system - **Transformer 7403C 25 kVA transformer with a 20 kW PV PV is 275' from transformer assumed 1/0AL Cable for service & Transformer 3842C 5 kVA transformer feeding a 7.6 kW PV.**	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 1554*	150	3240	5%	3074.01	5%	3.09
	#2 Orange	40.51	-350.24	352.57	0.11	113.99	107.07	108.55	99.64	99.85	100.21	6.27	4.79	6.11	17.16	Overvoltages only on secondaries at (121-123 V on 15 kV side): **3149C 5 kVA transformer feeding a 14.3 kW PV,** 2890C 5 kVA transformer 5.6 kW PV, 21500_CLARK_5KW fed by a 10kVA transformer and a 450' service, **C4135 10 kVA transformer feeding a 10 kW PV with a 300' service**, 21448_CADDY_7.6KW - fed by 15 kVA transformer and a 300' service. 21524_HEWITT_7.6KW - fed by a 10 kVA transformer 400' service, 21604_OBRIEN_7.6KW - 10 kVA transformer 678' service, **25382_HOGAN_5.4KW - fed by 5 kVA transformer**, 23500_COUTURE_14.6KW - 15 kVA transformer 180' service, 25250_COLGATE_3.9KW - fed by a 5 kVA transformer 700' service, 22601_MOOTE_9.8KW - 10 kVA transformer 240' service, **22227_FREY_14.3KW - fed by a 5 kVA transformer, 24008_MULLENDORE_10KW - fed by 10 kVA transformer & 300' service**	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 1554*	150	3240	20%	2586.67	11%	2.89
	#3 County Rd	-1289.58	818.49	1527.40	-0.84	104.43	107.66	120.87	96.72	97.89	97.92	54.44	59.32	76.08	189.84	Overvoltages only on secondaries at (15 kV voltages around 121 to 122): 22413_SENECAL_10KW fed by 10kVA 430' service, 40346_TWOMBLY_11.4KW - 15 kVA transformer 250' service, 25373_CRAIG_8KW - 300' service 10 kVA transformer, 25369_WILLIS_8.4KW - 10 kVA transformer 200' service, 21251_DUNCAN_10KW - 25 kVA transformer, 390' service, 31805_POWERS_10KW - 25 kVA transformer, 305', 21003_VISTRO_4.8KW - 5 kVA transformer 114' service, **25738_BISSELL_7.1KW - 5 kVA transformer**, 21036_SMITH_13.6KW - 15 kVA transformer, 30756_KANE_7.6KW - 10 kVA transformer 160' service, 20964_COCHRAN_8KW - 10 kVA transformer 273' service, **31706_SOLARSENSE_150KW single phase worst at 122 Vpu. 31025_CHICKERING_11.4KW - 10 kVA transformer**, 20438_RYEA_7.6KW - 10 kVA transformer 300' service	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 1554*	150	3240	16%	2705.43	47%	1.71
	Total	-1396.71	448.05	1466.81	-0.95	113.99	107.66	120.87	96.72	97.89	97.92	62.81	66.07	88.77	217.65		Substation Transformer	231	5000	26%	3680.39	29%	3.53
GMP Mountain View #27	#2 Jones Brook Metering Point	-4.08	10.68	11.44	-0.36	104.69	0.00	0.00	99.70	0.00	0.00	1.00	0.00	0.00	1.00		50H Single phase recloser	50	1080	4%	1036.46	1%	1.07

Table 30: LRP – Minimum Load, 100% DER – Load Flows – Pg 1

Minimum Load

Total kW Losses 317.9

All capacitors Assumed to be on

Min Load Flow 30% of Peak, with DG

Substation	Circuit	kW	kVAR	kVA	Circuit PF	Highest Downstream Vpu A	Highest Downstream Vpu B	Highest Downstream Vpu C	Lowest Downstream Vpu A	Lowest Downstream Vpu B	Lowest Downstream Vpu C	KW Losses Phase A	KW Losses Phase B	KW Losses Phase C	KW Losses Total	Low Voltage locations or Overload Location – Distribution transformers in a separate list	Limiting Element	Amp Rating	Limiting Element kVA	Min Load No DER Output % Loading	Min Load No DER Output Remaining kVA	Min Load Full DER Output % Loading	Min Load Full DER Output Remaining MVA
#3 Mount Knox	#1 Peacham	7.25	-64.32	64.73	0.11	104.68	105.97	101.52	99.75	99.02	98.63	2.21	1.79	0.83	4.84	High voltage only on secondary voltage at **27318_CARBEE_9.4KW fed by a 5 kVA transformer.**	Recloser Bypass	150	3240	7%	3010.17	2%	3.18
	#2 Corinth	163.67	-1137.15	1148.87	0.14	105.89	104.25	116.22	98.19	98.10	99.63	14.70	24.16	19.09	57.96	Widespread 15 kV issues due to **regulator set to bi-directional REG28076 &** some secondary high voltage (some 15 kV is at 124V, not all though): 27223_MURPHY_14KW - 15 kVA 500' service, 27192_MERCHANT_7.6KW 10 kVA transformer 55' service, 16401_COPELAND_5KW - 10 kVA transformer 185' cable service, 21826_MAXWELL_6KW - 10 kVA trasnformer 131' service, **30041_KUPKE_11.4KW - 10 kVA transformer 340' cable service, 27232_KURYLO_7.6KW - 5 kVA transformer, 29066_KELLEY_10KW - 10 kva transformer,** 20843_OLSEN_4.8KW - 5 kVA transformer 500' service, 28761_MANN_7.6KW - 10 kVA transformer 311' service, **28773_GROSS_15KW - 15 kVA transofmer 253' service, 28768_NAROWSKI_10KW - 330' service 10 kVA transformer**	Recloser Bypass	150	3240	40%	1943.21	35%	2.09
	Total	170.92	-1201.47	1213.57	0.14	105.89	105.97	116.22	98.19	98.10	98.63	16.92	25.96	19.92	62.79		Bus Regulators	150	3240	45%	1772.27	37%	2.03
#4 West Danville	#1 Hookerville A Phase	31.07	-123.37	127.22	0.24	106.67	104.32	109.09	100.92	100.40	99.84	1.83	0.94	4.18	6.95	Only High V on secondary Voltage (15 kV voltage is reasonable) - 27165_MULLIGAN_7.6KW 10 kVA transformer 205' service, 30049_SCRIBNER_9.8KW - 310' service 15 kVA	Substation Transformers 3-500 kVA	69	1500	15%	1268.40	8%	1.37
	#2 Peacham B Phase	Other "Circuit" info is above																		#DIV/0!	0.00	#DIV/0!	0.00
	#3 W. Danville C Phase															Only High V on secondary voltage (15 kV voltage is reasonable) - **40380_COCHRAN_5KW - 5 kVA transformer 600' service,** 31608_VILANDRIE_34KW - 50 kVA transformer 166' service				#DIV/0!	0.00	#DIV/0!	0.00
#5 S. Walden	#1 Greensboro Single Phase Circuit	18.14	-67.36	69.76	0.26	100.57	106.98	100.44	100.57	99.97	100.44	0.00	4.45	0.00	4.45	Only High V on secondcary voltage at one location (15 kV voltage is reasonable) - 27782_ADESW_8.9KW - 10 kVA transformer 376' service	Voltage Regulators & Reclower Bypass	150	1080	17%	899.10	6%	1.01
	#2 Cabot	-9.15	-64.75	65.39	-0.14	107.53	100.68	104.87	99.66	99.82	99.81	4.81	0.06	2.11	6.98	Only high V on secondary voltage (15 kV voltage is reasonable) - **27908_BELLAIRS_7.6KW fed by 5**	Voltage Regulators &	150	3240	6%	3039.52	2%	3.17
	#3 West Hill Pond	25.55	26.58	36.87	0.69	103.87	104.66	104.76	99.51	99.68	99.15	0.38	1.12	1.36	2.86		Voltage Regulators & Reclower	150	3240	4%	3096.50	1%	3.20
	#5 S. Walden - 12.47 kV Bus	34.54	-105.53	111.04	0.31	107.53	106.98	104.87	99.51	99.68	99.15	5.19	5.63	3.46	14.29		Transformer 3-1,250 kVA transformers	63	3750	14%	3239.34	3%	3.64
	#5 SOUTH WALDEN 34.5	36.30	-115.76	121.32	0.30	105.32	106.38	104.36	99.58	99.74	99.18	5.52	6.28	4.24	16.04		2/0ACSR	276	16480	3%	15963.13	1%	16.36
#7 Graniteville - *Not load allocated*	34.5 kV feed to Jackson Corners	-3441.10	69.49	3441.80	-1.00	106.88	107.89	110.69	97.13	99.43	98.84	97.76	107.26	112.88	317.90		4/0ACSR Condu	357	21310	6%	20103.27	16%	17.87

Table 30: LRP – Minimum Load, 100% DER – Load Flows – Pg 2

Minimum Load

Total kW Losses 317.9

All capacitors Assumed to be on

		Min Load Flow 30% of Peak, with DG																		Min Load No DER Output		Min Load Full DER Output	
						Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses											
Substation	**Circuit**	**kW**	**kVAR**	**kVA**	**Circuit PF**	**A**	**B**	**C**	**A**	**B**	**C**	**Phase A**	**Phase B**	**Phase C**	**Total**	**Low Voltage locations or Overload Location – Distribution transformers in a separate list**	**Limiting Element**	**Amp Rating**	**Limiting Element kVA**	**% Loading**	**Remaining kVA**	**% Loading**	**Remaining MVA**
#8 Jackson Corners (Served by #7 Graniteville)	#1 Topsham	-150.60	-8.00	150.82	-1.00	104.95	107.89	110.69	97.13	100.25	101.48	4.32	2.83	5.93	13.08	Voltage already pretty high on the main line – High voltage on secondary v – 28637_HILFERTY_7.6KW –	Recloser Bypass 150A	150	3240	6%	3044.16	5%	3.09
	#2 Chelsea	-17.29	-75.85	77.80	-0.22	105.59	106.64	106.94	97.20	100.68	99.20	2.54	2.56	2.15	7.25	Only high V on secondary voltage (15 kV voltage is reasonable) – 21439_JOHNSON_10KW– 10 kVA	Recloser Bypass 150A	150	3240	5%	3065.73	2%	3.16
	#3 Northfield	-3317.07	-86.37	3318.20	-1.00	106.88	107.17	109.04	97.55	99.43	98.84	78.16	86.15	89.40	253.71	High voltage on 15 kV at two locations – North – this includes Martin Solar and some capacitors & South this appears to be an issue with high	Recloser Bypass 150A Overhead Line –	150	3240	26%	2382.19	102%	-0.08
	Martin Solar	-1492.56	77.91	1494.59	-1.00	103.89	105.93	106.55	103.57	105.56	106.12	2.44	2.44	2.44	7.32					#DIV/0!	0.00	#DIV/0!	-1.49
	Williamstown Solar	-1988.22	109.28	1991.22	-1.00	101.23	103.15	103.29	100.85	102.68	102.80	3.91	3.90	3.91	11.72					#DIV/0!	-0.76	#DIV/0!	-1.99
	12 kV Total	-3484.96	-170.22	3489.12	-1.00	106.88	107.89	110.69	97.13	99.43	98.84	85.01	91.55	97.48	274.04		Sub transformer	174	3758.4	32%	2557.50	93%	0.27
#9 Moretown	#1 Middlesex	-1402.58	153.11	1410.91	-0.99	102.84	101.97	139.30	97.93	87.18	87.34	9.96	1.22	59.14	70.32	150 kW PV must be three phase at Meter 21722, & there is some significant low voltage beyond the Regulator 12926 these have bi-directional	Regulators & Reclower	150	3240	10%	2931.72	44%	1.83
	#2 Moretown Common Single Phase Circuit	-160.42	17.32	161.35	-0.99	0.00	0.00	105.98	0.00	0.00	99.11	0.00	0.00	7.09	7.09	Voltage on 15 kV side is reasonable, secondary voltage locations that have issues: 40476_LAWSON_15KW – 15 kV transformer & 24446_BARTON_15KW 15 kVA transformer	Recloser 70 V4L *Voltage Regulators & Reclower*	70	504	19%	410.59	32%	0.34
	#3 Fayston	-521.57	-135.04	538.77	-0.97	148.79	149.79	149.14	99.46	100.10	98.95	45.34	51.54	47.84	144.72	Voltage on 15 kV side is reasonable, secondary voltage locations that have issues:	75 A regulators outside	75	1620	30%	1133.55	33%	1.08
	Total - 12.47 kV side of Moretown	-2084.56	35.38	2084.87	-1.00	148.79	149.79	149.14	97.93	87.18	87.34	55.30	52.76	114.07	222.13		Substation Transformer 3-1250 kVA 65E Power fuses	174	3758.4	23%	2905.05	55%	1.67
	Total - 34.5 kV side of Moretown	-2075.18	124.09	2078.89	-1.00	148.79	149.79	149.14	97.93	87.18	87.34	57.76	55.41	118.35	231.52		65E Power Fuses	65	3880.5	22%	3024.04	54%	1.80
#10 Maple Corners	#1 North Calais	-55.93	29.25	63.12	-0.89	105.09	104.01	106.04	99.17	103.94	101.15	3.64	0.00	1.85	5.49	Voltage on 15 kV side is reasonable, secondary voltage locations that have issues: 20058_ECKHAUS_7.6KW-	100A Circuit regulators	100	5970	3%	5819.04	1%	5.91
	#2 Middlesex	-195.31	54.95	202.89	-0.96	109.74	119.48	108.40	99.99	100.97	101.78	9.65	6.03	1.85	17.53	Voltage on 15 kV side is reasonable, secondary voltage locations that have issues: Transformer 15 kVA with 15.3 kW of reverse power, 20638_JOHN_34KW –	100A Circuit regulators	100	5970	4%	5723.48	3%	5.77
	#10 Maple Corners 12 kV	-251.24	84.20	264.97	-0.95	109.74	119.48	108.40	99.17	100.97	101.15	13.29	6.03	3.70	23.02		Sub transformer 3-833 kVA	116	2499	16%	2101.58	11%	2.23
#11 Tunbridge	#1 Corinth - Includes 100 kVA of proposed load at the Vershire Town	-3.55	-252.29	252.32	-0.01	103.74	105.04	109.63	98.02	98.50	98.32	3.12	1.18	6.08	10.37	Voltage on 15 kV side is reasonable, secondary voltage locations that have issues: 30961_KEYSER_11.4KW - 330' service 15 kVA transformer, 25842_GRIFFIN_10KW – 650' service 10 kVA transformer	Recloser Bypass	150	3240	12%	2848.47	8%	2.99
	#2 South Tunbridge	-4.17	-51.88	52.05	-0.08	107.52	0.00	0.00	97.58	0.00	0.00	4.01	0.00	0.00	4.01	Voltage on 15 kV side is reasonable, secondary voltage locations that have issues: 15492_LEFEBVRE_15KW - 360' service 25 kVA transformer	6/8CWC - 100A	100	720	15%	611.68	7%	0.67
	#3 Brookfield Single Phase Circuit	-12.75	-40.07	42.05	-0.30	98.20	99.68	100.72	97.59	99.22	88.49	0.02	0.01	5.25	5.27	Extensive low voltage due to bi-directional regulato settings REG28951	Recloser Bypass	150	1080	15%	921.22	4%	1.04
	Total - 12 kV Bus - Includes 100 kVA of proposed load at the Vershire Town Garage	-20.47	-344.24	344.85	-0.06	107.52	105.04	109.63	97.58	98.50	88.49	7.14	1.18	11.33	19.66		Substation Transformers 3-1250 kVA	174	3758.4	17%	3108.31	9%	3.41
	Total - At VELCO Chelsea	-14.90	-404.12	404.40	-0.04	107.52	105.04	109.63	97.58	98.50	88.49	9.02	2.92	13.28	25.23		4/0ACSR Condu	357	21312.9	3%	20628.55	2%	20.91

Table 30: LRP – Minimum Load, 100% DER – Load Flows – Pg 3

Present Peak - All Recommendations Implemented																		Total kW Losses												
		Cyme Results from load allocation																213.841					Change in Lowest Downstream Vpu from Original							
										Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses														
Substation	Circuit	A Amps	B Amps	C Amps	I Neutral	kW	kVAR	kVA	Circuit PF	A	B	C	A	B	C	Phase A	Phase B	Phase C	Total	Notes	Original Peak I Neutral	I Neutral Difference	A	B	C	Limiting Element	Amp Rating	Limiting Element kVA	% Loading	Remaining kVA
#1 East Montpelier 34.5 kV Feed		76.42	78.08	90.50	0.03	4992.60	587.05	5026.99	99%	104.60	103.95	104.93	95.40	96.55	95.12	71.49	50.84	91.51	213.84		0.0256	0.00	4.88	2.14	2.85	HS Fuses 125E	125	7462.5	67%	2435.51
34.5 kV feed from EM to Maple Corners		19.93	19.91	27.12	0.03	1341.78	206.33	1357.55	99%	103.27	103.58	103.23	95.83	97.56	95.12	16.80	8.47	27.86	53.14		0.0256	0.00	3.51	0.46	-0.96	4/0ACSR Conductor	357	21312.9	6%	19955.35
#1 East Montpelier 12 kV Distribution	#1 Cabot	13.94	15.02	48.33	34.43	559.86	98.93	568.54	98%	102.62	102.02	104.93	99.92	97.27	96.65	0.94	2.72	21.33	24.99		49.39084	-14.96	1.15	0.79	1.71	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	3240	18%	2671.46
	#2 Orange	97.91	79.23	78.36	19.81	1901.04	263.76	1919.25	99%	104.60	103.95	104.49	95.40	96.55	96.17	39.59	23.68	29.30	92.57		22.48108	-2.67	4.88	1.71	3.89	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	3240	59%	1320.75
	#3 County Rd	58.66	53.13	48.17	10.53	1171.61	-150.61	1181.26	99%	102.68	102.66	102.56	98.16	96.86	98.43	7.86	10.37	6.62	24.84		10.47409	0.05	3.65	2.44	4.06	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	3240	36%	2058.74
	Total	170.87	145.91	173.77	20.05	3632.52	212.08	3638.70	100%	104.60	103.95	104.93	95.40	96.55	96.17	48.38	36.77	57.25	142.40		28.17347	-8.12	4.88	2.14	3.89	Substation Transformer	231	5000	73%	1361.30
GMP Mountain View #27	#2 Jones Brook Metering Point	20.88	0.00	0.00	20.88	142.82	41.14	148.63	96%	101.68	0.00	0.00	97.34	0.00	0.00	3.06	0.00	0.00	3.06		20.90502	-0.02	0.18	0.00	0.00	50H Single phase recloser	50	1080	14%	931.37
#3 Mount Knox	#1 Peacham	35.55	34.20	32.57	8.05	753.39	104.72	760.63	99%	103.62	103.20	104.06	96.65	97.57	96.89	9.72	9.29	10.66	29.67		8.808828	-0.76	2.06	0.60	0.25	Recloser Bypass 100 K	150	3240	23%	2479.37
	#2 Corinth	93.11	82.56	96.05	27.64	2013.49	80.76	2015.11	100%	103.62	104.36	104.06	96.19	96.77	95.41	35.14	47.10	54.83	137.06		37.99541	-10.35	0.52	1.31	-0.21	Recloser Bypass 100 K	150	3240	62%	1224.89
	Total	128.65	116.27	128.46	35.58	2766.88	185.47	2773.09	100%	103.62	104.36	104.06	96.19	96.77	95.41	44.85	56.39	65.49	166.73		37.45919	-1.88	1.60	1.31	-0.21	Bus Regulators	150	3240	86%	466.91
#4 West Danville	#1 Hookerville A Phase	26.19	32.53	34.96	1.98	656.27	121.73	667.47	98%	101.89	102.11	102.10	96.63	98.63	97.02	4.03	3.38	7.25	14.67		9.405969	-7.42	-0.47	0.78	-1.44	Substation Transformers 3-500 kVA	69	1500	44%	832.53
	#2 Peacham B Phase																					0.00	0.00	0.00	0.00					
	#3 W. Danville C Phase																					0.00	0.00	0.00	0.00					

Table 31: LRP – Present Peak Load, No DER – All Proposed Recommendations in Place – Load Flows – Pg 1

Present Peak - All Recommendations Implemented																		Total kW Losses												
		Cyme Results from load allocation																	213.841				Change in Lowest Downstream Vpu from Original							
										Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses														
Substation	Circuit	A Amps	B Amps	C Amps	I Neutral	kW	kVAR	kVA	Circuit PF	A	B	C	A	B	C	Phase A	Phase B	Phase C	Total	Notes	Original Peak I Neutral	I Neutral Difference	A	B	C	Limiting Element	Amp Rating	Limiting Element kVA	% Loading	Remaining kVA
#5 S. Walden	#1 Greensboro Single Phase Circuit	0.02	78.24	0.02	78.24	582.61	71.81	587.02	99%	99.25	104.22	98.36	99.24	98.15	98.32	0.00	27.85	0.00	27.85	Would be good to extend three phase, make sure substation can accomadate three phase	78.01035	0.23	0.26	-0.40	-0.06	Voltage Regulators & Reclower Bypass *URD Getaway 1/0 AL 155A*	150	1080	54%	492.98
	#2 Cabot	38.70	13.54	35.65	24.90	646.78	23.04	647.19	100%	103.59	101.81	103.24	98.02	98.32	95.14	7.98	1.05	10.15	19.18		36.11332	-11.22	-0.11	-0.11	1.21	Voltage Regulators & Reclower Bypass *URD Getaway 1/0 AL 155A*	150	3240	20%	2592.81
	#3 West Hill Pond	11.70	24.43	30.84	17.75	477.94	130.51	495.44	96%	101.11	102.99	103.24	96.99	97.15	96.90	1.32	5.78	4.86	11.96		17.56525	0.19	3.64	2.40	0.73	Voltage Regulators & Reclower Bypass *URD Getaway 1/0 AL 155A*	150	3240	15%	2744.56
	#5 S. Walden - 12.47 kV Bus	52.22	121.44	69.49	59.99	1707.33	225.37	1722.14	99%	103.59	104.22	103.24	96.99	97.15	95.14	9.30	34.67	15.01	58.99		48.29216	11.70	3.64	2.40	1.21	Transformer 3-1,250 kVA transformers	63	3750	46%	2027.86
	#5 SOUTH WALDEN 34.5 KV 3319 GMP TAP	32.47	35.28	21.87	0.00	1720.06	281.18	1742.89	99%	103.59	104.22	103.24	96.99	97.15	95.14	12.90	40.80	18.01	71.71		0	0.00	3.48	2.19	1.23					
#7 Graniteville - *Not load allocated*	34.5 kV feed to Jackson Corners	59.43	58.30	63.09	0.00	3501.48	634.82	3558.56	98%	104.38	104.76	104.71	96.57	96.35	96.52	62.19	57.66	55.70	175.55		0.003265	0.00	-0.68	0.42	1.25					
#8 Jackson Corners (Served by #7 Graniteville)	#1 Topsham	39.55	20.82	30.38	16.38	659.45	178.72	683.24	97%	104.38	104.76	104.71	99.67	100.32	98.17	4.49	2.71	7.87	15.07		34.3105	-17.93	0.03	1.88	2.31	Recloser Bypass 150A Overhead Line - 2/0ACSR 276A	150	3240	21%	2556.76
	#2 Chelsea	23.53	20.38	30.15	11.42	520.59	-187.54	553.34	94%	104.38	104.76	104.71	100.04	100.28	98.98	4.23	4.29	10.88	19.39		16.25931	-4.84	0.03	4.35	3.70	Recloser Bypass 150A Overhead Line - 1/0AAAC 256A	150	3240	17%	2686.66
	#3 Northfield	106.51	105.69	99.95	6.05	2287.71	540.59	2350.71	97%	104.38	104.76	104.71	96.57	96.35	96.52	42.11	40.44	24.81	107.36		31.3682	-25.32	-0.68	-0.56	1.25	Recloser Bypass 150A Overhead Line - 4/0AAAC 395A	150	3240	73%	889.29
	Martin Solar	0.00	0.00	0.00	0.00	0.00	0.00	0.00		102.14	101.68	100.73	102.14	101.68	100.73	0.00	0.00	0.00	0.00		6.1E-06	0.00	0.61	1.01	0.50					
	Williamstown	0.04	0.04	0.04	0.00	0.00	-0.78	0.78		101.10	102.79	102.49	101.10	102.79	102.49	0.00	0.00	0.00	0.00		0.000998	0.00	0.79	1.48	0.96					
	12 kV Total	165.45	142.12	158.27	18.98	3467.75	531.78	3508.29	99%	104.38	104.76	104.71	96.57	96.35	96.52	50.83	47.43	43.56	141.82		77.16825	-58.19	-0.68	0.42	1.25	Sub transformer is rated at 174A 3750 MVA	174	3758.4	93%	250.11

Table 31: LRP – Present Peak Load, No DER – All Proposed Recommendations in Place – Load Flows – Pg 2

Present Peak - All Recommendations Implemented

Total kW Losses 213.841

		Cyme Results from load allocation								Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses							Change in Lowest Downstream Vpu from Original							
Substation	Circuit	A Amps	B Amps	C Amps	I Neutral	kW	kVAR	kVA	Circuit PF	A	B	C	A	B	C	Phase A	Phase B	Phase C	Total	Notes	Original Peak I Neutral	I Neutral Difference	A	B	C	Limiting Element	Amp Rating	Limiting Element kVA	% Loading	Remaining kVA
#9 Moretown	#1 Middlesex	35.85	56.15	53.24	19.51	1043.14	299.93	1085.40	96%	102.81	104.39	103.87	97.43	97.11	96.55	8.49	23.75	18.83	51.07		18.97025	0.54	0.53	1.12	-0.07	Voltage Regulators & Reclower Bypass *URD Getaway 1/0 AL URD 155A*	150	3240	34%	2154.60
	#2 Moretown Common Single Phase Circuit	0.00	0.00	44.18	44.18	313.56	83.47	324.48	97%	0.00	0.00	102.02	0.00	0.00	96.90	0.00	0.00	8.92	8.92		46.5888	-2.41	0.00	0.00	3.93	Recloser 70 V4L *Voltage Regulators & Reclower Bypass 150A*	70	504	64%	179.52
	#3 Fayston	75.55	79.64	55.31	17.10	1562.28	221.70	1577.93	99%	104.67	104.39	104.48	97.49	97.46	98.60	31.29	43.83	16.39	91.50		16.42077	0.68	0.21	0.23	-0.51	75 A regulators outside substation *Recloser Bypass 150A* *1/0 AL Cable 155A*	75	1620	97%	42.07
	Total - 12.47 kV side of Moretown	116.33	143.06	160.82	41.11	2918.98	605.10	2981.04	98%	104.67	104.39	104.48	97.43	97.11	96.55	39.78	67.58	44.14	151.50		43.42603	-2.32	0.53	1.12	3.58	Substation Transformer 3-1250 kVA 65E Power fuses	174	3758.4	79%	777.36
	Total - 34.5 kV side of Moretown	48.16	55.96	47.92	0.00	2924.84	676.23	3002.00	97%	104.67	104.39	104.48	97.43	97.11	96.55	41.10	69.58	46.68	157.36		0	0.00	0.53	1.12	3.58	65E Power Fuses	65	3880.5	77%	878.50
#10 Maple Corners	#1 North Calais	47.58	0.00	24.36	40.57	506.58	138.40	525.14	96%	101.67	102.42	101.46	95.83	101.86	95.29	9.64	0.01	5.83	15.48		40.14766	0.43	1.27	-0.59	-0.80	100A Circuit regulators	100	5970	9%	5444.86
	#2 Middlesex	32.25	33.62	46.32	13.39	820.98	75.56	824.45	100%	102.15	102.38	102.10	96.86	97.56	95.12	2.35	5.12	15.95	23.43		37.83817	-24.44	4.54	0.46	-4.30	100A Circuit regulators	100	5970	14%	5145.55
	#10 Maple Corners 12 kV	79.54	33.41	70.43	43.29	1327.55	213.95	1344.68	99%	102.15	103.02	102.10	95.83	97.56	95.12	12.00	5.13	21.78	38.91		70.63462	-27.34	3.51	0.46	-0.96	Sub transformer 3-833 kVA	116	2499	54%	1154.32
#11 Tunbridge	#1 Corinth	50.91	20.98	63.59	34.64	1003.07	-100.36	1008.08	100%	103.57	102.69	103.90	99.89	99.89	96.93	14.18	2.25	39.79	56.22		41.26645	-6.62	0.42	2.69	0.45	Recloser Bypass	150	3240		
	#2 South Tunbridge	43.10	0.00	0.00	43.10	319.62	-33.68	321.39	99%	103.57	0.00	0.00	97.32	0.00	0.00	13.89	0.00	0.00	13.89		43.04403	0.06	1.36	0.00	0.00	6/8CWC - 100A	100	720	45%	398.61
	#3 Brookfield Single Phase Circuit	2.42	39.76	26.25	32.87	507.22	32.18	508.24	100%	103.73	103.95	103.90	101.65	96.60	96.81	0.18	19.83	7.59	27.59		66.3343	-33.47	-0.23	-1.52	1.50	Recloser Bypass	150	1080		
	Total - 12 kV Bus	100.64	63.00	93.32	33.10	1829.91	-101.85	1832.74	100%	103.73	103.95	103.90	97.32	96.60	96.81	28.25	22.07	47.38	97.70		111.3467	-78.25	1.36	-0.60	1.50	Substation Transformers 3-1250 kVA	174	3758.4	49%	1925.66
	Total - At VELCO Chelsea	22.96	20.51	26.45	0.00	1843.20	-87.88	1845.30	100%	103.73	103.95	103.90	97.32	96.60	96.81	33.36	25.43	52.20	110.99		0.00232	0.00	1.36	-0.60	1.50	100E HS fuses	100	5970	31%	4124.70

Table 31: LRP – Present Peak Load, No DER – All Proposed Recommendations in Place – Load Flows – Pg 3

Present Minimum Load, 100% DER - All Recommendations Implemented																											
		Cyme Results from load flow														Total kW Losses 328.87				Change in Lowest Downstream Vpu from Original Peak *Positive values indicates a rise in voltage*							
										Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses											
Substation	**Circuit**	**A Amps**	**B Amps**	**C Amps**	**I Neutral**	**kW**	**kVAR**	**kVA**	**Circuit PF**	**A**	**B**	**C**	**A**	**B**	**C**	**Phase A**	**Phase B**	**Phase C**	**Total**	**A**	**B**	**C**	**Limiting Element**	**Amp Rating**	**Limiting Element kVA**	**% Loading**	**Remaining kVA**
#1 East Montpelier 34.5 kV Feed		27.38	35.14	33.63	0.03	-1914.52	544.42	1990.42	-96%	105.17	104.99	105.14	96.80	97.31	97.02	72.04	72.42	79.66	224.12	6.27	2.89	4.75	HS Fuses 125E	125	7462.5	27%	5472.08
34.5 kV feed from EM to Maple Corners		4.01	3.99	6.64	0.03	-255.01	-133.51	287.84	-89%	105.17	104.99	105.14	98.48	101.61	99.49	6.39	2.66	10.19	19.25	6.16	4.51	3.41	4/0ACSR Conductor	357	21312.9	1%	21025.06
#1 East Montpelier 12 kV Distribution	#1 Cabot	9.19	3.46	9.64	10.51	-152.62	-19.61	153.87	-99%	103.77	103.94	103.65	100.09	100.03	98.53	1.49	1.00	3.17	5.66	1.32	3.55	3.58	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	3240	5%	3086.13
	#2 Orange	12.58	9.26	11.29	15.15	33.01	-191.32	194.15	17%	104.06	104.74	104.94	100.24	99.86	100.53	3.27	2.94	3.46	9.67	9.71	5.02	8.26	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	3240	6%	3045.85
	#3 County Rd	80.42	77.85	90.68	13.48	-1552.63	848.07	1769.15	-88%	103.47	104.95	103.65	96.80	97.31	97.02	56.76	61.70	58.37	176.83	2.29	2.89	2.64	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	3240	55%	1470.85
	Total	72.36	72.89	94.62	27.12	-1672.23	637.14	1789.50	-93%	104.06	104.95	104.94	96.80	97.31	97.02	61.52	65.63	65.00	192.16	6.27	2.89	4.75	Substation Transformer	231	5000	36%	3210.50
GMP Mountain View #27	#2 Jones Brook Metering Point	1.66	0.00	0.00	1.66	-4.27	11.13	11.92	-36%	104.03	0.00	0.00	99.72	0.00	0.00	0.80	0.00	0.00	0.80	2.56	0.00	0.00	50H Single phase recloser	50	1080	1%	1068.08
#3 Mount Knox	#1 Peacham	6.11	4.94	5.05	9.55	6.58	-64.50	64.84	10%	104.65	104.53	101.52	100.12	99.78	99.08	2.10	1.37	0.70	4.16	5.53	2.81	2.45	Recloser Bypass 100 K	150	3240	2%	3175.16
	#2 Corinth	17.56	31.52	8.88	28.90	129.89	-380.41	401.97	32%	104.55	104.86	104.64	98.05	100.12	99.60	6.09	12.82	5.24	24.15	2.37	4.67	3.97	Recloser Bypass 100 K	150	3240	12%	2838.03
	Total	21.57	35.48	7.08	25.78	136.46	-444.91	465.37	29%	104.65	104.86	104.64	98.05	99.78	99.08	8.19	14.19	5.93	28.31	3.46	4.32	3.46	Bus Regulators	150	3240	14%	2774.63
#4 West Danville	#1 Hookerville A Phase	1.22	7.43	3.56	10.82	28.56	-17.65	33.57	85%	104.80	104.46	104.90	100.29	100.62	99.53	0.84	0.83	2.74	4.41	3.19	2.77	1.08	Substation Transformers 3-500 kVA	69	1500	2%	1466.43
	#2 Peacham B																			0.00	0.00	0.00					
	#3 W. Danville C Phase																			0.00	0.00	0.00					

Table 32: LRP – Present Minimum Load, 100% DER Output – All Proposed Recommendations in Place – Load Flows – Pg 1

Present Minimum Load, 100% DER - All Recommendations Implemented																	Total kW Losses											
		Cyme Results from load flow																		328.87	Change in Lowest Downstream Vpu from Original Peak *Positive values indicates a rise in voltage*							
										Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses												
Substation	Circuit	A Amps	B Amps	C Amps	I Neutral	kW	kVAR	kVA	Circuit PF	A	B	C	A	B	C	Phase A	Phase B	Phase C	Total	A	B	C	Limiting Element	Amp Rating	Limiting Element kVA	% Loading	Remaining kVA
#5 S. Walden	#1 Greensboro Single Phase Circuit	0.02	9.32	0.02	9.30	17.35	-65.30	67.57	26%	100.60	104.08	100.45	100.60	99.04	100.45	0.00	3.69	0.00	3.69	1.63	0.49	2.07	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	1080	6%	1012.43
	#2 Cabot	4.86	6.33	4.96	0.81	-11.54	-113.56	114.15	-10%	104.80	104.74	104.26	99.75	100.09	99.49	2.11	0.97	1.50	4.58	1.62	1.66	5.56	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	3240	4%	3125.85
	#3 West Hill Pond	1.72	2.41	1.88	1.14	24.89	27.64	37.20	67%	102.17	104.48	104.27	99.65	100.09	99.20	0.24	0.92	1.03	2.19	6.30	5.34	3.03	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	3240	1%	3202.80
	#5 S. Walden - 12.47 kV Bus	4.14	14.11	3.13	9.47	30.70	-151.22	154.30	20%	104.80	104.74	104.27	99.65	99.04	99.20	2.34	5.58	2.53	10.46	6.30	4.30	5.27	Transformer 3-1,250 kVA transformers	63	3750	4%	3595.70
	#5 SOUTH WALDEN 34.5	3.89	3.61	1.46	0.00	34.78	-166.38	169.97	0%	104.80	104.74	104.27	99.65	99.04	99.20	3.71	6.97	3.87	14.55	6.15	4.09	5.29					
#7 Graniteville - *Not load allocated*	34.5 kV feed to Jackson Corners	56.60	59.51	57.30	0.00	-3430.17	529.31	3470.77	-99%	104.31	104.00	104.85	96.11	96.69	96.21	97.44	111.21	120.22	328.87	-1.14	0.75	0.94					
#8 Jackson Corners (Served by #7 Graniteville)	#1 Topsham	5.41	6.97	10.95	6.72	-154.81	47.08	161.81	-96%	104.31	101.20	104.85	97.28	96.81	97.18	2.63	2.30	3.94	8.87	-2.36	-1.63	1.33	Recloser Bypass 150A Overhead Line - 2/0ACSR 276A	150	3240	5%	3078.19
	#2 Chelsea	13.08	14.64	12.23	10.72	-17.53	-264.11	264.69	-7%	101.32	102.91	103.84	97.65	97.52	97.01	1.97	2.88	2.16	7.01	-2.37	1.58	1.72	Recloser Bypass 150A Overhead Line - 1/0AAAC 256A	150	3240	8%	2975.31
	#3 Northfield	151.69	155.72	167.30	13.93	-3302.49	500.93	3340.27	-99%	103.82	104.00	103.23	96.11	96.69	96.21	79.06	90.47	98.79	268.33	-1.14	-0.23	0.94	Recloser Bypass 150A Overhead Line - 4/0AAAC 395A	150	3240	103%	-100.27
	Martin Solar	68.59	68.59	68.59	0.00	-1492.03	83.80	1494.39	-100%	101.10	101.34	101.33	100.77	100.98	100.88	2.65	2.65	2.65	7.94	-0.75	0.31	0.66					
	Williamstown S	93.86	93.86	93.86	0.00	-1987.30	117.24	1990.76	-100%	98.52	98.92	98.52	98.12	98.48	98.01	4.23	4.22	4.23	12.67	-2.18	-2.83	-3.52					
	12 kV Total	153.63	168.36	173.52	19.69	-3474.83	283.91	3486.41	-100%	104.31	104.00	104.85	96.11	96.69	96.21	83.66	95.66	104.89	284.21	-1.14	0.75	0.94	Sub transformer is rated at 174A 3750 MVA	174	3758.4	93%	271.99

Table 32: LRP – Present Minimum Load, 100% DER Output – All Proposed Recommendations in Place – Load Flows – Pg 2

Present Minimum Load, 100% DER - All Recommendations Implemented																			Total kW Losses								
		Cyme Results from load flow																	328.87	Change in Lowest Downstream Vpu from Original Peak *Positive values indicates a rise in voltage*							
										Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses											
Substation	Circuit	A Amps	B Amps	C Amps	I Neutral	kW	kVAR	kVA	Circuit PF	A	B	C	A	B	C	Phase A	Phase B	Phase C	Total	A	B	C	Limiting Element	Amp Rating	Limiting Element kVA	% Loading	Remaining kVA
#9 Moretown	#1 Middlesex	65.75	64.79	71.11	4.75	-1439.48	124.26	1444.83	-100%	104.02	104.30	104.58	99.69	99.00	99.51	12.99	6.25	14.31	33.55	2.78	3.02	2.89	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL URD 155A*	150	3240	45%	1795.17
	#2 Moretown Common Single Phase Circuit	0.00	0.00	22.64	22.64	-162.04	19.47	163.21	-99%	0.00	0.00	104.11	0.00	0.00	99.30	0.00	0.00	5.47	5.47	0.00	0.00	6.33	Recloser 70 V4L *Voltage Regulators & Recloser Bypass* 150A	70	504	32%	340.79
	#3 Fayston	27.42	33.04	31.03	22.68	-624.01	-139.57	639.43	-98%	104.87	104.49	104.32	98.43	98.10	98.24	10.68	19.29	12.31	42.28	1.14	0.87	-0.87	75 A regulators outside substation *Recloser Bypass 150A 1/0 AL Cable 155A*	75	1620	39%	980.57
	Total - 12.47 kV side of Moretown	88.36	95.76	124.31	34.64	-2225.53	4.16	2225.53	-100%	104.87	104.49	104.58	98.43	98.10	98.24	23.66	25.55	32.09	81.29	1.52	2.12	5.27	Substation Transformer 3-1250 kVA 65E Power fuses	174	3758.4	59%	1532.87
	Total - 34.5 kV side of	32.35	38.64	40.69	0.00	-2215.56	102.22	2217.91	-100%	104.87	104.49	104.58	98.43	98.10	98.24	26.44	28.57	36.26	91.27	1.52	2.12	5.27	65E Power Fuses	65	3880.5	57%	1662.59
#10 Maple Corners	#1 North Calais	5.83	0.19	3.25	5.85	-56.53	31.10	64.52	-88%	103.02	102.36	103.75	98.48	102.19	99.71	3.33	0.00	1.56	4.89	3.92	-0.26	3.62	100A Circuit regulators	100	5970	1%	5905.48
	#2 Middlesex	7.76	4.87	20.59	16.49	-202.60	-96.29	224.32	-90%	104.72	104.54	104.64	100.57	101.61	99.49	1.78	1.34	7.11	10.23	8.25	4.51	0.07	100A Circuit regulators	100	5970	4%	5745.68
	#10 Maple Corners 12 kV	10.40	4.92	22.68	20.44	-259.14	-65.19	267.21	-97%	105.17	104.99	105.14	98.48	101.61	99.49	5.11	1.34	8.66	15.11	6.16	4.51	3.41	Sub transformer 3-833 kVA	116	2499	11%	2231.79
#11 Tunbridge	#1 Corinth	8.86	2.31	19.47	15.67	-5.73	-207.63	207.71	-3%	104.33	103.72	104.55	99.68	99.78	99.33	2.20	0.85	5.14	8.19	0.20	2.58	2.85	Recloser Bypass	150	3240		
	#2 South	7.22	0.00	0.00	7.22	-5.05	-52.26	52.50	-10%	104.66	0.00	0.00	99.63	0.00	0.00	3.13	0.00	0.00	3.13	3.67	0.00	0.00	6/8CWC - 100A	100	720	7%	667.50
	#3 Brookfield Single Phase	0.77	0.83	3.60	4.30	-14.77	-4.20	15.35	-96%	101.04	103.85	104.71	100.45	99.94	100.92	0.02	1.32	1.91	3.24	-1.42	1.82	5.61	Recloser Bypass	150	1080		
	Total - 12 kV Bus	16.34	1.53	19.99	15.28	-25.55	-264.09	265.32	-10%	104.66	103.85	104.71	99.63	99.66	99.33	5.35	2.16	7.05	14.56	3.67	2.45	4.02	Substation Transformers 3-1250 kVA	174	3758.4	7%	3493.08
	Total - At VELCO Chelsea	3.12	3.98	5.92	0.00	-20.14	-325.45	326.08	-6%	104.66	103.85	104.71	99.63	99.66	99.33	7.16	3.88	8.93	19.97	3.67	2.45	4.02	100E HS fuses	100	5970	5%	5643.92

Table 32: LRP – Present Minimum Load, 100% DER Output – All Proposed Recommendations in Place – Load Flows – Pg 3

Four Year Peak Loads, Pre-Recommendations																		Total Losses								
		Cyme Results from load flow																	267.99							
										Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses										
Substation	Circuit	A Amps	B Amps	C Amps	I Neutral	kW	kVAR	kVA	Circuit PF	A	B	C	A	B	C	Phase A	Phase B	Phase C	Total	2026-2027 Forecasted Loads kW	Difference between Forecast and Cyme Results *(Positive indicates Cyme has higher value)*	Limiting Element	Amp Rating	Limiting Element kVA	% Loading	Remaining MVA
#1 East Montpelier 34.5 kV Feed		80.55	83.10	95.38	0.03	5263.55	710.27	5311.26	99%	104.36	104.40	104.47	94.92	95.67	94.89	75.08	55.11	102.28	232.47			HS Fuses 125E	125	7462.5	71%	2.151
34.5 kV feed from EM to Maple Corners		19.95	19.94	27.15	0.03	1341.97	207.01	1357.84	99%	103.19	103.50	103.13	95.73	97.48	94.89	16.83	8.48	28.02	53.33			4/0ACSR Conductor	357	21312.9	6%	19.955
#1 East Montpelier 12 kV Distribution	#1 Cabot	16.13	17.39	56.31	40.02	649.11	130.86	662.17	98%	102.48	101.82	104.47	99.37	96.35	95.27	1.23	3.61	29.01	33.85	650	-0.89	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL*	150	3240	20%	2.578
	#2 Orange	98.20	78.83	78.65	20.36	1901.37	264.38	1919.66	99%	104.36	104.40	104.18	94.92	97.06	95.80	39.97	23.36	29.63	92.96	1793	108.37	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL*	150	3240	59%	1.320
	#3 County Rd	67.56	61.06	55.19	12.06	1351.57	-88.16	1354.45	100%	102.44	102.47	102.25	97.17	95.67	97.41	10.35	13.74	8.70	32.79	1365	-13.43	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL*	150	3240	42%	1.886
	Total	182.62	156.64	189.66	24.70	3902.05	307.07	3914.11	100%	104.36	104.40	104.47	94.92	95.67	95.27	51.55	40.72	67.33	159.61	3807	95.05	Transformer	231	5000	78%	1.086
GMP Mountain View #27	#2 Jones Brook Metering Point	22.19	0.00	0.00	22.19	151.61	43.86	157.82	96%	101.59	0.00	0.00	96.98	0.00	0.00	3.46	0.00	0.00	3.46	152	-0.39	50H Single phase recloser	50	1080	15%	0.922
#3 Mount Knox	#1 Peacham	39.40	38.15	36.13	8.12	839.85	133.22	850.35	99%	104.41	103.43	104.77	96.56	96.89	96.84	11.90	11.61	13.02	36.53	836	3.85	Recloser Bypass 100 K	150	3240	26%	2.390
	#2 Corinth	103.29	91.78	107.20	28.46	2251.46	164.42	2257.46	100%	104.41	104.76	104.77	96.14	96.08	94.57	42.66	58.14	67.85	168.65	2259	-7.54	Recloser Bypass 100 K	150	3240	70%	0.983
	Total	142.68	129.51	143.20	36.33	3091.31	297.63	3105.61	100%	104.41	104.76	104.77	96.14	96.08	94.57	54.57	69.75	80.86	205.18	3094	-2.69	Bus Regulators	150	3240	96%	0.134
#4 West Danville	#1 Hookerville A Phase	27.86	34.58	37.25	2.53	697.00	134.88	709.93	98%	101.82	102.01	102.00	96.22	98.30	94.80	4.56	3.81	8.51	16.89	691	6.00	Substation Transformers 3-500	69	1500	47%	0.790
	#2 Peacham B Phase																				0.00					0.000
	#3 W. Danville C Phase																				0.00					0.000

Table 33: LRP – 4 Year Peak, No DER Output – Present Recommendations Implemented/Prior to 4 Year Recommendations – Load Flows – Pg 1

Four Year Peak Loads, Pre-Recommendations																	Total Losses									
		Cyme Results from load flow																	267.99							
										Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses										
Substation	Circuit	A Amps	B Amps	C Amps	I Neutral	kW	kVAR	kVA	Circuit PF	A	B	C	A	B	C	Phase A	Phase B	Phase C	Total	2026-2027 Forecasted Loads kW	Difference between Forecast and Cyme Results *(Positive indicates Cyme has higher value)*	Limiting Element	Amp Rating	Limiting Element kVA	% Loading	Remaining MVA
#5 S. Walden	#1 Greensboro Single Phase Circuit	0.02	80.36	0.02	80.36	600.79	77.30	605.74	99%	99.20	104.70	98.28	99.19	98.36	98.25	0.00	29.38	0.00	29.38	556	44.79	Voltage Regulators & Reclower Bypass *URD Getaway 1/0 AL*	150	1080	56%	0.474
	#2 Cabot	39.69	13.90	36.58	25.43	666.61	28.28	667.21	100%	104.16	101.68	103.77	98.44	98.08	95.46	8.39	1.12	10.68	20.19	643	23.61	Voltage Regulators & Reclower Bypass *URD Getaway 1/0 AL*	150	1080	62%	0.413
	#3 West Hill Pond	12.07	25.23	31.62	18.20	492.63	135.13	510.83	96%	101.06	102.87	103.77	96.80	96.83	97.27	1.40	6.16	5.10	12.67	492	0.63	Voltage Regulators & Reclower Bypass *URD Getaway 1/0 AL*	150	3240	16%	2.729
	#5 S. Walden - 12.47 kV Bus	53.87	125.46	71.72	62.19	1760.03	240.70	1776.42	99%	104.16	104.70	103.77	96.80	96.83	95.46	9.79	36.66	15.78	62.23	1690	70.03	Transformer 3-1,250 kVA transformers	63	3750	47%	1.974
	#5 SOUTH WALDEN 34.5 KV 3319 GMP TAP	33.55	36.40	22.57	0.00	1773.34	301.27	1798.74	0%	104.16	104.70	103.77	96.80	96.83	95.46	13.54	43.10	18.89	75.54							-1.799
#7 Graniteville - *Not load allocated*	34.5 kV feed to Jackson Corners	69.90	68.40	73.89	0.00	4014.39	1095.16	4161.10	96%	104.79	104.33	104.77	96.73	94.32	96.04	87.91	89.76	78.46	256.13							-4.161
#8 Jackson Corners (Served by #7 Graniteville)	#1 Topsham	44.65	23.72	34.55	18.41	747.44	207.04	775.59	96%	104.79	104.33	104.77	99.49	100.15	97.97	5.71	3.51	10.12	19.33	748	-0.56	Recloser Bypass 150A Overhead Line -	150	3240	24%	2.464
	#2 Chelsea	25.82	22.21	33.88	12.96	590.68	-163.71	612.94	96%	104.79	104.33	104.77	99.82	99.08	98.11	5.15	5.39	13.81	24.35	591	-0.32	Recloser Bypass 150A Overhead Line -	150	3240	19%	2.627
	#3 Northfield	121.30	122.76	113.74	9.34	2611.05	666.65	2694.81	97%	104.79	104.33	104.77	96.73	94.32	96.04	54.41	61.32	31.49	147.22	2600	11.05	Recloser Bypass Changed to 150K fuses, rated at 225A Overhead Line - 4/0AAAC 395A	225	4860	55%	2.165
	Martin Solar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0%	103.10	102.30	100.82	103.10	102.30	100.82	0.00	0.00	0.00	0.00							0.000
	Williamstown Solar	0.04	0.04	0.04	0.00	0.00	-0.79	0.79	0%	101.91	103.52	102.84	101.91	103.52	102.84	0.00	0.00	0.00	0.00							-0.001
	12 kV Total	188.00	164.37	180.23	18.74	3949.17	709.98	4012.48	98%	104.79	104.33	104.77	96.73	94.32	96.04	65.27	70.22	55.42	190.90	3625	324.17	Sub transformer is rated at 174A 3750 MVA	174	3758.4	107%	-0.254

Table 33: LRP – 4 Year Peak, No DER Output – Present Recommendations Implemented/Prior to 4 Year Recommendations – Load Flows – Pg 2

Four Year Peak Loads, Pre-Recommendations																		Total Losses								
		Cyme Results from load flow																	267.99							
										Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses										
Substation	Circuit	A Amps	B Amps	C Amps	I Neutral	kW	kVAR	kVA	Circuit PF	A	B	C	A	B	C	Phase A	Phase B	Phase C	Total	2026-2027 Forecasted Loads kW	Difference between Forecast and Cyme Results *(Positive indicates Cyme has higher value)*	Limiting Element	Amp Rating	Limiting Element kVA	% Loading	Remaining MVA
#9 Moretown	#1 Middlesex	45.07	71.37	67.09	24.33	1321.90	395.75	1379.87	96%	103.33	104.73	105.37	96.56	94.35	95.23	13.37	38.54	29.97	81.87	1393	-71.10	Voltage Regulators & Reclower Bypass *URD Getaway 1/0 AL URD 155A*	150	3240	43%	1.860
	#2 Moretown Common Single Phase Circuit	0.00	0.00	55.97	55.97	395.25	110.39	410.37	96%	0.00	0.00	101.85	0.00	0.00	93.16	0.00	0.00	14.48	14.48	364	31.25	Recloser 70 V4L *Voltage Regulators & Reclower Bypass 150A*	70	504	81%	0.094
	#3 Fayston	96.86	102.51	70.05	22.31	1987.43	395.86	2026.47	98%	104.55	104.73	104.84	94.59	96.50	97.10	51.43	71.54	25.75	148.71	1867	120.43	75 A regulators outside substation, upgrade to 219A *Recloser Bypass 150A 1/0 AL Cable 155A*	150	3240	63%	1.214
	Total - 12.47 kV side of Moretown	150.72	187.81	209.46	53.88	3704.57	902.00	3812.80	97%	104.55	104.73	105.37	94.59	94.35	93.16	64.80	#####	70.19	245.07	3625	79.57	Substation Transformer 3-1250 kVA	174	3758.4	101%	-0.054
	Total - 34.5 kV side of Moretown	63.01	73.11	62.99	0.00	3727.49	1209.85	3918.92	95%	104.55	104.73	105.37	94.59	94.35	93.16	70.35	#####	79.64	267.99			65E Power Fuses	65	3880.5	101%	-0.038
#10 Maple Corners	#1 North Calais	47.63	0.00	24.38	40.62	506.61	138.46	525.19	96%	101.57	102.34	101.36	95.73	101.78	95.18	9.66	0.01	5.84	15.52	528	-21.39	100A Circuit	100	5970	9%	5.445
	#2 Middlesex	32.28	33.64	46.39	13.44	821.12	75.92	824.62	100%	102.05	102.30	101.99	96.76	97.48	94.89	2.36	5.13	16.08	23.57	707	114.12	100A Circuit	100	5970	14%	5.145
	#10 Maple Corners 12 kV	79.62	33.43	70.52	43.37	1327.73	214.38	1344.92	99%	102.05	102.95	101.99	95.73	97.48	94.89	12.02	5.14	21.93	39.09	1235	92.73	Sub transformer 3-833 kVA	116	2499	54%	1.154
#11 Tunbridge	#1 Corinth	58.02	23.84	73.18	40.96	1153.95	-65.58	1155.81	100%	103.92	103.16	103.61	99.22	100.09	94.07	18.37	2.78	53.42	74.57	1116	37.95	Recloser Bypass	150	3240	36%	2.084
	#2 South Tunbridge	49.13	0.00	0.00	49.13	366.48	-28.57	367.59	100%	103.92	0.00	0.00	96.99	0.00	0.00	17.94	0.00	0.00	17.94	386	-19.52	6/8CWC - 100A	100	720	51%	0.352
	#3 Brookfield Single Phase Circuit	2.76	45.60	30.22	37.64	583.04	42.27	584.57	100%	104.11	104.48	103.61	101.73	96.07	95.39	0.23	25.95	10.09	36.28	644	-60.96	Recloser Bypass	150	1080	54%	0.495
	Total - 12 kV Bus	115.38	72.46	107.62	39.19	2103.46	-51.88	2104.10	100%	104.11	104.48	103.61	96.99	96.07	94.07	36.54	28.73	63.52	128.79	2147	-43.54	Substation Transformers 3-1250	174	3758.4	56%	1.654
	Total - At VELCO Chelsea	26.17	23.88	30.22	0.00	2119.36	-12.98	2119.40	100%	104.11	104.48	103.61	96.99	96.07	94.07	42.70	32.67	69.31	144.68			100E HS fuses	100	5970	36%	3.851

Table 33: LRP – 4 Year Peak, No DER Output – Present Recommendations Implemented/Prior to 4 Year Recommendations – Load Flows – Pg 3

Four Year Peak Loads, Post Recommendations

Total losses kW: 254.49

		Cyme Results from load flows								Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses											
Substation	Circuit	A Amps	B Amps	C Amps	I Neutral	kW	kVAR	kVA	Circuit PF	A	B	C	A	B	C	Phase A	Phase B	Phase C	Total	2026-2027 Forecasted Loads MW	Difference between Forecast and Cyme Results *(Positive indicates Cyme has higher value)*	Notes	Limiting Element	Amp Rating	Limiting Element kVA	% Loading	Remaining kVA
#1 East Montpelier 34.5 kV Feed		80.55	83.10	95.36	0.03	5263.16	709.98	5310.83	99%	104.36	104.40	104.48	95.15	95.67	95.01	74.84	55.12	102.17	232.13				HS Fuses 125E	125	7462.5	71%	2151.67
34.5 kV feed from EM to Maple Corners		19.95	19.93	27.14	0.03	1341.87	207.00	1357.74	99%	103.19	103.50	103.13	95.73	97.48	95.01	16.83	8.48	27.92	53.23				4/0ACSR Conductor	357	21312.9	6%	19955.16
#1 East Montpelier 12 kV Distribution	#1 Cabot	16.13	17.39	56.31	40.02	649.07	130.84	662.13	98%	102.48	101.82	104.48	99.37	96.35	95.28	1.23	3.61	29.00	33.84	650	-0.93		Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	3240	20%	2577.87
	#2 Orange	98.16	78.83	78.65	20.32	1901.12	264.17	1919.39	99%	104.36	104.40	104.18	95.15	97.06	95.80	39.73	23.37	29.63	92.73	1793	108.12	Adjusted secondaries to address low V	Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	3240	59%	1320.61
	#3 County Rd	67.56	61.06	55.19	12.05	1351.57	-88.17	1354.44	100%	102.44	102.47	102.25	97.17	95.67	97.41	10.35	13.74	8.70	32.79	1365	-13.43		Voltage Regulators & Recloser Bypass *URD Getaway 1/0 AL 155A*	150	3240	42%	1885.56
	Total	182.58	156.64	189.65	24.70	3901.76	306.83	3913.80	100%	104.36	104.40	104.48	95.15	95.67	95.28	51.32	40.72	67.33	159.36	3807	94.76		Substation Transformer	231	5000	78%	1086.20
GMP Mountain View #27	#2 Jones Brook Metering Point	22.19	0.00	0.00	22.19	151.61	43.86	157.82	96%	101.59	0.00	0.00	96.98	0.00	0.00	3.46	0.00	0.00	3.46	152	-0.39		50H Single phase recloser	50	1080	15%	922.18
#3 Mount Knox	#1 Peacham	39.40	38.15	36.13	8.12	839.85	133.22	850.35	99%	104.41	103.43	104.77	96.56	96.89	96.84	11.90	11.61	13.02	36.53	836	3.85		Recloser Bypass 100 K	150	3240	26%	2389.65
	#2 Corinth	103.29	91.78	107.18	28.46	2251.31	164.36	2257.31	100%	104.41	104.76	104.77	96.14	96.08	95.01	42.67	58.14	67.69	168.50	2259	-7.69	Adjusted secondaries to	Recloser Bypass 100 K	150	3240	70%	982.69
	Total	142.68	129.51	143.18	36.33	3091.17	297.58	3105.46	100%	104.41	104.76	104.77	96.14	96.08	95.01	54.57	69.75	80.71	205.03	3094	-2.83	Replace 150A Regs with 219A Regs at minimum for load growth, but would recommend 437A Regs or use 219A circuit regulators to maximize feeder backup capability. Use forward & reverse settings of 120V, 3V BW, R=6, 2=X	With Bus Regs upgraded from 150 to 219A the next limiting element is the substation transformer which is a set of of 3-1250 kVA transformers	174	3758.4	83%	652.94

Table 34: LRP – 4 Year Peak, No DER Output – Present Recommendations Implemented/Post 4 Year Recommendations – Load Flows – Pg 1

Four Year Peak Loads, Post Recommendations

																		Total losses kW:									
		Cyme Results from load flows														254.49											
										Highest Downstream Vpu			Lowest Downstream Vpu			KW Losses											
Substation	Circuit	A Amps	B Amps	C Amps	I Neutral	kW	kVAR	kVA	Circuit PF	A	B	C	A	B	C	Phase A	Phase B	Phase C	Total	2026-2027 Forecasted Loads MW	Difference between Forecast and Cyme Results *(Positive indicates Cyme has higher value)*	Notes	Limiting Element	Amp Rating	Limiting Element kVA	% Loading	Remaining kVA
#4 West Danville	#1 Hookerville A Phase	27.86	34.58	37.21	2.50	696.70	134.83	709.62	98%	101.82	102.01	102.00	96.22	98.30	96.59	4.56	3.81	8.21	16.58	691	5.70	Adjusted secondaries to address low V	Substation Transformers 3-500 kVA	69	1500	47%	790.38
	#2 Peacham B Phase																				0.00						
	#3 W. Danville C Phase																				0.00						
#5 S. Walden	#1 Greensboro Single Phase Circuit	0.02	80.36	0.02	80.36	600.79	77.30	605.74	99%	99.20	104.70	98.28	99.19	98.36	98.25	0.00	29.38	0.00	29.38	556	44.79	Between 4-10 years - Recommend strategically extending three phase to reduce neutral current, make sure substation can	Voltage Regulators & Reclower Bypass *URD Getaway 1/0 AL 155A*	150	1080	56%	474.26
	#2 Cabot	39.69	13.90	36.58	25.43	666.61	28.28	667.21	100%	104.16	101.68	103.77	98.44	98.08	95.46	8.39	1.12	10.68	20.19	643	23.61		Voltage Regulators & Reclower Bypass *URD Getaway 1/0 AL 155A*	150	3240	21%	2572.79
	#3 West Hill Pond	12.07	25.23	31.62	18.20	492.63	135.13	510.83	96%	101.06	102.87	103.77	96.80	96.83	97.27	1.40	6.16	5.10	12.67	492	0.63		Voltage Regulators & Reclower Bypass *URD Getaway 1/0 AL 155A*	150	3240	16%	2729.17
	#5 S. Walden - 12.47 kV Bus	53.87	125.46	71.72	62.19	1760.03	240.70	1776.42	99%	104.16	104.70	103.77	96.80	96.83	95.46	9.79	36.66	15.78	62.23	1690	70.03		Transformer 3-1,250 kVA transformers	63	3750	47%	1973.58
	#5 SOUTH WALDEN 34.5 KV 3319 GMP TAP	33.55	36.40	22.57	0.00	1773.34	301.27	1798.74	99%	104.16	104.70	103.77	96.80	96.83	95.46	13.54	43.10	18.89	75.54								
#7 Graniteville - *Not load allocated*	34.5 kV feed to Jackson Corners	68.37	66.84	72.33	0.00	3984.90	852.27	4075.02	98%	104.95	104.77	104.73	96.28	95.35	95.94	79.96	74.87	71.86	226.68								

Table 34: LRP – 4 Year Peak, No DER Output – Present Recommendations Implemented/Post 4 Year Recommendations – Load Flows – Pg 2

Four Year Peak Loads, Post Recommendations

Total losses kW: 254.49

Substation	Circuit	Cyme Results from load flows: A Amps	B Amps	C Amps	I Neutral	kW	kVAR	kVA	Circuit PF	Highest Downstream Vpu: A	B	C	Lowest Downstream Vpu: A	B	C	KW Losses: Phase A	Phase B	Phase C	Total	2026-2027 Forecasted Loads MW	Difference between Forecast and Cyme Results (Positive indicates Cyme has higher value)	Notes	Limiting Element	Amp Rating	Limiting Element kVA	% Loading	Remaining kVA
#8 Jackson Corners (Served by #7 Graniteville)	#1 Topsham	44.58	23.61	34.58	18.45	747.47	207.14	775.64	96%	104.95	104.77	104.73	99.65	100.08	97.25	5.68	3.49	10.18	19.35	748	-0.53		Recloser Bypass 150A Overhead Line - 2/0ACSR 276A	150	3240	24%	2464.36
	#2 Chelsea	25.79	22.16	33.91	13.14	590.71	-164.88	613.29	96%	104.95	104.77	104.73	99.99	99.54	98.05	5.13	5.35	13.88	24.36	591	-0.29		Recloser Bypass 150A Overhead Line - 1/0AAAC 256A	150	3240	19%	2626.71
	#3 Northfield	121.09	121.00	113.87	7.16	2602.28	664.16	2685.69	97%	104.95	104.77	104.73	96.28	95.35	95.94	54.13	52.56	31.83	138.53	2600	2.28	3/12 CWC conductor reconductor with 1/0AAAC **991.5', 0.19 miles** of RC - WR_3/12CWC to 1/0AAAC SPAN_2247 to SPAN_8171 - P8-3-207 to P8-3-207R3 East Roxbory Rd to Roxbury, VT **THERE IS 0.65 MILES OF 1/0AAAC BETWEEN THIS AND THE NEXT RUN OF SMALL CONDUCTOR.** **670'** #6CWC ~ 2 spans to 1/0AAAC from P8-3-207R12 to P8-3-207R14 East Roxbury Rd, Roxbury, VT. **THERE IS 0.15 MILES OF 1/0AAAC BETWEEN THIS AND THE NEXT RUN OF SMALL CONDUCTOR.** **6,400'** of RC SPAN_4180 to SPAN_8152 from WR_3/12CWC to 1/0AAAC, P8-3-207R17 VT Rte 12 S, Northfield, VT to P8-3-207R37 Bailey Rd, Northfield, VT **Regulator REG25601 Bypassed** Pole #8-3-207R2A - East Roxbury Rd, Roxbury, VT	Recloser Bypass 150A Overhead Line - 4/0AAAC 395A	150	3240	83%	554.31
	Martin Solar	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0%	102.66	101.54	100.73	102.66	101.54	100.73	0.00	0.00	0.00	0.00								
	Williamstown S	0.04	0.04	0.04	0.00	0.00	-0.78	0.78	0%	101.48	102.78	102.73	101.48	102.78	102.73	0.00	0.00	0.00	0.00								
	12 kV Total	187.67	162.42	180.41	20.50	3940.46	706.41	4003.28	98%	104.95	104.77	104.73	96.28	95.35	95.94	64.94	61.40	55.90	182.24	3625	315.46	Replace existing 167 Bus regulators with 328A units Replace existing 3.75 MVA transformer with a 7.5 MVA unit assumed Z=5.75 & X/R=12.125 (New Substation transformer at minimum this should be a 5 MVA unit but would recommend a 7.5/10.5 MVA unit for feeder backup. Jackson Corners is centrally located and can provide backup to multiple substations. New Bus regulators would 328A at minimum but would recommend circuit regulators with 219A units for feeder backup or new 546A bus regulators (non-standard item))	New Limit is 328A bus regulators	328	7084.8	57%	3081.52

Table 34: LRP – 4 Year Peak, No DER Output – Present Recommendations Implemented/Post 4 Year Recommendations – Load Flows – Pg 3

Four Year Peak Loads, Post Recommendations

Total losses kW: 254.49

Substation	Circuit	Cyme Results from load flows: A Amps	B Amps	C Amps	I Neutral	kW	kVAR	kVA	Circuit PF	Highest Downstream Vpu: A	Highest Downstream Vpu: B	Highest Downstream Vpu: C	Lowest Downstream Vpu: A	Lowest Downstream Vpu: B	Lowest Downstream Vpu: C	KW Losses: Phase A	KW Losses: Phase B	KW Losses: Phase C	KW Losses: Total	2026-2027 Forecasted Loads MW	Difference between Forecast and Cyme Results *(Positive indicates Cyme has higher value)*	Notes	Limiting Element	Amp Rating	Limiting Element kVA	% Loading	Remaining kVA
#9 Moretown	#1 Middlesex	44.96	71.60	67.36	25.01	1322.09	396.18	1380.17	96%	103.56	104.43	104.47	96.81	95.11	95.17	13.32	38.59	30.05	81.97	1393	-70.91		Voltage Regulators & Reclower Bypass *URD Getaway 1/0 AL URD 155A*	150	3240	43%	1859.83
	#2 Moretown Common Single Phase Circuit	0.00	0.00	55.84	55.84	395.04	110.24	410.13	96%	0.00	0.00	102.02	0.00	0.00	95.52	0.00	0.00	14.24	14.24	364	31.04		Recloser 70 V4L *Voltage Regulators & Reclower Bypass 150A*	70	504	81%	93.87
	#3 Fayston	96.58	102.85	70.29	22.43	1987.55	394.08	2026.24	98%	104.80	104.43	104.47	95.27	96.78	97.39	51.22	71.76	25.62	148.60	1867	120.55	Replace 75A regulators with 219A which are good for 3.607 MVA Existing settings 121 V, 3 V BW, locked forward, 30 sec TD	*Recloser Bypass 150A 1/0 AL Cable 155A*	150	3240	63%	1213.76
	Total - 12.47 kV side of Moretown	149.41	185.15	205.39	51.08	3704.67	900.50	3812.54	97%	104.80	104.43	104.47	95.27	95.11	95.17	64.54	110.35	69.92	244.81	3625	79.67	Replace existing 3.75 MVA transformer with a 7.5 MVA unit	65E Power fuses	347	7500	51%	3687.46
	Total - 34.5 kV side of Moretown	61.90	71.50	62.03	0.00	3714.35	1017.87	3851.29	96%	104.80	104.43	104.47	95.27	95.11	95.17	66.73	113.71	74.05	254.49			HS fuses will be replaced with new transformer	65E Power Fuses	125	7500	51%	3648.71
#10 Maple Corners	#1 North Calais	47.63	0.00	24.38	40.62	506.61	138.46	525.19	96%	101.57	102.34	101.36	95.73	101.78	95.18	9.66	0.01	5.84	15.52	528	-21.39		100A Circuit regulators	100	5970	9%	5444.81
	#2 Middlesex	32.28	33.64	46.38	13.42	821.02	75.92	824.53	100%	102.05	102.30	101.99	96.76	97.48	95.01	2.36	5.13	15.99	23.48	707	114.02		100A Circuit regulators	100	5970	14%	5145.47
	#10 Maple Corners 12 kV	79.62	33.43	70.51	43.37	1327.63	214.38	1344.83	99%	102.05	102.95	101.99	95.73	97.48	95.01	12.02	5.14	21.83	38.99	1235	92.63		Sub transformer 3-833 kVA	116	2499	54%	1154.17
#11 Tunbridge	#1 Corinth	58.02	23.84	73.17	40.95	1153.88	-65.60	1155.75	100%	103.92	103.16	103.61	99.22	100.09	95.02	18.37	2.78	53.36	74.51	1116	37.88		Recloser Bypass	150	3240	36%	2084.25
	#2 South Tunbridge	49.13	0.00	0.00	49.13	366.48	-28.57	367.59	100%	103.92	0.00	0.00	96.99	0.00	0.00	17.94	0.00	0.00	17.94	386	-19.52		6/8CWC - 100A	100	720	51%	352.41
	#3 Brookfield Single Phase Circuit	2.76	45.60	30.22	37.64	583.04	42.27	584.57	100%	104.11	104.48	103.61	101.73	96.07	95.39	0.23	25.95	10.09	36.28	644	-60.96		Recloser Bypass	150	1080	54%	495.43
	Total - 12 kV Bus	115.38	72.46	107.61	39.18	2103.40	-51.90	2104.04	100%	104.11	104.48	103.61	96.99	96.07	95.02	36.54	28.73	63.45	128.72	2147	-43.60		Substation Transformers 3-1250 kVA	174	3758.4	56%	1654.36
	Total - At VELCO Chelsea	26.17	23.88	30.22	0.00	2119.30	-13.01	2119.34	100%	104.11	104.48	103.61	96.99	96.07	95.02	42.70	32.67	69.25	144.62				100E HS fuses	100	5970	35%	3850.66

Table 34: LRP – 4 Year Peak, No DER Output – Present Recommendations Implemented/Post 4 Year Recommendations – Load Flows – Pg 4

D. Existing Distribution Line Equipment

Line Regulator – Rating, Manufacturer, Control, & Location							
Substation	**Circuit**	**REG #**	**Location**	**Amp Rating**	**Phase**	**Manufacturer**	**Control**
#1 East Montpelier	#1 Cabot	REG13301	Pole #70, Max Gray Rd, Calais	75	C	Cooper	CL 6B
	#2 Orange	REG17201	Pole #80-2L6, East Hill Rd, Plainfield	100	B	Cooper	CL 5D
#2 Jones Brook	#2 Jones Brook	REG14851	Pole #5, Jones Brook Rd, Berlin	75	A	Cooper	CL 6B
#3 Mount Knox	#1 Peacham	REG17551	Pole #87 - L34, VT Rte. 232, Groton	75	B	Siemens	CL 6A
	#2 Corinth	REG24676	Pole #158 & 158A, VT Rte. 25, Topsham	75	ABC	Cooper	CL 5E
		REG28076	Pole # 210 - R67, Brook Rd, Corinth	75	C	Cooper	CL 6B
#5 South Walden	#1 Greensboro *Single Phase Circuit*	REG06401	Pole #81, Richards Crossing Rd, Walden	100	B	Cooper	CL 7A
		REG05376	#63 - R1, Bailey-Hazen Rd, Walden	75	B		CL 53
#8 Jackson	#1 Topsham	REG22726	Pole # 112 & 112A Tucker Rd, Orange	150	A, B, C	Cooper	CL 6A, CL 6B
	#2 Chelsea	REG28901	Pole #205-R19, Bobbinshop Rd, Chelsea	100	C		CL 6B
	#3 Northfield	REG23925	Pole #122-R25, Ferno Rd, Williamstown	100	A		CL 7A
		REG24076	Pole #80 & 80A, Rood Pond Rd, Williamstown	150	ABC		CL 7A
		REG25626	Pole #146 & 146A, Stone Rd, Brookfield	100	ABC		CL 6B
		REG25601	Pole #207-R2A, Rte. 12, Roxbury	75	B		CL 6A
#9 Moretown	#1 Middlesex	REG12926	Circuit, Pole #152, Molly Supple Hill Rd, Middlesex	75	B	Cooper	CL 5C
		REG11176	Circuit pole #164, French Rd, Middlesex	100	C		CL 6B
	#3 Fayston	REG14551	Circuit, #72 & 72A, Rte. 100, Duxbury	145	ABC	Cooper	CL 5E
		REG16376	#32, North Calais Road, Fayston	163	B		CL 5A
#10 Maple Corners	#1 North Calais	REG09776	Circuit #150A, North Fayston Road, Calais	75	A	Cooper	CL 5C
#11 North Tunbridge	#1 Corinth	REG29201	Bus, #292, Chelsea Road, Vershire	100	A	Cooper	CL 6B
		REG30501	#173-R26, Rt. 113, Vershire	75	C		CL 5E
	#2 South Tunbridge	REG32626	#56A, Hoyt Hill Rd., Tunbridge	75	C		CL 5E
	#3 Brookfield	REG28951	#82, Hook Rd., Chelsea	100	B		CL 6B

Table 35: Distribution Line Regulators - Rating, Manufacturer, Control, & Locatio

Capacitors					
Substation	**Feeder**	**CAP #**	**Location**	**Total Size (kVAR)**	**Phasing**
#1 East Montpelier	#1 Cabot	CAP13326	Pole #1-1-80, Max Gray Rd, Calais	50	C
	#2 Orange	CAP19051	Pole #1-2-154R11, Cutler Corner Rd, Barre	300	ABC
		CAP17176	Pole #1-2-96, Upper Rd, Plainfield	150	ABC
	#3 County Road	CAP15101	Pole #1-3-42, Lyle Young Rd, East Montpelier	150	ABC
		CAP16901	Pole #1-3-14L64, Bliss Rd, Montpelier	300	ABC
#3 Mount Knox	#1 Peacham	CAP17601	Pole #3-1-190, The Great Rd, Groton	50	A
	#2 Corinth	CAP17501	Pole #3-1-14L64, Ricker Pond Campground, Groton	50	B
		CAP26326	Pole #3-2-172, VT-25, Corinth	300	ABC
		CAP26477	Pole #3-2-210R10, Brook Rd, Corinth	50	C
		CAP28026	Pole #3-2-210R61, Brook Rd, Corinth	50	C
		CAP23176	Pole #3-2-21L132, Lime Kiln Rd, Topsham	50	A
		CAP28201	Pole #3-2-227R18L2, Waits River Rd, Bradford	50	B
		CAP28151	Pole #3-2-227R48, Hayward Rd, Corinth	100	B
		CAP26476	Pole #3-2-236, Corlis Hill, Corinth	50	A
		CAP24525	Pole #3-2-93, VT-25, Topsham	600	ABC
#4 West Danville	#1 Hookerville	CAP11826	Pole #4-1H-116, VT-2, Cabot	50	A
		CAP08976	Pole #4-1N-48, VT-15, Danville	50	A
		CAP10351	Pole #4-1P-52, Bayley-Hazen Rd, Peacham	50	A
#5 South Walden	#1 Greensboro	CAP06401	Pole #5-1-62, Bayley-Hazen Rd, Walden	100	B
	#2 West Danville	CAP08876	Pole #5-2-107, Dubray Rd, Cabot	50	C
		CAP07751	Pole #5-2-45L25, VT-RTE 15, Walden	50	A
#8 Jackson Corners	#2 Chelsea	CAP27676	Pole #8-2-114, VT-110, Chelsea	100	AB
	#3 Northfield	CAP22401	Pole #8-3-122R76, Onion River Rd, Northfield	50	A
		CAP23951	Pole #8-3-207R51A, Herriott Rd, Northfield	50	B
		CAP25601	Pole #8-3-209, Ladd Rd, Roxbury	100	AC
		CAP24151	Pole #8-3-38, South Hill Rd, Williamstown	150	ABC
		CAP20751	Pole #8-3-89R104, Hebert Rd, Williamstown	150	ABC
		CAP22501	Pole # 8-3-89R63, Hebert Rd, Williamstown	150	ABC
#9 Moretown	#1 Middlesex	CAP22676	Pole #9-1-53, Tower Rd, Williamstown	50	A
	#3 Fayston	CAP16376	Pole #9-3-156, North Fayston Rd, Fayston	50	B
		CAP18201	Pole #9-3-221, Center Fayston Rd, Fayston	50	B
		CAP14576	Pole #9-3-58, Brook Rd, Duxbury	50	A
		CAP12676	Pole #9-3-66R33L2A, Crossett Hill Rd, Duxbury	50	A
		CAP16401	Pole #9-3-94, VT RTE 100, Duxbury	50	A
#11 South Tunbridge	#1 Corinth	CAP29076	Pole #11-1-102, Densmore Rd, Chelsea	100	AC
		CAP30526	Pole #11-1-173R41, Richardson Rd, Vershire	100	C
		CAP29301	Pole #11-1-262, Chelsea Rd, Corinth	50	A
	#2 South Turnbridge	CAP32676	Pole #11-2-80A, Potash Hill, Tunbridge	50	C
	#3 Brookfield	CAP27576	Pole #11-3-139, Chelsea Rd, Brookfield	50	C

Table 36: Distribution Line Capacitors

Substation	Feeder	Device ID	Location	Device Function	Cooper Recloser Model	Control
#1 East Montpelier	#1 Cabot	RC11590	Pole #1-1-92, East Hill Rd, Calais	LR	35H	N/A
		RC11608	Pole #1-1-120, East Hill Rd, Calais	LR	35H	N/A
		RC13306	Pole #1-1-57A, Lightening Ridge Rd, Calais	LR	50H	N/A
	#2 Orange	RC17105	Pole #1-2-45, Lower Rd, Plainfield	LR	Triple-Single	Form 5
		RC17115	Pole #1-2-45A, Lower Rd, Plainfield	LR	Triple-Single	Form 6
		RC17184	Pole #1-2-80L4, Brook Rd, Plainfield	LR	50H	N/A
		RC19058	Pole #1-2-154R14, Cutler Corner Rd, Barre	LR	35H	N/A
		RC19079	Pole #1-2-155, Bission Rd, Orange	LR	35H	N/A
		RC19106	Pole #1-2-112, Brook Rd, Plainfield	LR	50H	N/A
	#3 County Road	RC13082	Pole #1-3-14L189, Mill St, Montpelier	PCCR Wrightsville Hydro	Triple-Single	N/A
		RC15015	Pole #1-3-14L133A, East Montpelier	LR	50H	N/A
		RC15114	Pole #1-3-31, East Montpelier	LR	70 4H	N/A
		RC15162	Pole #1-3-14L2, Vincent Flats Rd, East Montpelier	LR	70L	N/A
#3 Mount Knox	#1 Peacham	RC17526	Pole #3-1-87L35, State Forest Rd, Groton	LR	50H	N/A
		RC17604	Pole #3-1-182, Great Rd, Groton	LR	50H	N/A
		RC17655	Pole #3-1-166RR1, Minard Hill Rd, Groton	LR	35H	N/A
		RC19405	Pole #3-1-87, Goodwin Rd, Groton	LR	70 4H	N/A
		RC19407	Pole #3-1-90, Scott Highway, Groton	LR	AØ -70 4H & B&CØ -50H	N/A
	#2 Corinth	RC22942	Pole #3-2-21L1, Wiley Hill Rd, Topsham	LR	70L	N/A
		RC23153	Pole #3-2-21L87, Powder Spring Rd, Topsham	LR	35H	N/A
		RC24581	Pole #3-2-109, VT-25, Topsham	LR	50L	N/A
		RC24582	Pole #3-2-101R1, VT-25, Topsham	LR	50H	N/A
		RC24683	Pole #3-2-159, Watson Hill Rd, Topsham	LR	50H	N/A
		RC24703	Pole #3-2-21L108, Lime Kiln Rd, Topsham	LR	35 H	N/A
		RC24704	Pole #3-2-21L108R1, Lime Kiln Rd, Topsham	LR	35H	N/A
		RC26455	Pole #3-2-210R1, Brook Rd, Corinth	LR	50H	N/A

Substation	Feeder	Device ID	Location	Device Function	Cooper Recloser Model	Control
		RC26477	Pole #3-2-227R1, Fairground Rd, Corinth	LR	50H	N/A
		RC26478	Pole #3-2-227, VT-25, Corinth	LR	50H	N/A
#4 West Danville	#1 Hookerville	RC10203	Pole #4-1H-72, US-2, Cabot	LR	35H	N/A
		RC12007	Pole #4-1P-63, Slack St, Peacham	LR	35H	N/A
#5 South Walden	#1 Greensboro	RC04307	Pole #5-1-200, Gonyaw Rd, Greensboro	LR	35H	N/A
		RC05404	Pole #5-1-120, Stannard Mountain Rd, Stannard	LR	50H	N/A
		RC06406	Pole #5-1-65, Richard Crossing, Walden	LR	70 4H	N/A
		RC06431	Pole #5-1-63R1, Nicholson Rd, Walden	LR	50 4H	N/A
	#2 East Cabot	RC07683	Pole #5-2-45, VT-15, Walden	LR	50H	N/A
		RC08907	Pole #5-2-82L1, Bricketts Crossing Rd, Cabot	LR	50H	N/A
		RC08956	Pole #5-2-83, Bricketts Crossing Rd, Cabot	LR	50H	N/A
	#3 West Hill Pond	RC07608	Pole #5-3-15, Houston Hill, Walden	LR	50H	N/A
		RC08761	Pole #5-3-123, West Hill Rd, Cabot	LR	35H	N/A
		RC08762	Pole #5-3-125, West Hill Rd, Cabot	LR	35H	N/A
		RC08786	Pole #5-3-73A, Houston Hill Rd, Cabot	LR	50 4H	N/A
#8 Jackson Corners	#1 Topsham	RC22679	Pole #8-1-69, Lambert Rd, Williamstown	LR	70 4H	N/A
	#2 Chelsea	RC27632	Pole #8-2-70, Williamstown Rd, Washington	LR	70 4H	N/A
		RC28934	Pole #8-2-137, VT-110, Chelsea	LR	35H	N/A
		RC29005	Pole #8-2-171, Corinth Rd, Chelsea	LR	50H	N/A
	#3 Northfield	RC22429	Pole #8-3-89R35L1, Herbert Rd	PCCR Martins Brook Solar	Triple-Single	Form 6-TS
		RC23808	Pole #8-3-301A, Homewild Ln, Northfield	LR	35H	N/A
		RC23809	Pole #8-3-301A, Homewild Ln, Northfield	LR	25H	N/A
		RC23932	Pole #8-3-122R17R2, VT-64, Williamstown	PCCR Williamstown Solar	Triple Single	Form 6
		RC24007	Pole #8-3-122R18, Ferno Rd, Williamstown	LR	50H	N/A
		RC24058	Pole #8-3-122, Covey Rd, Williamstown	LR	70L	N/A

Substation	Feeder	Device ID	Location	Device Function	Cooper Recloser Model	Control
		RC24087	Pole #8-3-89R2, Rood Pond Rd, Williamstown	LR	70L	N/A
		RC24088	Pole #8-3-79, Rood Pond Rd, Williamstown	LR	35H	N/A
		RC25610	Pole #8-3-208, Ladd Rd, Roxbury	LR	50H	N/A
		RC25611	Pole #8-3-207, East Roxbury Rd, Roxbury	LR	50H	N/A
#9 Moretown	#1 Middlesex	RC11180	Pole #9-1-162L1, Molly Supple Hill Rd, Middlesex	LR	35L	N/A
		RC11181	Pole #9-1-163, French Rd, Middlesex	LR	35H	N/A
		RC12827	Pole #9-1-94, Center Rd, Middlesex	LR	50H	N/A
		RC12853	Pole #9-1-48, VT-2, Middlesex		Triple-Single	Form 6-TS
	#3 Fayston	RC16380	Pole #9-3-150L1, North Fayston Rd, Fayston	LR	35H	N/A
		RC14502	Pole #9-3-66, VT-100, Duxbury	LR	50H	N/A
		RC16384	Pole #9-3-150, North Fayston Rd, Fayston	LR	50H	N/A
		RC16414	Pole #9-3-103R1, Dowsville Rd, Duxbury	LR	35H	N/A
		RC16415	Pole #9-3-109, VT-100, Duxbury	LR	70L	N/A
#10 Maple Corner	#2 Middlesex	RC09580	Pole #10-2-101, West Hill Rd, Worcester	LR	35H	N/A
		RC09581	Pole #10-2-100RR1, West Hill Rd, Worcester	LR	25H	N/A
		RC09582	Pole #10-2-100, West Hill Rd, Worcester	LR	35H	N/A
		RC09761	Pole #10-2-13, Worcester Rd, Worcester	LR	50H	N/A
#11 South Tunbridge	#1 Corinth	RC28056	Pole #11-1-341, Cookeville Rd, Corinth	LR	35H	N/A
		RC29035	Pole #11-1-111, Blackhawk Rd, Chelsea	LR	70 4H	N/A
		RC29188	Pole #11-1-173R2, VT-113, Vershire	LR	50H	N/A
		RC29205	Pole #11-1-208, Chelsea Rd, Corinth	LR	50H	N/A
		RC30531	Pole #11-1-173R63, VT-113, Vershire	LR	35H	N/A
	#2 South Tunbridge	RC32629	Pole #11-2-57, Hoyt Hill Rd, Tunbridge	LR	50H	N/A
	#3 Brookfield	RC28828	Pole #11-3-106, Hook Rd, Chelsea	LR	35H	N/A
		RC30229	Pole #11-3-51, East Randolph Rd, Chelsea	LR	50H	N/A

Table 37: Circuit Line Reclosers[21]

[21] Only the slow curves are shown for the reclosers. Device Function – LR= Line Recloser & PCC = Point of Common Coupling

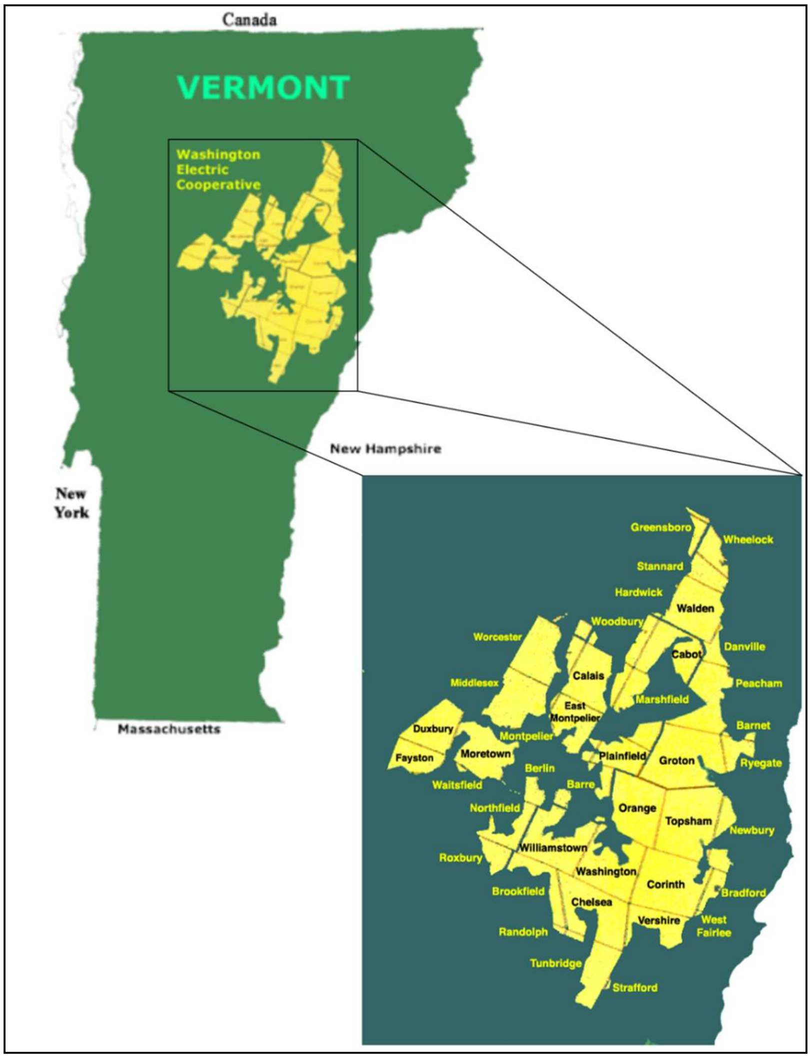
E. WEC 2023 System Reliability Report

WASHINGTON ELECTRIC COOPERATIVE, INC.

2023 SYSTEM RELIABILITY REPORT

1.0 Background

Washington Electric Cooperative served an average of 11,527 members in 2023 via an electrical distribution system that includes 26 miles of WEC-owned transmission line and 1,266 miles of distribution line. The system includes eight distribution substations, seven of which depend on third-party transmission provider Green Mountain Power for service. The remaining substation is served via a WEC owned transmission line interconnected to Vermont Electric Power Company's (VELCO) high voltage substation in Chelsea, VT. WEC's distribution lines are located throughout 41 towns in Central Vermont, covering approximately 2,728 square miles and serve remote locations composed of rural homes, small farms and small businesses. There are approximately 8 service locations per mile of line, many of which are located on unpaved roads in small valleys within the 41 towns.



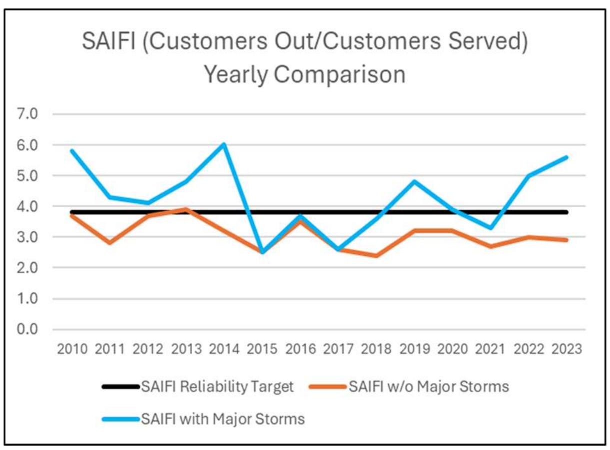
The distribution system was constructed during a time when much of the land in Vermont was open fields and pasture that has since grown in. Vermont lies within a biological transition zone between the northern boreal forest to the southern deciduous forests. The northern hardwood mix of beech, birch, and maple dominates Vermont's forests, accounting for 71% of the forest cover. The remote location of the lines and abundance of fast-growing species such as red maple, poplar and white birch coupled with severe weather events, significantly increases the exposure of the lines to tree-related outages which can only be combated through hardening of the lines and increased maintenance clearing.

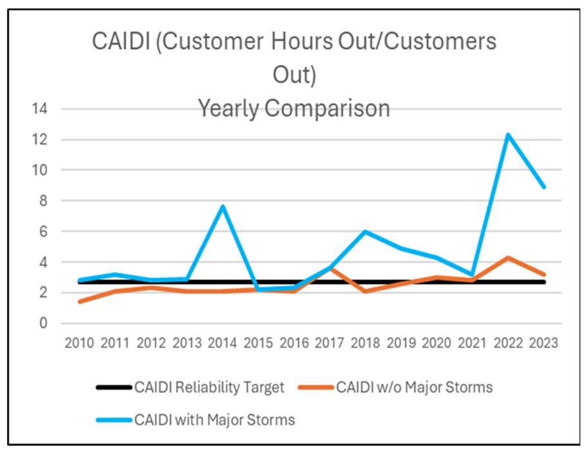
WEC records data associated with all power outages occurring over the calendar year and provides a year end Service Reliability Report to the Vermont Public Utilities

Commission as required by Rule 4.900. To compare trends more effectively in WEC's reliability performance and associated efforts to make improvements in those performance areas, this report generally excludes those outages associated with severe weather events determined to be "Major Storms" as defined in WEC's Successor Service Quality and Reliability Performance Plan. However, a distinctive increase in frequency and severity of these weather events is significantly contributing to a decline in service reliability across most of WEC's service territory and therefore must be taken into consideration when analyzing service reliability and planning for improvements. While it is true that severe weather events do create conditions that exceed the design capability of the electrical delivery system, it remains obvious that design criteria and maintenance schedules must be improved to counteract the increased severity of these events.

2.0 Reliability Summary:

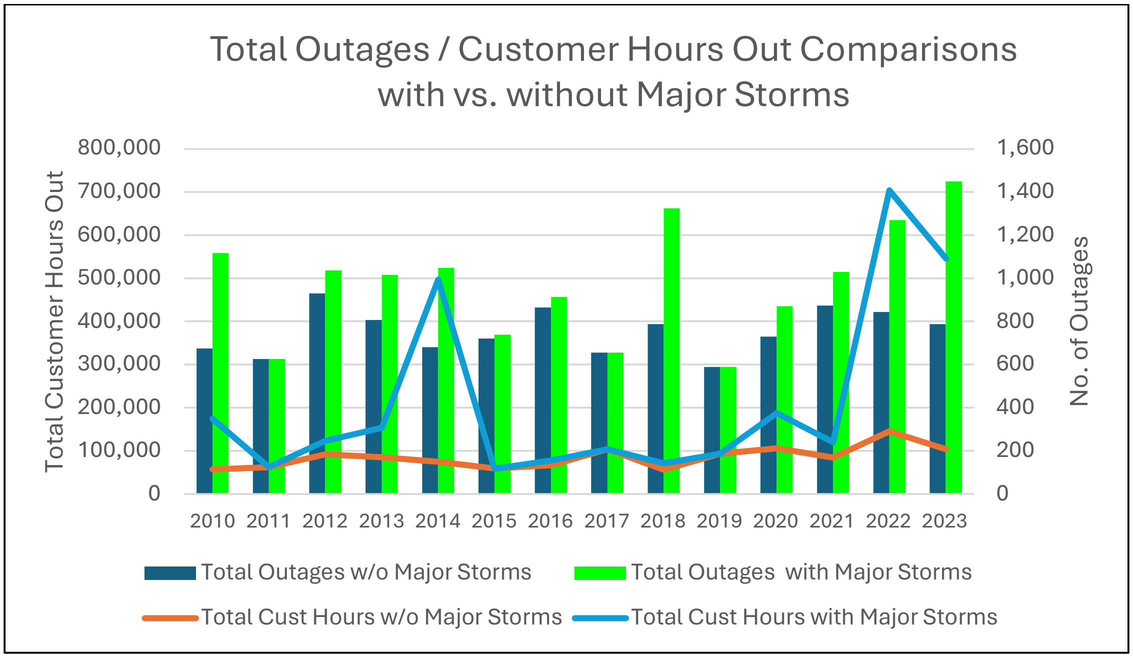
The SAIFI and CAIDI performance measure targets established in WEC's Successor Service Quality and Reliability Plan are **3.8** and **2.7** respectively. The SAIFI and CAIDI indices for 2023**,** exclusive of major storms, were **2.8** and **3.2** respectively. The SAIFI and CAIDI indices**,** exclusive of major storms, have averaged 2.8 and 3.4 over the last three years and the 10-year averages are 2.9 and 2.8 respectively.





3.0 Outage Totals/Customer Hours Out Summary:

In 2023 WEC experienced 787 separate outages, exclusive of major storms, on the distribution system compared to 843 in 2022. The rolling 3-year average for total number of outages, exclusive of major storms, is 835, and the rolling 10-year average is 753. The total number of consumer-hours-out in 2023, exclusive of major storms, was 103,876 compared to 145,304 in 2022. The rolling 3-year average of consumer-hours-out, exclusive of major storms, is 111,220 and the 10-year rolling average is 89,264.

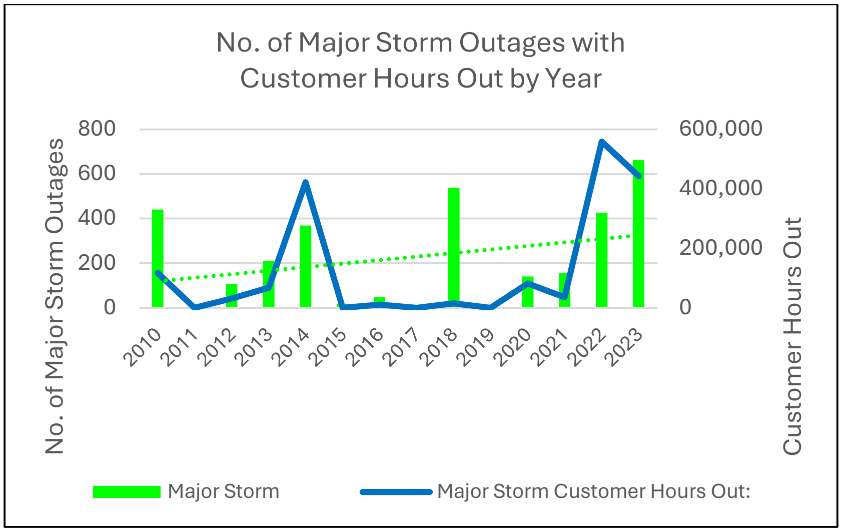


4.0 Impact of Major Weather Events:

During 2023, WEC experienced four severe weather events that met the criteria for Major Storm. Major Storms are defined in WEC's Successor Service Quality and Reliability Performance Plan as:

1. Extensive mechanical damage to the utility infrastructure has occurred;
2. More than 10% of the customers in a service territory are out of service due to the storm or the storm effects; and
3. At least 1% of the customers in the service territory are out of service for at least 24 hours.

In total, these four major storms almost doubled the number of regular outages WEC experienced in 2023 with an additional 662 outage events involving 29,294 customers out and 441,839 customer-hours-out.



Major Storm Details:

March 14, 2023: This severe weather event produced 8” to 14” of wet heavy snow in much of WEC’s territory and snow totals approaching 40” in southern Vermont. Damages included broken poles and wires downed due to heavy snow loading, winds and falling trees.

Duration: 3/14/23 at 04:00 through 3/16/23 at 18:00
Peak: 3,370 out
Broken poles: 2

July 9, 2023: This severe weather event featured 3” to 9” of prolonged heavy rainfall across Vermont resulting in catastrophic flooding in several parts of WEC’s service territory including several areas where poles, wires and secondary roads were washed away. Several outage locations were not accessible for days due to washed out roads and bridges.

Duration: 7/9/23 at 16:40 through 7/14/23 at 13:00
Peak: 2,135 out
Broken poles: 13

November 27, 2023: Over 8” of heavy wet snow brought down trees which brought down wires and broke poles across WEC’s territory. WEC requested mutual aid for 24 additional line crews and ROW crews to help with outage restoration.

Duration: 11/27/23 at 01:30 through 11/30/23 at 16:00
Peak: 7,260 out

Broken poles: 5

December 3, 2023: This severe weather event seemed to be concentrated over WEC's territory and central Vermont with 4" to 6" of heavy wet snow and winds damaging poles and wires. WEC received restoration help from 15 additional Mutual Aid line crews and ROW crews for this event.

Duration: 12/3/23 at 19:00 through 12/6/23 at 14:00
Peak: 4,824 out
Broken poles: 5

NOTE: Although they did not qualify as Major Storms in 2023 WEC territory would experience two more events in December that damaged WEC's infrastructure including an additional seven broken poles. In total, WEC replaced 32 broken poles in 2023 due to the increased severity of weather events Vermont is experiencing.

December 10, 2023: This severe weather event, for the second weekend in a row, seemed to be concentrated over WEC's territory and central Vermont with an additional 4" to 6" of heavy wet snow and winds. WEC received restoration help from one additional Mutual Aid line crew.

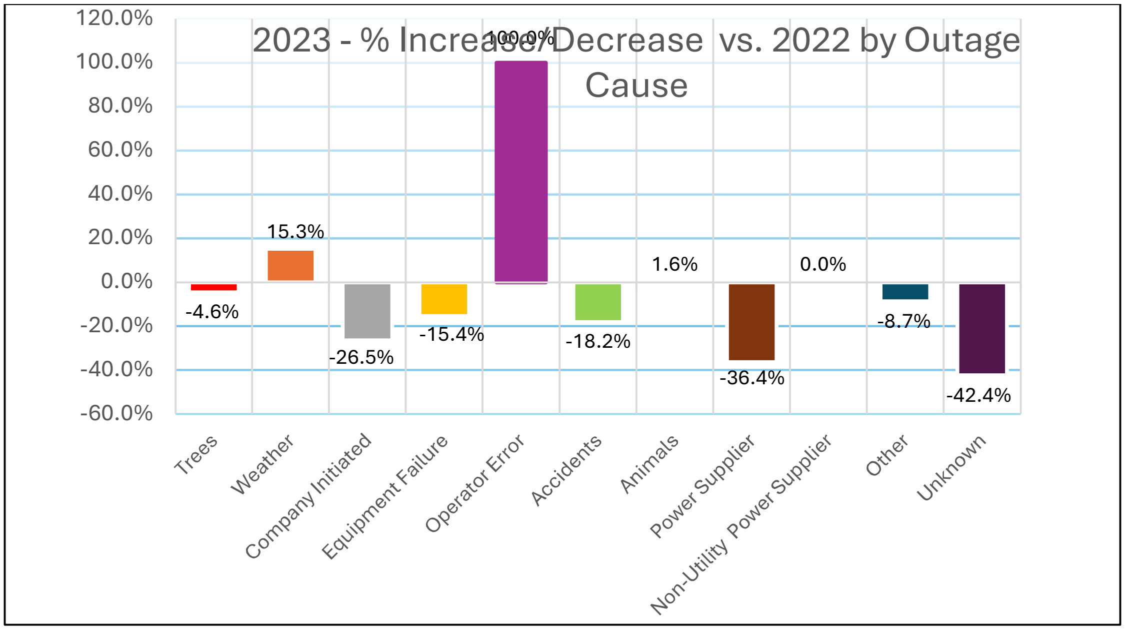
Duration: 12/10/23 at 16:00 through 12/12/23 at 01:00
Peak: 1,166 out
Broken poles: 3

December 18, 2023: This severe weather event brought heavy rains and high winds gusts between 35-55 MPH to Vermont and parts of WEC's territory.

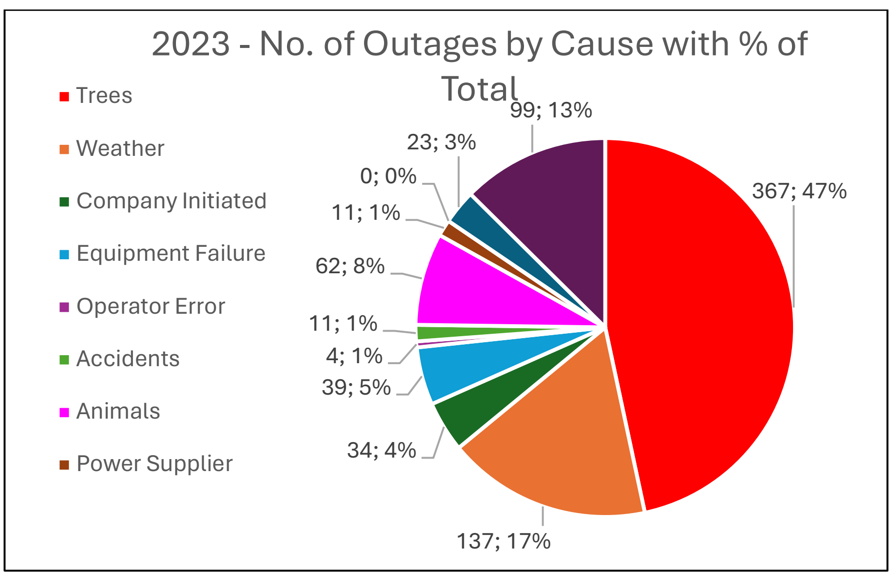
Duration: 12/18/23 at 07:00 through 12/19/23 at 12:00
Peak: 1,552 out
Broken poles: 4

5.0 Outage causes and assessments:

Most outage categories in 2023 had either slight increases or decreases over 2022 with seven categories having decreases, three having slight increases, and one category, Operator Error, increasing with four outages in 2023 over zero in 2022.



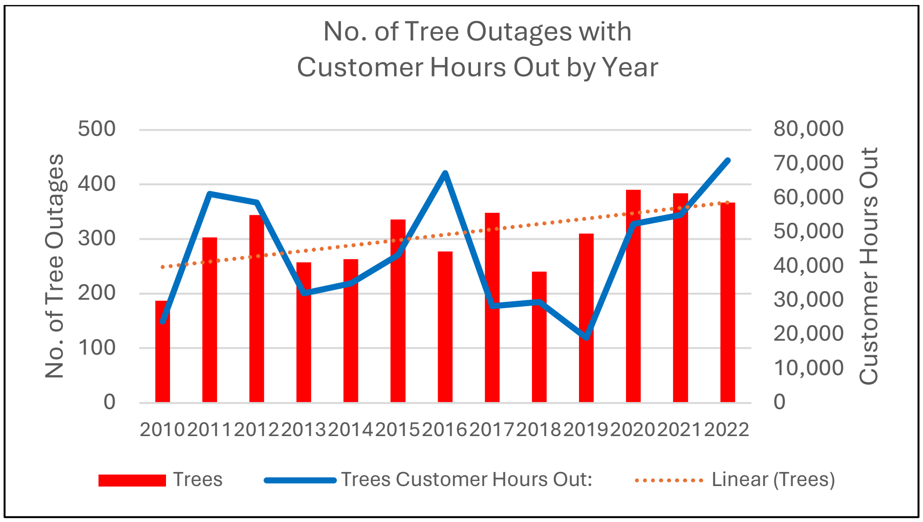
The top three outage categories that WEC experienced most during 2023 are: Trees = 367 outages; Weather = 137 outages; and Unknown = 99 outages. These categories were also the top three in 2022.



6.0 Outage Category Assessment

6.1 Tree Outages

At 47% of total outages, trees continue to be the largest cause of outage events on WEC's distribution system. In 2023, WEC experienced 367 tree outages with 71,139 member hours out compared to 384 and 55,033 member hours out in 2022. The three-year average for tree outages is 380 and 59,519 member hours out and the 10-year average is 317 and 43,328 member hours out.



In 2023, WEC completed a study of tree outages that occurred on the distribution system over a six-year period from 2017 through 2022 to determine the worse performing substations and circuits.

Sub-Feeder	Miles of Line	No. of Meters	Sub-Feeder	# of Outages
EM-CA	193	277	**1-1**	128
EM-PL	222	610	**1-2**	325
EM-MC	124	888	**1-3**	227
JB	8	80	**2-1**	48
MK-PE	77	1443	**3-1**	172
MK-CO	202	557	**3-2**	512
WD-HV, WD, PE	56	465	**4-1**	94
WAL-GRE	67	507	**5-1**	127
WAL-ECA	64	459	**5-2**	150
WAL-WHP	49	314	**5-3**	123
JC-TO	56	351	**8-1**	113
JC-CH	67	1378	**8-2**	204
JC-NO	163	453	**8-3**	368
MO-MI	62	878	**9-1**	192
MO-MOCO	25	163	**9-2**	81
MO-FA	96	504	**9-3**	216
MC-NCS	42	298	**10-1**	93

MC-MI	72	607	**10-2**	217
TU-CO	109	267	**11-1**	320
TU-ST	40	705	**11-2**	121
TU-BR	49	240	**11-3**	140
21 Feeders	1843	11444	**Grand Total**	**3971**

Results of the study identified the top four worst performing substation/feeders are:

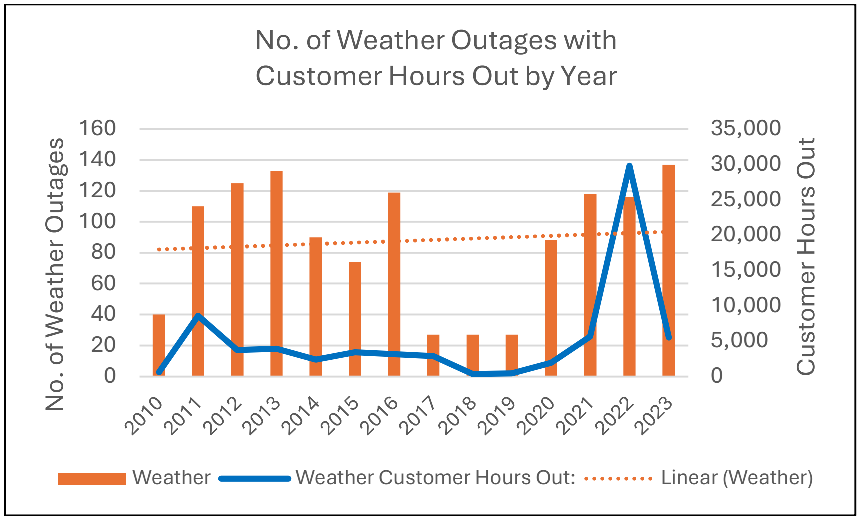
1. Mt. Knox substation, #3 Corinth Feeder
2. Jackson Corners substation, #3 Northfield Feeder
3. East Montpelier substation, 2 Plainfield Feeder
4. So. Tunbridge substation, #1 Corinth Feeder

Note: The Jackson Corners, Mt. Knox and East Montpelier substations also rank as the top three in terms of total number of outages, number of meters served and miles of line.

Sub	Total No. of Outages	Outage Rank	Total Miles of Line	Miles Rank	Total Meters	Rank Meters
EM	680	3	539	1	1775	3
JB	48	9	8	9	80	9
MK	684	2	279	3	2000	2
WD	94	8	56	8	465	8
WAL	400	6	180	6	1280	5
JC	685	1	286	2	2182	1
MO	489	5	183	5	1545	4
MC	310	7	114	7	905	7
TU	581	4	198	4	1212	6

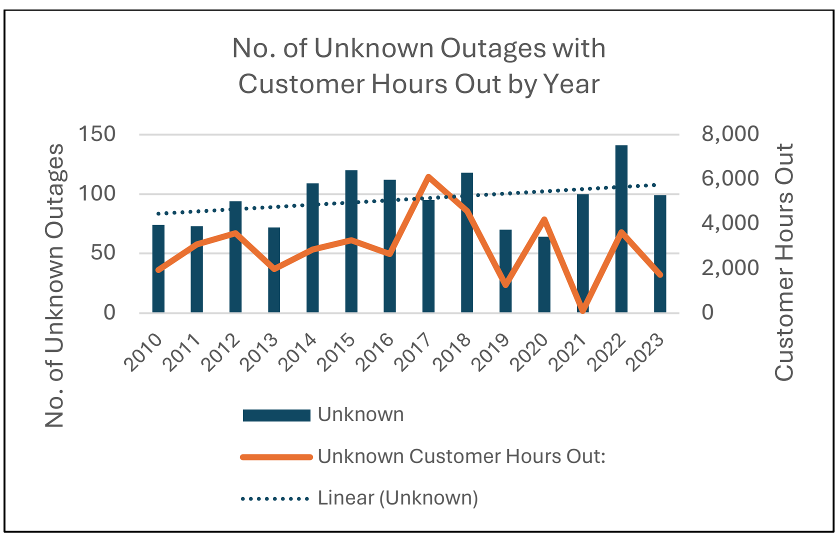
6.2 Weather Outages

At 17% of total outages, weather was the second highest cause of outage events on WEC's distribution system in 2023. WEC experienced 137 weather related outages with 5,474 member hours out compared to 116 and 29,842 member hours out in 2022. The three-year average for weather outages is 124 and 13,645 member hours out and the 10-year average is 82 and 5,536 member hours out.



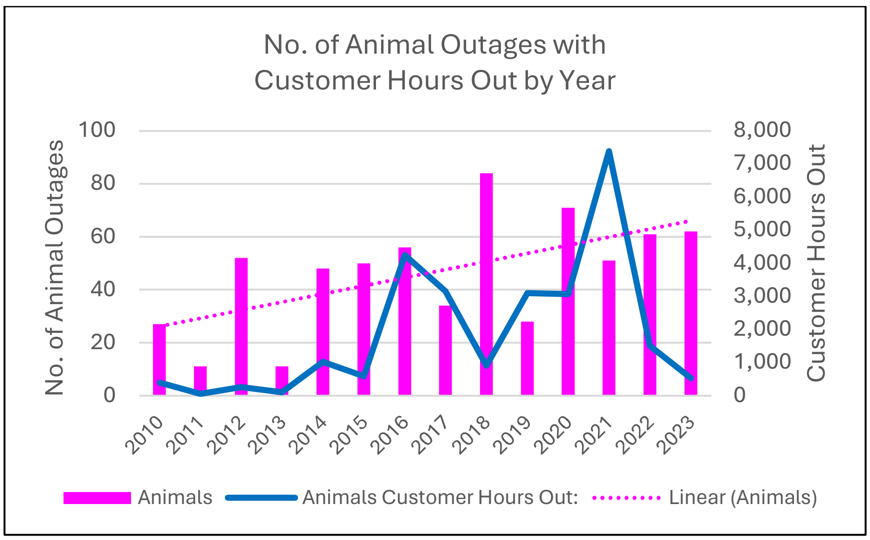
6.3 Unknown Outages

Unknown outages ranked 3rd in 2023 at 17% of total outages. In 2023, WEC experienced 99 unknown outages with 1,705 member hours out compared to 144 and 3,623 member hours out in 2022. The three-year average for unknown outages is 113 and 1,806 member hours out and the 10-year average is 103 and 3,029 member hours out.



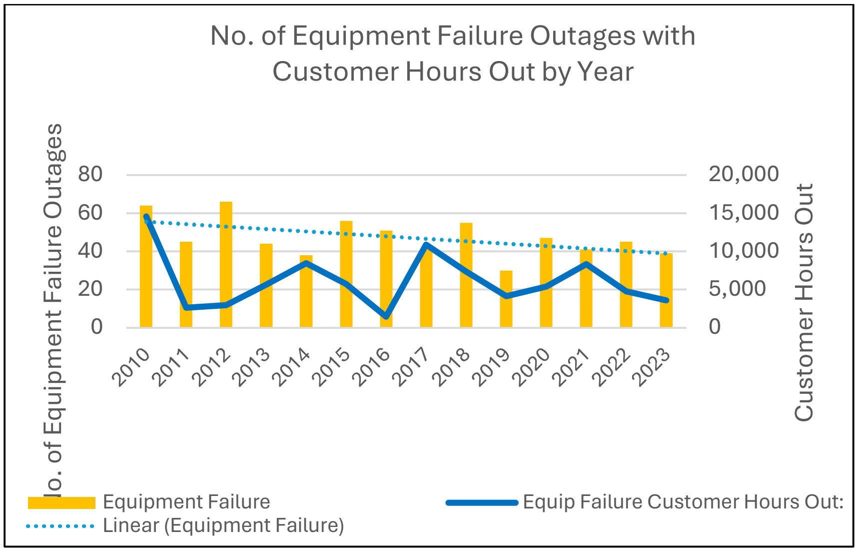
6.4 Animal Outages

Ranked 4th, animal outages were 8% of total outages. In 2023, WEC experienced 62 animal outages with 525 member hours out compared to 61 outages and 1,499 member hours out in 2022. The three-year average for animal outages is 58 and 3,140 member hours out and the 10-year average is 55 and 2,549 member hours out.



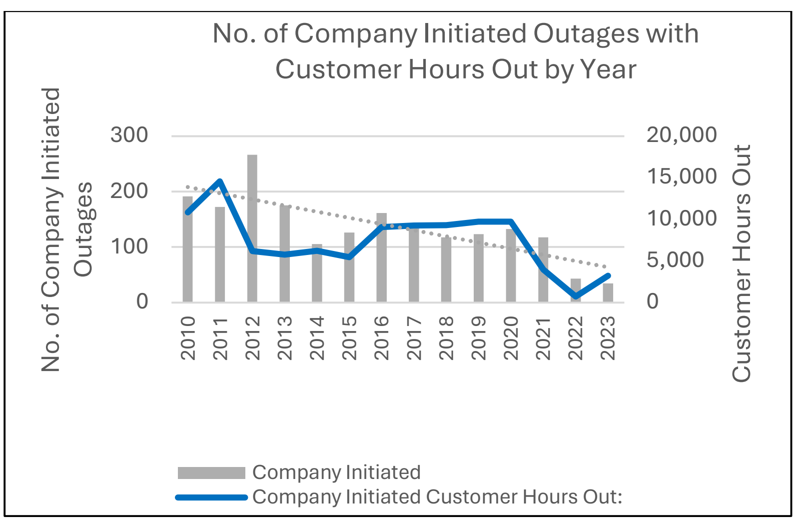
6.5 Equipment Failure

At 5% of total outages, equipment failure outages ranked 5th in terms of number of outages. WEC experienced 39 equipment failure outages with 3,574 member hours out compared to 45 and 4,743 member hours out in 2022. The three-year average for equipment failure outages is 42 and 5,545 member hours out and the 10-year average is 44 and 6,000 member hours out.



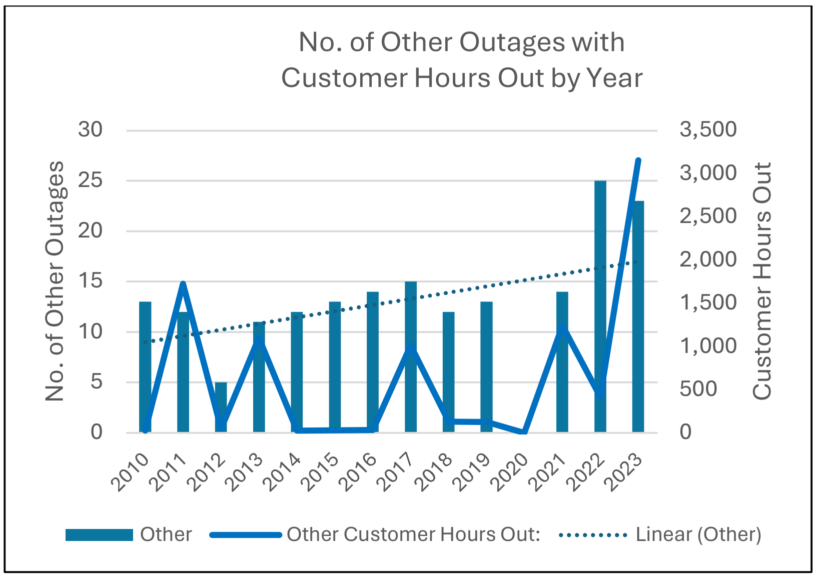
6.6 Company Initiated Outages

Ranked at 6th, company initiated outages made up 4% of the total outages in 2023. WEC experienced 34 company initiated outages with 3,574 member hours out compared to 43 outages and 712 member hours out in 2022. The three-year average for company-initiated outages is 65 and 2,614 member hours out and the 10-year average is 110 and 6,641 member hours out.



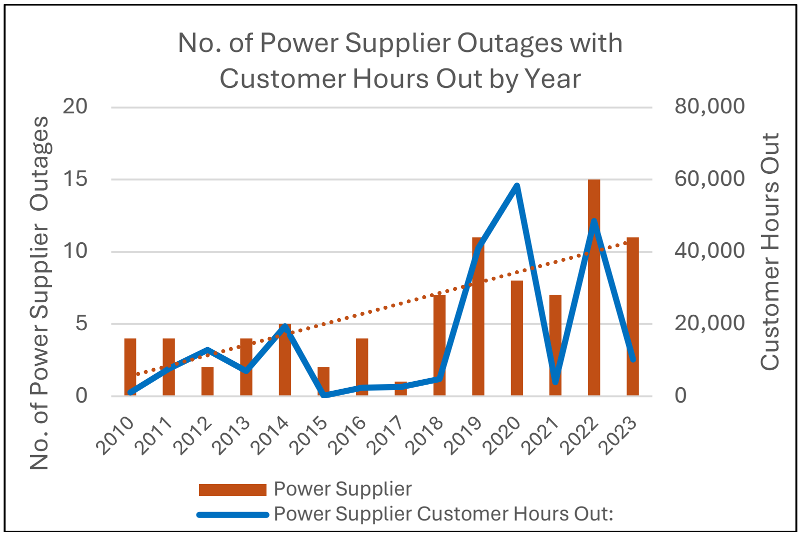
6.7 Other Outages

At 3% of total outages, other outages ranked 7th. In 2023, WEC experienced 23 Other outages with 3,159 member hours out compared to 25 and 418 member hours out in 2022. The three-year average for other outages is 21 and 1,606 member hours out and the 10-year average is 14 and 616 member hours out.



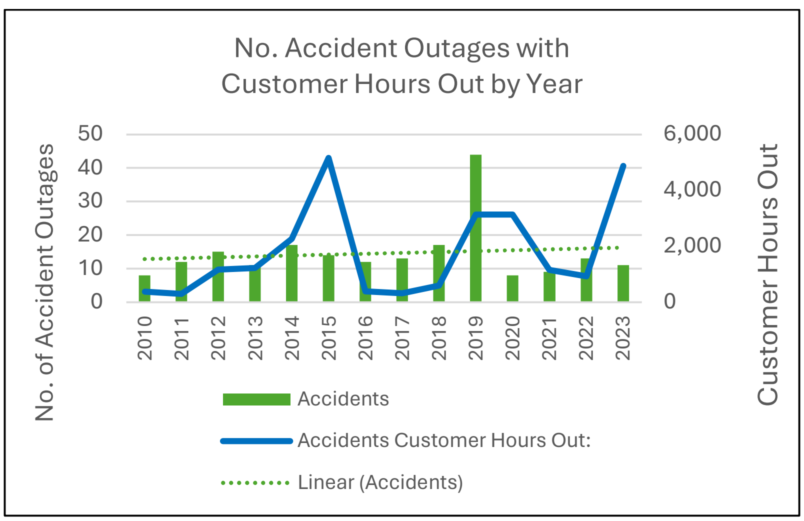
6.8 Power Supplier Outages

At 1% of total outages, power supplier outages ranked 8th. In 2023, WEC experienced 11 outages caused by the GMP transmission system with 10,113 member hours out compared to 15 and 48,517 member hours out in 2022. The three-year average for power supplier outages is 11 and 20,838 member hours out and the 10-year average is 7 and 19,105 member hours out.



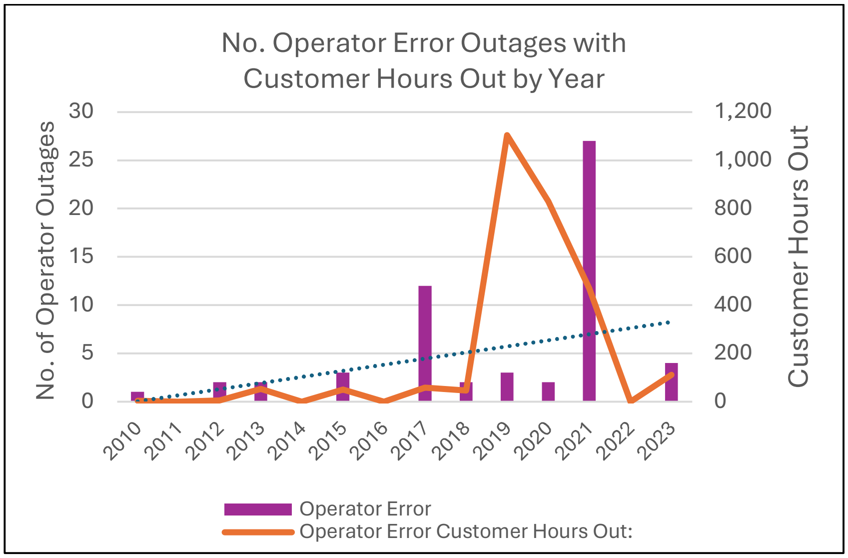
6.9 Accidents

At 1% of total outages, Accident outages ranked 9th with 11 outages and 4,879 member hours out compared to 13 Accident outages and 917 member hours out in 2022. The three-year average for Accident outages is 11 and 2,314 member hours out and the 10-year average is 16 and 2,193 member hours out.



6.10 Operator Error

At 1% of total outages and ranked 10th (last), Operator Error outages accounted for 4 outages in 2023 with 110 member hours out compared to no outages in 2022. The three-year average for Operator Error outages is 10 and 193 member hours out and the 10-year average is 5 and 267 member hours out.



7.0 Action Plan:

Over the last 25 years WEC has been adhering to USDA Rural Utility Services (RUS) construction standards that help harden the distribution system from the effects of increased storm severity. These practices are funded through the RUS approved Construction Work Plan (CWP) process. The four-year CWP is focused on continued improvement and enhanced reliability of WEC's transmission and distribution system.

Over the last ten years 100% of WEC's pole plant has been inspected and WEC continues to inspect 10% of the plant each year as required by RUS standards. WEC has also recently conducted an inspection of all primary underground installations to ensure they meet RUS and NESC requirements and present no inherent safety or reliability issues. The results of these inspections are used to assess the current condition of WEC's pole plant to maximize their life cycle value. The inspection data is crucial in determining pole condition and the results are fully integrated into the WEC's four-year CWP. During the 2019-22 CWP work period, WEC replaced and/or installed a total of 1,071 poles. Also in 2022, WEC moved away from using Class 3 pole sizes and started replacing poles with a stronger, thicker Class 2 pole to provide added protection against falling trees.

In 2023, WEC's consulting engineering group completed a system wide study to develop a ten-year long-range plan (LRP) to determine the immediate and long-term distribution system requirements through the year 2033. The study reviewed all of

WEC's distribution substations, distribution lines and transmission lines and evaluations included thermal, voltage, reverse power, reactive compensation, short circuit, asset condition, reliability and operational considerations based on historical load and load growth projections over the next ten years. The evaluations determined a list of short and long-term recommendations that WEC will incorporate into its new 2024-2027 CWP and subsequent CWPs through 2034.

The new 2024-2027 CWP calls for approximately 75% of the dollars being spent on reconstruction and upgrades on circuits in WEC's service territory. The CWP also outlines system-hardening improvements including, but not limited to, the following: replacement of small and aged conductors, installation of capacitors to reduce line loss, the replacement of deteriorated poles, the addition of mid-span poles to reduce conductor span lengths and the reconstruction of approximately 14 miles of line.

Upgrades and system enhancements in the new 2024-2027 CWP include a complete AMI system replacement, installation of Transmission Ground Fault Over Voltage (TGFOV) protection at six substations, installation and/or upgrades of 24 new reclosers, installation and/or replacement of approximately 750 distribution transformers, installation of new voltage regulators and capacitors, upgrades at two substations and the complete replacement of two other substations.

In addition to the above CWP projects, fourteen line rehabilitation projects were identified and added to the new plan, two of which will extend three-phase conductors on two feeders beyond their current end points to help with phase balancing, voltage control and outage management by further segmenting long, single-phase lines. A third three-phase project was created from the December 2022 winter storm that was eligible as a FEMA event. FEMA will provide mitigation funding for this project, where an off-road section of this three-phase line was heavily damaged during that storm.

The mitigation plan will replace 46 old class 4, 5, and 6 poles with taller class 2 poles, relocate an off-road section of the line to the road and replaces the older, smaller conductors with the stronger Cable Spacer System. The Cable Spacer System's compact design shrinks the strike zone from falling trees and uses a support messenger to support the insulated conductors. This system is better suited to keeping the conductors in the air and energized when struck by a falling tree. It will be used for all applicable three-phase upgrade projects in the future for added reliability. WEC also reviews all single-phase upgrade projects to determine if they should be upgraded in place or moved to the road or if it should be converted to underground.

WEC continues the practice of conducting annual inspections of its entire 34.5 kV and 46 kV transmission lines in the spring and fall of each year. An infrared hot spot scan of equipment and equipment connections within the substations is also completed. During the 2019-22 CWP period, WEC completed upgrades on the Graniteville to Jackson

Corners 34.5 kV transmission line and installed a new 34.5 kV switch at the Mt. Knox substation. WEC also completed 65% of the upgrades on the South Walden 34.5 kV transmission line during the last CWP work period. In the upcoming 2024-2027 CWP, WEC plans on completing the upgrades on the South Walden 34.5 kV line and adding a new recloser at the GMP/WEC tap location.

For the last five years and again for 2024, WEC's Board of Directors has approved significant funding for ROW clearing. The funding will be used to target clearing those lines directly affected by wet snow loading and danger trees. During 2023, ROW clearing crews maintained approximately 67 miles of distribution line and 1.16 miles of transmission line. A total of 4,326 danger trees were cut during ROW operations.

In 2023, WEC also conducted a study of tree outages over the 2017-2022 six-year period to determine which substations and distribution circuits were the worst performers. Individual circuits were evaluated down to the fuse level to identify those sections of line with a higher frequency of outages. WEC plans on utilizing the results of this study and combining this information with new emerging technologies and other system information to develop a new cutting plan in 2024.

Emerald Ash Borer (a continued threat to service reliability): In 2018, the Emerald Ash Borer (EAB) was detected in Orange County which is the heart of WEC's service territory. The EAB is an insect of Asiatic origin that bores into the Ash tree and lays eggs. The resulting larvae feed off the soft tissue of the tree below the bark effectively girdling the tree and cutting off the flow of water and nutrients to the tree's canopy, killing the tree. Based on experience in other states, the EAB is expected to devastate most Ash trees located within any infected area. Historically, utilities have purposely left the Ash tree to populate along and adjacent to electric line corridors as it was a hardy and resilient species. Unfortunately, the Ash trees once infected with the EAB are expected to be dead within 2 to 4 years and hence become a significant threat to electric lines and therefore service reliability. Ash trees are prioritized by WEC ROW clearing crews while performing maintenance cutting in WEC rights-of-way.

The 2024 ROW clearing budget will fund a targeted distribution system trim cycle of just over eight years and a transmission trim cycle of approximately six years. The additional funding provided over the last 4 budget years was mostly allocated to WEC's three phase main line feeders and danger tree removal on transmission, three phase and single phase main - line circuits. The additional trimming did provide significantly improved reliability to those lines.

Outage Management: In 2023 WEC made several changes internally to the way outages are managed. Working with our OMS software vendor WEC changed the way our online outage map displays outage information. Members can now see if their general location is affected by an outage or is part of a larger outage. By hovering over the outage point on the map, information regarding the outage i.e., when reported, when crews are assigned, cause and estimated restoration time, can be displayed. Also in 2023, WEC deployed tablets to our line crews who now have the ability to view all outage information including any information regarding the outage called in by members.

Storm Response: WEC monitors the weather on a daily basis and when notification of an approaching severe weather event is received from the VELCO weather forecasters, WEC participates in the VELCO emergency prep conference calls for these events. WEC personnel are then put on alert ahead of the pending situation and preparations are made ahead of the event to coordinate deployment of resources and restoration. WEC also utilizes the NEPPA Mutual Aid program for Major Storm restoration and depending on the type and amount of damage that occurs, WEC will request any needed resources from NEPPA, WEC Line Contractors and other Vermont utilities to expedite restoration.

The 2023 Reliability Report is being submitted to the Board via ePUC.

Respectfully submitted,

Dave Kresock
Director of Operations & Engineering

F. Vegetation Management Plan

WASHINGTON ELECTRIC COOPERATIVE, INC.

VEGETATION MANAGEMENT PLAN

July 2006

I. Purpose

The primary purpose of this document is to provide guidance on methods to be used to manage vegetation within Washington Electric Cooperative's (WEC) rights-of-way (ROW) in a safe, efficient and environmentally sound manner. In providing this guidance, it is understood that all line clearing, maintenance and other vegetation management work shall be performed in strict conformance with all applicable federal, state and local government laws and regulations, including OSHA Rule 29 CFR 1910.269, Electric Power Generation, Transmission and Distribution Regulations.

II. Background

WEC currently serves approximately 10,000 members in 41 rural Vermont towns in the counties of Washington, Orange, Caledonia and Orleans. Today, WEC's electric system consists of 1,237 miles of distribution line and 18 miles of local transmission line, plus an additional 7.4 miles of transmission line in Coventry. Of those line miles, approximately 800 miles of distribution line and 10.47 miles of local transmission line require tree trimming.

The terrain in WEC's service territory is described as hilly, often rugged and for the most part heavily forested with various deciduous and coniferous species. While distribution lines were constructed across fields in the early years of the Co-op in order to minimize time and the cost of construction, WEC has been routinely relocating those lines nearer to roadsides during major rehabilitation projects whenever possible. However, in many cases, it is likely that landowners will be reluctant to allow WEC to relocate their lines due to aesthetic and environmental impacts.

For the last several years, the WEC Board of Directors has authorized increased funding of the annual ROW budget in an effort to improve reliability. The amount of money budgeted and spent on tree trimming in each of the past four years is as follows:

III. Policy

WEC shall strive to maintain its transmission and distribution ROW corridors in accordance with Policy 80, attached hereto as Appendix A, as well as in the following manner:

a. In a safe, professional, efficient and environmentally sound manner, while being sensitive to the concerns of property owners and the general public.

b. In a manner that will provide reliable electrical service in conformance with the Electrical Safety Code;

c. In a manner that protects all electrical system infrastructure necessary to transmit power between substations;

d. In a manner that uses the services and knowledge of employees and contract ROW crews who are professionally trained and inherently concerned with proper ROW techniques in conjunction with safe work practices.

IV. ROW Management Practices

Inspections:

As part of WEC's annual pole inspection and treatment program, and in accordance with RUS operational planning requirements, a visual inspection of ten percent (10%) of WEC's electrical T&D system shall be conducted on an annual basis. In addition to noting the physical condition of the poles and wires, ROW vegetation growth conditions shall be noted.

Species:

It is the practice of WEC to control the following tree species the full width of the ROW:

Ash	Cherry	Locust	Pine
Basswood	Fir	Maple	Poplar
Beech	Hemlock	Oak	Spruce
Birch	Larch		

This practice of vegetation management control allows for safe passage by WEC employees and contractors within the ROW for maintenance purposes, and removes potential fire and safety hazards to humans and animals in the area.

In general, it is desirable to use or enhance existing natural vegetation that does not interfere with the distribution of electricity. Herbs, most shrubs and low maturing trees should be left in the ROW to suppress the invasion of tall-growing trees. Following is a partial list of some of the low shrubs and plants that are native to WEC's service territory:

Alpine Azalea	Juniper	Rhododendron
American Yew	Laurel	Serviceberry
Dogwood	Leatherwood	Steeplebush

Dwarf Willow
Eastern Redbud
Fern
Gooseberry
Meadowsweet
Partridge Berry
Pussy Willow
Raspberry/Blackberry
Virginia Creeper
Wintergreen
Witch Hazel

Notification:

In general, the Cooperative membership and affected property owners will be notified prior to any ROW clearing or reclearing maintenance work, except during emergency restoration or if hazardous conditions exist. Such notification shall include one or more of the following:

First: by a general article in *Co-op Currents* listing all ROW maintenance projects scheduled for the year

Second: by a mailed postcard to the member, or to the property owner if different from the member and readily known, who will be affected by the ROW maintenance work

Third: by either an automated or personal telephone call to the member, or to the property owner if different from the member and readily known, informing them that ROW maintenance work is about to commence

General Practices

A. The Removal of Trees by Manual Means (Chainsaws)

This method of control is primarily used for softwood and hardwood trees which have the potential for interfering with line reliability. The principal method of dealing with this type of vegetation is to cut it at ground level (flat cutting) using chainsaws and brush saws. Whenever trees are removed, all stumps are to be cut as close to the ground as practical so as to discourage multi-stemmed sprout regrowth. Side trimming and danger tree removal work are to be performed in conjunction with flat cutting.

B. Trimming/Pruning

It may not always be necessary, economically feasible or aesthetically acceptable to flat cut all trees within the ROW. This may be in response to a property owner's request, when the tree is a compatible, non-interfering vegetation variety, or it may be that while the tree itself is in the required clearance zone, only its branches immediately threaten the electric line. In these cases, it may be appropriate to prune or trim the tree.

Limbs to be removed are those that are dead, decayed, insect damaged, or structurally weak, including limbs which could break at weak points and strike conductors when swinging down in an arc. Pruning guidelines are as follows:

1. <u>Tree Under Conductor – Under Trimming</u>

   Under-trimming is cutting back large portions of the upper crown of a tree. Under- trimming is required when a tree is located directly beneath a line. The main leader or leaders are cut back to a suitable lateral. (The lateral should be at least one-third the diameter of the limb being removed.) Most cuts should be made with a saw; the pole pruner is used only to trim some of the smaller lateral branches.

   For the sake of appearance and the health of the tree, it is best not to remove more than one-third of the crown when under-trimming.

2. Tree at Side of Conductor – Side Trimming

   Side trimming consists of cutting back or removing the side branches that are threatening the conductors. Side trimming is required where trees are growing adjacent to utility lines.

   Limbs shall be removed to the trunk or to a lateral that is growing parallel to or away from the conductors.

   Where possible, or as designated by WEC, the contractor shall eliminate all branches growing within 10 feet beneath and toward the conductors.

3. Tree Over Conductors – Overhead Trimming

   Overhead trimming consists of removing limbs beneath the tree crown to allow wires to pass below. Most of the natural shape of the tree is retained in this type of trimming, and the tree can continue much of its normal growth. Overhanging limbs should be removed as dictated by the species of the tree, location, and the general condition of the tree. When trimming, remove all dead branches above the wires, since this dead wood could easily break off and cause an interruption.

   The contractor shall remove all weakly attached overhanging limbs that are capable of hitting the conductor if the limb were to split at the point of attachment.

   Where possible, all branches within ten (10) feet above conductors shall be removed as dictated by the species of the tree, location, and the general condition of the tree.

Overhead trimming must be performed in accordance with current VOSHA/OSHA trimming regulations.

4. Combination Trimming

It is often necessary to use judgment in combining several types of arborcultural trimming techniques in order to achieve a good looking job and provide adequate clearances.

5. Improper Trimming Techniques

a. Pollarding: This is done by stubbing off major limbs until the tree assumes the desired shape. The result is not only unsightly, but a multitude of fast-growing suckers will sprout from the stubs, resulting in a line clearance problem more serious than before. The stubs are quite likely to fall victim to decay and disease.

b. Rounding Over: Rounding over or shearing is done by making small cuts so that the tree top is sheared in a uniform line. This creates an unhealthy condition and results in rapid regrowth of suckers directly toward the electrical conductors.

c. Side Trim Stubbing: This is done by stubbing off portions of limbs along the side of the tree to obtain clearance. This method of trimming, like pollarding and rounding over, creates many fast growing suckers that become a serious line clearance problem. These trimming methods should be avoided.

d. Topping: Removing top and upright branches should be avoided. Where necessary, use natural or directional pruning methods.

C. Proper Trimming Techniques

Various trimming shapes were previously described. The following provides the details for WEC standard line clearance and can be used for overhead trimming, side trimming, under trimming, and combinations. Pollarding, rounding over and side trim stubbing shall be avoided.

All trimming shall be performed to direct the growth of a tree away from the conductors. Branches shall be cut back toward the center of a tree to a suitable lateral branch, parent limb or the tree trunk. This is commonly called drop crotch, lateral or natural trimming (see Figure 1). When cutting back to a lateral branch, the diameter of the lateral branch must be at least one-third of the diameter of the branch being removed in order to sustain growth. Almost all cuts are made with a saw and very little pruner work is required. If a proper lateral branch is not available, the branch shall be cut back to the parent limb or tree trunk.

Trimming shall be done in such a manner as to protect tree health and condition.

All saw and pruner cuts shall be made back to the branch collar at an angle equal to but opposite of the branch bark ridge on the parent limb or trunk in order to leave no stubs.

No damage by loosening or stripping of the bark or splitting of branches shall be caused during trimming.

All severed limbs and branches (hangers) shall be removed from trees after trimming.

C. Removal of Trees by Mechanical Means (Brontosaurus)

WEC shall utilize the Brontosaurus wherever possible to clear ROW. The Brontosaurus is an excavator on steel tracks that utilizes a hydraulically driven shearing mechanism that pulverizes the tree and root system. Having utilized this machine over the past several years, WEC's field observations indicate that it effectively reduces the rate of resprout in many species. The Brontosaurus effectively removes trees, shrubs and brush within a ROW, however, this method still requires contract ROW crews to revisit the ROW to do side trimming and danger tree removals which adds to the cost of this method of clearing. Use of the Brontosaurus is limited due to its inability to safely work in narrow ROWs, and near roadsides and members' homes.

D. Danger Tree Removal

A danger tree is any tree, due to its location, species and condition, which is tall enough to pose a threat to WEC's electric lines. Many of the trees at the edge of the ROW have crowns that are heavily grown in towards the line, and when they fall, are likely to make contact with the electrical conductors. Danger tree removal is most effective towards reducing outages associated with high wind storms, prolonged rain incidents and routine outages due to "rotten trees". This, in effect, targets short-term and long-term reliability while also reducing the duration of outages due to excessive damage. For every danger tree that is targeted and removed, a future outage is avoided. (See Figure 2 for minimum clearances for danger tree removal.)

E. "Hot Spot" Clearing

Selective clearing of ROW line sections outside the normal reclearing schedule helps to improve reliability to those members located at the end of a single-phase line. Identification of these problem line sections normally comes from the members who are affected by poor reliability. Devoting resources to “hot spot” line sections improves reliability and/or power quality to specific problem areas, improves line crew access and outage restoration time, and improves overall reliability of a particular line. Hot spot trimming is the least efficient method of ROW clearing, but is essential to good member relations.

F. ROW Clearing During Emergency Restoration and When Hazardous Conditions Exist

In the best interests of employee and public safety, any tree making contact with WEC’s electric system conductors shall be immediately removed to mitigate the hazard. It is not reasonable to provide advance notification to property owners under these conditions.

In the event of a power outage caused by trees within or outside of WEC’s ROW, the trees shall be cut to the extent that is necessary to safely restore power. Advance notification to property owners is not possible under these conditions.

Under both of the above circumstances, a WEC employee shall coordinate with WEC’s ROW Management Coordinator to arrange for any necessary cleanup.

G. Clearing Within Municipal Street or Highway ROW

In situations where the Cooperative does not hold a valid ROW easement along a public street or highway, whether for a new service or for relocation of an existing line, no tree within that street or highway shall be cut in the construction, relocation, maintenance or repair of electric power lines without the written consent of the adjoining property owner(s) or occupant, unless the transportation board or selectmen of the town in which the tree is situated, after due notice to the parties and upon provision for a hearing, shall decide that such cutting is necessary (Title 30 VSA, § 2506), or unless such decision is made by the appointed municipal tree warden for the town (Title 24 VSA, § 67).

H. Clearing Within Wetlands

Wetlands are considered to be sensitive areas for vegetation management practices. These may include swamps, marshes and bogs, and other areas identified in the National Wetlands survey, and will be identified by WEC’s representative prior to ROW management activities. Handcutting will be used near wetland areas where necessary to control undesirable vegetation. If extensive wetlands are encountered, WEC may elect to carry out the work in winter because of improved access. Vegetation in wetland areas will be managed according to the Vermont Department of Environmental Conversation's policy on wetlands.

I. Clearing Within Stream Corridors

Stream buffers are areas adjacent to streams requiring special vegetation management, and these areas shall generally be maintained to a minimum width of 75 feet on each side of the stream. Where distribution lines cross streams, standing woody vegetation, shrubs and low mature height trees will be allowed to grow within the ROW if consistent with the terrain and existing land use. This cover will protect fish habitat, service wildlife travel lanes, and control soil erosion.

Where the electric line spans a ravine, streamside vegetation may be allowed to grow taller as specified by WEC's representative. Where an undesirable woody species becomes taller than 12 feet, it will be removed to ensure protection of line conductors. In general, provision of the Vermont Agency of Environmental Conservation policy on river and stream bank management shall be followed.

J. Clearing Where Electric Lines Cross Roads

Electric lines that cross roads will be treated similarly to streams. Low woody shrubs, such as Sweet Gale and other compatible plant species identified on page 4, which have a low height at maturity, will be permitted and encouraged at road crossings in order to provide screening of the electric lines.

K. Clearing Within Wildlife Travel Areas

Wildlife travel areas shall be maintained to promote the movement of white-tail deer and other wildlife across the corridor of extended cross-country distribution and transmission lines. In general, WEC's objectives will be to favor vegetation that can support snow and thereby keep the snow depth on the ground shallow enough for deer to move about and to conceal wildlife as it crosses through wildlife travel lanes. Treatment will be similar to high visibility ROW areas, and preference may be given where practical to preserving a conifer canopy. WEC shall use the Vermont Agency of Natural Resources policy on wildlife management as a guide to maintaining wildlife travel lanes.

L. Stump Height

ROW clearing will be limited during winter months. Deep snow during winter months often results in unsightly ROWs because of excessive stump height, which oftentimes need to be recut in the spring, which adds to the cost. Excessive stump height also encourages the regrowth of saplings. At other times of the year whenever trees are removed, all stumps will be cut as close to the ground as practical so as to discourage multi-stemmed regrowth of the original species.

M. Cherry Tree Disposal Precaution

Wilted leaves from cherry trees are poisonous to livestock. Therefore, in areas frequented by livestock, any cherry cuttings shall be disposed of immediately by removing any cuttings from the enclosed livestock grazing area.

V. Trees and Debris Removal

Disposal techniques for each ROW section will be determined by WEC's representative, taking into account federal, state and local regulations, the practicality of certain disposal methods, the potential for wood utilization, and the wishes of the property owner. Whenever roadside trimming is performed, all log length material shall be picked up by a log truck as soon as possible and disposed of in accordance with the property owner's request. All other brush and wood material shall be removed from the ditch and municipal ROW and appropriately chipped or stacked at the tree line. If the ROW maintenance area is located more than fifty (50) feet from a public road or highway, then the log or tree length wood shall be moved to the tree line. All brush shall be windrowed at the edge of the ROW in order to provide unobstructed access for maintenance purposes. All other wood material shall be cut in four foot lengths and stacked at the tree line (see Figure 3). There will be no brush left in stream beds, across fence lines, stone walls, paths or roadways.

VI. Prioritization of ROW Clearing

WEC's Vegetation Management Plan promotes the prioritization of ROW clearing as it statistically relates to reliability of service. In general, the focus of the ROW management program shall be as follows:

1. Transmission Lines
   - Annually patrol 18 miles of local transmission line as well as 7.4 miles of 46 kV transmission line in Coventry for purposes of identifying potential equipment problems and marking danger trees for removal.
   - Flatcut WEC's 10.47 miles of local transmission line as needed to ensure maximum reliability to WEC's substations.
   - Flatcut WEC's 7.4 miles of Coventry transmission line as needed based on annual patrol to ensure 100% availability.

2. 3 Phase Lines
Three-phase circuits are critical links from substations to all members. Damage to one conductor of a three-phase line require the entire three conductors to be de-energized when repairs are made. WEC's three-phase lines are prone to greater damage for any given tree contact due to construction type and phase-to-phase voltage levels. The reliability of three-phase circuits, like substations, have a direct impact on the reliability of all single-phase lines. Improving the reliability of WEC's three-phase circuits is essential to achieving state mandated SAIFI and CAIDI indices.

3. Two-Phase Lines
Two-phase lines shall be treated similarly to three-phase lines as they serve a greater number of members than do single-phase lines.

4. Single-Phase Lines
Maintain single-phase line ROWs based on member density.

5. Worst-Performing Circuits

At the beginning of each year, WEC shall analyze circuit performance for the previous calendar year and identify the five worst performing circuits based on annual reliability. The reliability of the worst-performing circuits shall be further analyzed to determine if there are conditions that can be changed to improve the reliability of the circuits, including danger tree removals, flat cutting, line relocation and reconstruction if needed. In all cases, the circuit analysis shall take into consideration year-to-year fluctuations and longer-term trends to identify root causes of the reliability problems.

VII. CLEARANCE ZONE REQUIREMENTS

In general, single phase primary and/or secondary conductors shall be cleared of trees within 15 feet of each side of the pole line center. Three phase primary conductors shall be cleared 25 feet each side of the pole line center. (See Figure 4 for clearance zone dimension measurements.)

VIII. ROW Contractor Training and Requirements

ROW contractors hired by WEC are required to become familiar with the procedures and requirements of this plan and to utilize safe and proper ROW clearing techniques that are in compliance with state and federal laws and regulations. Each ROW crew must have two (2) qualified line clearance tree trimmers. Minimum qualifications include the following:

- Annual CPR and first aid training
- Annual electrical hazard awareness training
- Ability to perform an aerial rescue from a minimum height of 35 feet in four minutes or less. Aerial rescue must be practiced at least once a year.
- Knowledge of electric line voltages and minimum approach distances
- Annual inspection and dielectric testing of bucket trucks to be used for tree trimming

This plan has been prepared and adopted in order to provide a broad assessment of WEC’s ROW vegetation management goals and policy objectives, and the operational methods and practices that shall be used in attaining those goals and objectives. The procedures outlined herein are designed to provide general guidelines for the safe operation and maintenance of electrical distribution and transmission lines, while minimizing visual and other environmental impacts within the communities served by WEC.

Washington Electric Cooperative, Inc.

P.O. Box 8, 40 Church Street · ***Telephone*: 802-223-5245; *Fax*: 802-223-6780**
East Montpelier, Vermont 05651 · **www.washingtonelectric.coop**

Ms. Holly Anderson, Clerk
Vermont Public Utility Commission
112 State Street
Montpelier, VT 05620-2701

23-3715 2024 Tier III program plan

1 November 2023

Dear Ms. Anderson:

Washington Electric Co-op herein provides its 2024 Tier III program plan responsive to the Order of 26 October 2023.

Please contact me if there are questions.

Sincerely,

Bill Powell

William Powell
Director, Products & Services

Filed by ePUC.

A renewable energy provider owned by its members since 1939.
Washington Electric Cooperative is an equal opportunity provider and employer.

WASHINGTON ELECTRIC COOPERATIVE

2024 ANNUAL PLAN FOR TIER III COMPLIANCE

WITH VERMONT'S RENEWABLE ENERGY STANDARD

I. INTRODUCTION

In compliance with requirements from the Vermont Public Utility Commission's Order 19-4452-INV, and Dockets 8550 and 23-3715, Washington Electric Cooperative (WEC) submits its 2024 Annual Plan for Tier III compliance with Vermont's Renewable Energy Standard (RES).

This Tier III Annual Plan is submitted by WEC, with support from Vermont Energy Investment Corporation (VEIC), to the Vermont Public Utility Commission ("PUC" or "Commission") and to the Public Service Department ("PSD" or "Department"). This Annual Plan addresses the strategy that WEC will use to meet its Tier III compliance obligation for 2024.

WEC continues to work with Efficiency Vermont and our distribution utility (DU) partners to design and implement member services responsive to the goals of Act 151 ("Energy Efficiency Modernization Act"). Overall, this Annual Plan will describe:

1) the estimated Tier III compliance obligation for 2024;
2) the overall strategy to be implemented to meet the Tier III compliance obligation in 2024; and
3) the types of energy transformation projects that will be undertaken and anticipated number of participants and the budget required to support WEC's 2024 Tier III plan

WEC's 2024 Annual Plan revises the measures for which WEC provided Tier III member incentives that have been screened and vetted through the Technical Advisory Group (TAG) screening process.

II. PARTNERSHIP-BETWEEN WEC AND VEIC

Implementation of the projects described in this Annual Plan will be closely coordinated with Vermont Energy Investment Corporation as the administrator of Efficiency Vermont, the statewide energy efficiency utility (EEU). In addition, coordination of data collection, management, reporting, and evaluation and verification activities will be maximized to the extent possible with protocols and schedules already in place for Efficiency Vermont (EVT). In cases where entities other than VEIC and its subcontractors deliver WEC Tier III programs and services independently, WEC will ensure coordination of data collection and reporting to provide a single deliverable to regulators.

The Parties have reached an understanding on the implementation of energy transformation projects for WEC's member/customers that will include the coordinated use of customer and supply-side incentives, standards for measuring performance, and methods to allocate savings and reductions in fossil fuel consumption and greenhouse gas emissions among VEIC and WEC with a strong emphasis on weatherization. The details of WEC's plan as well as discussion of roles and responsibilities of each party are outlined in table 1, which remain consistent with WEC's original 2017 filed design.

Table 1: Roles and Responsibilities for 2024 Tier III Programs

Washington Electric Cooperative	Efficiency Vermont

• Leverage local presence and relationships with members
• Utilize multiple communications channels to reach members
    • Newsletter
    • Member Service Rep staff
    • Promotional material
• Leverage existing EEU programs like Button Up to deploy savings
• Provide call center support
	• Maintain program delivery model
	• Maintain contractor and supplier network
	• Statewide marketing
	• Call center support
	• Capture sales data
	• Custom, mid-stream and upstream incentives

III. 2024 Washington Electric Cooperative Tier III Compliance Obligation and Overall Strategy

WEC continues to participate with VEIC and other DUs through the Technical Advisory Group (TAG) process; all measures included in the 2024 WEC program either meet TAG standards for characterization and energy savings, or have been approved by Order of the Commission[1].

One distinction for measure screening which adds additional value to WEC program is due to the Co-op's qualification as 100% renewable, as defined statutorily. Utilities which have not yet met the Vermont renewability standard, based on the portfolio of power sources today, use a "blended" portfolio in the TAG modeling process; a blended portfolio reduces the savings claims for the same measure(s) compared to a utility with 100% renewability today.[2]

[1] See 17-4632 Order of 24 August 2018

[2] See Appendix C

A. 2024 WEC Tier III Requirements

Vermont's RES establishes a required amount for Tier III compliance of 6.7% of WEC's 2024 forecast retail sales of 72,500,062 kwh, or 4,883 MWh.

Table 2.

	Implementation Model	
	Washington Electric Co-op	
Program Year	2024	
Distribution Utility	WEC	
MWh Target		4,833
Maximum Investment (ACP)	$	356,217
proposed incentives only	$	121,400
2024 ACP	$	73.70

Modeled Savings Totals		6,934
Over/(Under) Target		2,101
Non-Incentive Totals	$	18,210
Incentive Totals	$	121,400
portfolio average $/MWh	$	25.12

	Washington Electric Co-op 2024 Tier 3 plan	(1-4) 2024 EVT incentives paid by WEC	(5-9) WEC member direct incentive$	2024 # measures forecast	2024 estimate MWHe	2024 EVT incentives paid by WEC	WEC member direct incentive$	2024 total Tier 3 incentives	ACP $73.70
1	HPWH	$ 650	$ 100	25	425	$ 16,250	$ 2,500	$ 18,750	$ 44.12
2	HP & integrated controls		$ 1,000	2		$ 2,000	$ 2,000	$ 4,000	custom
3	HP	$ 250	$ 100	191	4966	$ 47,750	$ 19,100	$ 66,850	$ 13.46
4	geothermal HP 2024	$ 4,300		2	137	$ 8,600	$ -	$ 8,600	custom
	2024 EVT incentives paid by WEC					$ 74,600			
new	EVT adminstrative 10%					$ 7,460			
5	EV	$ 1,200	$ 500	30	870		$ 15,000	$ 15,000	$ 17.24
6	PHEV	$ 950	$ 250	12	276		$ 3,000	$ 3,000	$ 10.87
7	E-bike	$ 100	$ 100	42	210		$ 4,200	$ 4,200	$ 20.00
8	wood stove		$ 100	5	15		$ 500	$ 500	$ 33.33
9	pellet stove		$ 100	5	15		$ 500	$ 500	$ 33.33
					6934			$ 121,400	$ 17.51
	income eligible budget								
	EVT mid stream incentives				0	$ 82,060	**WEC admin$**	$ 18,210	
	DPS income eligible proxy 32%				0	$ 26,259	**total budget**	$ 139,610	
	Act 151 incentives		$ 2,000	16	0	$ 32,000			
	Capstone WAP incentives								
	WEC EV incentive	$ 1,200		3	870	$ 3,600			
	WEC PHEV incentive	$ 950		2	276	$ 1,900			
			income eligible		1146	$ 63,759		53%	

3

Table 2: Tier III Requirement

As noted in Table 2 WEC's compliance target is 4833 MWH. This target is based on WEC's expected 2024 sales of 72,500,062 kwh's.

WEC allocates its Button Up administrative cost proportionately to measure savings achieved.

Using the Alternative Compliance Payment rate of $73.70, WEC's maximum budget for incentives, program delivery and administration is $ 356,217.

WEC has forecast a 2024 Tier 3 budget of $139,610. After allowing for its 2024 administrative cost and other incentives up to $121,400 there is $63,759 attributable to income eligible members participating in Tier III and other WEC initiatives for income eligible members.

WEC's forecast of EVT mid-stream heat pumps (HP) and heat pump water heaters (HPWH) is based on estimates provided in October 2023 by Efficiency Vermont.

In 2024 WEC intends to assign to the "mid stream" incentives paid to Efficiency Vermont the DPS proxy of 32% of the cost as constituting WEC's on-going support of income eligibility to the membership.

In addition there will be an estimated $32,000 of Act 151 cost towards a specific cohort of WEC members whose income eligibility is confirmed and who have been targeted by EVT for service upgrades and heat pumps in 2024. WEC pays a $2000 per income eligible household under the Act 151 scheme.

Another critical mechanism WEC deploys to meet its income eligible membership is its on-going relationship with Capstone and the Weatherization Assistance Program.

WEC continues to offer income eligible additional incentives for EVs and PHEVs in 2024.

In all cases of income eligible incremental incentives, the payment produces no additional MWh savings, but increases costs and pushes the program towards a higher cost per MWh saved.

B. Proposed Measures & Program Design

In 2024 WEC will continue the list of eligible measures to offer to the membership under the 2023 Button Up incentive program. The main difference for 2024 will be the prospective additional "administrative fee" of 10% to Efficiency Vermont based on the "mid-stream" incentive program. As with "income eligible" incentives, the 10% fee produces no additional savings and drives the cost per MWh up further.

WEC has banked Tier 2 credits which it will apply towards its Tier 3 target in 2024, as allowed under the RES.

In 2024 WEC will support the HP and HPWH incentives for which WEC reimburses EVT. WEC will continue to supplement the EVT incentive for eligible HPWH when a fossil hot water system is replaced.

WEC is adding a custom measure for HP with integrated controls to encourage the member to better manage when HP cost of operation makes sense, and when temperature conditions warrant use of the fossil back up. WEC also will support the geothermal heat pump incentive provided by Efficiency Vermont as a custom measure.

WEC believes when HP are installed to supplement an existing fossil system, the member and contractor should be "marrying" the two systems with integrated controls. The ulterior motive for WEC to provide incentives for HP and integrated controls is the possible access by WEC to the integrated controls to assist WEC with a possible additional measure for Flexible Load Control (FM).

2024 WEC Button Up incentive comparison to 2023

Measure	EVT incentive & admin*	2023 WEC incentive	2024 WEC incentive
Heat Pump	$275	$100	$100
Heat Pump WH	$715	$100	$100
HPWH replacing fossil	$715	$250	$250
HP & integrated controls (custom)	Custom measure incentive	$0	$1000 or custom incentive based on BTU displaced by HP
Geothermal HP	Custom measure incentive	$0	$1000 or custom incentive based on BTU displaced by HP
Wood stove		$250	$100
Pellet stove		$250	$100
EV**		$1200	$500
PHEV**		$900	$250
e-mower		$100	$0
e-bike		$100	$100*

- E-bike incentive valid on MSRP up to $1000
- * At time of filing (1 November 2023) Efficiency Vermont has not finalized the 10% administrative fee imposed on the "mid-stream" incentives; WEC will revise this if what EVT finalizes is not 10%.
- ** WEC offers a $700 income eligible incentive in addition to EV & PHEV incentives.

C. Estimated Number of Participants, Program Goals and Shared Responsibilities

WEC's plan and estimates of the number of participants, incentives, and MWh savings are provided in the approved DPS file format and excerpted in Table 2 (above). While all WEC members are eligible to participate, based on the budget constraint of the Alternate Compliance Payment (ACP), in actuality WEC will promote the Button Up services on a “first come, first served” basis up to the target numbers noted in Table 2.

What this means is once WEC hits the target rates of participation it will no longer offer its extra incentives toward the measures. The EEU program incentive dollars will continue but any incremental WEC incentives will cease if the participation targets are achieved. The pace of the program incentives is budget constrained, and will be monitored closely for alignment with savings goals.

D. **Income Eligible Plan** – WEC has provided supplemental incentives based on income eligibility for electric vehicles since 2018.

In PUC case 20-0203 the PUC has proposed that distribution utilities create a discount on electric bills for income eligible members, using a model where the discount is paid by all other members. This cross subsidy would have a negative impact on WEC rates of up to 1.85%.

WEC has an on-going agreement with Capstone to purchase thermal energy reduction savings from Capstone’s WEC households where weatherization services (WAP) are provided. This mechanism falls under Rule 4.416, wherein a distribution utility which does purchase thermal energy reduction savings must pay a mandated rate set annually by OEO.

For its 2024 program budget WEC is allocating up to $63,759 for its income eligible member households.

APPENDIX A (BACKGROUND)

BACKGROUND

On June 11, 2015, the Governor of Vermont signed into law Public Act No. 56, an act relating to establishing a renewable energy standard ("RES"). Vermont’s RES is categorized into three tiers of required resources that must be met by Vermont electric utilities to meet the requirements of the States’ renewable energy standard: total renewable energy, distributed renewable generation and energy transformation.

The third tier of the RES (“Tier III”) (Energy Transformation Tier) requires that DUs either procure additional renewable distributed generation eligible for Tier II or acquire fossil-fuel savings from energy transformation projects. Energy transformation projects are those that reduce fossil fuel consumed by DU customers and the emission of greenhouse gases attributable to that consumption. For Tier III, the RES establishes a required amount of 2% of a DU’s annual retail sales in 2017, increasing by two-thirds of a percent each year and reaching 12% in 2032.

This category encourages Vermont retail electricity providers to support additional distributed renewable generation or to support other projects to reduce fossil fuel consumed by their customers and the emission of greenhouse gases attributable to that consumption. A retail electricity provider may satisfy the energy transformation requirement through distributed renewable generation in addition to the generation used to satisfy subdivision (a)(2) of this section or energy transformation projects or a combination of such generation and projects.

“Energy transformation projects” are defined in 30 V.S.A. § 8002(25) to mean:

“an undertaking that provides energy-related goods or services but does not include or consist of the generation of electricity and that results in a net reduction in fossil fuel consumption by the customers of a retail electricity provider and in the emission of greenhouse gases attributable to that consumption. Examples of energy transformation projects may include home weatherization or other thermal energy efficiency measures; air source or geothermal heat pumps; high efficiency heating systems; increased use of biofuels; biomass heating systems; support for transportation demand management strategies; support for electric vehicles or related infrastructure; and infrastructure for the storage of renewable energy on the electric grid.”

(C) Eligibility criteria. For an energy transformation project to be eligible under this subdivision (a)(3), each of the following shall apply: (i) Implementation of the project shall have commenced on or after January 1, 2015. (ii) Over its life, the project shall result in a net reduction in fossil fuel consumed by the provider’s customers and in the emission of greenhouse gases attributable to that consumption, whether or not the fuel is supplied by the provider. (iii) The project shall meet the need for its goods or services at the lowest present value life cycle cost, including environmental and economic costs. Evaluation of whether this subdivision (iii) is met shall include analysis of alternatives that do not increase electricity consumption. (iv) The project shall cost the utility less per MWH than the applicable alternative compliance payment rate. Act 56 p.18 (3)(A)

Section 8 of Vermont’s Renewable Energy Standard (RES) requires the Vermont Public Utility Commission ("Commission") to commence a rulemaking proceeding to determine details for the implementation of Tier III. The outcome of this rulemaking requires that a DU shall file a Tier III annual plan no later than the November 1st immediately prior to the start of the next compliance year.

This Annual Plan is filed to meet this requirement.

APPENDIX C

WEC qualifies as a 100% renewable distribution utility, as defined by statute:

(b) Reduced amounts; providers; 100 percent renewable.

(1) The provisions of this subsection shall apply to a retail electricity provider that:

(A) as of January 1, 2015, was entitled, through contract, ownership of energy produced by its own generation plants, or both, to an amount of renewable energy equal to or more than 100 percent of its anticipated total retail electric sales in 2017, regardless of whether the provider owned the environmental attributes of that renewable energy; and

(B) annually each July 1 commencing in 2018, owns and has retired tradeable renewable energy credits monitored and traded on the New England Generation Information System or otherwise approved by the Commission equivalent to 100 percent of the provider's total retail sales of electricity for the previous calendar year.

(2) A provider meeting the requirements of subdivision (1) of this subsection may:

(A) satisfy the distributed renewable generation requirement of this section by accepting net metering systems within its service territory pursuant to the provisions of this title that govern net metering; and (B) if the Commission has appointed the provider as an energy efficiency entity under subsection 209(d) of this title, propose to the Commission to reduce the energy transformation requirement that would otherwise apply to the provider under this section.

(i) The provider may make and the Commission may review such a proposal in connection with a periodic submission made by the provider pursuant to its appointment under subsection 209(d) of this title.

(ii) The Commission may approve a proposal under this subdivision (B) if it finds that:

(I) the energy transformation requirement that would otherwise apply under this section exceeds the achievable potential for cost-effective energy transformation projects in the provider's service territory that meet the eligibility criteria for these projects under this section; and

(II) the reduced energy transformation requirement proposed by the provider is not less than the amount sufficient to ensure the provider's deployment or support of energy transformation projects that will acquire that achievable potential.

(iii) The measure of cost-effectiveness under this subdivision (B) shall be the alternative compliance payment rate established in this section for the energy transformation requirement.

WASHINGTON ELECTRIC COOPERATIVE, INC.

VEGETATION MANAGEMENT PLAN

July 2006

I. Purpose

The primary purpose of this document is to provide guidance on methods to be used to manage vegetation within Washington Electric Cooperative's (WEC) rights-of-way (ROW) in a safe, efficient and environmentally sound manner. In providing this guidance, it is understood that all line clearing, maintenance and other vegetation management work shall be performed in strict conformance with all applicable federal, state and local government laws and regulations, including OSHA Rule 29 CFR 1910.269, Electric Power Generation, Transmission and Distribution Regulations.

II. Background

WEC currently serves approximately 10,000 members in 41 rural Vermont towns in the counties of Washington, Orange, Caledonia and Orleans. Today, WEC's electric system consists of 1,237 miles of distribution line and 18 miles of local transmission line, plus an additional 7.4 miles of transmission line in Coventry. Of those line miles, approximately 800 miles of distribution line and 10.47 miles of local transmission line require tree trimming.

The terrain in WEC's service territory is described as hilly, often rugged and for the most part heavily forested with various deciduous and coniferous species. While distribution lines were constructed across fields in the early years of the Co-op in order to minimize time and the cost of construction, WEC has been routinely relocating those lines nearer to roadsides during major rehabilitation projects whenever possible. However, in many cases, it is likely that landowners will be reluctant to allow WEC to relocate their lines due to aesthetic and environmental impacts.

For the last several years, the WEC Board of Directors has authorized increased funding of the annual ROW budget in an effort to improve reliability. The amount of money budgeted and spent on tree trimming in each of the past four years is as follows:

Distribution System and Danger Tree Removal

Year	2003	2004	2005	2006
Budgeted	$351,000*	$418,000	$436,000	$467,620
Actual	$347,496	$410,993	$435,751	$467,539

* Original 2003 budget was $378,000, but funding had to be curtailed due to budget constraints.

Transmission System

Year	2003	2004	2005	2006
Budgeted	$13,000	$13,400	$13,500	$14,000
Actual	$11,522	$8,121	$10,267	$13,966

The number of miles of line that WEC has cleared and maintained, and the number of danger trees removed, in each of the last three years is as follows:

2003

Distribution Miles Cleared:	54.26	Distribution Miles Maintained:	83.48
Transmission Miles Cleared:	1.20	Transmission Miles Maintained:	2.03
Danger Trees Removed:	700		

2004

Distribution Miles Cleared:	59.94	Distribution Miles Maintained:	85.62
Transmission Miles Cleared:	.78	Transmission Miles Maintained:	1.30
Danger Trees Removed:	900		

2005

Distribution Miles Cleared:	55.12	Distribution Miles Maintained:	84.80
Transmission Miles Cleared:	.98	Transmission Miles Maintained:	1.51
Danger Trees Removed:	1,000		

III. Policy

WEC shall strive to maintain its transmission and distribution ROW corridors in accordance with Policy 80, attached hereto as Appendix A, as well as in the following manner:

a. In a safe, professional, efficient and environmentally sound manner, while being sensitive to the concerns of property owners and the general public.

b. In a manner that will provide reliable electrical service in conformance with the Electrical Safety Code;

c. In a manner that protects all electrical system infrastructure necessary to transmit power between substations;

d. In a manner that uses the services and knowledge of employees and contract ROW crews who are professionally trained and inherently concerned with proper ROW techniques in conjunction with safe work practices.

IV. ROW Management Practices

Inspections:

As part of WEC's annual pole inspection and treatment program, and in accordance with RUS operational planning requirements, a visual inspection of ten percent (10%) of WEC's electrical T&D system shall be conducted on an annual basis. In addition to noting the physical condition of the poles and wires, ROW vegetation growth conditions shall be noted.

Species:

It is the practice of WEC to control the following tree species the full width of the ROW:

Ash	Cherry	Locust	Pine
Basswood	Fir	Maple	Poplar
Beech	Hemlock	Oak	Spruce
Birch	Larch		

This practice of vegetation management control allows for safe passage by WEC employees and contractors within the ROW for maintenance purposes, and removes potential fire and safety hazards to humans and animals in the area.

In general, it is desirable to use or enhance existing natural vegetation that does not interfere with the distribution of electricity. Herbs, most shrubs and low maturing trees should be left in the ROW to suppress the invasion of tall-growing trees. Following is a partial list of some of the low shrubs and plants that are native to WEC's service territory:

Alpine Azalea	Juniper	Rhododendron
American Yew	Laurel	Serviceberry
Dogwood	Leatherwood	Steeplebush
Dwarf Willow	Meadowsweet	Virginia Creeper
Eastern Redbud	Partridge Berry	Wintergreen
Fern	Pussy Willow	Witch Hazel
Gooseberry	Raspberry/Blackberry	

Notification:

In general, the Cooperative membership and affected property owners will be notified prior to any ROW clearing or reclearing maintenance work, except during emergency restoration or if hazardous conditions exist. Such notification shall include one or more of the following:

First: by a general article in *Co-op Currents* listing all ROW maintenance projects scheduled for the year

Second: by a mailed postcard to the member, or to the property owner if different from the member and readily known, who will be affected by the ROW maintenance work

Third: by either an automated or personal telephone call to the member, or to the property owner if different from the member and readily known, informing them that ROW maintenance work is about to commence

General Practices

A. The Removal of Trees by Manual Means (Chainsaws)

This method of control is primarily used for softwood and hardwood trees which have the potential for interfering with line reliability. The principal method of dealing with this type of vegetation is to cut it at ground level (flat cutting) using chainsaws and brush saws. Whenever trees are removed, all stumps are to be cut as close to the ground as practical so as to discourage multi-stemmed sprout regrowth. Side trimming and danger tree removal work are to be performed in conjunction with flat cutting.

B. Trimming/Pruning

It may not always be necessary, economically feasible or aesthetically acceptable to flat cut all trees within the ROW. This may be in response to a property owner's request, when the tree is a compatible, non-interfering vegetation variety, or it may be that while the tree itself is in the required clearance zone, only its branches immediately threaten the electric line. In these cases, it may be appropriate to prune or trim the tree.

Limbs to be removed are those that are dead, decayed, insect damaged, or structurally weak, including limbs which could break at weak points and strike conductors when swinging down in an arc. Pruning guidelines are as follows:

1. Tree Under Conductor – Under Trimming

Under-trimming is cutting back large portions of the upper crown of a tree. Under-trimming is required when a tree is located directly beneath a line. The main leader or leaders are cut back to a suitable lateral. (The lateral should be at least one-third the diameter of the limb being removed.) Most cuts should be made with a saw; the pole pruner is used only to trim some of the smaller lateral branches.

For the sake of appearance and the health of the tree, it is best not to remove more than one-third of the crown when under-trimming.

2. Tree at Side of Conductor – Side Trimming

Side trimming consists of cutting back or removing the side branches that are threatening the conductors. Side trimming is required where trees are growing adjacent to utility lines.

Limbs shall be removed to the trunk or to a lateral that is growing parallel to or away from the conductors.

Where possible, or as designated by WEC, the contractor shall eliminate all branches growing within 10 feet beneath and toward the conductors.

3. Tree Over Conductors – Overhead Trimming

Overhead trimming consists of removing limbs beneath the tree crown to allow wires to pass below. Most of the natural shape of the tree is retained in this type of trimming, and the tree can continue much of its normal growth. Overhanging limbs should be removed as dictated by the species of the tree, location, and the general condition of the tree. When trimming, remove all dead branches above the wires, since this dead wood could easily break off and cause an interruption.

The contractor shall remove all weakly attached overhanging limbs that are capable of hitting the conductor if the limb were to split at the point of attachment.

Where possible, all branches within ten (10) feet above conductors shall be removed as dictated by the species of the tree, location, and the general condition of the tree.

Overhead trimming must be performed in accordance with current VOSHA/OSHA trimming regulations.

4. Combination Trimming

It is often necessary to use judgment in combining several types of arborcultural trimming techniques in order to achieve a good looking job and provide adequate clearances.

5. Improper Trimming Techniques

a. Pollarding: This is done by stubbing off major limbs until the tree assumes the desired shape. The result is not only unsightly, but a multitude of fast-growing suckers will sprout from the stubs, resulting in a line clearance problem more serious than before. The stubs are quite likely to fall victim to decay and disease.

b. Rounding Over: Rounding over or shearing is done by making small cuts so that the tree top is sheared in a uniform line. This creates an unhealthy condition and results in rapid regrowth of suckers directly toward the electrical conductors.

c. Side Trim Stubbing: This is done by stubbing off portions of limbs along the side of the tree to obtain clearance. This method of trimming, like pollarding and rounding over, creates many fast growing suckers that become a serious line clearance problem. These trimming methods should be avoided.

d. Topping: Removing top and upright branches should be avoided. Where necessary, use natural or directional pruning methods.

C. Proper Trimming Techniques

Various trimming shapes were previously described. The following provides the details for WEC standard line clearance and can be used for overhead trimming, side trimming, under trimming, and combinations. Pollarding, rounding over and side trim stubbing shall be avoided.

All trimming shall be performed to direct the growth of a tree away from the conductors. Branches shall be cut back toward the center of a tree to a suitable lateral branch, parent limb or the tree trunk. This is commonly called drop crotch, lateral or natural trimming (see Figure 1). When cutting back to a lateral branch, the diameter of the lateral branch must be at least one-third of the diameter of the branch being removed in order to sustain growth. Almost all cuts are made with a saw and very little pruner work is required. If a proper lateral branch is not available, the branch shall be cut back to the parent limb or tree trunk.

Trimming shall be done in such a manner as to protect tree health and condition.

All saw and pruner cuts shall be made back to the branch collar at an angle equal to but opposite of the branch bark ridge on the parent limb or trunk in order to leave no stubs.

No damage by loosening or stripping of the bark or splitting of branches shall be caused during trimming.

All severed limbs and branches (hangers) shall be removed from trees after trimming.

C. Removal of Trees by Mechanical Means (Brontosaurus)

WEC shall utilize the Brontosaurus wherever possible to clear ROW. The Brontosaurus is an excavator on steel tracks that utilizes a hydraulically driven shearing mechanism that pulverizes the tree and root system. Having utilized this machine over the past several years, WEC's field observations indicate that it effectively reduces the rate of resprout in many species. The Brontosaurus effectively removes trees, shrubs and brush within a ROW, however, this method still requires contract ROW crews to revisit the ROW to do side trimming and danger tree removals which adds to the cost of this method of clearing. Use of the Brontosaurus is limited due to its inability to safely work in narrow ROWs, and near roadsides and members' homes.

D. Danger Tree Removal

A danger tree is any tree, due to its location, species and condition, which is tall enough to pose a threat to WEC's electric lines. Many of the trees at the edge of the ROW have crowns that are heavily grown in towards the line, and when they fall, are likely to make contact with the electrical conductors. Danger tree removal is most effective towards reducing outages associated with high wind storms, prolonged rain incidents and routine outages due to "rotten trees". This, in effect, targets short-term and long-term reliability while also reducing the duration of outages due to excessive damage. For every danger tree that is targeted and removed, a future outage is avoided. (See Figure 2 for minimum clearances for danger tree removal.)

Since 2002, WEC has been aggressively targeting and removing danger trees in an effort to improve reliability. In 2005, approximately 1,000 danger trees were removed at a cost of $96,333.

E. "Hot Spot" Clearing

Selective clearing of ROW line sections outside the normal reclearing schedule helps to improve reliability to those members located at the end of a single-phase line. Identification of these problem line sections normally comes from the members who are affected by poor reliability. Devoting resources to "hot spot" line sections improves reliability and/or power quality to specific problem areas, improves line crew access and outage restoration time, and improves overall reliability of a particular line. Hot spot trimming is the least efficient method of ROW clearing, but is essential to good member relations.

F. ROW Clearing During Emergency Restoration and When Hazardous Conditions Exist

In the best interests of employee and public safety, any tree making contact with WEC's electric system conductors shall be immediately removed to mitigate the hazard. It is not reasonable to provide advance notification to property owners under these conditions.

In the event of a power outage caused by trees within or outside of WEC's ROW, the trees shall be cut to the extent that is necessary to safely restore power. Advance notification to property owners is not possible under these conditions.

Under both of the above circumstances, a WEC employee shall coordinate with WEC's ROW Management Coordinator to arrange for any necessary cleanup.

G. Clearing Within Muncipal Street or Highway ROW

In situations where the Cooperative does not hold a valid ROW easement along a public street or highway, whether for a new service or for relocation of an existing line, no tree within that street or highway shall be cut in the construction, relocation, maintenance or repair of electric power lines without the written consent of the adjoining property owner(s) or occupant, unless the transportation board or selectmen of the town in which the tree is situated, after due notice to the parties and upon provision for a hearing, shall decide that such cutting is necessary (Title 30 VSA, § 2506), or unless such decision is made by the appointed municipal tree warden for the town (Title 24 VSA, § 67).

H. Clearing Within Wetlands

Wetlands are considered to be sensitive areas for vegetation management practices. These may include swamps, marshes and bogs, and other areas identified in the National Wetlands survey, and will be identified by WEC's representative prior to ROW management activities. Handcutting will be used near wetland areas where necessary to control undesirable vegetation. If extensive wetlands are encountered, WEC may elect to carry out the work in winter because of improved access. Vegetation in wetland areas will be managed according to the Vermont Department of Environmental Conversation's policy on wetlands.

I. Clearing Within Stream Corridors

Stream buffers are areas adjacent to streams requiring special vegetation management, and these areas shall generally be maintained to a minimum width of 75 feet on each side of the stream. Where distribution lines cross streams, standing woody vegetation, shrubs and low mature height trees will be allowed to grow within the ROW if consistent with the terrain and existing land use. This cover will protect fish habitat, service wildlife travel lanes, and control soil erosion.

Where the electric line spans a ravine, streamside vegetation may be allowed to grow taller as specified by WEC's representative. Where an undesirable woody species becomes taller than 12 feet, it will be removed to ensure protection of line conductors. In general, provision of the Vermont Agency of Environmental Conservation policy on river and stream bank management shall be followed.

J. Clearing Where Electric Lines Cross Roads

Electric lines that cross roads will be treated similarly to streams. Low woody shrubs, such as Sweet Gale and other compatible plant species identified on page 4, which have a low height at maturity, will be permitted and encouraged at road crossings in order to provide screening of the electric lines.

K. Clearing Within Wildlife Travel Areas

Wildlife travel areas shall be maintained to promote the movement of white-tail deer and other wildlife across the corridor of extended cross-country distribution and transmission lines. In general, WEC's objectives will be to favor vegetation that can support snow and thereby keep the snow depth on the ground shallow enough for deer to move about and to conceal wildlife as it crosses through wildlife travel lanes. Treatment will be similar to high visibility ROW areas, and preference may be given where practical to preserving a conifer canopy. WEC shall use the Vermont Agency of Natural Resources policy on wildlife management as a guide to maintaining wildlife travel lanes.

L. Stump Height

ROW clearing will be limited during winter months. Deep snow during winter months often results in unsightly ROWs because of excessive stump height, which oftentimes need to be recut in the spring, which adds to the cost. Excessive stump height also encourages the regrowth of saplings. At other times of the year whenever trees are removed, all stumps will be cut as close to the ground as practical so as to discourage multi-stemmed regrowth of the original species.

M. Cherry Tree Disposal Precaution

Wilted leaves from cherry trees are poisonous to livestock. Therefore, in areas frequented by livestock, any cherry cuttings shall be disposed of immediately by removing any cuttings from the enclosed livestock grazing area.

V. Trees and Debris Removal

Disposal techniques for each ROW section will be determined by WEC's representative, taking into account federal, state and local regulations, the practicality of certain disposal methods, the potential for wood utilization, and the wishes of the property owner. Whenever roadside trimming is performed, all log length material shall be picked up by a log truck as soon as possible and disposed of in accordance with the property owner's request. All other brush and wood material shall be removed from the ditch and municipal ROW and appropriately chipped or stacked at the tree line. If the ROW maintenance area is located more than fifty (50) feet from a public road or highway, then the log or tree length wood shall be moved to the tree line. All brush shall be windrowed at the edge of the ROW in order to provide unobstructed access for maintenance purposes. All other wood material shall be cut in four foot lengths and stacked at the tree line (see Figure 3). There will be no brush left in stream beds, across fence lines, stone walls, paths or roadways.

VI. Prioritization of ROW Clearing

WEC's Vegetation Management Plan promotes the prioritization of ROW clearing as it statistically relates to reliability of service. In general, the focus of the ROW management program shall be as follows:

1. Transmission Lines

- Annually patrol 18 miles of local transmission line as well as 7.4 miles of 46 kV transmission line in Coventry for purposes of identifying potential equipment problems and marking danger trees for removal.

- Flatcut WEC's 10.47 miles of local transmission line as needed to ensure maximum reliability to WEC's substations.

- Flatcut WEC's 7.4 miles of Coventry transmission line as needed based on annual patrol to ensure 100% availability.

2. 3 Phase Lines

Three-phase circuits are critical links from substations to all members. Damage to one conductor of a three-phase line require the entire three conductors to be de-energized when repairs are made. WEC's three-phase lines are prone to greater damage for any given tree contact due to construction type and phase-to-phase voltage levels. The reliability of three-phase circuits, like substations, have a direct impact on the reliability of all single-phase lines. Improving the reliability of WEC's three-phase circuits is essential to achieving state mandated SAIFI and CAIDI indices.

3. Two-Phase Lines

Two-phase lines shall be treated similarly to three-phase lines as they serve a greater number of members than do single-phase lines.

4. Single-Phase Lines

Maintain single-phase line ROWs based on member density.

5. Worst-Performing Circuits

At the beginning of each year, WEC shall analyze circuit performance for the previous calendar year and identify the five worst performing circuits based on annual reliability. The reliability of the worst-performing circuits shall be further analyzed to determine if there are conditions that can be changed to improve the reliability of the circuits, including danger tree removals, flat cutting, line relocation and reconstruction if needed. In all cases, the circuit analysis shall take into consideration year-to-year fluctuations and longer-term trends to identify root causes of the reliability problems.

VII. CLEARANCE ZONE REQUIREMENTS

In general, single phase primary and/or secondary conductors shall be cleared of trees within 15 feet of each side of the pole line center. Three phase primary conductors shall be cleared 25 feet each side of the pole line center. (See Figure 4 for clearance zone dimension measurements.)

VIII. ROW Contractor Training and Requirements

ROW contractors hired by WEC are required to become familiar with the procedures and requirements of this plan and to utilize safe and proper ROW clearing techniques that are in compliance with state and federal laws and regulations. Each ROW crew must have two (2) qualified line clearance tree trimmers. Minimum qualifications include the following:

- Annual CPR and first aid training
- Annual electrical hazard awareness training
- Ability to perform an aerial rescue from a minimum height of 35 feet in four minutes or less. Aerial rescue must be practiced at least once a year.

- Knowledge of electric line voltages and minimum approach distances
- Annual inspection and dielectric testing of bucket trucks to be used for tree trimming
- *Need to add all references to OSHA 1910.269 material*

This plan has been prepared and adopted in order to provide a broad assessment of WEC's ROW vegetation management goals and policy objectives, and the operational methods and practices that shall be used in attaining those goals and objectives. The procedures outlined herein are designed to provide general guidelines for the safe operation and maintenance of electrical distribution and transmission lines, while minimizing visual and other environmental impacts within the communities served by WEC.

2020 Residential Member Satisfaction Study

Washington Electric Cooperative

PREPARED BY:

NRECA Market Research Services

January 11, 2021

Table of Contents

Executive Summary

Following are the top-line findings based on the results of a telephone/online survey of 561 residential members of Washington Electric Cooperative conducted in December of 2020:

- Overall satisfaction with WEC is good, with a mean rating of 8.34 on a 10-point scale. Satisfaction is higher among phone respondents (8.58) than online respondents (8.09), which is typical when comparing scaled questions from an interview-administered survey to one that is self-administered. The mean rating for overall satisfaction among phone respondents does not differ significantly from the co-op's previous studies.

- Of the nine attributes of service tested, members indicate that *providing reliable service*, *having competent/knowledgeable employees*, *providing good value*, *having friendly/courteous employees*, and *handling individual complaints and problems* are most important to them. In rating WEC's performance for each of the attributes, member evaluations are positive; six have mean ratings above 8.0 on a 10-point scale, which is considered good. The two attributes evaluated most positively are in regard to the employees being *friendly/courteous* and *competent/knowledgeable* which is good considering they are among the most important. The co-op being *committed to the community* and *communicating with members and keeping them informed* are also evaluated well. However, performance ratings for five of the nine attributes significantly decreased from the 2015 study.

- The attributes for which the co-op is evaluated least well, with mean performance ratings below 8.00 are *helping members learn to manage their energy use*, *providing a good value for the money spent*, and *looking out for members' best interests*. The attributes with the largest gaps between mean importance and performance ratings are *providing a good value for the money spent*, *providing reliable service*, and *looking out for members' best interests*. It is very typical that these cost-related attributes are found to be the areas with the most room for improvement in members' perceptions.

- Two-thirds of the members feel it is very important that WEC provides them with renewable energy sources, giving a rating of "9" or "10. Just over half say they would definitely or probably use a time-of-day rate if available. This is significantly higher than in 2015.

- *Co-op Currents* readership is consistent with previous years, with 68% saying they read the newsletter regularly or fairly often.

- Overall, six in ten members are aware of SmartHub and 44% have used it, including 15% who have used the mobile app. While awareness of SmartHub among phone respondents has not changed significantly from the 2015 study, use has increased from 7% to 18%.

Objectives, Methodology, & Analysis

Objectives

This residential member survey addresses but is not limited to the following informational objectives:

- **Overall Satisfaction:** Assess how satisfied members are with Washington Electric Cooperative.
- **Performance Quality Attributes:** Evaluate how residential member perceive the importance of and WEC's performance on various service aspects (e.g., problem resolution, co-op employees, community commitment, reliability, value, etc.).
- **Performance Quality Trends and Benchmarks:** Compare the results to past studies to identify trends and benchmark the results against co-ops nationwide using NRECA's Co-op Norms Database (where possible).
- **Programs, Services, and Communication:** Explore members' interest in time-of-use program, awareness and use of SmartHub, and newsletter readership.
- **Member Identity:** Estimate the proportion of consumers who identify themselves as a member-owner, just a customer of the co-op, or both a member-owner and customer.
- **Member Demographics:** Provide demographics of the residential member base and identify differences in attitudes between demographic groups.

Methodology

As in 2015, data were collected through telephone and online surveying. Telephone interviewers were thoroughly trained on the questionnaire prior to initiating the survey. On average, the telephone interviews lasted approximately 11 minutes.

Telephone surveys were completed with a total of 201 residential members of WEC between December 17 and December 28, 2020, with random sampling done proportionate to monthly kWh use. Of those contacted, 277 declined to participate, resulting in a response rate of 42%. Additionally, 121 of the phone numbers attempted were disconnected or were otherwise unable to be used to complete a survey (place of business, fax number, etc.).

Online surveys were collected in a couple different ways. First, between December 7 and December 19, messages were posted to the Front Porch bulletin board forum, both notifying members of the upcoming survey and including a link to the survey for members to use to take the survey early. A total of 61 surveys were completed in this manner between December 7 and December 28.

Second, an e-mail invitation was sent on December 15 to a random sample of 860 members for whom WEC has an e-mail address, with 28 returned as being undeliverable. The survey was closed on

December 23 with a total of 299 surveys completed, resulting in a response rate of 36%.

For the purposes of analysis, the surveys completed through the Front Porch link and the surveys completed through the email invitation are combined and referred to as “online” responses. These online survey respondents are weighted to represent 50% of the total data and are also weighted by monthly kWh use to match the overall electric use distribution of the co-op.

The margin of error at the 95% confidence level for the weighted sample is plus or minus 4.4 percentage points. This means that a result of 50% in the survey may range between 45.6% and 54.4% in an infinite number of residential samples this size.

Analysis

The graphics presented in this report are based on data collected from the current study and tracking comparable results from two studies conducted in 2010 and 2015. The results of tracking surveys provide value by demonstrating when results remain consistent and indicating where there has been significant change over time. Because the study in 2010 was conducted as a phone survey, comparisons to previous years are made using just the phone respondents unless otherwise specified.

Comparisons are also made to results from similar studies conducted by 69 co-ops among more than 86,000 residential members across the country between July 2017 and June 2020. These “Co-op Norms” are not taken from the universe of all cooperatives; rather, these are co-ops who value, monitor, and measure the satisfaction of their members and therefore represent higher performing co-ops, not all co-ops.

Differences between current and previous studies and between member segments, such as differences by age or service tenure, are either statistically significant or not. A “significant” change refers to the certainty of a difference, not the magnitude or size of the difference. Throughout this report, only significant changes or comparisons will be mentioned even if the word “significant” is not used, unless noted otherwise. Significance is measured at the 95% confidence level, meaning that at least 95% of the time, using the same sampling procedure, this difference will occur; the difference is likely not a matter of chance.

When evaluating the mean ratings in this report, on a 10-point scale a mean of 9.0 or above should be considered “excellent” and a mean between 8.0 and 8.99 is considered “good”. Means below 8.0 may be cause for concern and those below 7.50 indicate a need for improvement.

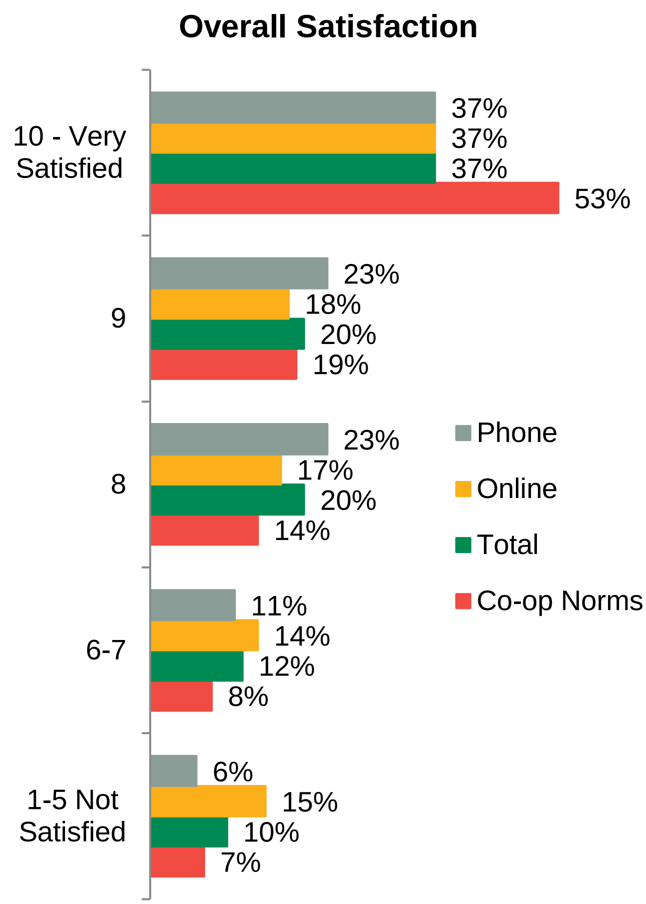
Key Findings

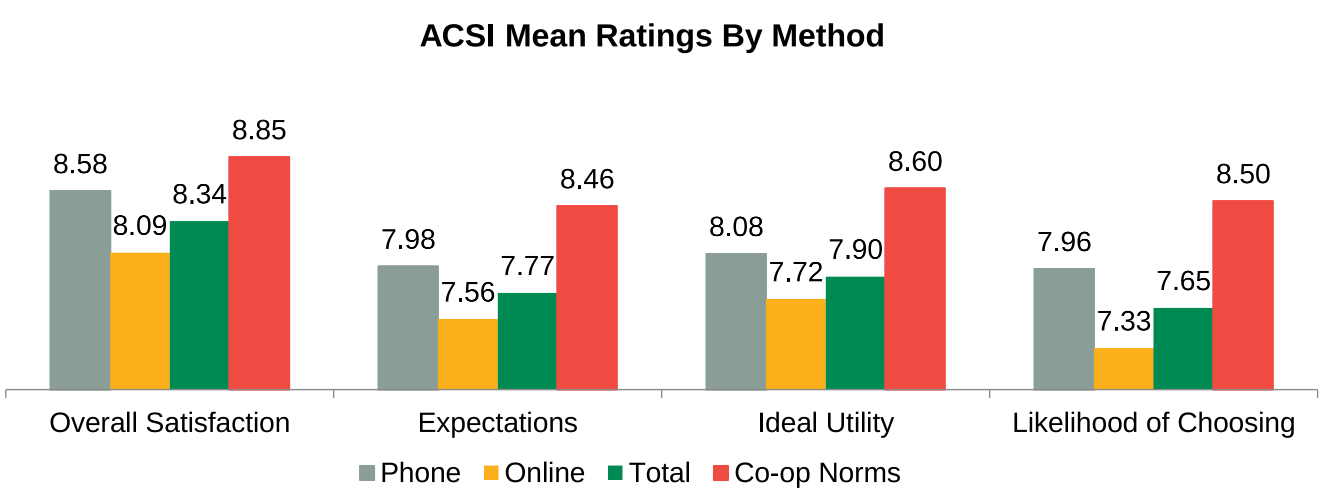
Overall Satisfaction

Overall satisfaction among WEC's residential members is good. The mean overall satisfaction rating is 8.34 and 57% give a top rating of "9" or "10".

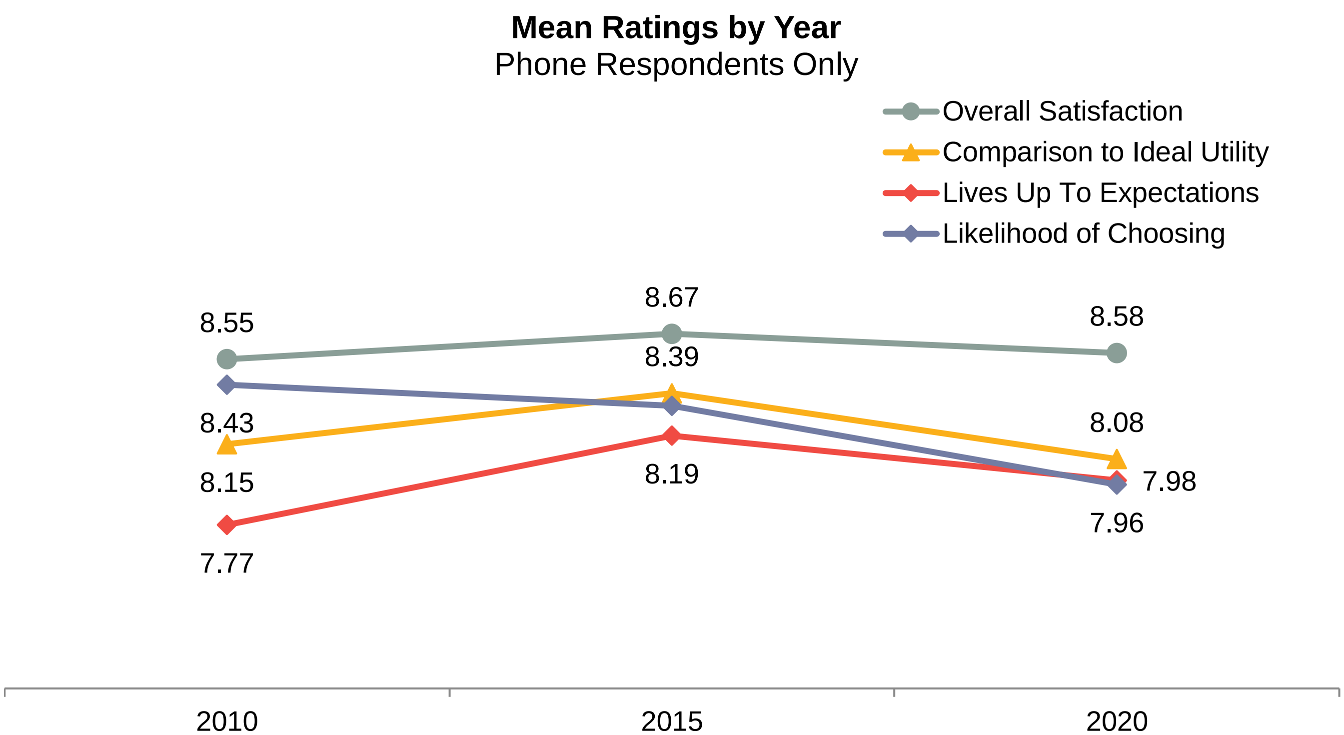
The mean satisfaction in 2020 does not differ significantly from any of the recent studies but is lower than the Co-op Norms. Older members, longer-tenured members, and those living alone or with one other person are more satisfied than are their counterparts. Additionally, phone respondents give higher ratings than online respondents, which is typical in a mixed methodology study.

Mean ratings for the other three ACSI measures fall below the "good" threshold and are also lower than the Co-op Norms. As with overall satisfaction, mean ratings among phone respondents are higher than online respondents, with all differences being significant except for *comparison to the ideal utility.*





As previously mentioned, the mean rating for *overall satisfaction* among the phone respondents has not changed significantly from the previous studies. Likewise, neither *the extent the co-op meets expectations* nor *comparison to the ideal utility* have changed significantly from the 2010 and 2015 studies. However, the *likelihood of members choosing WEC* if given a choice is lower than the 2010 study.



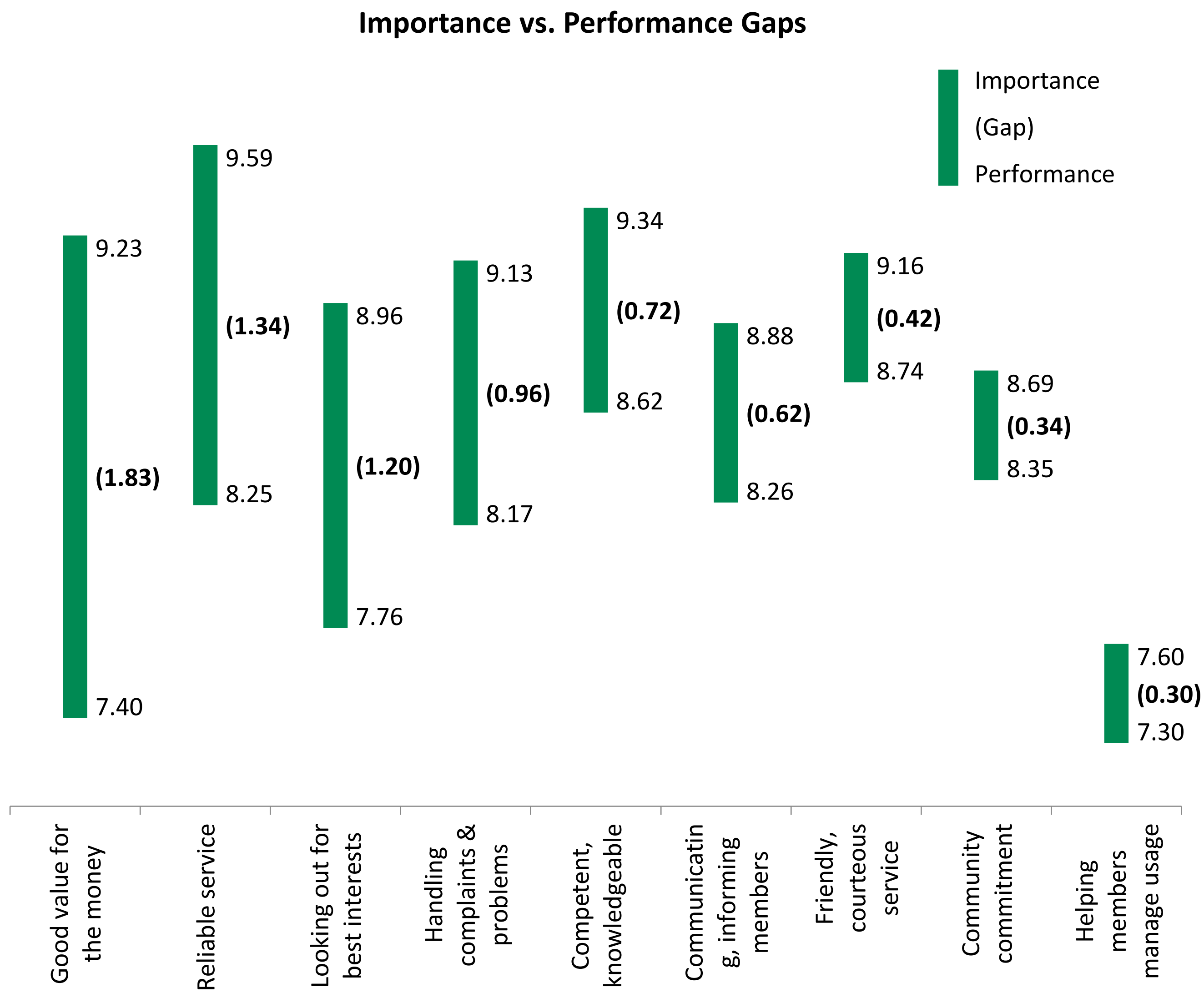
Attributes of Service

Members were asked to evaluate nine attributes of service regarding both importance to the member and WEC's performance in each area. On all but one of the attributes measured, the mean ratings for importance are above 8.50 on a 10-point scale indicating high importance. The mean ratings for how well WEC is meeting expectations on each attribute vary.

Members give the highest importance ratings for *providing reliable service*. The performance rating for this attribute is also high, with a mean rating of 8.25. The lowest rating for both importance and performance is for *helping members learn to manage their energy use*.

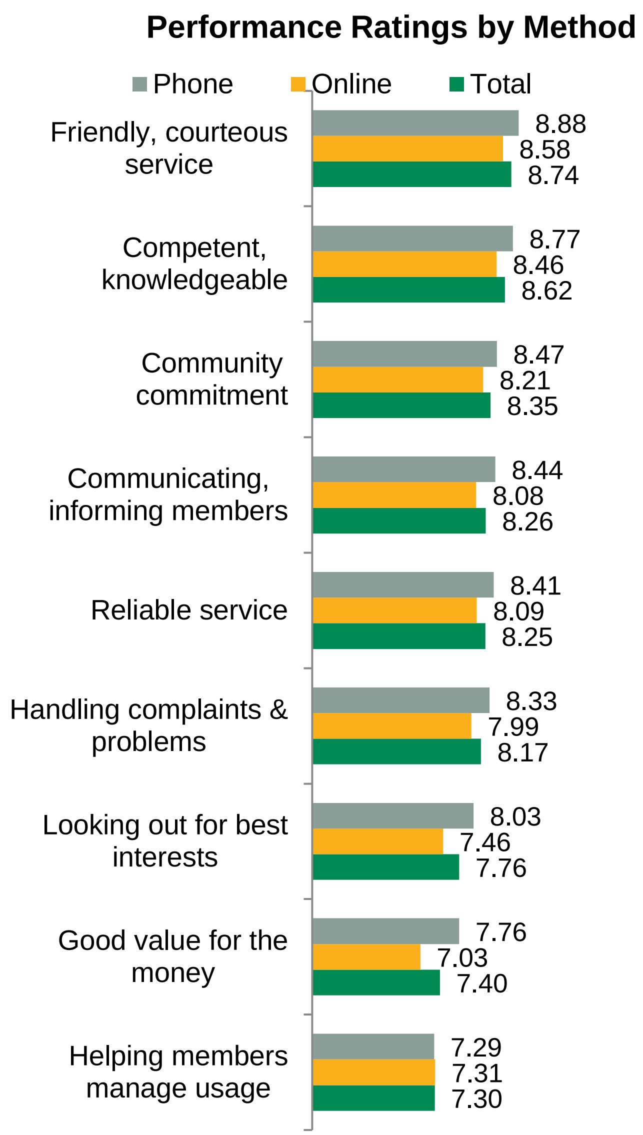
	Importance		Performance		Gap – Difference Between Mean Importance and Performance
	Mean Rating	Rank	Mean Rating	Rank	
Providing reliable service	9.59	1	8.25	5	1.34
Having competent and knowledgeable employees	9.34	2	8.62	2	0.72
Providing a good value for the money you spend	9.23	3	7.40	8	1.83
Being friendly and courteous in the service they provide	9.16	4	8.17	6	0.96
Handling individual complaints and problems	9.13	5	8.74	1	0.42
Looking out for your best interests	8.96	6	7.76	7	1.20
Communicating with you and keeping you informed	8.88	7	8.26	4	0.62
Being committed to the community	8.69	8	8.35	3	0.34
Helping you to manage your energy use	7.60	9	7.30	9	0.30

The largest gaps between mean importance and performance ratings are for *delivering good value for the money*, *providing reliable service*, and *looking out for members' best interests*. Not surprisingly, value is an area that is rated as very important to members, with a mean importance rating of 9.23. Also typical for a cost-related attribute, value receives the second-lowest performance rating with a mean of 7.40.



Phone respondents give higher performance ratings on most of the attributes although not all of the differences are statistically significant. Among phone respondents, performance ratings have decreased from 2015 for:

- Handling individual complaints and problems
- Being friendly and courteous in the service they provide
- Having competent and knowledgeable employees
- Providing a good value for the money you spend
- Providing reliable service

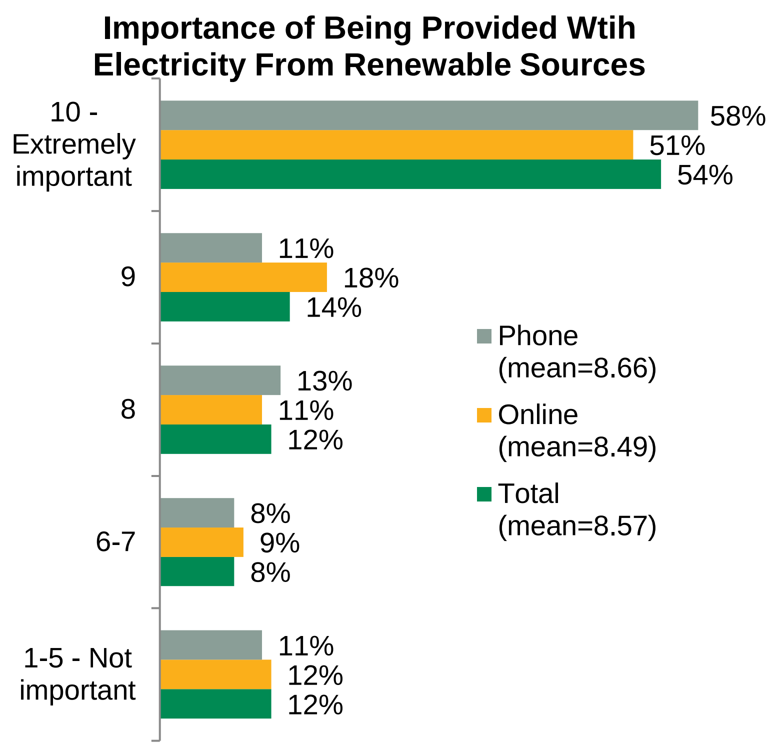


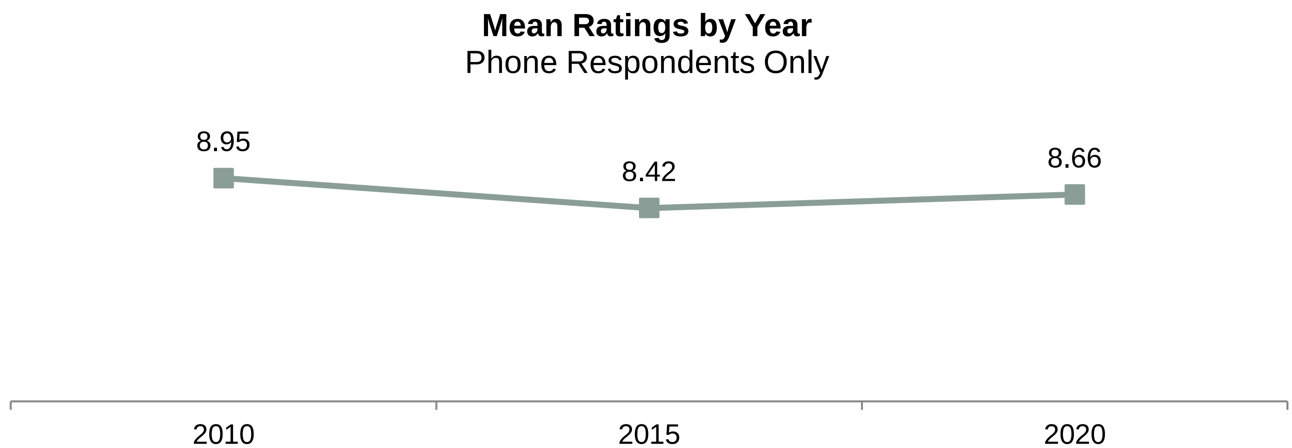
Renewable Energy and Energy Conservation

Two-thirds feel it is very important that WEC provides them with electricity from renewable energy sources, giving a rating of "9" (14%) or "10" (54%).

Those more satisfied with WEC overall, older members (65 or older), and females give higher ratings than their individual counterparts for the importance of receiving electricity from renewable sources.

Ratings are consistent with the previous studies.

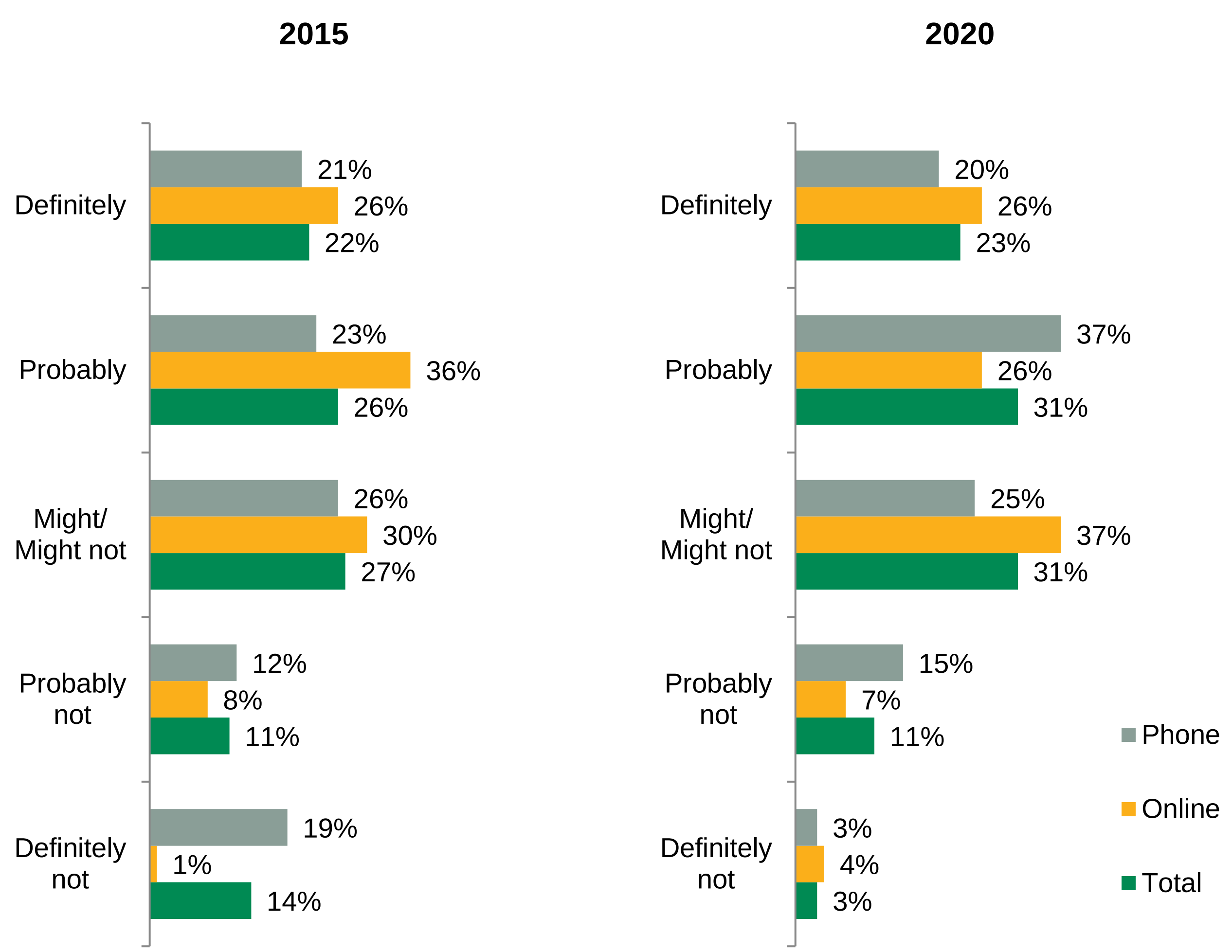




More than half of the members say they would probably (31%) or definitely (23%) use a time-of-day rate program if one were available from WEC. Three in ten are not sure whether or not they would use such a plan.

Longer-tenured members are more likely than newer members to use a time-of-day rate plan, while newer members are more likely to be unsure if they would or not. Younger members (under 45) are more likely than older members to say they would definitely use such a plan while older members are more likely to say they would probably use it.

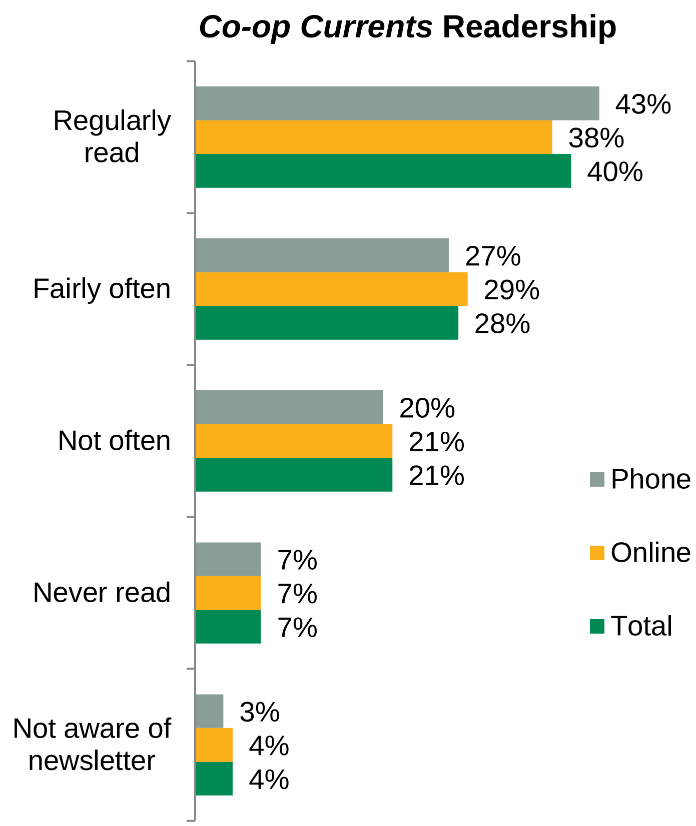
Members in 2020 are more likely than those in 2015 to use a time-of-day rate.

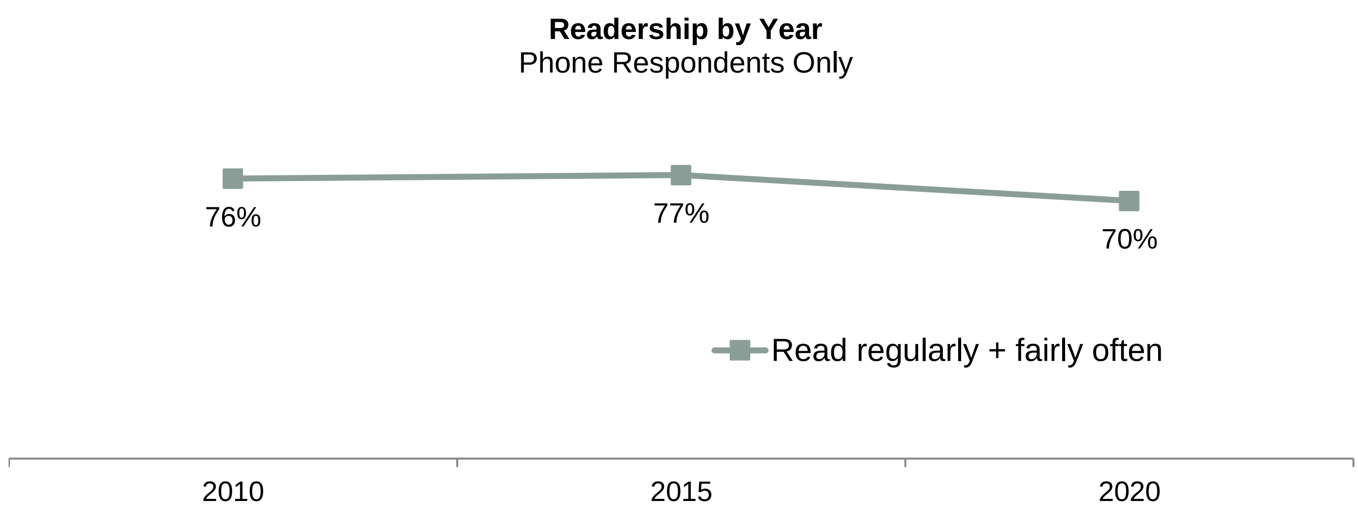


Communication

Almost all of the members are aware they receive the monthly *Co-op Currents* newsletter and approximately seven in ten indicate they read it regularly or fairly often. While this is down from the 2010 and 2015 studies, the differences are not significant.

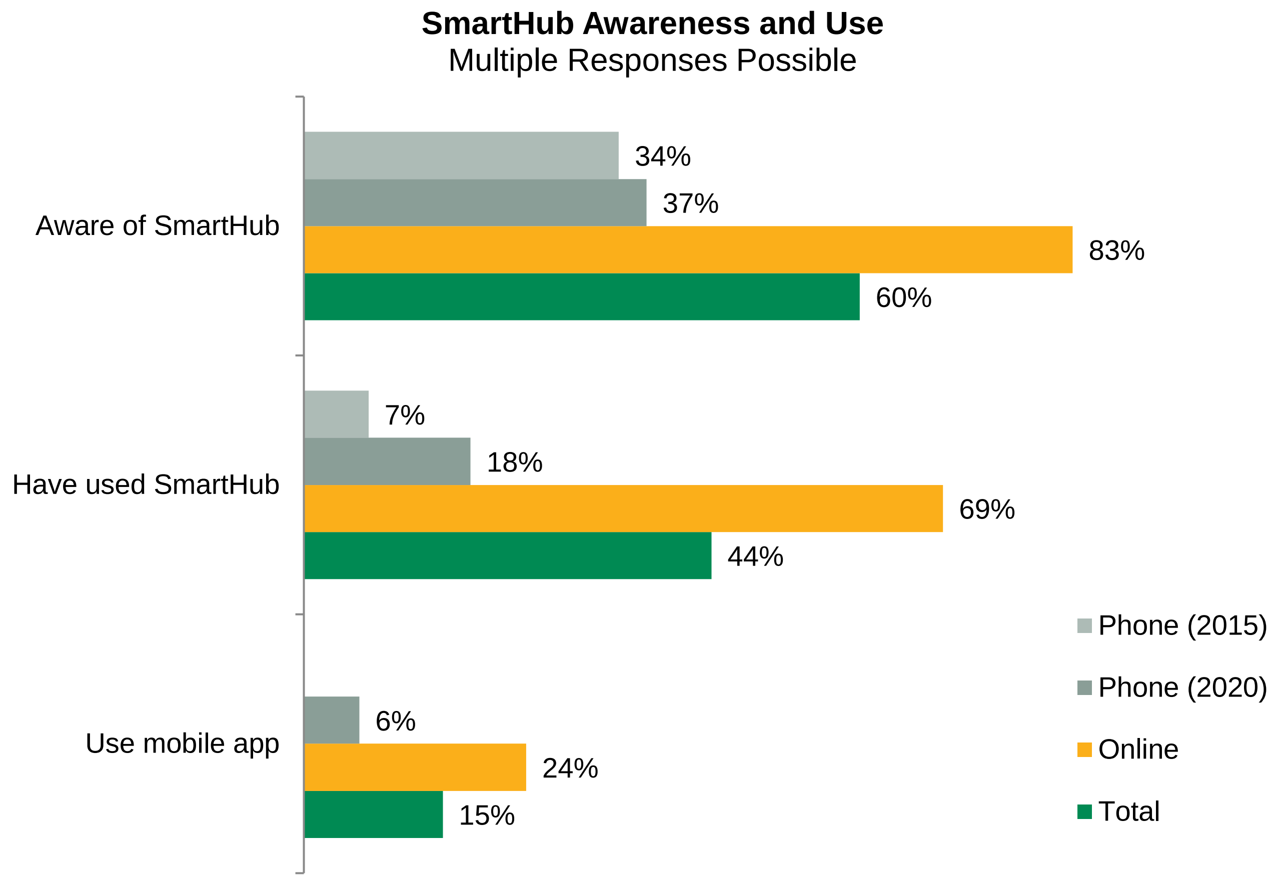
Those more satisfied with the co-op, older members, longer-tenured members, those living alone or with one other person, and males are more likely than their counterparts to say they regularly read *Co-op Currents*.





Fully six in ten members are aware of SmartHub, 44% have used it, and 15% have used the mobile app. While awareness of SmartHub has not changed significantly from the 2015 study, the use has increased.

It is not surprising that both awareness and use of SmartHub are significantly higher among online respondents and younger members than they are among phone respondents or older members. Awareness and use are also higher among newer members and those living with at least one other person.

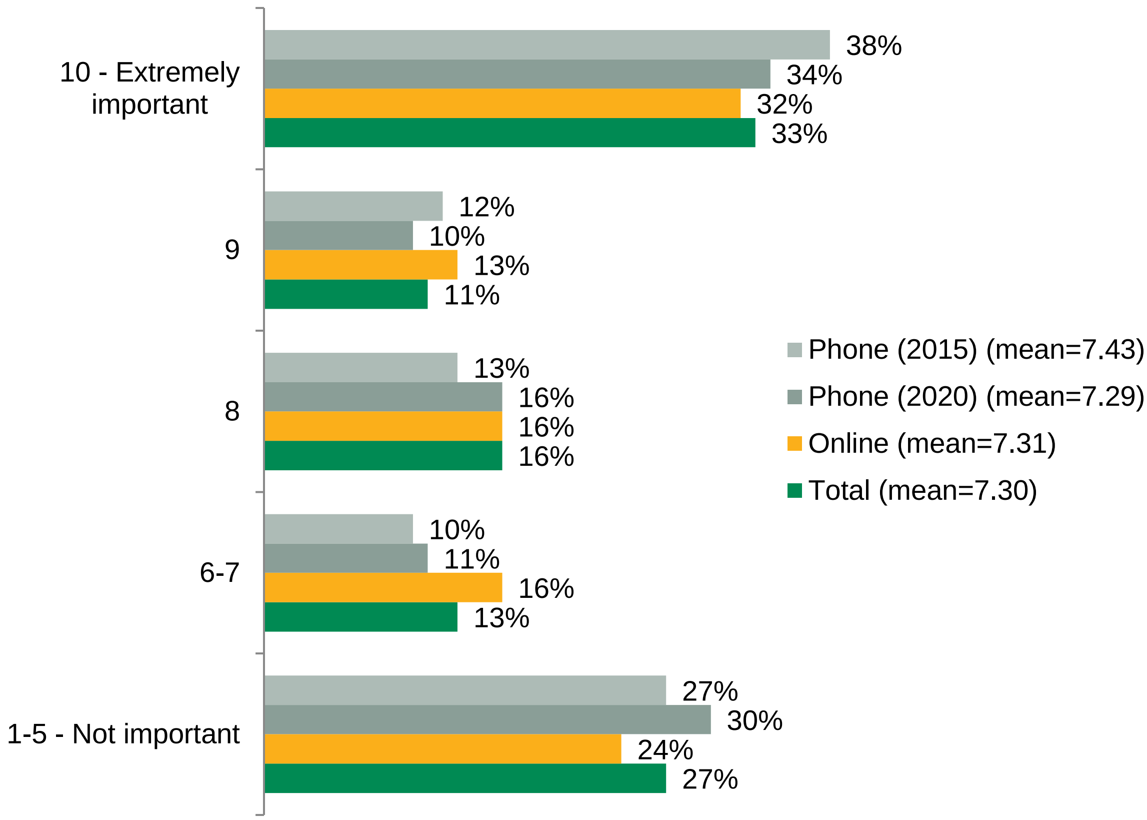


Member Identity

More than four in ten members say it is important to them to be a member of a non-profit electric cooperative, giving a rating of "9" (11%) or "10" (33%). This has not changed significantly from the 2015 study.

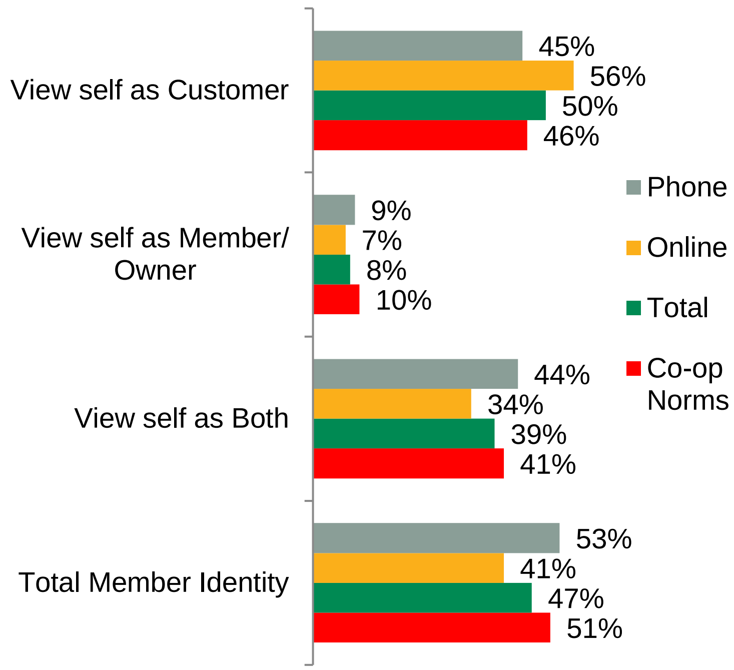
Those more satisfied with WEC overall, older members, those living alone or with one other person, and those with lower electric use give higher ratings than do their individual counterparts.

Importance of Being Member of Non-Profit Electric Cooperative



Nearly half view themselves as a member of the co-op as opposed to feeling like a customer. That is, they view themselves as a member/owner (8%) or both a member/owner and a customer (39%).

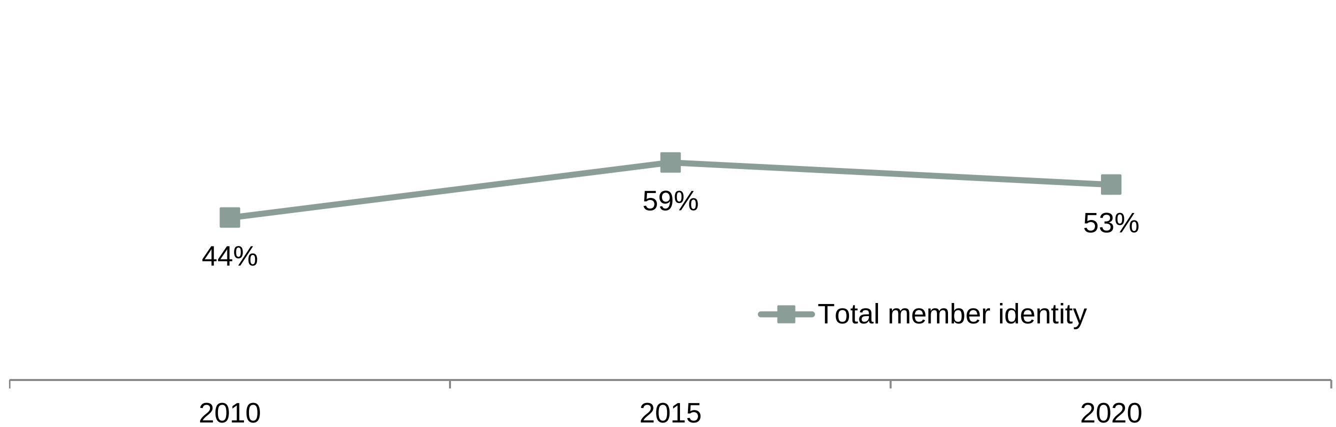
Although the proportion who view themselves as a member/owner only has decreased from the 2010 study, the proportion who view themselves as a customer has also decreased, resulting in overall member identity not changing significantly. However, it is slightly lower than the Co-op Norms.



Phone respondents, those more satisfied with WEC, older members, longer-tenured members, those living alone or with one other person, and homeowners are more likely than their counterparts to have member identity.

Those with member identity are more satisfied than are those who view themselves as a "customer" and give higher ratings on the other three ACSI measures and performance attributes (both importance and performance ratings), with most of the differences being significant. "Members" also give higher ratings for the importance of being a member of a non-profit electric co-op, the importance of WEC providing members with renewable energy sources and are more likely to be aware they receive *Co-op Currents* and read it more frequently.

Member Identity by Year
Phone Respondents Only



Member Demographics and Segmentation

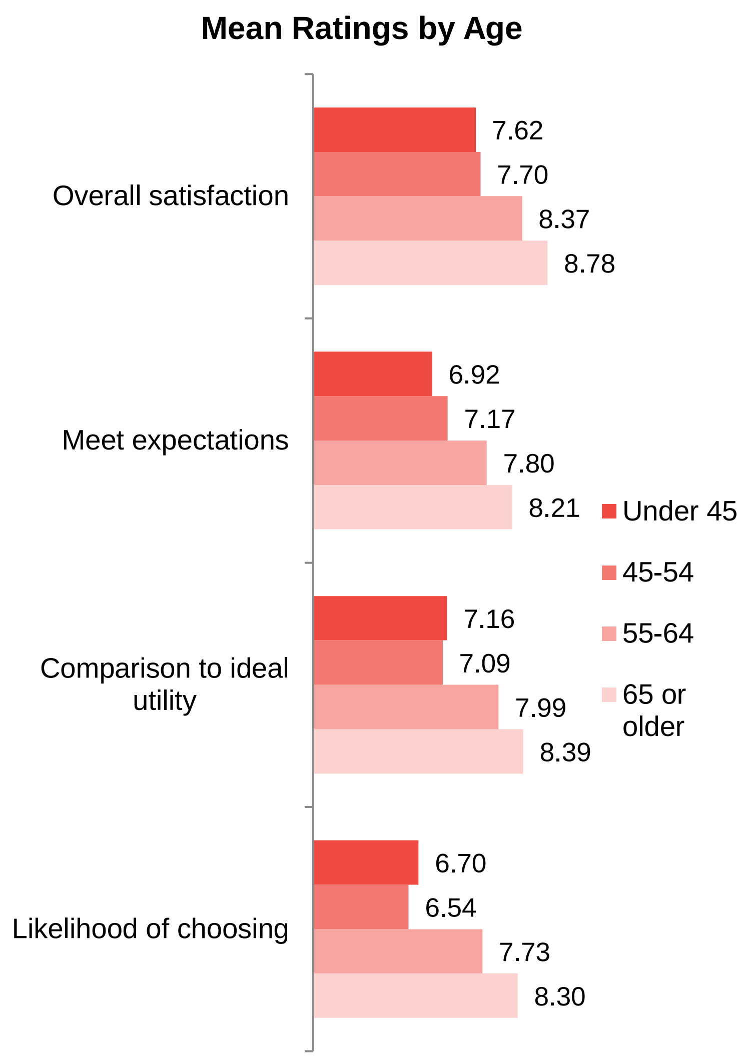
Member segments that are significantly more satisfied than their counterparts include older members (55 or older), longer-tenured members, and those living alone or with one other person.

These segments also give higher ratings on the other three ACSI measures, although not all of the differences are significant.

Although older members tend to give higher ratings for the importance of the service attributes, most of the differences are not significant. However, older members do give significantly higher ratings for the co-op's performance on those attributes.

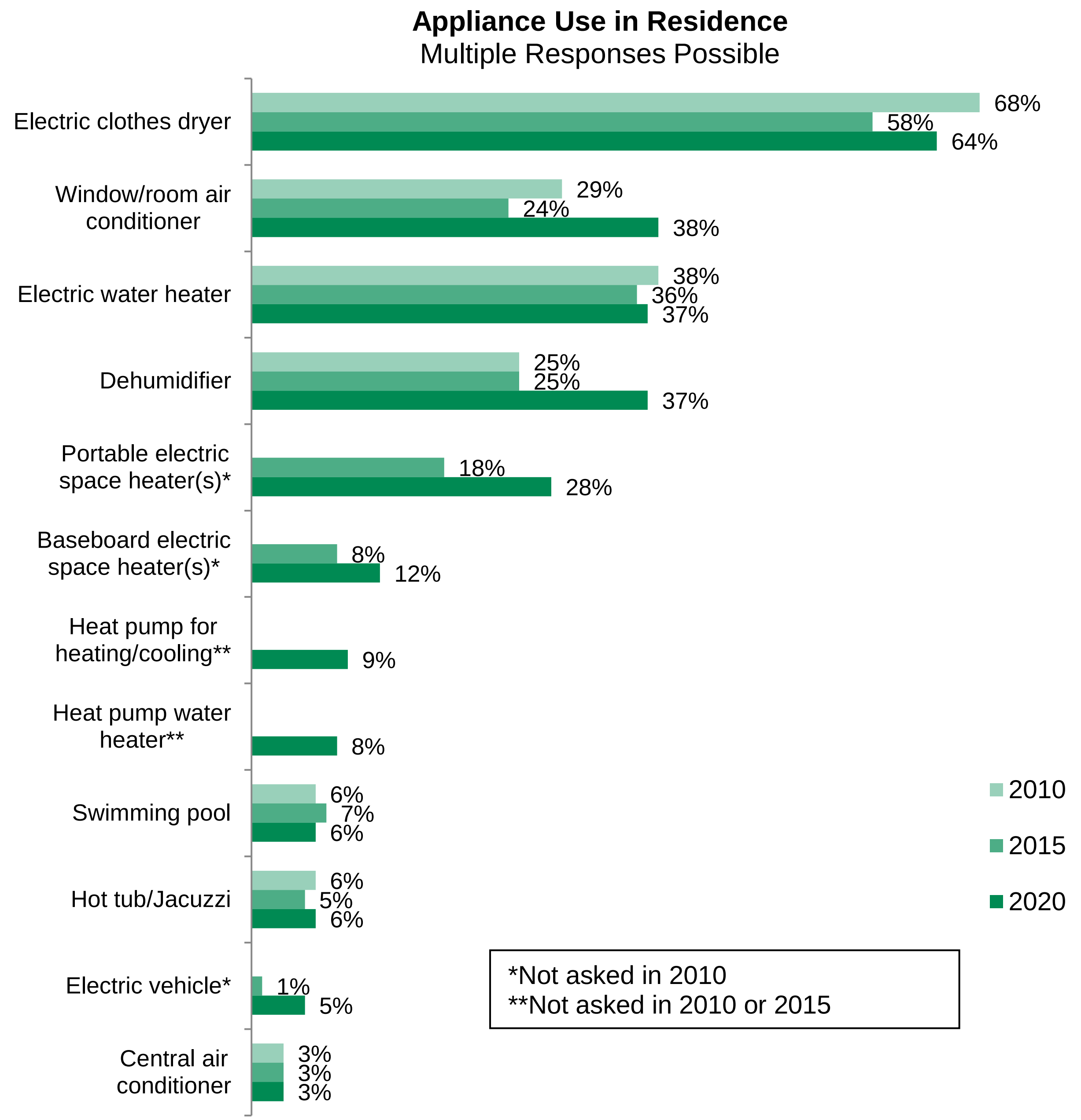
Additionally, older members give higher ratings on the importance of being a member of a non-profit electric co-op and WEC providing them with electricity from renewable sources, are more likely to feel like a member of the co-op, and more likely to regularly read *Co-op Currents*.

Conversely, younger members, especially those younger than 45, are significantly more likely to be aware of and use SmartHub and to use the mobile app.



Members are most likely to have an electric clothes dryer in their home, although they continue to be less likely to have one than they were in the 2010 study. Just over one-third have a window/room air conditioner, electric water heater, and/or dehumidifier. Members are least likely to have a central air conditioner.

Compared to the 2015 study, members are more likely to have a window/room air conditioner, dehumidifier, baseboard electric space heater(s), portable electric space heater(s), and/or electric vehicle.

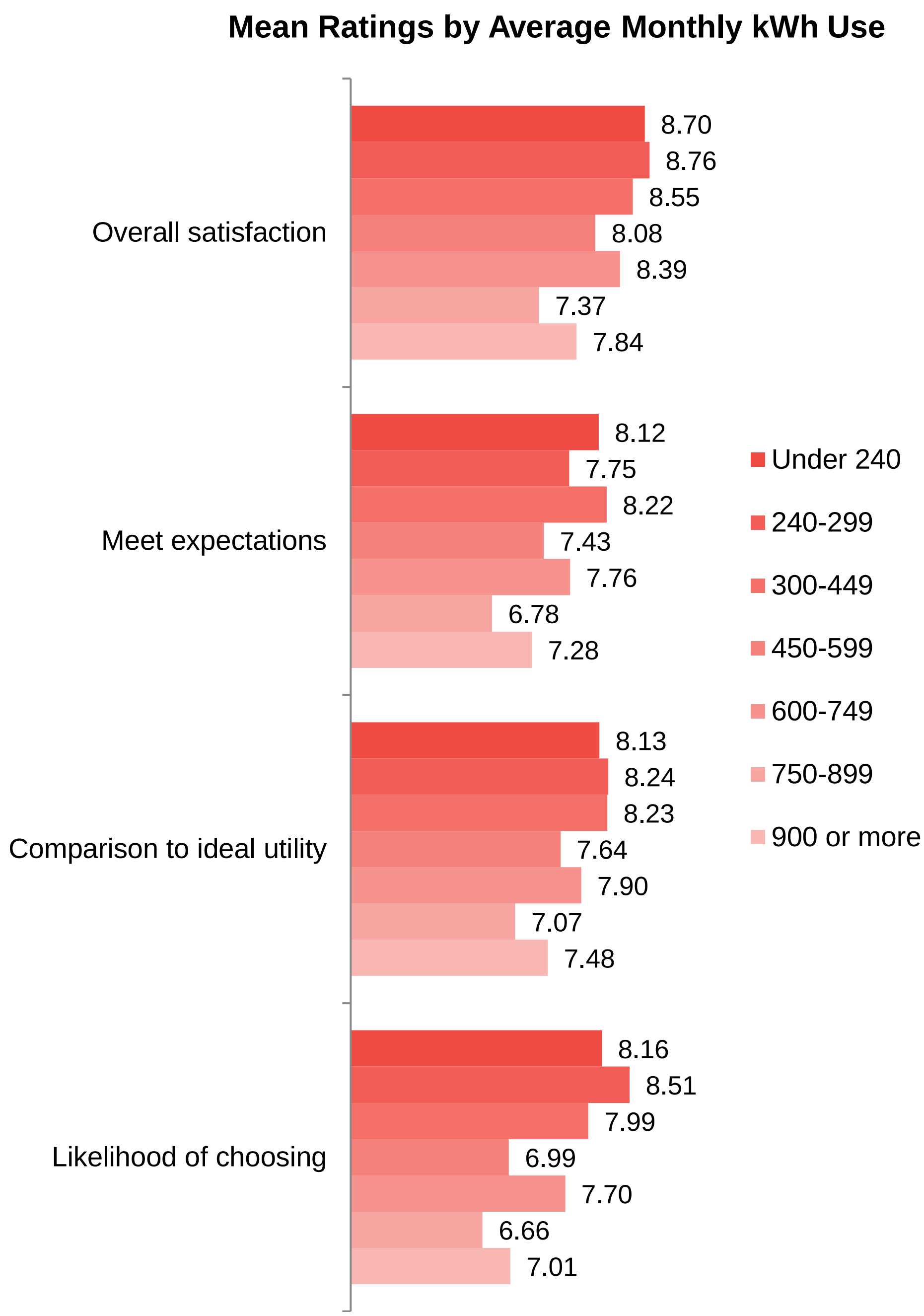


Members with lower electric use, especially those averaging less than 450 kWh per month, evaluate their overall satisfaction significantly higher than those with higher electric use.

While those with lower electric use also tends to give higher ratings on the other three ACSI measures, differences are not consistently significant. For example, those with less than 240 kWh use and those with 300-449 kWh use give significantly higher ratings than those with 450 kWh use or more, but those with 240-299 kWh use give a rating similar to those with 600-749 kWh use.

Those with lower use also tend to give higher ratings for WEC's performance on the service attributes, but again, differences are not always consistently significant. The one attribute that is consistently higher among those who use less than 450 kWh is *providing a good value for the money members spend*.

Those with lower use are also more likely to give higher ratings for the importance of being a member of a non-profit electric co-op, view themselves as a member of the co-op (especially those with 240-299 kWh use), and regularly read the newsletter.



Conversely, those with higher use tend to be more aware of SmartHub and are more likely to use it, although few of the differences are significant.

Because only six respondents use net metering, statistical tests for significance are not valid.

APPENDIX A: Verbatim Responses

ADDITIONAL COMMENTS

It's too expensive. (2 mentions)

1. The crews that work the lines for outages are phenomenally good, ever since 1983. 2. With many utilities you are able to spin meters backwards, would like to be credited for excess unused energy so it doesn't encourage that type of pumping energy back into their grid--there is a lot they could harvest. Would like to be able to spin the meter back and create solar energy--have a credit if solar is available. 3. There is value in offering to lease Tesla solar battery system to those that provide solar energy. 4. Every time I have called for a power outage, I have been given the best information and courteous service, fantastic customer service.

A couple notes: We originally became customers when renting and I found the deposit amount to be quite high, when you could run a credit report to ensure customers will pay online. Our house has a generator, so not as much of an issue, but it seems like WEC could do more tree management throughout the summer to reduce outages. Compared to other locations we've lived, I rarely see tree cutting during the summer. Lastly, I know my father reads the newspaper, but I would suggest an online newsletter to save money, reduce paper (we have to pay to recycle), and increase customer change through direct links to opportunities and offers.

A couple years ago, I had an outage where they wanted me to walk to my pole. The problem is I cannot walk. It became a very expensive 10 days as I used about $1,000 worth of propane.

A customer for less than a year, so far, we have only lost power for 2-3 hours. Not too bad considering all the strong wind gusts that have powered their way through Washington County. The recent broadband initiative sounds interesting. Please keep us informed on how that plays out. Thank you!

A little easier access to information during an outage.

A while ago my daughter wanted me to put a notice to the co-op letting them know I'm on oxygen. Had to ask my daughter to acquire the note from the doctor then turn it into the co-op for me. Every couple of months I'm asked to send the doctor's note again. It is an aggravation having to refile that doctor note, so I just gave up trying to keep up with it because I want to limit the amount of times I have to get out of the house or ask for help.

Add a text/email notification system for when power goes out, comes on, or is impacted in your area. It would stop the long calls to report it, check on an outage, and keep customers informed. Rates continue to be too high.

After our 3-hour outage again this morning, the VT Public Utilities Commission will again be notified. This is like living in a third world country. Every month we experience an outage.

All I have to say is they're not very good about power outages.

All of my "less than perfect" responses are attributable to the cost per kilowatt hour which is too high. We have solar panels, but our costs are still too high.

Additional Comments (continued)

Any business I've had to do with them, they've been super. I had my mom living with me for a while and she was on oxygen, so they notified me whenever the electricity would be out. They were super about it.

Appreciate being part of a cooperative for my electric power.

Appreciate the service I get from employees. Glad that trash is renewable, though it seems ironical, and without food in the trash, how long will that last. So, what's next?

Appreciate WEC's commitment to renewable energy and addressing the climate crisis. Also appreciate their steps on bringing broadband to the membership. Fixing outages is generally prompt. Well-run utility.

As a low energy user and senior, it has been hard to see my minimal usage remain pretty stable, but my bills go from $60-$65 monthly to now around $80 or more to incentivize EVs and additional electrical usage. The irony of constant messaging to remove all electrical baseboard heating when I first moved in in 1984, to the complete reversal now, is rather frustrating. I understand times have changed, but the hit to the pocketbook is tough.

Average rates are very high in Vermont and WEC somehow manages to charge 1.5 times that. I'm amazed when I read in the newsletter you are trying to push for more EVs and electric heating, go green would be completely impractical given the relative prices of AC from WEC vs gasoline, propane and wood, not to mention insane from the perspective that it's not that unusual for power outages to last a week or more. (Don't blame you for that one, rural area, long runs, lots of trees, ice and heavy snow, etc. - but it is a fact of life here and someone relying always on electric power for heat and transportation in rural Vermont will be a sad frozen puppy.) Might help if the newsletter could break down exactly why rates are so damn high. Would be in favor of the fiber thing if you ever do that.

Base customer charge is too high. I have a second building directly across the road with a separate meter. I use about $3-4 of electricity a month and the rest are customer charges. It would be nice if that charge was based on energy usage. Meter is on a pole and entrance wire is buried. Washington Electric hasn’t had to touch that in 20 years, so maintenance is basically nothing.

Bottom line I appreciate it’s a co-op and I appreciate they go for renewable energy.

Cost is my only concern with my service at this time.

Costs and services compared to Green Mountain seem inadequate as does solar incentives/assistance, and I feel we need to be 100% renewable. Why are we not in the solar market too?

Customer premises is a summer camp, 5-6 month's usage per year.

Discouraging Washington Electric Cooperative members from going solar is neither forward thinking nor practical. The co-op should be encouraging the decentralization of clean energy while at the same time improving the infrastructure needed.

Do a little better on the outages. Keep the woods cleared out.

Additional Comments (continued)

Do not approve of moderate income members being forced to contribute to renewable energy grants to consumers who can afford to install solar or wind energy systems.

Don't use SmartHub maybe only 2-3 times. I use the information on bill mostly. The electronic newsletter? Have an air conditioner but do not use it. Since we don't have choice, why on earth would you ask those questions?

During one storm when trees were falling on the power lines and in driveways, I had no power. I looked around my house and in my driveway. The crew cutting the trees off the lines cut the tree laying across my driveway so I could get out of my drive. I needed to get out. I appreciated it more than you can imagine. Living alone and being a widow with a limited income helped me more than you can imagine! Thank you!

Even though there seems to be several outages a year, I think that those who are out there getting the service back (at all hours and weather conditions) are doing a great job of restoring power in a decent amount of time.

Everybody’s been personable and I think Steve Hart worked with me as much as he could on helping on prices with things and I appreciate that.

Fiber broadband service?

First of all, they never pay a dividend, so there's no point in being an owner. They make you pay a deposit and you never get it back. They don't care when you move, you won't get it. Basically, they are paying the people from 20 years ago and it's just a scam. The people who deal with your bills are snotty and dismissive when you go in to pay. They are knowledgeable about what your home usage is. There is one guy in there that will sit with you for an hour and explain everything, but everyone else is rude. Basically, they are overpriced, they don't wait one day if you are late, they will shut you off, and they just suck.

Focus more on customers’ needs and less on energy efficiency. Way too much emphasis has been placed on lowering overall usage. That only works for folks who have the resources ($$$) to make changes, whether they be new appliances, energy improvements to homes/buildings, or new heating systems. And meanwhile, you keep changing the rate structure to benefit those same folks, the ones who can afford to pay for solar panels, electric cars, etc. This is NOT taking care of your customers and community. There are many folks in the WEC community, like my household, who are doing what we can and are still barely making it. Heat pumps and electric cars aren’t a silver bullet. Heat pumps are NOT efficient for heating in VT in the wintertime. In fact, I received a “heads up” letter from you in December 2017 saying that you had noticed that our kilowatt hour usage was much higher than normal, like over $800 (compared to $200-$300); that was the first AND LAST time we used our heat pump to heat our house. And it had only been for a period of 8 days. WHAT A FREAKING MISTAKE! Go check our account records, you’ll see.

For all the talk of the importance of electrifying, the WEC prices are outrageous. My neighbor 1 mile down the (similarly rural) road with GMP pays $0.16 a kWh with a LOWER monthly account fee. Either get cheap, or GMP should be forced to acquire you and bring lower prices and better economy of scale. GMP also has a much better outage map that includes remarkably accurate estimated time of restoration.

Additional Comments (continued)

Get broadband service at my location--this is a #1 priority.

Give us fiber internet!

Going back to higher/lower rates at different times of the day might save some people money. Your marketing efforts aimed at explaining new/different rates and making us "feel better" about increased bills is a bunch of BS. Higher costs are a combination of many factors; trucks, equipment, wire, cable, and personnel all add up. Everyone wants a raise every year. Prices for ANYTHING in this world never go DOWN.

Great customer service! Beth is always friendly and helpful!

Happy with the service, just wish the rates were lower.

Happy with WEC.

Have a buy back for solar; if we make more solar, you buy back the excess.

High speed internet would be amazing.

Hoping WEC can be a part of tackling the internet connectivity issue we see in this area.

How do our rates compare with other VT electric companies?

I am disappointed that I am not eligible for a Tesla back-up battery. Why is it that GMP customers are and WEC members are not? I have a back-up generator, but in a sustained outage, that would use all my propane and I can't get winter deliveries due to our steep driveway.

I am happy they are not polluting the air.

I am pleased to do business with you.

I am very happy with them.

I am very pleased with the co-op's forward thinking on energy use, conservation, and environmental stewardship. Keep up the good work!

I am very, very satisfied and if there is an outage, they are on top of it. I am happy that it is a non-profit and that they give back to the community. Also, the newsletter they send out is informative.

I am worried that they are not planning for the future. I am also worried that they are not hiring the right workers who can make the upgrades necessary for the lines. I feel they are kicking the can down the road, meaning they are just doing patch-ups and if something really needs to be replaced, they aren't making it a priority to do so.

Additional Comments (continued)

I answered "not sure" on some questions referring to satisfaction, expectations, getting my money's worth, service, etc. because I don't know how to compare it to other companies. I like the idea that it's a co-op, but I can't say I know how that compares to private for-profits. I also like the idea that WEC uses renewables but have always questioned the environmental impact of what I understand is a large percentage of our energy source - that is, methane gas from Coventry, as well as large hydro and wind. I support the use of wind power in general but have concerns about wildlife and human impact as well as aesthetic impact on ridgelines. I have considered adding solar power to my home, but when I learned the expense of it and how long it would take for me to realize savings, I justified not getting it based on believing that WEC uses equally renewable and clean sources, but I'm never sure if that's really true.

I appreciate the fine work the linemen do to restore power line. They recently did on Gulf Hill about two days ago.

I believe that we should get more for our solar array.

I believe WEC should spend the bare minimum allowable on the Button Up Program that we can get away with. Just enough to satisfy the State of VT law imposed on us. In this day and age when most have no savings and are living day to day, it does not make sense that WEC is trying to get everyone to use more electricity on things they cannot afford on an already insufficient grid.

I do have questions about the kilowatt hour usage and the billing rates. Not sure I understand the more electricity you use the lower the rate.

I don't think that WEC has done a good job encouraging "members" to use solar electricity or reduce their electric usage. I am now aware that WEC has the most expensive electricity in the state! I wish you would cut some costs like the newsletter, or moving to your warehouse, so that electricity was cheaper. I am glad it's renewable, though. And, please do a better job of supporting solar on individual houses!!! I had to find a way to do that on my own, and now you are going to charge me for the new meter?

I feel like we get reasonably good service and appreciate renewable options. We would also have an interest if they would become an internet provider.

I feel the rates are very high and I wish they were lower.

I feel very grateful that WEC is our electric utility. I missed not being able to have the annual meeting this year.

I find a disconnect between the friendly "all in this together" attitude of the newsletter and how quick the co-op is to threaten to shut off the electricity if the bill is late.

Additional Comments (continued)

I find these types of questionnaires using scales 1-10 difficult to answer. I have lived in my house over 30 years and have not experienced many outages since we are located very close to the Moretown substation. The very few times I have had contact with employees, I have found them to be helpful and friendly. I have not had much experience to compare what other electric companies offer in terms of services or cost. Not sure what an "ideal" electric service would be. Not sure that we as a consumer should be looking for more ways to use electricity. Using more does not always help the environment regardless how it is produced. What could happen if we (or the world) are dependent on electricity for more and more, heat, EV, electronics, appliances. Thanks for the opportunity to comment.

I give them a good mark. They are doing the best job they can, and I endorse all their activities. These questions pertain to one of my electric meters and I have 4 meters. The answer given tonight pertains to my main residence. I have rental properties and collect the information from those meters, and I will be adding another meter to be hooked up to solar panels.

I give them, especially the line people and people who work in the field, a ton of credit for the work they do and the conditions they do it in. I hope they get paid enough.

I guess I would really encourage them to have an off-peak service so that you can shift your loads to off-peak.

I had a blinking light problem. Called WEC and the personnel I talked to and the workers they sent to help correct the problem were very courteous, knowledgeable, and went out of their way to correct my problem.

I had a few different folks come out here, I am in a prime location for solar and I wasn't able to do it. They are telling me that my electric is running into the ground because of the amount of money I have been spending over the years on electric. So, that is why I turned off the hot tub and all that. I met with a man that just gave me a graph and it wasn't to a layman's eye anything that I could discern that I was doing wrong. My bills have gone down considerably. I have just gone thru a divorce, I turned off the hot tub and the bills have gone down considerably as a result, so I don't know if it was just what he was doing, I don't know. When the solar guy came here, and I showed him my bill it was like holy sh*t, this is not about a hot tub. It should never be this amount of money, but yet it was. So, I took it up with your company they didn't offer me anything. I am in an old farmhouse that has been renovated, but he said you have to have energy going into the ground. I got it down to $100 a month right now with my recent bill because most of the time I sit in the dark. I am working from home and I have some computers going, but most of the time I sit here in the dark and it still costs me $100 a month and I don't have that money.

I have a couple comments. First, I think the co-op should be much more aggressive in dealing with the Vermont Public Service Commission. The co-op is very, very cautious with them. #2, the co-op could be working harder to help create an infrastructure to deliver the internet to people who are currently unserved. For all the work that's gone into rate structure adjustments, the results have been very unfortunate and people like me have been on the short end. There is a gross favoritism to farmers and people who can afford fancy solar generating facilities. Alternative energy is being subsidized by owners who can' t afford it.

Additional Comments (continued)

I have been a member of the cooperative for close to 40 years and have watched the transition to renewable energy sources and more reliable service over this time. I am very happy with the service provided.

I have been satisfied. They did a good tree trim about 7 year ago.

I have heard that you were thinking of offering fiber and I really support that idea and wanted to make sure you knew.

I heard they are offering free solar panels. I'd like to get more information.

I hope they keep on keeping the juice coming. I am satisfied with them. I don't live very far from the substation, so it hardly ever goes out.

I just want to say when there is a call for an outage for trees on the lines, the linemen are there in a good amount of time, it's remarkable! I would like to relay my thanks to the linemen.

I like and support WEC placing fiber optic cable to each served house and business.

I like co-ops. I have been very disappointed that WEC seems not helpful for low income members like me. I would hope that WEC would develop new programs to assist persons with low income rather than sending out disconnect notices.

I like the newsletter. As a new member, this is a new experience for me, and I look forward to learning more as time goes on.

I love that they have renewable electricity.

I love you guys. Love how nice everybody is. We almost bought a place in Marshfield until we found out it was Green Mountain Power. Never have regretted being part of this co-op.

I only remember one time that we've been without power for more than 2 days. I was very impressed with the crew that came to restore our power. Not only were they very good at what they did but were very apologetic for delays in getting to us and took the time to explain why. It was more than I expected from a crew that must have been exhausted!

I own a seasonal camp used from May to November. Whenever I have need assistance (downed power lines, etc.), we have always had prompt, knowledgeable, efficient, and courteous service. Can't say enough for the guys in the field.

I think co-ops are a good idea.

I think compared to other companies WEC is very expensive. There has never been any contact to reach out to me and tell me how I can lessen my payments each month.

I think I'm satisfied with the service except specifically the rates. It can run between $350 to $375 per month.

Additional Comments (continued)

I think it is important to work on your outage system so you can speak with a live person, the automated system is bad. Please make it more user friendly. Give an option to relay a problem to a real person.

I think just that sometimes we've gone 4-5 days without power after storms and we get left last. I understand that we don't have many people on our street but sometimes they will be across the street and ignore us.

I think the leadership has been great for the last 20 years or so. I am impressed.

I think the survey covered anything I would make a comment about. We are happy to be Washington Co-op members.

I think they are a great co-op and I think they do the best they can with the cards they've been dealt. I think net metering has forced the prices up. They are very expensive, but they do a great job. With the customers per mile, I understand why it is so expensive.

I think they are a great company that I hope will be able to cope with the future.

I think they are basically doing an excellent job.

I think they are doing a 100% job. I give them a '10'.

I think they are doing a good job. I get a phone call when there is going to be an outage. I only use electricity during deer season.

I think they are doing a great job, especially the renewable energy. That's a great plus for me.

I think they are doing okay considering we are out in the boonies.

I think they are doing very well.

I think they do a good job. But where we're at is rural, so the power goes out all the time.

I think they do a good service. When there is a problem, they're around and in weather I wouldn't want to be out in.

I think they do a pretty good job.

I think they do a very good job. I had Green Mountain Power and the bills were much higher, but I get it.

I think they do the best they can.

I think they have been a wonderful provider for over 50 years, but I do wish there was an easier to reach a "live" person.

I think they've done a good job of keeping the lines clear.

Additional Comments (continued)

I think Washington Electric does good work and I'm proud to be part of it.

I think WEC electrical service is top rate - probably because of where I am located. However, I am NOT a fan of its rate system, membership charge, and efficiency charge. I am miserly with and conscious of our usage and keep my propane-based heaters set at 60 degrees or lower in the winter. While I realize WEC tries to promote everyone using electric vehicles and heat pumps, in my situation those are not feasible at all. At the end of the day I am conserving as much as I can for the environment and my expenditures/budget. It is MY choice, as I think it should be my choice (and incentive) and likewise for others - to be educated and incentivized to reduce electric usage.

I think WEC has and does prioritize its own interests rather than those of members in relation to net metering and last year's rate increase. As an example, when considering installing solar, I was discouraged by WEC staff and board members despite that it would have been in my interest. I love Co-op Currents and wish I had more time to read it. I think it would be great if WEC provided fiber internet.

I think you do a good job. Thank you!

I was very disappointed when we tried to be green. Changed to heat pump and solar and then you raise the rates, so it hurts us trying to help the environment and our budget. I have gone to meetings to speak up and attended your seminars for having a better term.

I wish that more time was given toward clearing (especially dead) trees from the lines. On our road, there are at least a dozen dead or dying trees leaning toward the lines. One heavy wind or snowstorm, and the power goes out. (No heat from the pellet stove, no way to keep food safe.)

I wish the co-op participated in some of the solar programs, etc. like GMP does.

I wish there was a program to help those with disabilities, so it doesn't cost so much to use power. I am on a limited budget and am careful about using power during times that it costs more.

I wish they would be more flexible so I could get solar energy.

I wish they would provide internet access.

I wish we had more incentives like GMP - for example - deal to get Tesla wall battery.

I would be interested in internet if it becomes available.

I would like help understanding why one of my two accounts is so high, over $200 per month.

I would like more information on solar and more incentives to install solar.

I would like to say that over the long period that I have had Washington, they have improved way more than 100%. They have improved enormously.

I would like to say their rate structure change feels much fairer.

Additional Comments (continued)

I would like to thank everyone for their hard work when our electricity goes out. We get it back on within reason.

I would love to see a program for rent-to-own for energy efficient hot water heaters or even clothes dryers. Those are the three appliances that make a large spike in my electric bill.

I would say we are very happy to have their service and happy to have a co-op that is committed to renewable energy.

I'd like to ask why I have to pay more for my service than I do in electricity. I don't think they pay attention to poor people. They should help me fix up my house so that I can live at a higher standard of living.

I'd like to see them do more incentives for electric vehicles and solar power.

I'm a big fan.

I'm glad that I'm with this co-op. I like that it's a co-op and I think the employees care about us. I think they do a good job.

I'm happy with them and I like the newsletter. The newsletter is a very good thing. We don't live in Vermont, so it’s nice to be able to keep up with everything while I'm in town.

I'm just glad it’s a co-op and I appreciate that is a non-profit.

I'm quite satisfied with what they are doing.

I'm very pleased with their service.

I'm very supportive of who they are and what they do.

I've been satisfied with their performance. No complaints.

I’ve read you are considering offering broadband internet service. We hope this continues to fruition. Topsham Telephone needs competition for their slow, but expensive internet access.

If they would offer internet that would be awesome.

In the 5 years we lived here, we have lost power multiple times between September until spring. We lose power quite a bit and have had to install a generator. We were out of power for 4 days one time and lost all of our food in the refrigerator.

It is a lot more expensive than companies we’ve used in the past. I’d love to know more about discounts or rebates for things like electric vehicles.

It would be nice if a discount loan program on backup power (Tesla battery/generator) could be provided to those of us who lose power for extended periods.

Additional Comments (continued)

It would be nice if the power stayed on more in the summer and winter, more consistently.

It would be nice to see a Tesla power wall or similar product program, like Green Mountain Power has in place.

It's a good company and we wish we had more companies like this one where we live in Massachusetts.

It’s very, very expensive electric service. I think it’s one of the most expensive in Vermont.

Keep up good work! Help us get highspeed broadband.

Keep up the great work the employees do.

Keep up the great work!!

Looking to see about getting an upgrade on the property of the house.

Love the commitment to renewable energy. Feels expensive.

My answers most likely reflect my personal situation of being retired on a fixed income. WEC, to me, should spend more effort on streamlining to keep costs down instead of continually passing them on. Renewable energy is the buzz of the electrification community, but it's us the consumer that foots the increased rates/bills. While rate increases may not register to many of WEC consumers, they do to those of us who are on fixed incomes. Sorry, just the way I feel.

My biggest frustration is the frequencies of power outages and the time it takes to restore power. I contacted a rep about options for backup power and the rep was very dismissive of our questions and told us to trust them to take care of the lines better.

My home is still under renovation. Everyone at WEC was extremely helpful when setting up my account. I needed to work with an electrician to have new boxes and work done on the pole. The first electrician I talked to insisted I move my main off the pole. This was more than I could afford. The second electrician called and talked with Steve who was great. Within no time I had new boxes wired up and WEC was turning on my power! Thank you!!

My main complaint with WEC is when you came to clear the right-of-way, I was told you would be removing the debris. Instead it was piled in wind rows.

My major concern with Washington Electric is its failure to offer the same products as GMP does. Also, I note an obvious anti-solar panel bias which I know the co-op will deny but it’s there. On a plus note, Bill Powell is great. He is always helpful. Dan Weston and his crew are also excellent.

Additional Comments (continued)

My neighbor mentioned a surge protector on WEC line coming into his house and said you installed free. Could you tell me more? Do we all have them or need to request? We seem to have more and more outages. I have a heat pump H20 heater waiting to be installed. It is dependent on my generator being able to handle it! Will rebates continue into 2021? I have already been approved. Thank you and thank you for your good service.

Needs to commit to supporting broadband internet for WEC customers/owners.

I am just curious, where are you calling from?

Of all those things I did not answer just now, my light bill runs about $500 a month, and I am trying to find the answer to why the bill is so high?

On the question about choosing another utility, I would like to clarify that it would depend on rates, reliability, and other factors such as the ability to finance solar panels for our home and set them up in such a way that they can be used even if the main grid is offline. It isn't that WEC has given unsatisfactory service, it's more that it is costly so rates would have to factor into the choice.

One time I called them and told them the seal on the meter outside broke and when I called, the lady I spoke with acted like "Oh what did you do to it?" I told them we might have hit it and knocked it off while shoveling snow or something but wasn't really sure. I just wanted to let them know so they could come fix it and we never heard anything back from them. As far as I know no one has come and fixed it. I really haven't been out to look at it, but I thought that would be something they wanted to know and come to fix. Not that we were trying to steal power or anything like that.

Our biggest issue has been with cutting trees in the right-of-way on our property without notice and leaving a big mess behind. This has happened twice over the years. We are seasonal, and two different years we arrived to find large numbers of trees cut and big piles of woodchips and debris left behind. On the positive side, when there are power outages, WEC is quick to fix them.

Our power goes out a lot more, and for much longer periods, than I expected it would. I am very glad we have a generator.

Our property, which uses WEC, is a camp.

Our Vermont (second) home is a camp with power and propane, but no running water or central heat so far (wood stove only). Very satisfied with WE service, CS, and maintenance of lines. Had asked for tree removal on adjoining property that threatened our service and WE took care of it promptly and effectively. Pleased with online bill-pay and available usage information. I would have been happier paying twice a year as in the past instead of monthly, but it's easy enough and no big deal. Appreciate being part of WE.

Over the years they've done a good job. Every time I've had to contact them, they've taken care of it quickly. The same went for my parents as well.

Overall doing a VERY good job.

Additional Comments (continued)

Overall, we've been very happy with our service so far. The rates seem fairly pricey, but I hope these will come down as more and more renewables come online.

Please contact customers when you expect there to be routine service, such as shutting off the power for 2 hours a day in the middle of a work week. This happened for almost a week and no one ever told anyone on my road this was happening. It was very disruptive, and a quick call could have made this easier to manage.

Please keep outage information up to date including when crews expect to have areas back up. This is important even if it only affects a small number of customers

Please look into the possibility of providing internet connection thru your line/distribution/pole systems.

Please make the online tool easier to operate. I locked myself out a while ago and instead of a password reset, it says I need to call in and reset my password. I tried a few times and just gave up. I would like to have a paperless bill and just check everything online but can't get my password reset to work the website.

Please, please, please support locally owned fiber to the home. Initiatives like CV Fiber or better yet so it is in house. Internet is the new fundamental utility. People can make and store their own electricity; they can't make their own internet. Without reliable high-speed hardwired internet to every home, people will continue leaving our communities, especially younger people and families, property values will drop, and we will all be worse off. No need to comment unless there is anything I can do to help. Thanks for doing what you do.

Please, push the fiber optic offering as quickly as possible.

Prices are outrageously expensive.

Project Powershift is too limited in scope. Most people don't have an electric car. How about some options for the average Joe?

Rates are very high!!!

Reliability is the biggest issue with our service. Whenever we have a heavy storm, or one is forecasted, we get candles/flashlights ready since we almost always lose power.

Reliability of service and total cost are our leading concerns.

Reliable service in the winter is lacking. Some workers aren't friendly on the phone. The rate structure isn't fair to those that put solar in.

Service is expensive. I spend between $150-$300 per month for power. Also, the service goes out several times a year sometimes taking days or weeks to fix. I live on the very outskirts of the service area and feel the least important for outage repairs.

Should not be getting power from Hydro Quebec, they should be getting renewable energy from Vermont renewable energy sources.

Additional Comments (continued)

So far, we've had good luck and will soon look into solar power and the options the co-op is offering.

Solar projects are not equitable to low income families and the cost of those projects are passed on to the low-income families through higher rates.

Some of my earlier answers about dependability was mostly based on one outage that took overnight to fix. Overall, I don't have any issues with the co-op.

Some questions are difficult to answer because I don’t believe we even have the option of obtaining power from a different company

Sometimes we do get notices that the power will be out. What concerns me is the more they involve in solar or renewable energy, it makes our rates go up. It is disturbing to me. We have to pay the difference between the renewable energy and the solar. It doesn't seem fair. I would like to know why that is.

Stop punishing those who have installed solar panels.

Thank you for the opportunity to make a comment. I lost power for over a week in the late fall of 2018, and continue to lose power, often. Trees had not been adequately cleared along power lines. This is an ongoing problem that seriously affects service. So much of our home’s heat, safety, water, ability to work, etc. depend on steady power. An aggressive tree cutting, line clearing project needs to be done in the WEC service area to vastly improve the service. We should not lose power just because of a little snow and wind. Clear the area around the electric poles 30 feet on each side. This is ridiculous. New Hampshire has done it, and they lose power far less than us and have the same weather.

Thanks for all the service you provide!

Thanks for everything!!!!!!

Thanks for this opportunity to comment. Overall, my wife and I find WEC to be an excellent utility. We are aware that the WEC staff and line workers face a daunting environment, given Vermont's unpredictable weather and harsh winters. We also find that WEC does an admirable job coping with outages and other problems. So, we are fundamentally pleased with service. Our one minor complaint is that WEC's pay-by-phone service is not very well designed and is somewhat laborious to use. We've switched to paying online, which works well and takes less time. Again, this issue is fairly minor but worth nothing. Keep up the good work!

That they've been providing really good service for over 30 years. I like them a lot. Keep up the good work.

That when we call and have a problem or a question, don't be treated like an idiot. The people answering the phone make you feel that you put them out to make them do their job.

The billing rate changed in September, not in members’ best interests, it could have been explained better. The overall bill hasn't gone down, it has gone up a few dollars. We use a generator for our whole house, but the service is pretty good for the most part.

Additional Comments (continued)

The electricity rates, storm surcharges, and out of pocket cost of our net meter for our solar panels which feed the WEC energy grid are absolutely ridiculous. Our main reason for installing solar panels was to offset the high rates charged by WEC for our power. Honestly, we are hoping to be able to afford to install battery backups to our solar panels so that when a power outage occurs (which commonly takes at the minimum hours and sometimes days to restore), we would still have power.

The energy coach is not very helpful, but very impressed with being able to get back online when everyone is out. I'm very happy with co-op.

The first thing is that they have the highest rates in the state, and I think they should be more competitive. Every time I call in, the employees are very nice, but they fall short on their programs. I am thinking about getting an electric car and the rate I'd pay with the co-op may sway me to not get it.

The increased per meter charge really hurts customers such as us because our barn has a separate service from our house, and during sugaring we have a third meter. We have minimal kw hour usage at the barn and sugarhouse but pay significant charges for those services due to the meter fees.

The newsletter is very beneficial.

The newsletter, Co-op Currents, is a very thinly veiled self-serving mouthpiece of the Board/Manager. It does not feel objective. It does not feel like news. I do not feel edified for having read it. It comes across as a ten-page advertisement for a utility that I did not choose. The format is always the same with feel good stories from the Manager and Board President. Why not print some critical letters to the editor? Why not print what people are saying both positively and negatively? Why not publicly talk about issues being wrestled with? The writing is fine and well-turned, but the subjects are softballs repeatedly lobbed at members. You can do better.

The only comment I have is, I have been living here for 6 years and never have I ever seen anyone check my meter! Every year it seems I get smacked with a huge bill and I don't get it! Do they come every month? If not, then I want them there every month.

The only thing I would like from WEC would be to know how widespread a power outage is when there is one, that is, when we call to let WEC know that our power is out, I would like an indication as to the expanse of the outage. I believe that we are sometimes told this, but not always. Living out "in the woods" where I can't see another house, I have no idea if others have no power, unless it's a storm and I obviously assume that that is the case.

The price seems to keep going, that would be the biggest complaint.

The prices are very high, and the power goes out frequently.

The rates are absolutely ridiculous. They lose customers to solar power and raise everyone's bill exponentially!! We went from $97 to $280!!!! No change in our usage. In the summer we peaked at $400. This is ridiculous. But we don't have another option for electric. If we did, we would change.

Additional Comments (continued)

The rates are high.

The rates are my main concern. Compared to Green Mountain Power, the rates are more than double per kWh. I am currently looking into alternatives than buying power from WEC because of this. My bills in Chitt's Den County with the same usage ran me no more than $120 per month, in all three of the homes I owned. Sell WEC so I can buy power from GMP!

The rates are too high. This is our second home and are too high compared to Green Mountain Power.

Their prices are way too high and people can't afford it, especially me. $400 a month is way too much money. We are looking into solar as your prices are too high.

Their service is very good.

There are several outages a year, which I guess is not unusual. We've found them to be very responsive and informative with their outages. We get what we expected. We enjoy working with the people during outages and they seem to be in good cooperation with the men in the field.

They are doing a great job.

They are doing a pretty good job. I've noticed they are making more of an effort to trim trees to help decrease outages.

They are doing a real good job keeping the lines clear so the power stays on.

They are doing a good job and we haven't had many outages.

They are the BEST. I cannot say enough how much I appreciate WEC and all they have done for me in the past and present. They are so kind, considerate, thoughtful and the customer service is over the top!! God Bless them all.

They are very nice people, but I don't know why they are wasting time on this.

They did a lot of cleaning out of trees and the lights have gone out. They don't check the trees until they fall.

They do a good job.

They do a lot of work with minimal amount of people. It's amazing how much work they get done.

They do very well, and when I pay my bill, they are very pleasant.

They have always been reliable and good in power outages.

They have been Johnny on the spot and very reliable.

They have been very reliable over the years. The newsletter helps me humanize.

Additional Comments (continued)

They need to do something to lower their rates, they are astronomical.

They should consider getting into the internet provider business.

They were really helpful when I had questions. Their customer service is good.

They're the finest bunch of folks I've done business with. They are extremely competent, and they care about their customers. I really appreciate them.

They've improved dramatically since we first moved here.

This power company is great, especially during a power outage.

This service is a camp which due to the outrageous customer charge I have suspended service for the winter.

This year I added solar panels to a new garage. The process to do so with WEC was great at times and awkward at other times. The panels are on an outbuilding and I want the credits to go first to power use at the house. But the "waterfall" process may not be hooked up that way now. Our house is only used about 5 months a year. The 12-month credit window for solar panel generation doesn't encourage owners to invest in solar panels as much as an ongoing credit would. I'm hopeful that the monies we invested will be worth it although helping to generate renewable energy as a good citizen surely is.

This year I have billing questions that have remained unanswered, promises of billing rectification not fulfilled. This has annoyed me. Up until this year, my only complaint has been the frequent power outages--not really your fault I know.

To me, from what I've seen from other places in Vermont, they seem to average a little higher in their rates than other places. It seems like there are a lot of power outages up here. It might not be for long, they're usually not longer than 3 hours. When we lose power, I have no heat and we had 4 or 5 power outages last winter and we already had 1 or 2 this fall.

To me, there is a difference between informing customers of energy trends and relaying the "green" narrative as if every customer has adopted it. I, for one, subscribe to energy conservation as good at several levels but not see why, WEC being an electric utility, that is the only message. As many of your customers, obviously living in very rural areas subject to power failures, admittedly mostly due to storms, we have had a whole-house generator since being here full time. I don't recall even seeing anything about this necessity for those of who work from our homes. Fossil fuels still have their place, especially in places like rural Vermont. This includes vehicles and having a mix of heating options. I did not realize being a customer of WEC meant we were whole heartedly supporting the Efficiency Vermont narrative.

Additional Comments (continued)

Usually, surveys are anonymous. You probably would get more information if you made yours anonymous. It really is not WEC's business a lot of the questions that were asked. Yet you did not choose to ask questions about your service. Like that, we are out of power more than any other service provider in the state, yet we pay the highest electric rates in the entire state. Our feedback is we would like less expensive electric service that works more reliably. Out rates have doubled in the 15 years we have lived in our home, yet the power goes out more often and for longer periods than it used to. Every time there is a storm, hundreds of people lose power. Prevention is key. Maybe implementing preventative measures would be key instead of asking me what type of dryer I have.

VERY expensive. Historically when we have outages, which are VERY frequent, it takes hours to days to get the problem fixed. Recently the outages have been much less frequent which is nice, but the costs increasing in what I would call an outrageous fashion is a challenge.

Very good service.

Very pleased with the co-op and especially interested in your efforts to secure rural broadband. Lack of that is one of the few negatives we have about moving here in 2016.

Washington Electric supplies electricity for my sugar house, not my house, and if I could change that they would supply my house.

We appreciated the help we received from Bill Powell as we explored the benefits of solar panels with a Tesla backup for our home. I also enjoyed his enthusiasm for what lies ahead for solar vehicles and the connection between electric cars and home supply and backup.

We are very interested in the high-speed internet program WEC is considering (Consolidated Comm. DSL is slow/inconsistent and there is no mobile signal available). It would also be awesome if WEC was able to provide the Tesla Wall (or similar) which would both help the grid and provide emergency power during an outage.

We get our electricity from you not for our primary residence but for our workshop. This workshop is just electricity for lights and plug in heater/fans. So, this survey information I tried to answer relevant to that shop, not our home.

We had an enormous spike in usage for one day, there was no explanation, and it was hundreds more than ever before, and felt as though we were never given any good feedback. I reached out to others in the community and found another resident who had to take out a small personal loan one month when hers was more than her mortgage and with no explanation. We were concerned about the "smart meters" and the issues that had happened in Maine and other places with them but were quickly shut down.

We have always been conservative in our electric use but now pay more to be "fair". Not fair to us though.

We have always been very satisfied with the company. We lived in an old farmhouse down below and lived in NY and we have had WEC for 40 plus years.

Additional Comments (continued)

We have an oxygen machine 24/7. The doctor's note was sent to them, but they didn't have any record of it months later when the power went out. There were several towns out and they were repairing everyone else first and I would think that a priority person would be put on first.

We have been consistently disappointed by the quality of the customer service. Some of the customer service/administrative employees are unpleasant to deal with and generally unhelpful. Please consider retraining or rehiring new, friendly staff.

We love the service and love that WEC is community-based and we can trust them. I just wish the rates weren't so high. I also wish WEC could support more home solar projects - I didn't indicate that "renewables" were a top concern for me, but in a sense they are. I just know that hydro, wind, etc., are not without problems and conservation is key more than source of energy. I do love the idea of WEC getting involved in high-speed internet, an idea being batted around now.

We tend to lose power quite a bit. I know that we live in Vermont and that the weather contributes to that. However, we tend to lose power more frequently than others in our community (right up the road, but a different power company). We are, in fact, looking into purchasing a generator as a backup plan.

We tend to lose power, even in better weather, but never seem to know the reason why - could be more informed. If there is a big weather event, it is widely discussed in the Co-op Currents. Perhaps the reason could be found by going onto the SmartHub, but I'm not sure. We live in VT so know that we are susceptible to bigger weather events and know the reason for no power.

We wish our bill could be lower sometimes because it's crazy sometimes. We don't really have a lot on it. We have a lot of new stuff. We used to have an electric fence. We don't have that anymore. Sometimes it's really high.

We would like more reliable service. My power goes out a lot.

We would love to have incentives for solar panels, batteries and electric car rebates. By the way...your question below re. gender should have the choice "Non-binary" not "Binary."

We're happy with them.

WEC did a great job early on in moving to renewable generation. But now it is resting on its laurels and not doing enough to meet the leadership challenges posed by climate change. It is focused only on staying inside its own small box, its service territory, without paying enough attention to what it takes to integrate higher levels of renewables, specifically solar, into the state and regional grids. It ignores its net metering members and their needs. Its leadership has increasingly consolidated control and made it difficult for the membership to get information outside the limited range of questions the co-op itself poses - this feels undemocratic to me.

Additional Comments (continued)

WEC has been VERY helpful and exceeded my expectations re responsiveness, speed of resolving problems (outages for example, or low hanging tree limbs on a wire). I especially rate '10' on WEC performance: -- on their excellent determined and persistent efforts at power restoration; -- the helpful recorded messages when I call in about a power outage; -- the very informative and useful text and graphical website data and updates during outages.

WEC has made some excellent improvements to our service in the last year or two. Ratings would have been lower before the improvements.

WEC needs to move into the 21st century and start supporting distributed generation instead of blaming net metering for all their revenue shortfalls and rate increases. Battery storage and use to offset peak load transmission is a good example of localized generation/use which WEC still has not grasped. Annual net metering generation in the WEC service territory now exceeds the actual annual generation of the Wrightsville Hydro plant due to the numerous flow restrictions at that plant. However, WEC still refuses to acknowledge localized solar as a viable source of reliable energy, probably less expensive than the continual operation, maintenance, permitting, and liability costs associated with Wrightsville. Also, I know WEC claims they are 100% renewable, but the NE grid is not. Most of WEC's "renewable" power is generated outside of their service area and I am certain that none of the power WEC generates reaches my home. I get my power directly from a GMP distribution line, so not all the power WEC supplies to their members comes from 100% renewable sources. Also, I question the wisdom of owning a $50 million landfill gas energy plant in the NEK on a grid that is restricted. Seems like a lot of liability for a small co-op!

WEC rates have consistently gone up over the last five or so years. When you need more money, you apply to the state for a rate increase. You always get these increases. I am not sure exactly how many you have gotten over the last few years. I think it must be at least three. I understand you have increasing costs of doing business. So, you have two options, get more revenue or cut costs. It seems from what I have seen that you only do the former never the latter. I have never once heard one single word from WEC about what you do to keep costs down. Since labor is likely your biggest expense, I wonder: Have you ever frozen wages? Have you ever laid folks off? Have you ever done an analysis of your workforce needs? Most places can't just raise rates every time they need more money. There would be market consequences. For WEC there are no consequences as there is no competition. You have a complete monopoly. I must buy my electric from you. Where I work, wages are more or less stagnant and have been for years. Is that the case for WEC? Somehow, I doubt it. How about the next time you need more money, you cut costs before you raise the rates? That would be a refreshing change. I'd also love to see in your newspaper or on the website a comparison of WEC rates to those of other electric providers in the state and likewise a comparison of your wages to comparators. Finally, I'd like to see you shift your obsession from electric cars and devote a lot more energy to getting into the high-speed internet business. String fiber on your poles and offer me high speed internet.

Additional Comments (continued)

WEC should phase out Hydro Quebec power. As I understand it, this power source is not considered renewable in any other Northeastern state. WEC should change its "renewable power" goal to "green power". Much renewable power, such as Hydro Quebec, is not environmentally or socially sustainable, as it contributes methane gas to the atmosphere and floods aboriginal lands, making them unusable to wildlife and inhabitants. Calling garbage methane renewable clearly demonstrates why the term "renewable" has no relevance to helping the environment, since it's only renewable based on a non-sustainable practice of our society consuming non-recyclable materials and needing to dump poisoned soil and poisoned sewage waste. However, burning garbage methane could possibly be considered "green power" since it prevents a greenhouse gas from polluting, though making dumps look better is an environmental downside. WEC should increase support for business and home solar power to reduce reliance on Hydro Quebec. WEC should support business and home battery installations to improve the reliability of the WEC system.

WEC was formed because it was not profitable for investor owned utilities to set the poles and string the wires to rural Vermont. Today, the internet is a necessity, and again rural residents are outside of the profitability formula used by for-profit providers. WEC should be stepping up to support its members' needs. I am a proud member on the electric front but have higher expectations for how the co-op should (have) evolve(d) to address the needs of its members.

When I go there to pay my bill, they are very nice there. When I have a problem, they are very helpful.

When I have a question and I call, someone always gets back to me with lots of information and support. We are grateful for that! Really like the outage map ~ VERY helpful!

When I need them, they are there.

When it comes to a utility, they are the best that I have ever had and I'm glad they are looking at it.

When many other neighbors have power outages, we do not. They are very rare compared to many of my friends.

When they switched the billing, it costs more. It used to be billed every six months and since they moved to every month so now it's one and a half times the cost. It's upsetting.

While I VERY MUCH appreciate WEC's commitment to renewable energy, I feel your electric rates don't reflect the use of renewable energy. As well it's really too bad that your incentives either for moving to more electric or for having already moved don't match or exceed those of Green Mountain Power. Regarding the possibility of changing the high peak hours, I will always use low peak hours. It would be great if you considered some morning and early evening low peak hours.

Wickedly expensive, power goes out often, poor customer service. "Baseline" rate when we are not at the house is outrageous. Thank God we have a generator. One of the most expensive (per KwH) in the US.

With the solar panels and other energy ways WEC stated would save money on our bill, it was all wrong, our power bill is insane.

Additional Comments (continued)

Would like more information about solar and giving back to the grid. At one point my electricity went way up and I was able to talk to an employee about it to help me target the problem - I appreciated that a lot and he was very helpful.

Would like to see improved outage information available on iPhone.

Would love to know why they won't help us more to understand why our bill fluctuates TONS from month to month with no known change in our power usage routine!!!!!!!!! No one there has ever seemed forthcoming in their efforts!! Guess it doesn't matter to them as long as it's not THEIR wallet it comes from! No, we don't need help from the co-op with this issue any longer. We'll seek outside support so we are not cheated or otherwise!

Yes, to broadband.

You guys are doing a pretty good job. During the winter it can be hard to keep trees and other items off the lines, and you are fairly quick at addressing these issues.

You heard what I said about the service and the linemen, we get along really great. The other department will put cones down and leave and we stay by their side we don't leave them. The fire department is the Corinth Volunteer Fire Department.

You should come out when dig safe calls. Not ideal to dig without knowing.

You're the best!!!

Your rates are high, don’t see any information on battery backup availability for power outages from Washington Electric. Don’t like surcharges.

Your rates are outrageous. Since you put in your smart meter, my power bill almost doubled. If I had a choice, I would not use you as your rates are higher than any other company around. However, your staff in the office is friendly and helpful with regular billing questions.

Your work crew who cut the trees away from the power lines, those guys need to be trained not to cut down the 100-year-old apple trees in the community. I hate you guys because of how incompetent those guys are. They cut down these 100-year-old apple trees in the downtown community. I could shoot you for it. That's hurting the community and that's hurting wildlife.

APPENDIX B: Questionnaire

2020 Washington Electric Cooperative
RESIDENTIAL MEMBER SATISFACTION SURVEY

ACSI Questions in Blue
Draft 17 November 2020

INTRODUCTION:
May I please speak with the head of household who has or shares responsibility for the electric utility bills? Hello, my name is ____________ and I am calling on behalf of Washington Electric Cooperative, which has commissioned XXXXXXXX, an independent research service**,** to conduct a confidential survey with Washington Electric Cooperative members. Your household was chosen at random to participate in this survey. *[If hesitant, please offer the following option.] If you would like to first verify the legitimacy of this survey with Washington Electric Cooperative (Phone xxx-xxx-xxxx), I would be happy to schedule a convenient time to call you back.* Our survey will take about 8 minutes. May I continue now?

[ ] Yes … ***Continue*** [ ] No … When would be a more convenient time for me to call back?
Date to call: ____________ Time to call: _____________ (ET)

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1. How long have you received your electric service from Washington Electric Cooperative? Has it been … *[Read]*
   [ ]1 Less than 1 year [ ]3 3 to 7 years [ ]5 11 to 20 years
   [ ]2 1 to 2 years [ ]4 8 to 10 years [ ]6 Over 20 years [ ]8 Don't Know/Refused

ACSI Questions

2. Using a 10-point scale where 1 is "very dissatisfied" and 10 is "very satisfied," how satisfied overall would you say you are with Washington Electric Cooperative?
   Very Dissatisfied 1 2 3 4 5 6 7 8 9 10 Very Satisfied

3. Considering all of your expectations, to what extent has Washington Electric Cooperative fallen short or exceeded your expectations? Please use a 10-point scale where 1 means "falls short of your expectations" and 10 means "exceeds your expectations."
   Falls short 1 2 3 4 5 6 7 8 9 10 Exceeds expectations

4. Now, I'd like you to imagine an ideal utility company. [***Pause***] How well do you think Washington Electric Cooperative compares with that ideal utility company? Use a 10-point scale where 1 means "not very close to your ideal" and 10 means "very close to your ideal."
   Not close 1 2 3 4 5 6 7 8 9 10 Very close to ideal

5. Assume for a moment that you could choose your electric service provider from among more than one utility. Using a 10-point scale where 1 means "very unlikely" and 10 means "very likely," how likely would you be to choose Washington Electric Cooperative?
   Very unlikely 1 2 3 4 5 6 7 8 9 10 Very likely

Performance Attributes

6. Please tell me how important each of the following aspects of Washington Electric Cooperative's service is to you. Use a 10-point scale where 1 means it is "not at all important" and 10 means it is "extremely important." How important is … *[RANDOMIZE]*

		Not at all Important		Extremely Important	DK
a.	Handling individual complaints and problems	1	....	10	11
b.	Being friendly and courteous in the service they provide	1	....	10	11
c.	Having competent and knowledgeable employees	1	....	10	11
d.	Looking out for your best interests	1	....	10	11
e.	Being committed to the community	1	....	10	11
f.	Providing a good value for the money you spend	1	....	10	11
g.	Providing reliable service	1	....	10	11
h.	Helping you learn to manage your energy use	1	....	10	11
i.	Communicating with you and keeping you informed	1	....	10	11

7. Now, for the same attributes please tell me how well you think Washington Electric Cooperative is performing to meet your expectations. Please use a 10-point scale where 1 means they are "performing far below your expectations" and 10 means they are "performing far above expectations." How is Washington Electric Cooperative performing on … *[RANDOMIZE]*

	On …	Far Below Expectations		Far Above Expectations	DK
j.	Handling individual complaints and problems	1	....	10	11
k.	Being friendly and courteous in the service they provide	1	....	10	11
l.	Having competent and knowledgeable employees	1	....	10	11
m.	Looking out for your best interests	1	....	10	11
n.	Being committed to the community	1	....	10	11
o.	Providing a good value for the money you spend	1	....	10	11
p.	Providing reliable service	1	....	10	11
q.	Helping you learn to manage your energy use	1	....	10	11
r.	Communicating with you and keeping you informed	1	....	10	11

Cooperative Commitment

8. WEC is a cooperative, organized as a not-for-profit corporation. How important to you is being a member of a non-profit electric co-op? Again use a scale of 1 to 10 where 1 means it is "not at all important" and 10 means it is "extremely important."

    [RECORD RATING 1 - 10]: ____
    11 Don't know
    12 Refused

9. Do you view yourself as a member/owner or as a customer of your electric cooperative, or both?

    [ ]1 Member/owner [ ]2 Customer [ ]3 Both [ ]4 Don't Know / Refused

Renewable Energy

10. You may be aware that Washington Electric Co-op provides their customers with electricity from renewable sources. Again using a scale of 1 to 10 where 1 means it is "not at all important" and 10 means it is "extremely important," how important is it to you to have Washington Electric Co-op provide you with renewable energy sources?

    [RECORD RATING 1 - 10]: ____
    11 Don't know
    12 Refused

Programs and Services

11. If a time-of-day rate program were available from Washington Electric Cooperative, where you could potentially save energy costs by shifting your energy use from a higher daytime peak use rate to a lower evening off-peak rate, how likely would you be to use it? Would you…

[ ] Definitely use it [ ] Probably use it [ ] May or may not use it [ ] Probably not use it, or [ ] Definitely not use it

12. WEC provides all members with online access to their electric usage, and access to payment options, and notifications for outages and restoration. This online access is called SmartHub. Were you aware of SmartHub? (If yes,) have you used SmartHub? Do you use the smarthub mobile app?

    [ ] Have Used SmartHub [ ] Aware of SmartHub but Have Not Used [ ] Unaware

Communication

13. Are you aware that each month, Washington Electric Cooperative sends a monthly newsletter called "Co-op Currents" to your home? [ ] Yes [ ] No [ ] Don't Know

14. ***(If Q13 = YES)*** How often do you read "Co-op Currents"? Would you say you read it regularly, fairly often, not often, or do you never read it?

    [ ] Regularly read [ ] Fairly often [ ] Not Often [ ] Never [ ] Don't Know

Demographics – *The next few questions are for classification purposes only.*

15. Into which category does your age fall? ***[Read list]***

    ☐ 18 to 34 ☐ 45 to 54 ☐ 65 or older
    ☐ 35 to 44 ☐ 55 to 64 ☐ Refused

16. Which of the following is the best description of your home?

    ☐ Single-family home ☐ Apartment, duplex, townhouse, or condominium ☐ Something else
    ☐ Mobile home or trailer ☐ Pre-fabricated or modular home ☐ Refused

17. Washington Electric Cooperative would like to know if you have the following in your residence (read each)

    a. Electric water heater [ ] Yes [ ] No [ ] Don't Know
    b. Heat pump water heater
    c. Electric clothes dryer [ ] Yes [ ] No [ ] Don't Know
    d. Central air conditioner [ ] Yes [ ] No [ ] Don't Know
    e. Window or room air conditioner [ ] Yes [ ] No [ ] Don't Know
    f. Dehumidifier [ ] Yes [ ] No [ ] Don't Know
    g. Swimming pool [ ] Yes [ ] No [ ] Don't Know
    h. Hot tub/Jacuzzi [ ] Yes [ ] No [ ] Don't Know
    i. Baseboard electric space heater(s) [ ] Yes [ ] No [ ] Don't Know
    j. Portable electric space heater(s) [ ] Yes [ ] No [ ] Don't Know
    k. heat pump for heating/cooling [ ] Yes [ ] No [ ] Don't Know
    l. Electric vehicle [ ] Yes [ ] No [ ] Don't Know

18. How many people currently live in your residence?
[ ] 1 [ ] 2 [ ] 3 [ ] 4 [ ] 5 [ ] More than 5

19. Do you own or rent your home? [ ] Own [ ] Rent

20. Gender of respondent: ***[Do not ask]*** [ ] Male [ ] Female

Additional Comments you would like to make about Washington Electric Cooperative: ____________________
____

Thank you so much for your participation. Have a wonderful evening.

Respondent's First Name (for verification purposes): ____________________________________

Telephone Number: ____

Extreme Weather and Climate Change in Vermont: Implications for the Electric Grid

November 1, 2021

For: Vermont Electric Power Company

Prepared by: Northview Weather LLC

Contact: Dr. Jay Shafer - jason.shafer@northviewweather.com

Executive Summary

This report describes how climate change may present itself through the behavior of weather systems and climate states and how these changes may affect the reliable operation of Vermont's electric grid through 2049. High confidence results show that Vermont's climate is warming and becoming wetter, both of which will likely continue to increase into the future. Warmer and wetter storm systems will generally produce storms that are more intense (not necessarily more frequent) and cause more power outage disruptions to the distribution system. Seasonal changes to the warm season show a widening of the summer into early fall, which is expected to continue. This warm season widening will have the effect of lengthening the fall storm season into early winter (over 50% of all power outage impacts occur October to December). Despite a warming climate, the winter season will remain cold enough to sustain wet snow and ice risks through 2049. Overall weather-produced distribution system outage impacts are expected to increase by approximately 5% through 2049.

Heavy precipitation events are expected to continue to increase around twice as fast as annual precipitation. A higher frequency of heavy precipitation events may result in greater widespread flooding risks, especially during the fall season. More irregular precipitation patterns are also likely, potentially leading to more intense drought conditions. However, vegetation health and growth analysis show no clear or strong indications as to how temperature and precipitation changes may affect future tree health and growth.

The transmission system may be affected by more intense storm systems, in particular from wind storms related to inland tracking tropical storms/hurricanes, whose potential intensity will be stronger in a warmer climate. Increased long-duration heat waves will tend to shift annual peak loads to summertime. There did not appear to be significant changes to seasonal or annual solar energy variability.

Extreme weather has the potential to expose gaps or limitations in design standards. The most extreme weather impacts on design standards are from high wind events from late summer through fall when tropical storms or hurricanes can make New England landfall and/or combine with midlatitude storm systems to produce powerful storms (e.g., Superstorm Sandy). Atlantic Ocean temperatures are warming with climate change; ocean temperatures are one of the critical indicators for peak storm intensity. Warmer ocean temperatures will allow for tropical storm systems to produce higher winds and maintain their storm strength longer at higher latitudes.

The results described in this report are consistent with other published literature and provide deeper insights into how resilience investments may improve future reliability with climate change pressures across Vermont.

1. Introduction

It has been well documented that Earth's climate system is undergoing its most dramatic change in several million years in response to man-made greenhouse gas emissions. Carbon dioxide concentrations are now 418 ppm (Keeling and Tans, 2021), which are the highest in at least 3 million years (Rae et al, 2021). The pace of climate change may seem slow to human memory, but significant heat energy is currently accumulating in the oceans and the atmosphere, and the long residence time of atmospheric carbon dioxide ensures that responses to climate change will continue for generations even with dramatic actions to reduce greenhouse gas emissions today. A critical target to reducing the global risks to climate change is to keep global warming at or below 1.5°C; this target requires global carbon dioxide emissions to be at zero around 2050 (IPCC 2018). Regardless of the collective global actions of emissions reductions, the impacts from global climate change on Vermont's electric grid through 2049 will likely not be mitigated; in other words, it is prudent to take local action and plan based on current trends and higher-end projections.

It has been well documented that risks related to climate change are increasing pressures on the safe and reliable operations of the electric grid (e.g., Pantelli and Mancarella 2015). Weather variability is the largest single contributing factor to the day-to-day safe and reliable operation of the electric grid. Weather-sensitive applications may include load management for predicting electricity demand, storm planning and response for power outages, and renewable energy (solar, wind, hydro) management. This report quantifies extreme weather risks related to power outages examining various weather hazards (wind, snow, and ice). Both climate variability (long-term base states such as annual precipitation), and extreme weather variability (individual storm behavior) are described. It has been said that weather plays on the climate stage, which is to say that changing climate base states tend to stack the cards or change the percentages of how extreme weather states may occur. For example, increased average annual precipitation is associated with an even higher frequency of extreme precipitation events. Vermont's hazard mitigation plan has identified water and related flooding as the greatest risk to statewide infrastructure (Vermont Emergency Management 2018); by contrast wind storms pose the most significant risk to electric grid operations.

The relationship between climate indicators and vegetation growth and health is also generally described. Seasonal variability of temperature and precipitation is a significant factor affecting tree health and growth (VanHoutven et al. 2019). Longer growing seasons associated with seasonal warming may yield higher growth rates if soil moisture conditions remain adequate for sustained growth. However, more irregular precipitation patterns may potentially constrain seasonal growth and stress tree health. There appears to be significant uncertainty around species change and migration (e.g., Wang et al. 2016) across the Northeast US, with any tree species makeup changes being relatively nominal through 2049.

The purpose of this report is to understand the potential risks from climate change to the safe and reliable operations of the electric grid. As electrification accelerates, understanding these changes and their potential risks are critical for identifying future investments needed to maintain reliability. Results from this report should be used to inform decisions that may be necessary to maintain electric grid reliability with the pressures of climate change.

2. Data and Methods

a) Historic dataset and downscaling

The ECMWF Reanalysis 5 (ERA5) dataset was utilized in conjunction with a downscaled version to examine extreme weather and climatic trends from 1980-2019. The ERA5 reanalysis dataset uses the European Integrated Forecast System, more commonly the European/Euro weather model, to rerun known observations as input and is considered best in class. The native resolution of the ERA5 is 30-km; a downscaled version was created at a resolution of 5km using the Weather Research and Forecasting (WRF) model version 4.1 (Skamarock et al., 2019). WRF is a state-of-the-art computational fluid dynamics model used by national meteorological centers, private industry, and academia around the world to produce weather forecasts and climate simulations. The model is open-source and maintained by the National Center for Atmospheric Research (NCAR), Air Force Weather Agency, National Centers for Environmental Prediction, and the meteorological community. Downscaled versions were shown to improve performance resolving extreme wind events, as well as deriving the precipitation phase (wet snow and freezing rain).

b) Climate Projections Modeling

Climate simulations span the period covering 1980 through 2049, with historic baseline from 1980 to 2019 and the climate simulations starting in 2020 and ending in 2049. Projections are compared against the 1980-2019 baseline period, to determine the changes in frequency and magnitude of extreme weather events and seasonal climatic changes.

The projections use the WRF to downscale the Community Earth System Model version 1 (CESM). The CESM is a global climate model run by NCAR for the various Representative Concentration Pathways (RCP) scenarios. This work examined two climate scenarios representative concentration pathways from RCP8.5 (business as usual) and RCP4.5 (moderate emission curtailment) scenarios as initial conditions. NCAR has bias corrected the CESM1 output using the ERA-Interim dataset (the precursor to the ERA5). The native resolution of the CESM data is 1.0 degree and is downscaled to 5km on an hourly basis for this work.

i) Domain Setup and Runtime Settings

The WRF domains used a parent domain of 25-km and a single nest of 5-km as described in Figure 1.

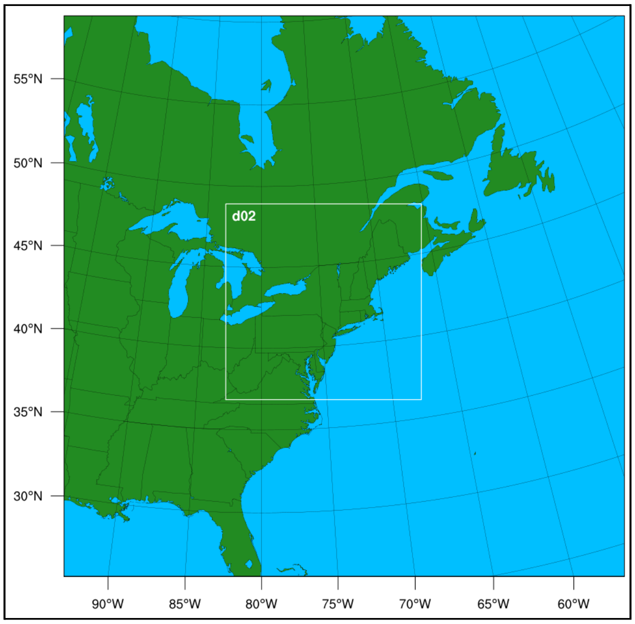

Figure 1. Regional climate model domain setup. The domains are a 25-5-km two-way nested setup. The 25-km domain matches the map boundary, while the 5-km domain is represented by the white bounding box.

ii) Model physics and dynamics options

The following model physics options were selected as shown in Table 1.

Physical Process	Physics Option Selected
Land Surface	Noah LSM (Tewari et al. 2004)
Surface Layer Physics	MM5 (Jimenez et al. 2012)
Planetary Boundary Layer	ACM2 (Pleim et al. 2007)
Cloud Microphysics	Thompson (Thompson et al. 2008)
Cumulus Parameterization	Kain Fritsch (Kain 2004)
Longwave Radiation	RRTM (Mlawer et al. 1997)
Shortwave Radiation	Dudhia (Dudhia 1989)

Table 1. WRF model physics options used for downscaling.

In the WRF model configuration particular attention was given to the choice of planetary boundary layer and cloud microphysics for their impact on wind speed and precipitation forecasting, respectively. The ACM2 planetary boundary layer scheme and MM5 surface layer scheme were selected based on work by Siuta et al. (2017), who found this scheme to have the highest accuracy of a number of schemes tested over complex terrain. For the cloud microphysics, the Thompson scheme was chosen for its superior fit to precipitation observations, notably in the wintertime when precipitation falls as snow (Thompson 2013; Lui et al, 2011). Settings for the Longwave Radiation, Shortwave Radiation, Noah LSM, and Cumulus Parameterization use the standard defaults for the WRF model.

Simulations were run a year at a time, starting at the beginning of fall (September 1). This allows the WRF model to adequately spin up its own snowpack/land cover/soil characteristics through the winter/spring months using the Noah land surface model physics. Throughout, the adaptive time stepping option was used to maximize numerical stability and runtime performance (speed of simulation). The process described in Bruyere et al. (2015) is followed with regards to the sea surface update settings.

iii) **Climate Simulation Limitations**

Climate simulations were limited to two high resolution simulations given project budget and the high computing costs. These two simulations were able to capture general climatic or base-state annual and seasonal changes for multiple variables (temperature, precipitation, solar radiation, wet snow, ice, and gradient winds). However, there were limitations with resolving extreme events. This under-sampling of extreme events was most apparent with gradient wind events, which showed approximately 20% fewer high wind events than the historic baseline (Figure 2). Poor representation of discrete extreme storm events with downscaled climate simulations is a known challenge (e.g., Seneviratne et al. 2012). In the simulations presented within this work mid latitude storm systems don’t produce adequately strong storm systems and associated pressure gradients resulting in fewer high wind events. In contrast, however, precipitation variables did not feature the same underprediction.

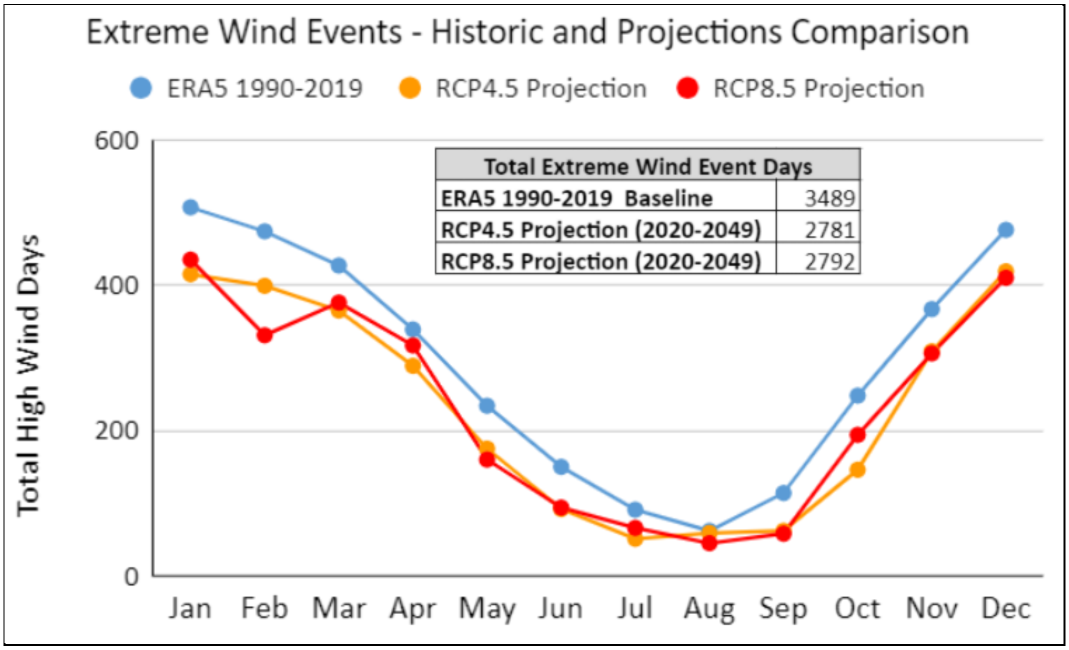

Figure 2. Gradient wind frequency for historic baseline (1990-2019) and climate simulations.

iv) Trend Analysis and Hazard Climatology

The ERA5 30km dataset was used for most of the historical references of precipitation with the exception of wind gusts and aggregated rasters which used the downscaled ERA5 5km dataset. For the trends analysis hourly ERA5 rasters would be averaged (or the max or min would be found) to derive the daily summation. A spatial average would be composed upon a particular area (such as Vermont) which in turn would average all the grid boxes in the area of interest; as long as the outline of the area was in a grid box that grid box would be included. A daily time series was developed from these daily spatial averages in order to produce the trend analysis. The daily rasters were used once again to produce a hazard climatology. A threshold was chosen for each raster and they were added together to get a raster of frequencies for a time period.

v) Historical Outage Reconstruction and Deep Learning Model

Historical power outage data on the distribution system was provided by Vermont Electric Cooperative (VEC) and Green Mountain Power (GMP) to develop a statewide aggregate. The overlapping data period extended from 2011 to 2019. Outage events and duration (in hours) were aggregated on a daily basis. Root cause was provided by VEC and GMP, but it was difficult to isolate weather-caused outages vs non-weather events based on inconsistent reporting. In order to reconstruct historic outages, a deep learning model was developed using the 20 variables described in Table 2. Most weather variables were from the ERA5 30km, except for 24 hour peak wind gusts which were from the 5km downscaled ERA5.

Incorporation of 48 hour precipitation accumulation allowed weather events of longer duration to be captured. The deep learning model featured a mean absolute error of approximately 24 power outages a day (for reference the daily average number of events was 36).

Variable//Feature	24 Hour Duration	48 Hour Duration
Month	-	-
Day of Year	-	-
Precipitation	X	X
Rain	X	X
Ice Thickness	X	X
Snow	X	X
Wet Snow	X	X
Temperature	X	-
Dew Point	X	-
Mean Sea Level Pressure	X	-
Soil Moisture level 1 (0 - 7cm)	X	-
Soil Moisture level 2 (7 - 28cm)	X	-
Wind Gust	X	-
Leaf Area Index	X	-
Wind Directions (NW,W,NE...)	X	-

Table 2. Variables (features) used to create historic outage data using a deep learning model.

Two deep learning models that were created; one using outage events and another using outage duration. Outage events and outage duration or label data (what is being solved for) were aggregated on a daily basis and therefore could be matched to the variables/features in Table 2. The data was then split into 80% training data and 20% test data. Both training and test datasets were standardized so the model would converge on a solution quicker during training. The training model had 3 layers with 64,32 and 1 neuron(s). The historical feature data covering the 1980-2019 time period was then inputted into the newly created model.

3. Climatic Trends

a) Temperature

i) Annual Temperature

Temperatures are steadily increasing. The average annual temperature aggregated across Vermont from 1980-2019 was 44.8°F (Figure 3). The maximum annual temperature during this period was 47.7°F and the minimum was 43.1°F. The annual trend has been positive with a 1980-1999 average temperature of 44.4°F and a 2000-2019 average temperature of 45.2°F therefore making a difference of +0.8°F between time periods. This warming is consistent with regional and global warming (USGCRP 2018).

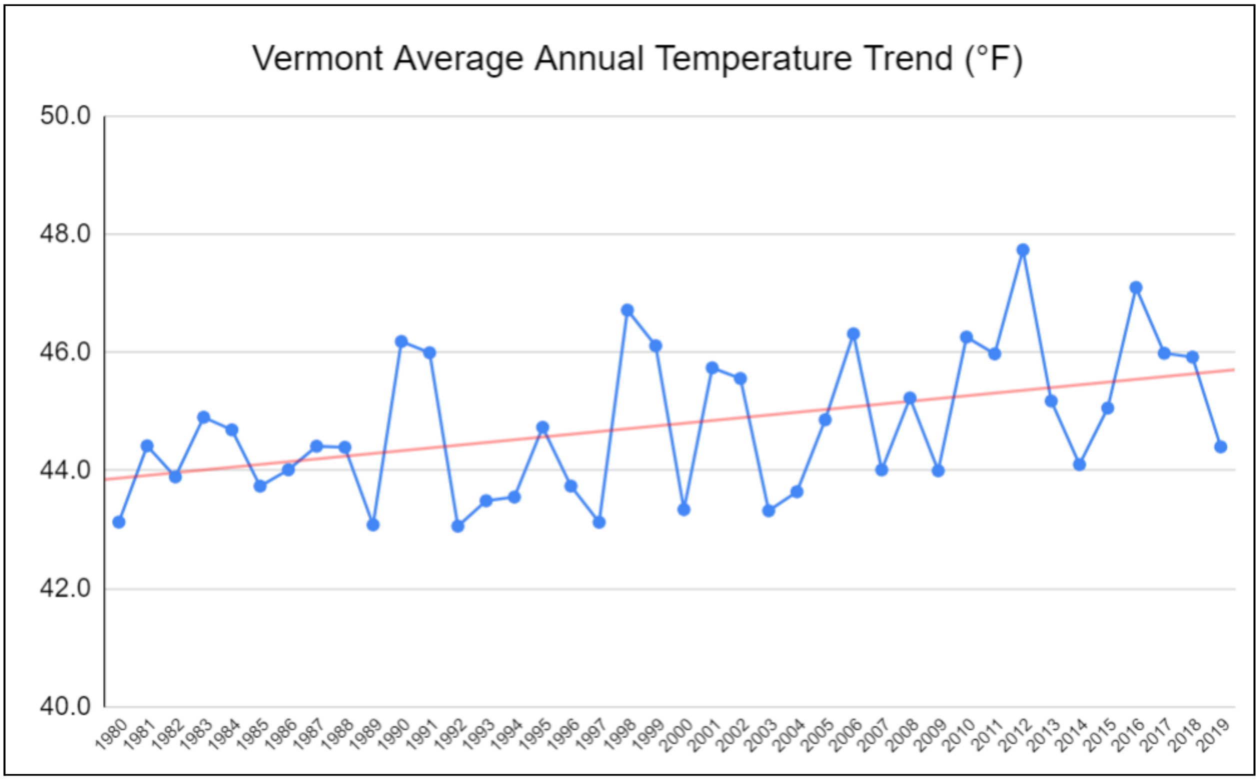

Figure 3. Vermont annual temperature trend from 1980-2019.

ii) Seasonal Temperature

Seasonal temperature changes are not equally distributed across all seasons. Spring and fall temperatures exhibit average temperatures that are near the range of the average annual temperatures with 47.5°F in the fall and 43.2°F in the spring. Summer has an average temperature of 66.6°F and winter has an average temperature of 21.8°F. All seasons show warming as seen in Figure 4. The strongest seasonal warming occurs in the fall with a temperature change of +1.5°F between 1980-1999 and 2000-2019. This warming trend appears to be associated with an elongation of the warm season into the fall season, with the months of August, September and October having the strongest warming signals (not shown).

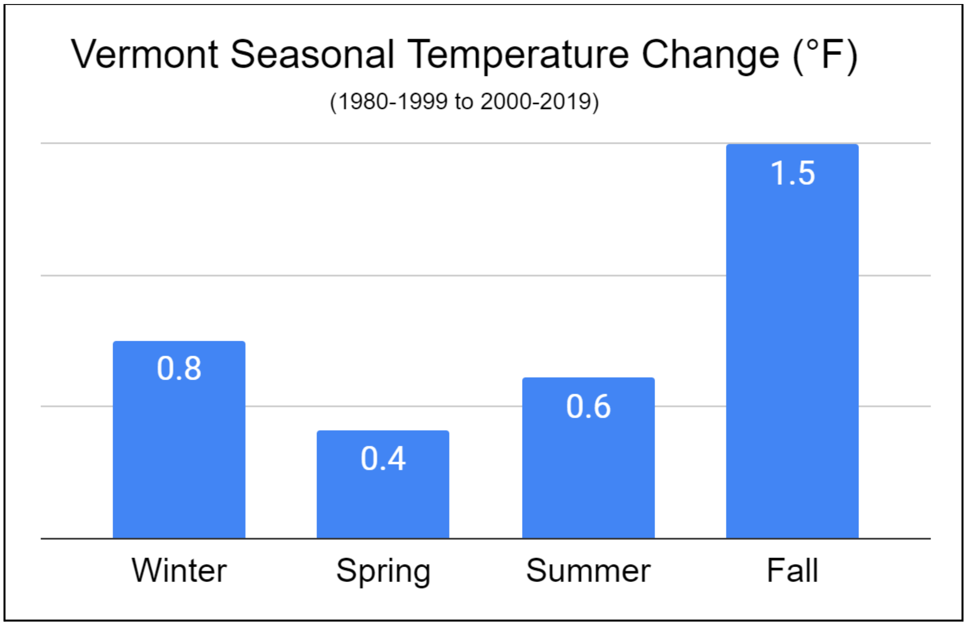

Figure 4. Vermont temperature change (°F) for each season between 1980-1999 and 2000-2019. Winter is Dec, Jan, Feb, Spring: Mar, Apr, May, Summer: Jun, Jul, Aug, Fall: Sep, Oct, Nov.

iii) Growing Degree Days

Warmer temperatures produce a longer growing season, at least as measured by growing degree days. Growing degree days are a measure of the accumulated heat energy and can be used to reference a variety of plant and tree species growth potential. There has been a steady increase in growing degree days from 1980 to 2019 (Figure 5). The average annual growing degree days from 1980-1999 was 1446 days while the average annual growing degree days from 2000-2019 was 1591 days, resulting in a +10.1% increase in growing degree days. The majority of this increase is due to a lengthening of the growing season in the late summer and early fall; not all plant and tree species may be able to realize this seasonal extension, as many tree species put up much of their seasonal growth in the first part of the growing season. Spring was shown to be a less reliable season despite a general earlier arrival of the growing season with colder temperatures being equally likely to linger or return after the first spring warm up.

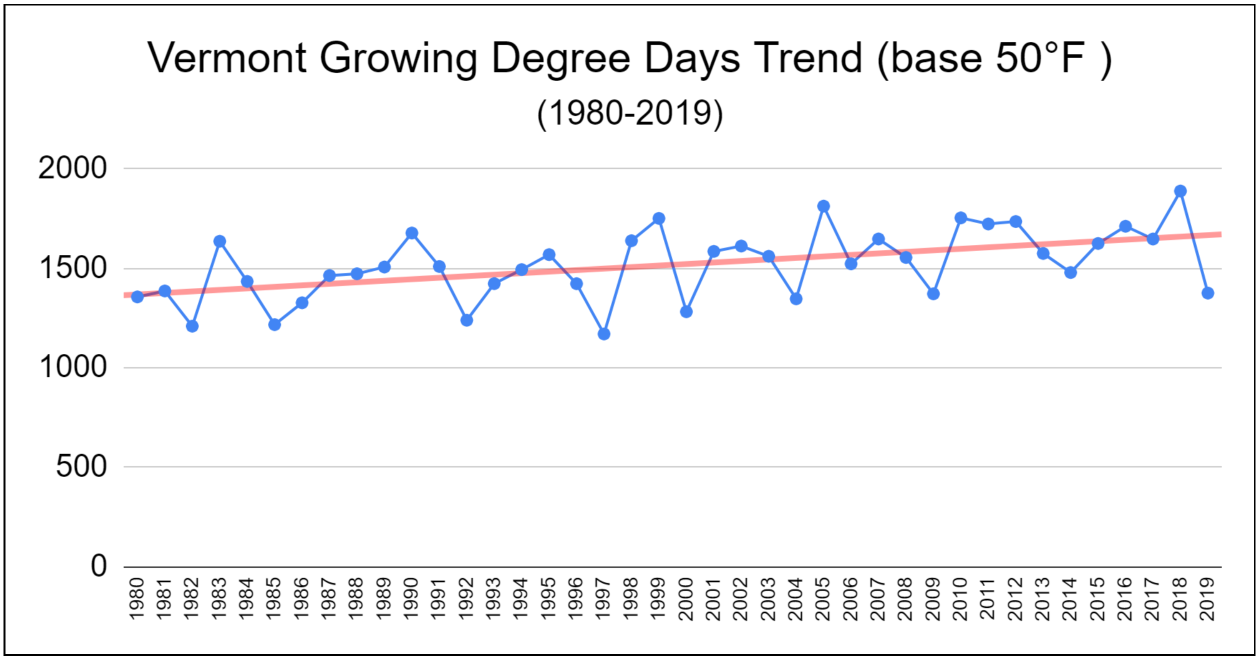

Figure 5. Vermont growing degree days trend with a base of 50°F for calculating growing degree days.

iv) Extreme Temperature Climatology and Trends - Heat

The spatial distribution of where temperatures reach above 80°F varies based on location and elevation (Figure 6). High elevations, locations near Lake Champlain, and northeasternmost Vermont have the lowest frequency of heat days while the deeper Champlain and Connecticut River Valleys experience the most. The warmest locations average approximately 35 days a calendar year above 80°F. Trends in heat days show an overall increase statewide, with the least number of increases at the highest elevations where temperatures remain below the 80°F threshold. However, the more rapid increases as percent show that middle elevations such as the Northeast Kingdom and Green Mountains are seeing more rapid warming as temperatures warm with elevation (Figure 7).

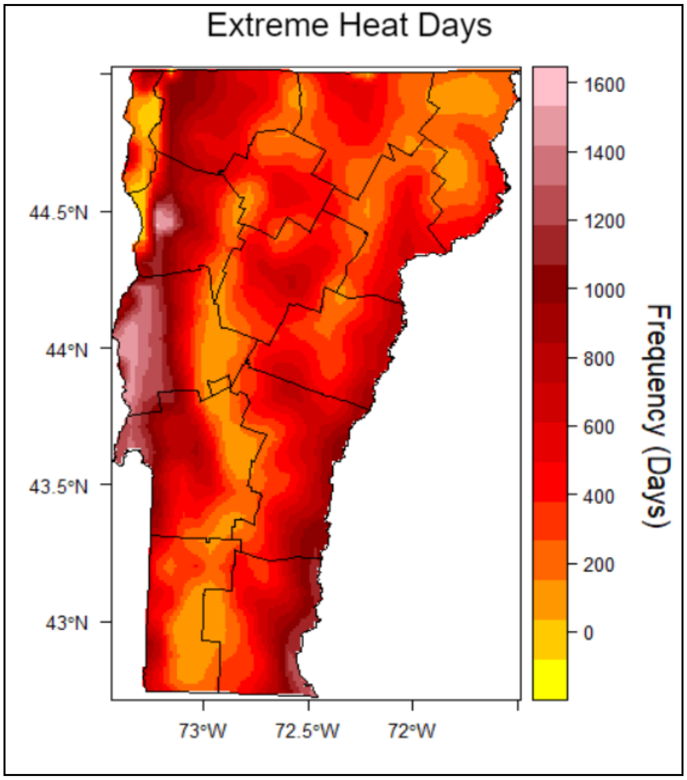

Figure 6. Extreme heat days as defined with a high temperature above 80°F in a 24 hour period per grid box during 1980-2019.

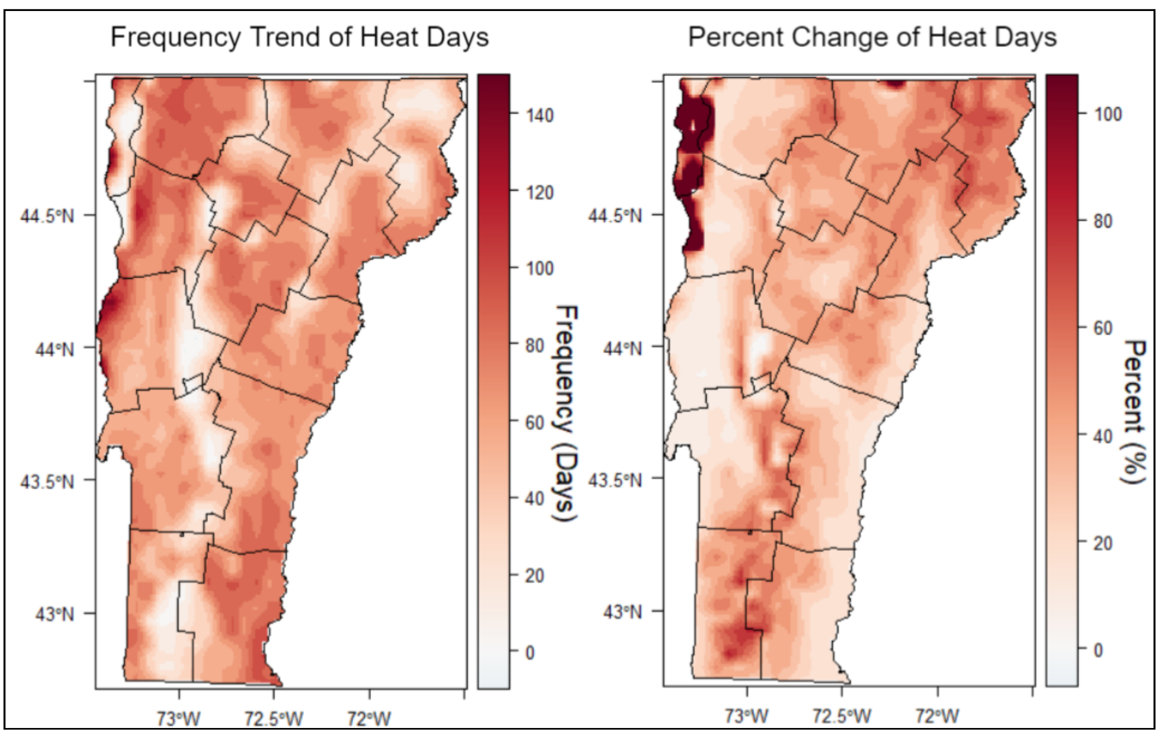

Figure 7. Extreme heat days (high temperature reached 80°F) frequency change from 1980-1999 to 2000-2019 (left) and percent change (right). Data based on downscaled ERA5 5km data.

11

v) Extreme Cold Temperature Climatology

Northeastern Vermont has the greatest amount of extreme cold days while locations near Lake Champlain have the least (Figure 8). The coldest locations approach 30-40 days a season with a low temperature at or below 0°F, whereas the warmest locations average closer to 10 days a winter.   As elevation increases, the amount of extreme cold days generally increases as well.

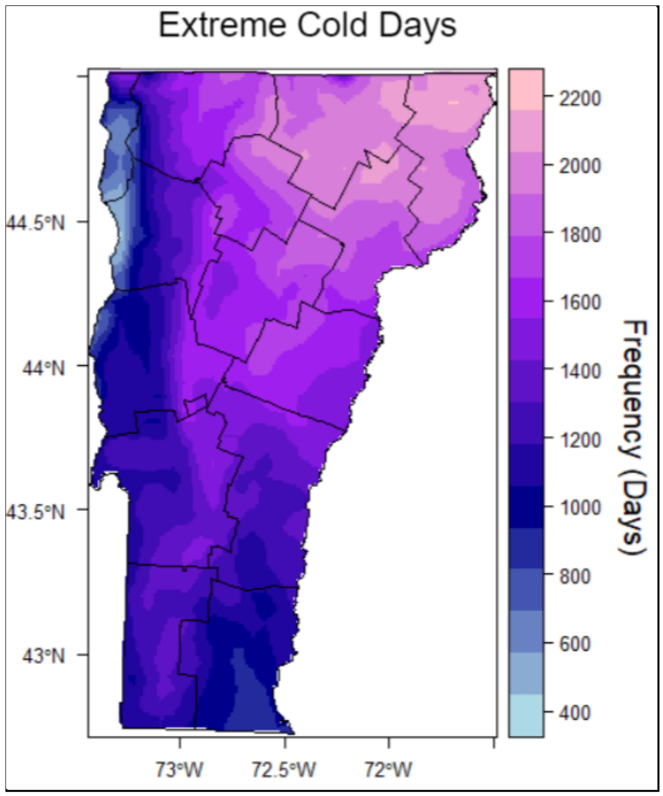

Figure 8. Extreme cold days as defined with a high temperature at or below 0°F in a 24 hour period from 1980-2019.

vi) Extreme Temperature Climatology and Trends - Cold

Extreme cold days have been decreasing throughout Vermont with about 1 to 3 fewer cold days a winter season as the 20-year trend (Figure 9). Northwestern Vermont has experienced the greatest decrease in extreme cold days as well as the greatest percentage decrease with relatively uniform spatial variability in other locations (Figure 9).

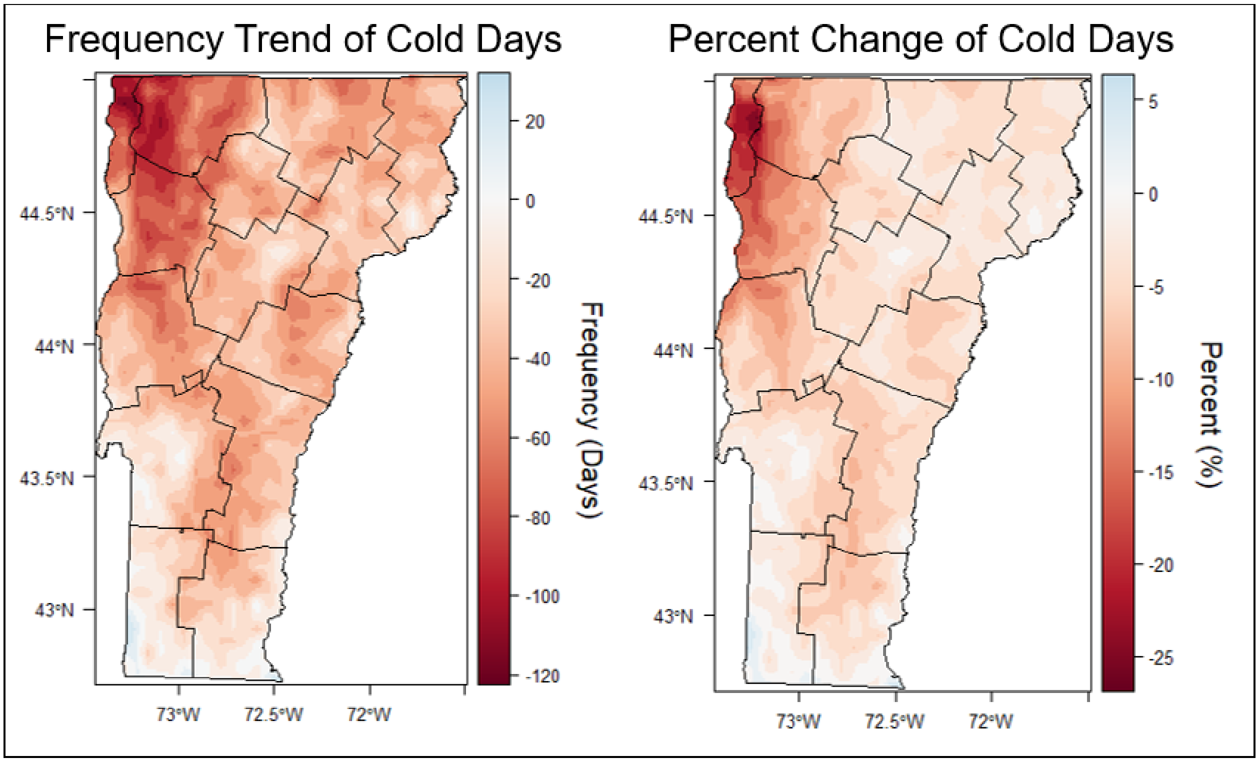

Figure 9. Difference in extreme cold days (days where minimum temperatures went below 0°F) between 1980-1999 to 2000-2019 (left). Percent increase or decrease in extreme cold days (days where minimum temperatures went below 0°F) between 1980-1999 to 2000-2019 (right).

b) Precipitation

i) Annual Precipitation

Precipitation is one of the most complex weather and climate variables whose formation depends on a variety of complex processes. At a simplified level precipitation formation in midlatitude climates such as Vermont depends on the availability of moisture, amount of upward motion (as driven by weather systems), and temperatures at which precipitation may grow within a cloud. More complex factors such as atmospheric stability, land-surface feedback processes (e.g., evaporation), track and movement of storm systems can also modulate precipitation formation.

Vermont averages about 48.2 inches of precipitation per year (1980-2019). The maximum precipitation during this period was 57.6 inches in 2011 and minimum in 2001 with 36 inches (Figure 10). Vermont's climate has been relatively stable with respect to annual precipitation variability. Annual precipitation has a strong influence on tree species growth, with available soil water capacity being a key indicator of annual growth potential (Swanston et al, 2017). There has been an increasing trend of precipitation from 1980-1999 to 2000-2019 with an increase of approximately 2" resulting in an approximate 4% increase as the 20-year trend (Figure 10).

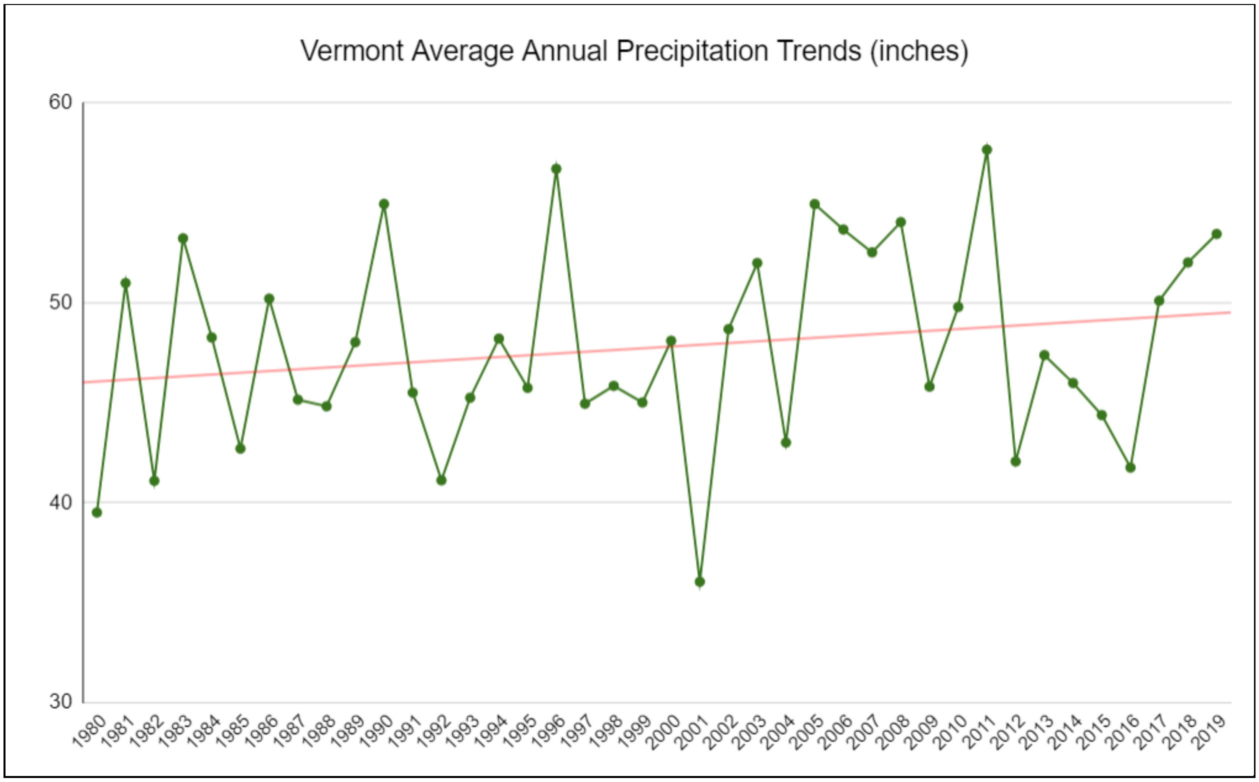

Figure 10. Annual precipitation (inches) in Vermont from 1980-2019 using the ERA5 30km dataset, spatially averaged using a statewide polygon.

ii) Seasonal Precipitation and Trends

The summer produces the most precipitation although October has the second most rainfall (Figure 11). This was a pattern seen in all Vermont counties (not shown). October's maximum is likely related to a combination of midlatitude storm systems interacting with remnant moisture from tropical storms (e.g., Huang et al, 2017). Winter has seen the greatest increases in overall precipitation, with a 20-year increase of 11%, while the remaining seasons are closer to 2% (Figure 12).

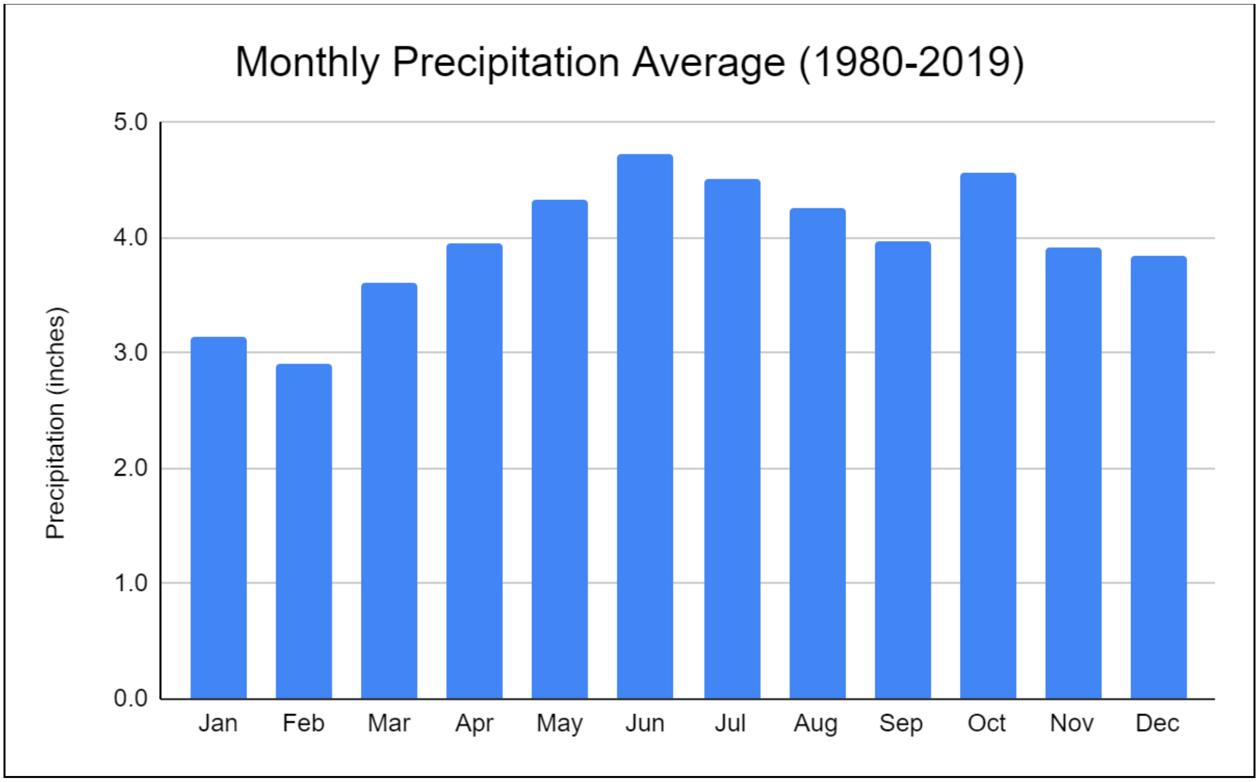

Figure 11. Monthly precipitation (inches) using the ERA5 30km reanalysis.

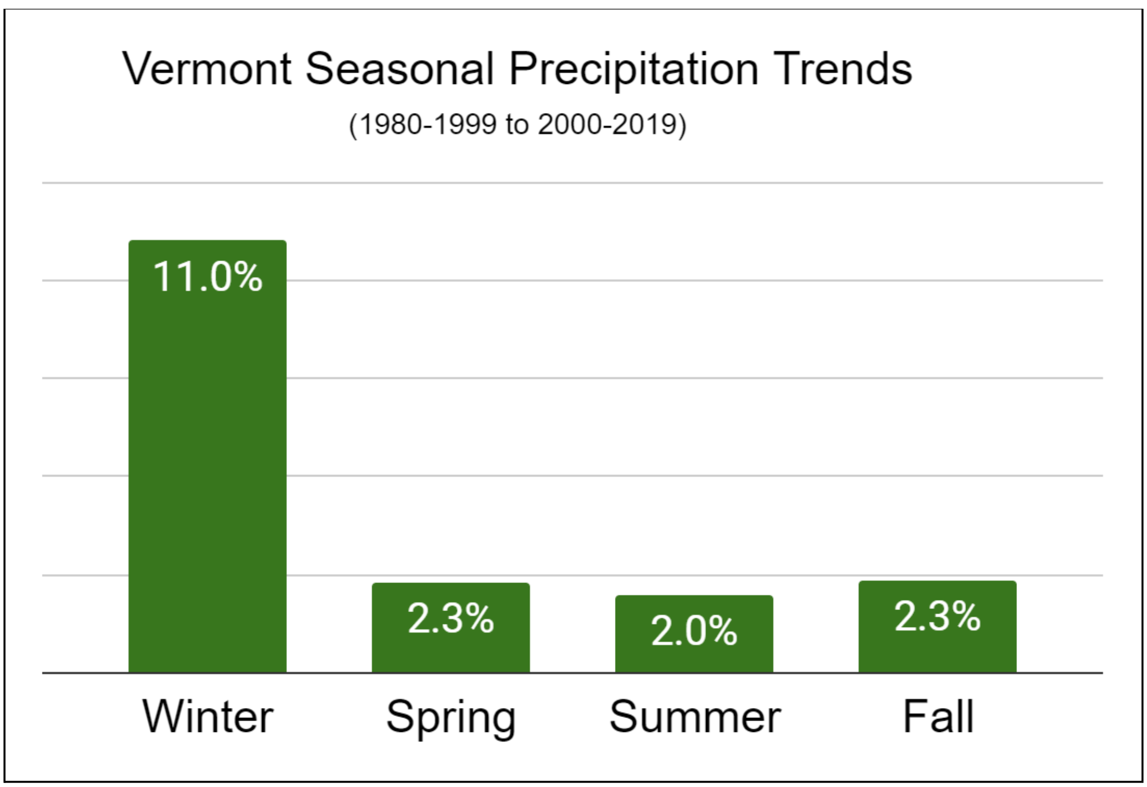

Figure 12. Monthly Vermont precipitation trend using the ERA5 30km reanalysis.

iii) Extreme Precipitation Climatology

Southern Vermont and the higher elevations saw the most extreme precipitation (Figure 13). These areas see 15 days or more of extreme precipitation (1" or greater in 24 hours). The rest of the state generally experienced 10 days or fewer of extreme precipitation (the majority of these events are rainfall). The higher amounts in southern Vermont are consistent with other work showing greater proximity to coastal storm systems (Perica et al, 2015). Higher precipitation occurrence in higher elevations is due to a combination of terrain-induced processes and limitations from model downscaling.

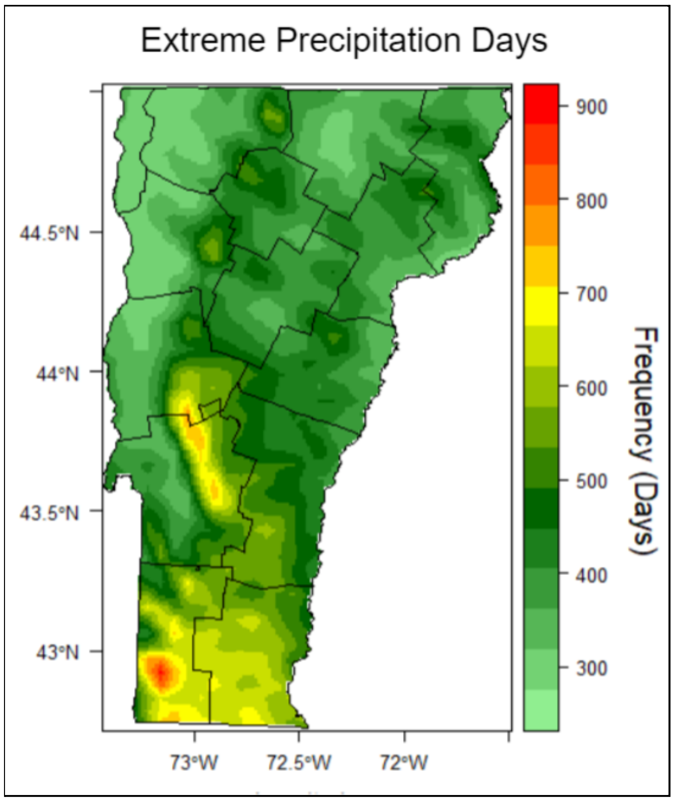

Figure 13. Frequency where precipitation was greater than 1 inch in a 24 hour duration from 1980-2019 using the downscaled ERA5 5km dataset.

iv) Extreme Precipitation Climatology Trends

The majority of Vermont saw increases in extreme precipitation events from 1980-1999 to 2000-2019. General increases were approximately 2 to 3 days a season from 1980 to 2019, with Caledonia and Essex counties showing greatest increases (Figure 14). Extreme precipitation days were less frequent over the northern portions of Lake Champlain and across Franklin county. This overall increase pattern is consistent with coastal storm systems and their widespread precipitation influencing greater extreme precipitation in eastern and southern Vermont.

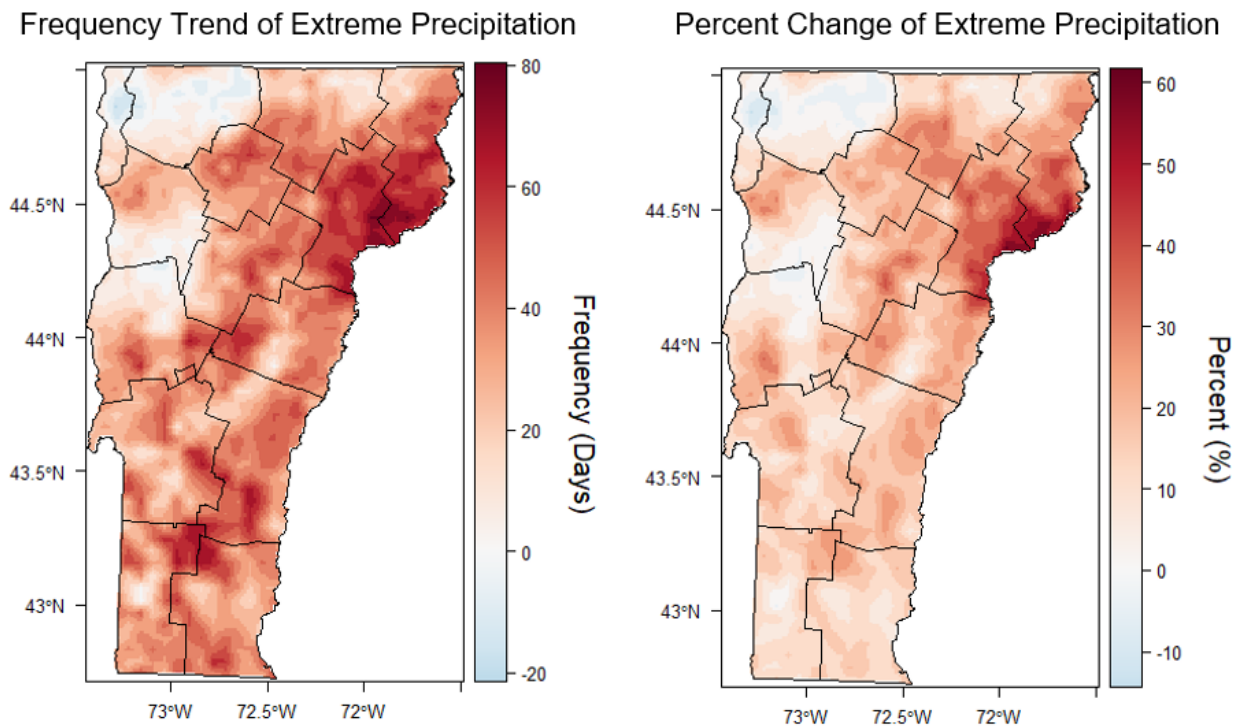

Figure 14. Difference in extreme precipitation days (days with precipitation greater than 1 inch) between 1980-1999 and 2000-2019 (left). Percent change in extreme precipitation days (days with precipitation greater than 1 inch) between 1980-1999 and 2000-2019 (right). Data source is the downscaled ERA5 5km.

v) Precipitation Phase

The majority of Vermont's precipitation reaches the ground as unfrozen hydrometeors with 78% of the total precipitation being rainfall. Snowfall accounts for around 21% and freezing rain is around 1%. (Figure 15). Freezing rain estimates are likely on the high side based on the FRAM ice accretion model used (Sanders and Barjenbruch 2016). There was no substantial change in the distribution of precipitation from 1980-2019 in rain vs. snow, however the 2010s did feature the highest amount of freezing rain precipitation. Warmer and wetter winter storm systems are more likely to have conflicts with air temperatures around freezing, likely producing more mixed-phase storm systems.

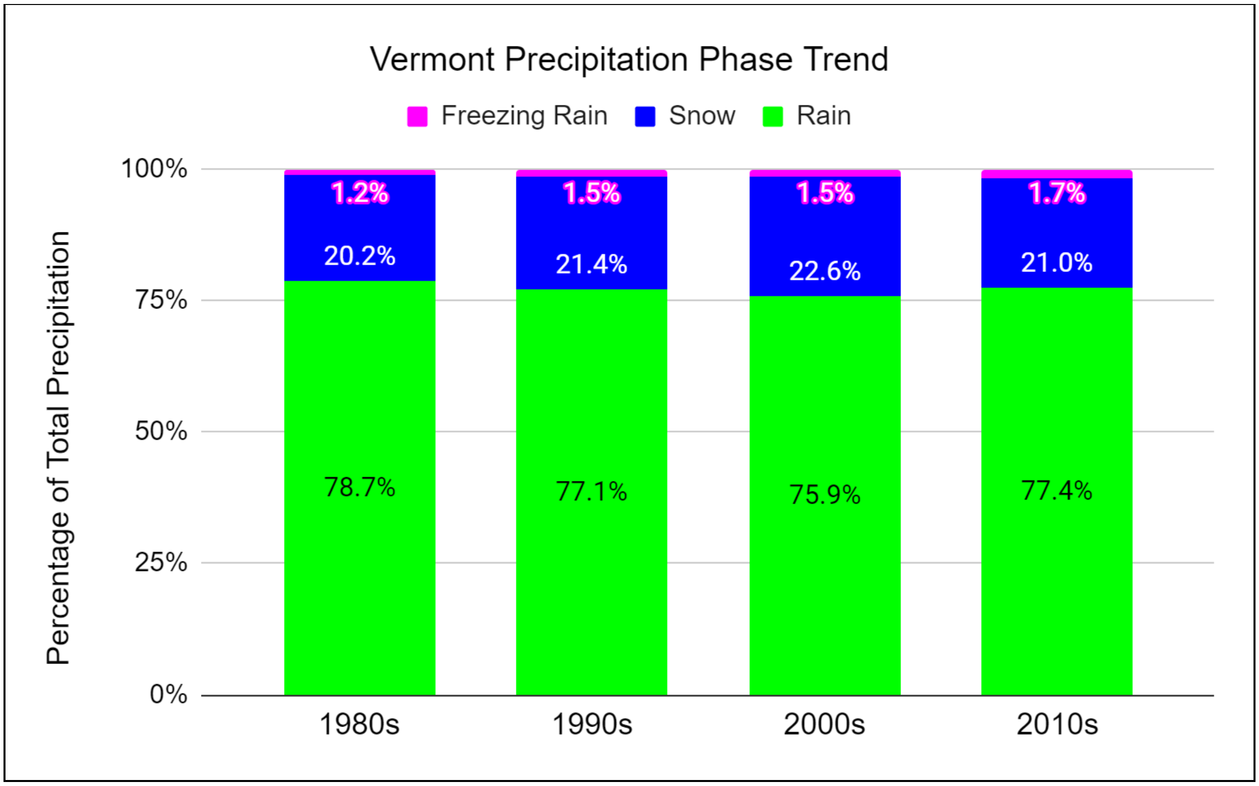

Figure 15. Percentage of precipitation amount by type for Vermont for each decade from 1980-2019. Data source is ERA5 30km.

4) Hazard Climatology

A variety of weather hazards may cause damage to the electric power system. This work focuses on large-scale or gradient winds, wet snow icing, and freezing rain icing. The climatology of these hazards is provided in more detail to understand locations generally at greater risks.

a) Gradient Wind Climatology

Gradient wind systems are typically associated with large-scale midlatitude storm systems. These storm systems have two general classes, those that track to the north of Vermont with strong backside westerly to northwesterly winds, and those that track to the east of Vermont that often come from the south with a more coastal track origin. The latter storm systems are often associated with a tropical storm system or hurricane interacting with a midlatitude storm system (e.g., Tropical Storm Philippe - October 2017). Topography plays an important role influencing the location of high winds, with winds generally increasing with elevation (Figure 16). The windiest lowland locations include the Champlain Valley and near Lake Champlain where pressure-gradient channeling often occurs with north to south flow.

There is a high sensitivity of peak winds to wind direction. Topography plays an important role with the orientation of terrain to wind direction where terrain may enhance or suppress wind speeds. Higher elevations generally experience a higher frequency of strong winds as wind speeds typically increase with height. Wind speed enhancement may occur from downsloping wind storms where the flow breaks as a wave on the lee side of barriers causing higher winds in lower elevations away from terrain, or wind speed enhancement may occur due to terrain acting to mix winds aloft closer to leeside valleys. Terrain wind enhancement depends on a variety of complex factors such as atmospheric stability and the location and strength of the low-level jet. Northerly or southerly wind directions tend to have the highest frequencies in the Champlain Valley (Figure 17). Westerly winds, on the other hand, tend to be the most frequent and strongest in the southern Green Mountains and locations to the east (Figures 17 &18). Southeasterly to easterly wind directions tend to be more likely east of the Green Mountains ranges.

The seasonal frequency of high winds shows that the greatest number of high wind days occurs in January while August has the lowest (Figure 19). Higher winds are more likely during the cold season when transient weather systems are stronger due to increased temperature gradients producing larger pressure gradient forces.

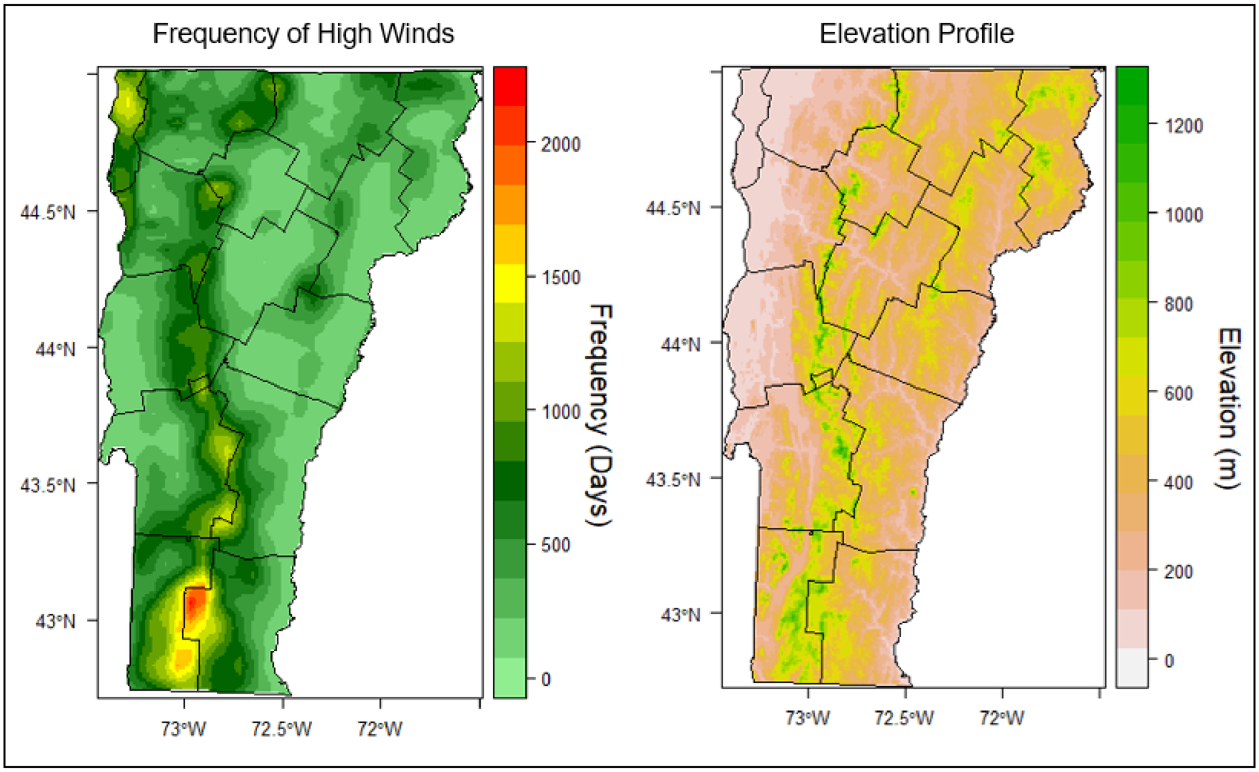

Figure 16. Days with 10-meter elevation wind gusts above 45 mph 1980-2019 (left) and elevation (right). Wind data source is the downscaled 5-km ERA5.

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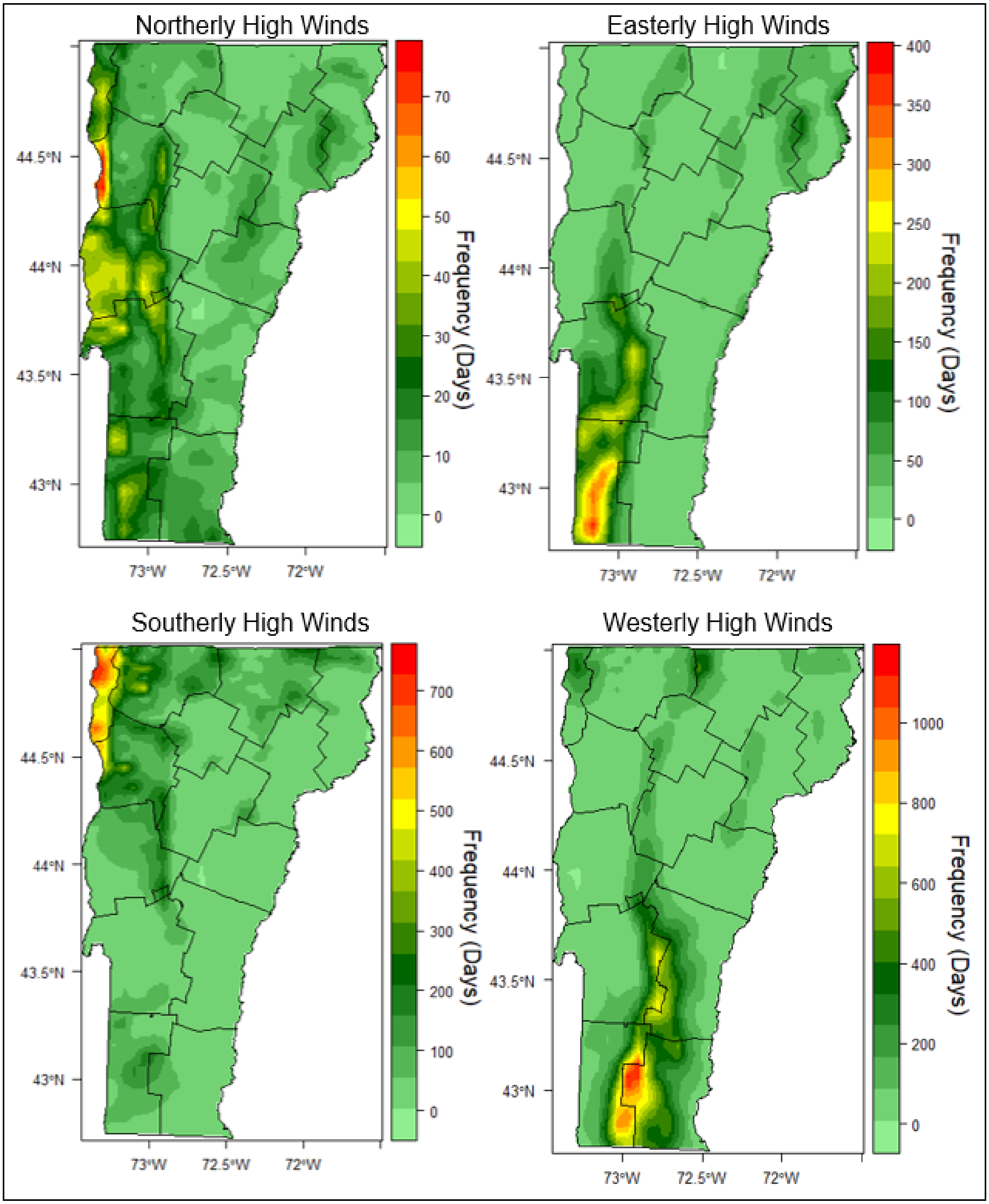

Figure 17. Frequency of high wind days by wind direction from 1980-2019 using the downscaled ERA5 5km dataset. A high wind day is defined as a day with a 10-meter wind gusts above 45 mph.

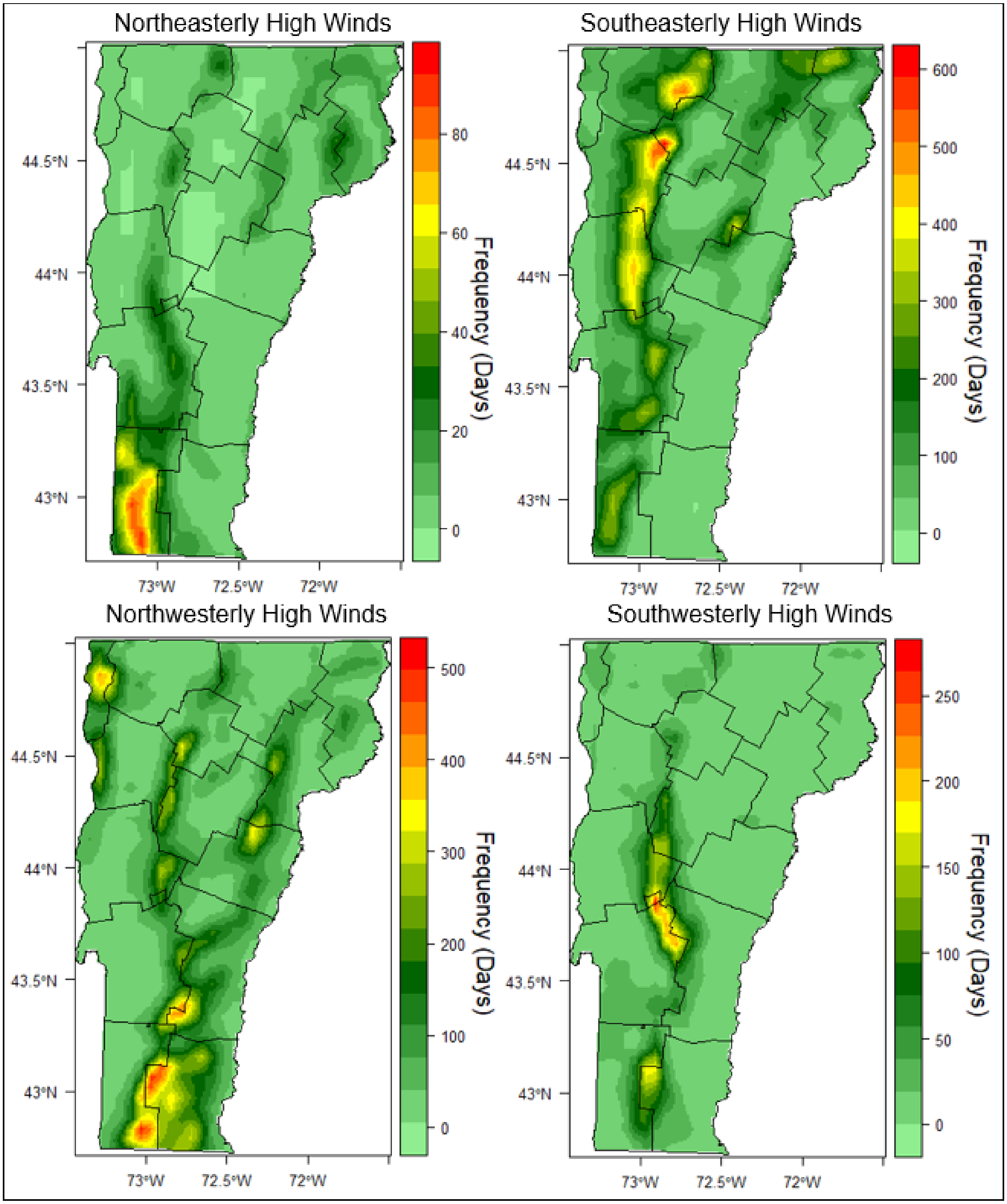

Figure 18. Frequency of high wind days by wind direction from 1980-2019 using the downscaled ERA5 5km dataset. High wind day is defined as a day with a 10-meter wind gusts above 45 mph.

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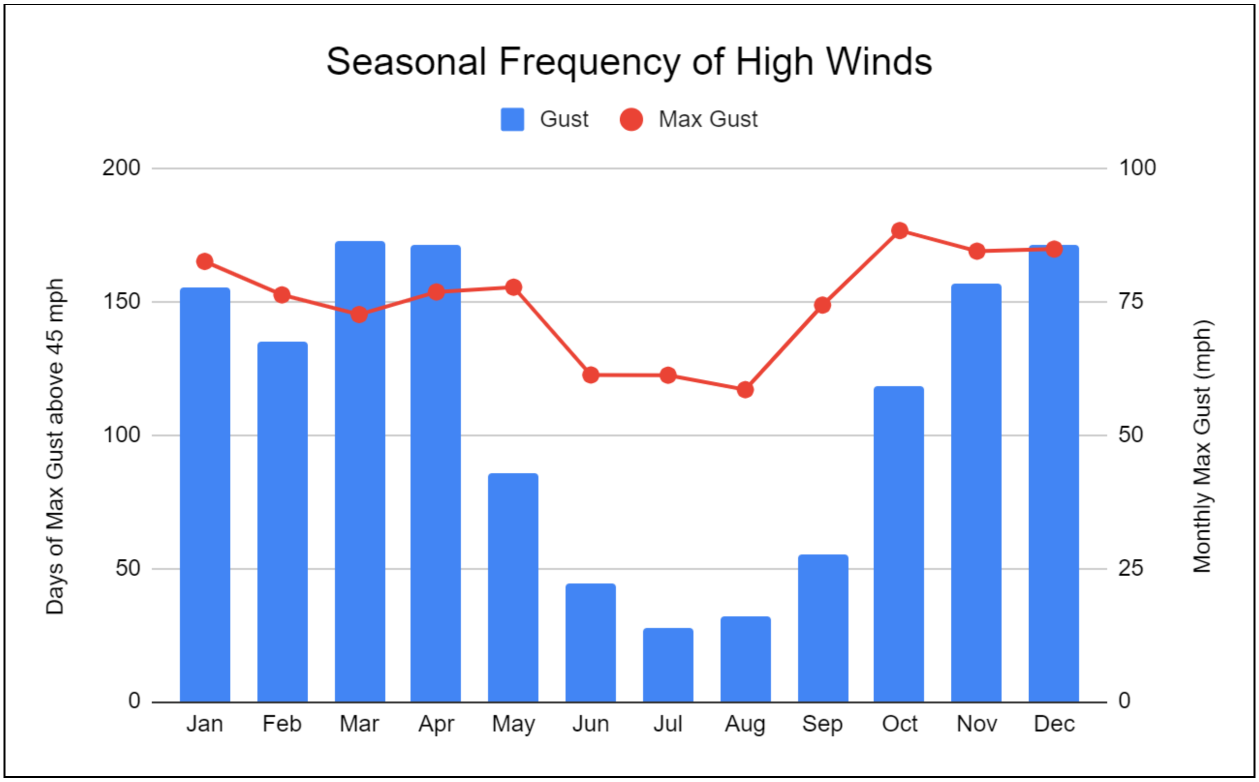

Figure 19. Days with Vermont spatial max gust at 10-m greater than 45mph aggregated monthly and spatial max monthly top gusts from 1980-2019 using the downscaled ERA5 5km dataset.

b) Gradient Winds Trends

The 20-year trend in gradient wind shows some spatial variability with high wind days declining slightly in the Connecticut River Valley within the Champlain Valley had a slight increase (Figure 20). Higher winds east of the southern Green Mountains in Windham county were likely associated with a higher frequency of westerly to northwesterly wind events, based on the climatology described in Figures 17 and 18. The general pattern suggests that locations with greater high wind event days had a higher frequency of windy days while locations with lower high wind frequency saw fewer from 1980 to 2019. The overall statewide aggregated change in gradient wind events featured negligible change from 1980 to 2019.

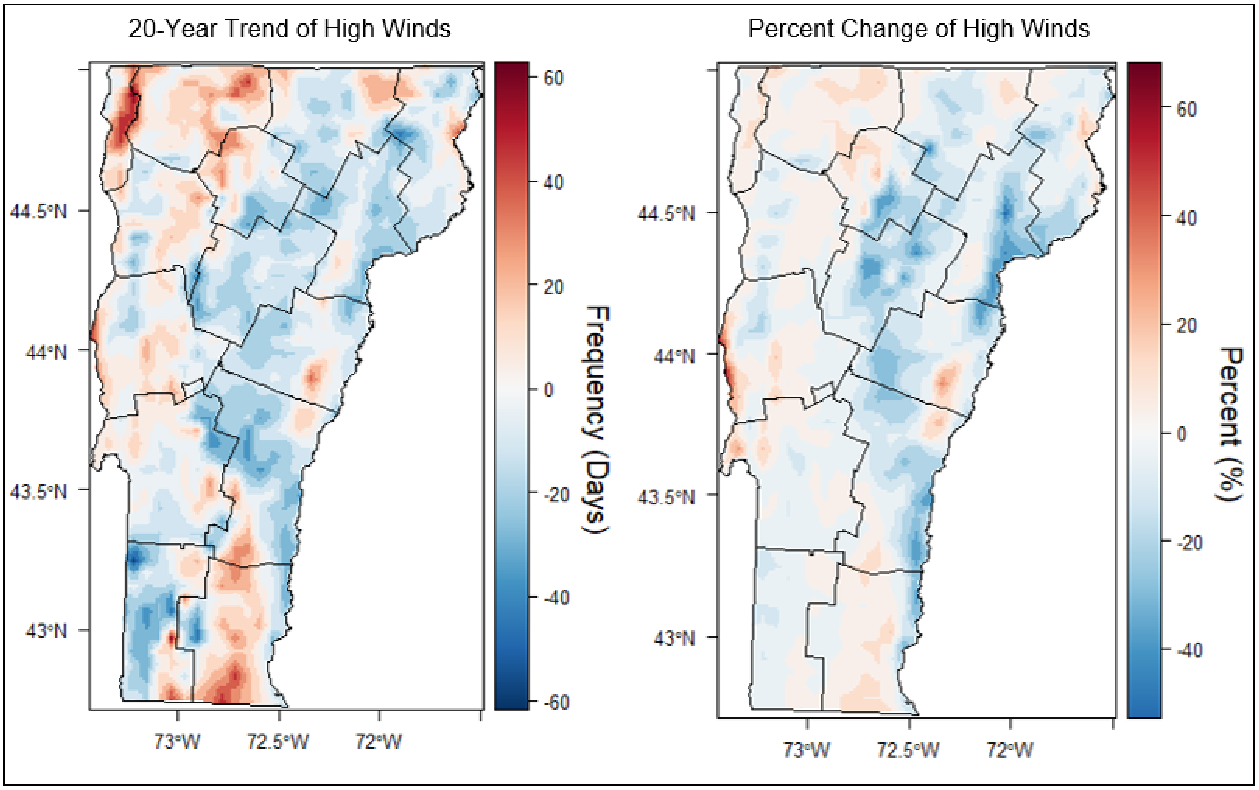

Figure 20. Difference in the number of extreme wind days between 1980-1999 and 2000-2019 using the downscaled ERA5 5km (left). Percent difference in the number of extreme wind days (right).

c) Wet Snow Icing Climatology and Trends

Wet snow icing occurs when partially melted snow flakes accrete or stick onto trees and/or powerlines. The weight of the wet snowfall often produces power outages by damaging trees within or near right of ways. Wet snowfall is defined when the reanalysis precipitation type was snowfall and the surface wet bulb temperature was greater than -2°C. The spatial climatology illustrates fairly wide varying accumulations, generally from less than 1 day to 2 days per year. A moderately strong elevation signal is identified, with lower elevations west of the Green Mountains featuring the fewest days, while areas east of the Green Mountain crest were more vulnerable (Figure 21).

The seasonal frequency of wet snowfall illustrates that all months during which snow can fall feature wet snowfall, with March and April having the highest peaks (Figure 22). Few mid-winter wet snowfall event days occurred as a result of colder temperatures producing a higher fraction of dry snowfall.

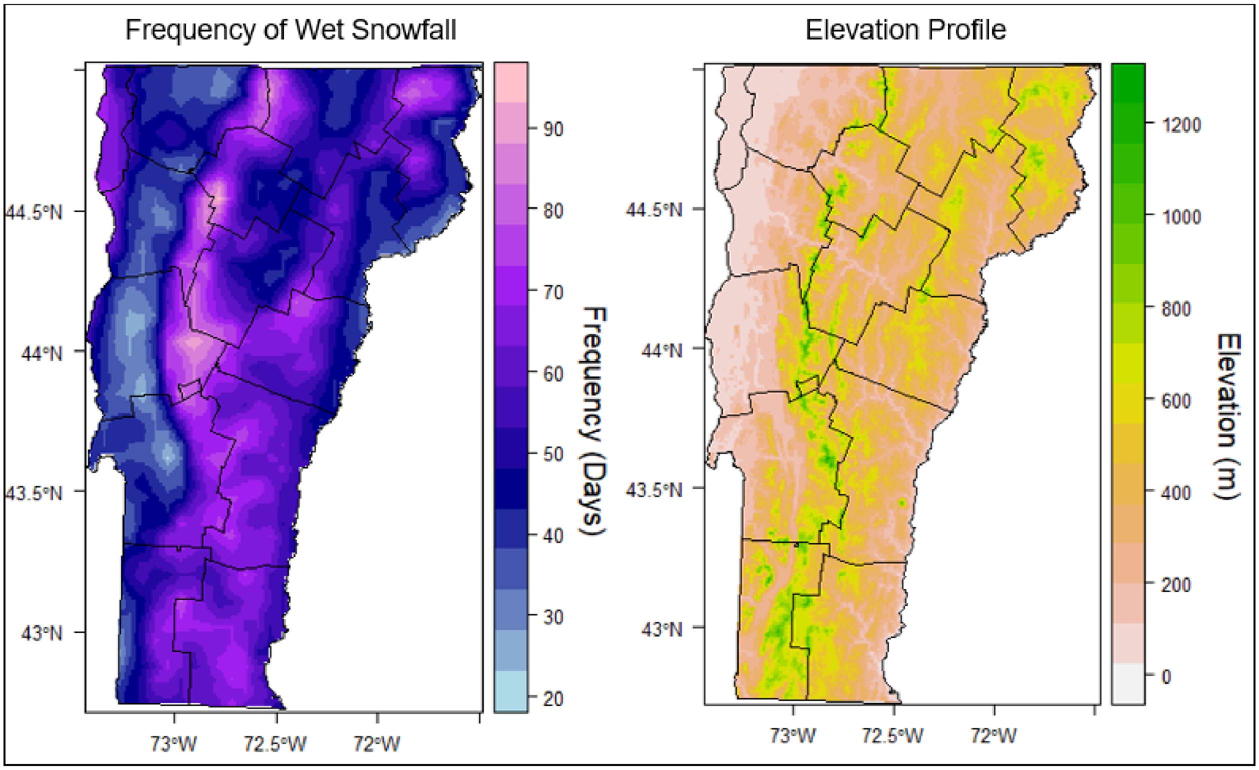

Figure 21. Total extreme wet snow days (wet snow liquid water equivalent is greater than 0.40" in a 24 hour accumulation period) for 1980-2019.

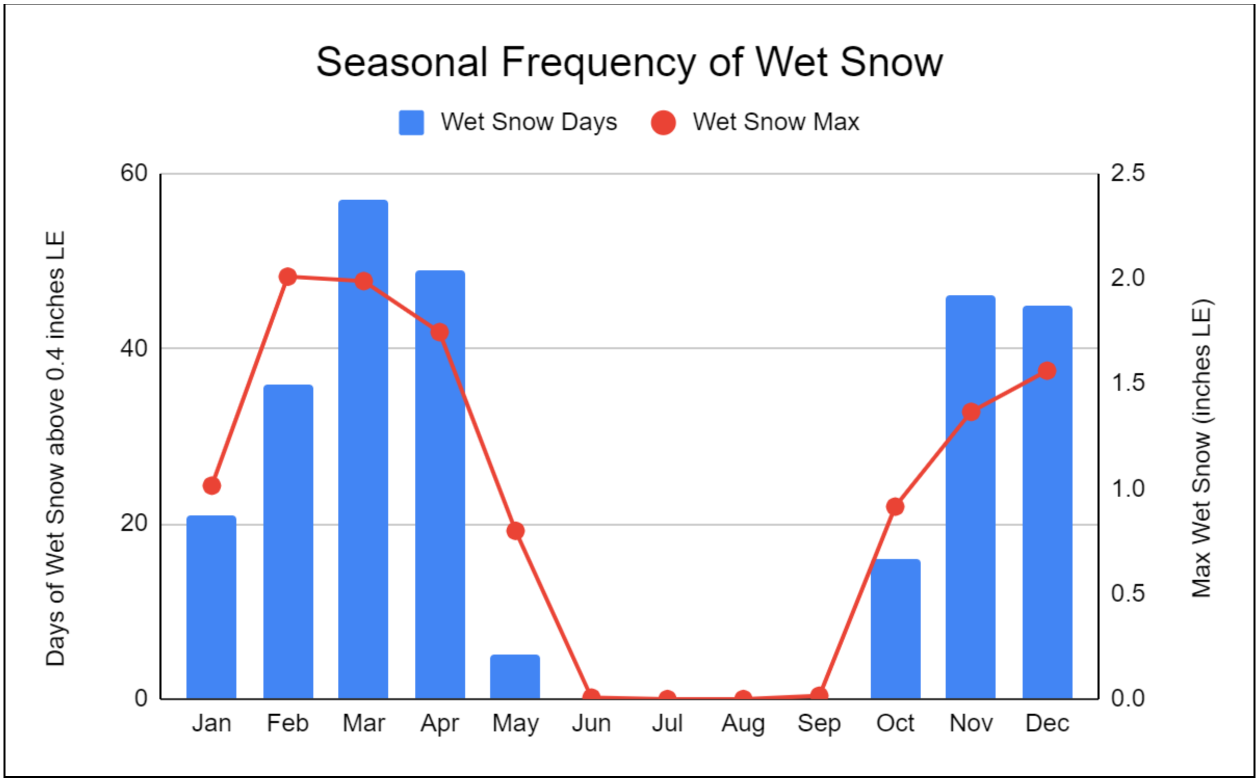

Figure 22. Days of spatial max wet snow greater than 0.4” liquid equivalent (LE) aggregated monthly and monthly max wet snow using the ERA5 30km dataset. Accumulation duration was 24 hours.

With more mild winter temperatures and increased precipitation there was a general increase in the overall wet snowfall. This risk came primarily as more early-season snowfall events in late October through December (e.g., Dec 9-10, 2014). There was some spatial variability in wet snowfall trends with northeastern Vermont and southern Vermont seeing the greatest increases (not shown).

d) Freezing Rain Climatology and Trends

Freezing rain occurs when rain reaches the ground, vegetation, or infrastructure and freezes on contact (typically the air temperature is or has been recently below freezing). Freezing rain icing frequency is more prevalent in the higher terrain and Southern Vermont (Figure 23). Given the limitations of the ice accretion model and other challenges within determining precipitation phase in the downscaled model, the pattern of freezing rain likely underrepresents the frequency of freezing rain in some valley locations, in particular across the northern Champlain Valley. The ice storm of January 1998 featured some of the highest ice accretions in northernmost Valley locations and middle-elevation zones (1500-2500’ elevation) north of Montpelier (Miller-Weeks et al. 1999). In the nine years (2011-2019) of power outage analysis conducted within this work there was only one significant ice storm (Dec 21, 2013), which was concentrated over northern areas.

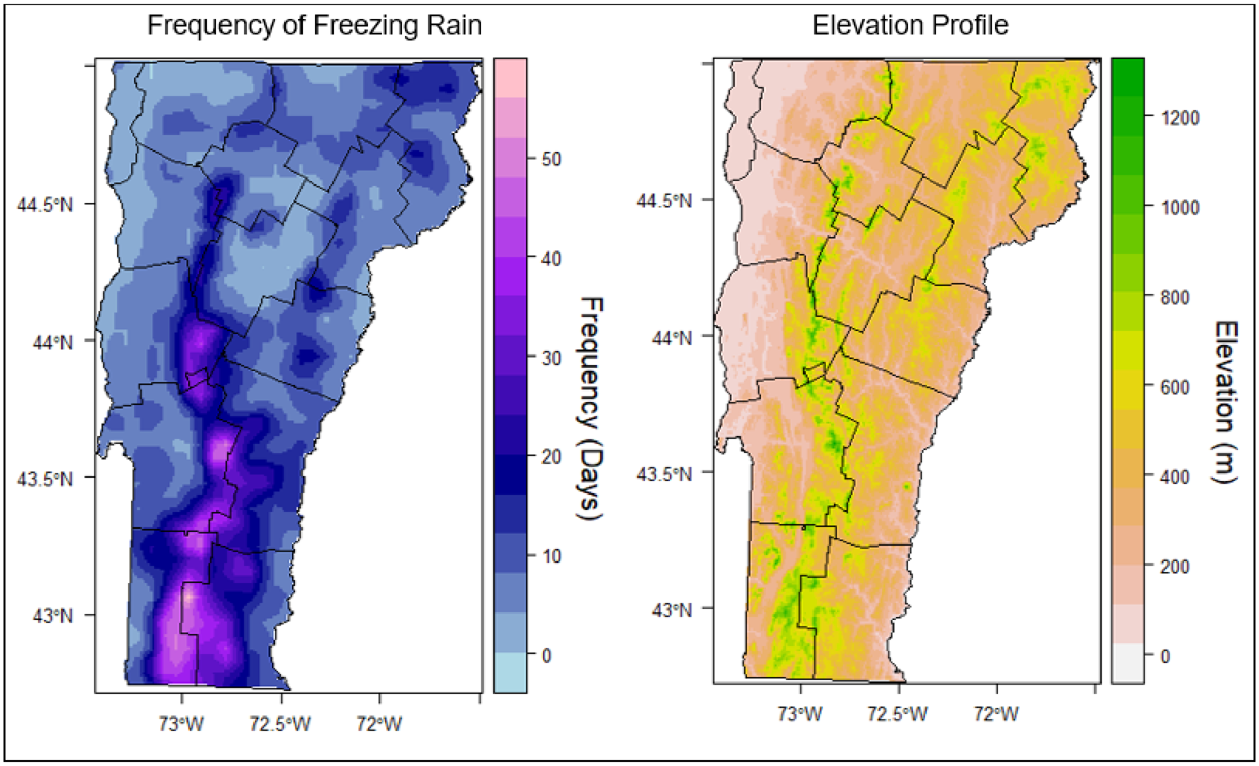

Figure 23. Total freezing rain days (ice thickness is greater than 0.25”) for 1980-2019 using the ERA5 5km dataset.

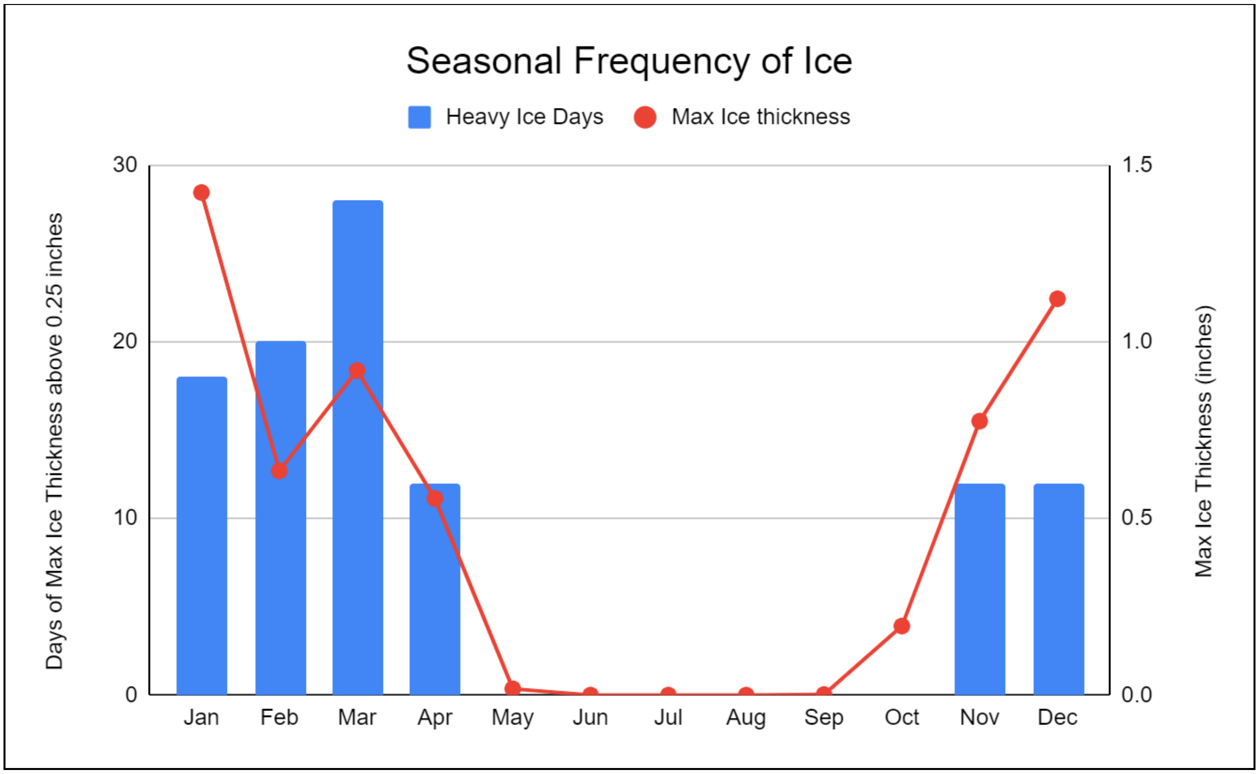

Figure 24. Days of spatial max ice thickness greater than 0.25” aggregated monthly and monthly max wet snow using the ERA5 30km dataset (1980-2019).

The frequency of freezing rain icing is greatest during mid to late winter, with a March peak. The peak ice thickness occurred during the January 8, 1998 ice storm (Figure 24). Given the relatively small number of freezing rain icing days, no trend was able to be determined. However, an increase in the number of low-end freezing rain days was observed for ice accumulations of 0.10” and above; this is likely related to more mixed-phase storm systems.

5. Outage Analysis

a. Hazard Climatology

Extreme weather events feature significant seasonal variability with the cold season bringing the highest number of high-wind events, and late summer to early fall featuring the greatest risks for widespread heavy rainfall (Figure 25). As a fraction of overall risk, wind represents the greatest overall hazard; this is primarily through gradient or large-scale wind events. Heavy rainfall has a peak occurrence during October when tropical moisture related to remnant or active tropical storm systems may interact with midlatitude storm systems to produce widespread or organized precipitation. It should be noted that this work did not conduct hydrologic modeling or other flood impact analysis to determine the degree to which heavy rainfall may have produced any electric grid impacts. Flooding is a comparatively low risk to other hazards described in Figure 25, although potentially high-impact when major storm systems are involved (e.g., Tropical Storm Irene, Anderson et al 2017). Heavy rainfall combined with high wind events do often aggravate the risk for outages, when soil moisture content is high and may contribute to the risk of trees uprooting.

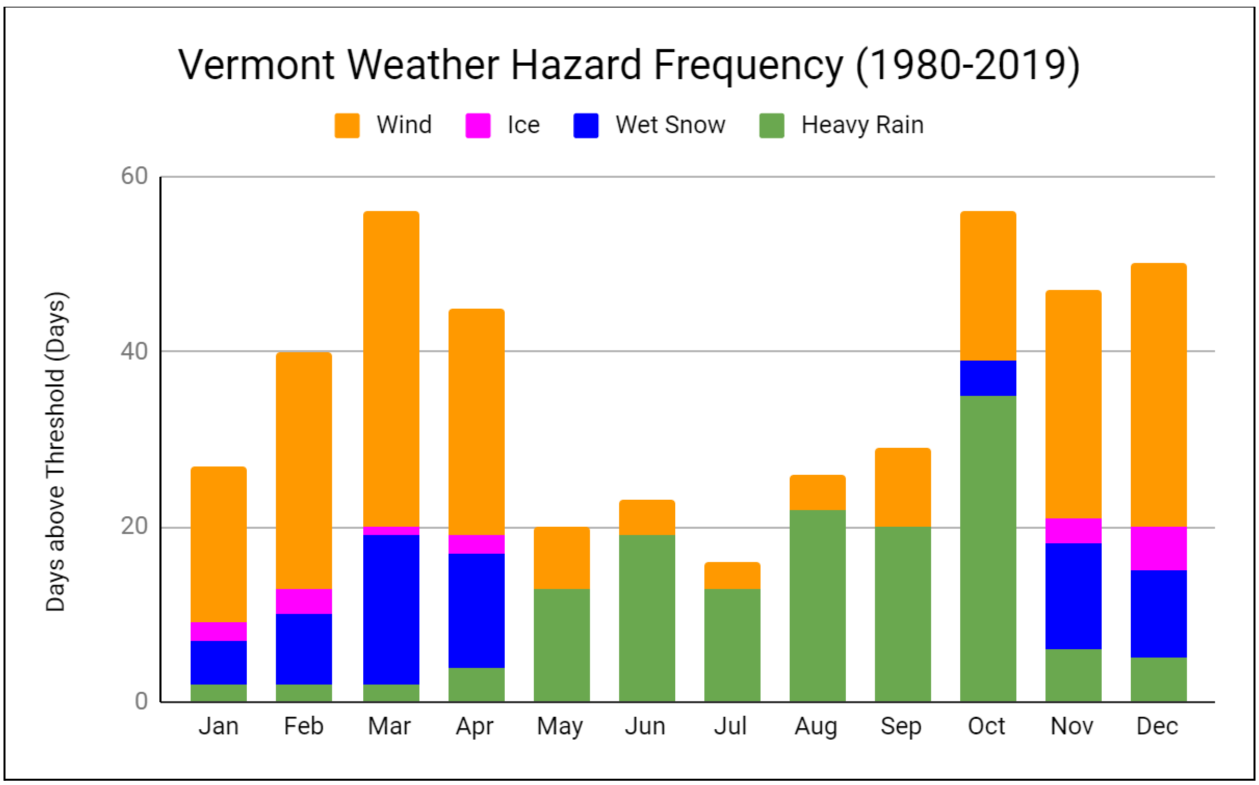

Figure 25. Average days a year above the following extreme weather thresholds as defined by the Vermont statewide polygon. Rainfall 1.0 inches or greater, wet snowfall - 0.4 inches liquid equivalent or greater, ice thickness - 0.25 inches or greater, spatially averaged wind gust - 45mph. Data sources include ERA5 30km for precipitation variables and the ERA5 5km dataset for wind.

b. Distribution System Outage Climatology

Power outage data was provided by GMP from 2008-2019 and VEC from 2011-2019. This data was aggregated daily and statewide from 2011-2019. The seasonal frequency shows two peaks, one in July and a fall and early winter peak (Figure 26). Fewer mid-winter outages are likely associated with seasonal system self-hardening from cold temperatures, trees after leaf drop, and more resilience after some fall weather events.

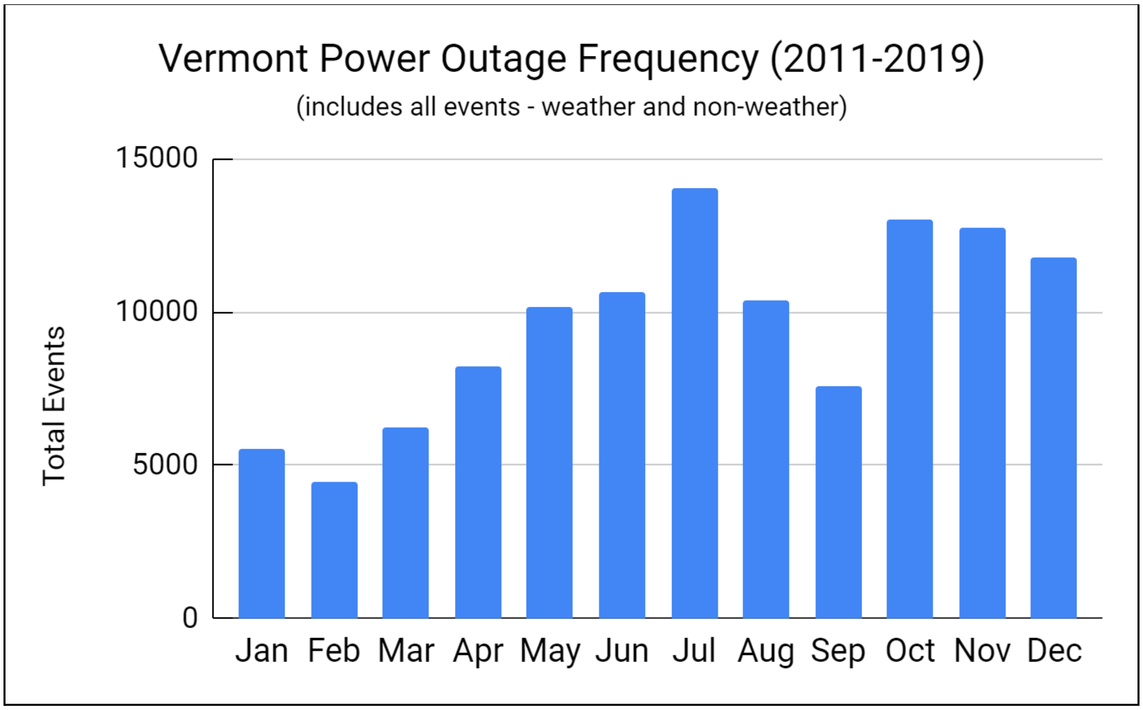

Figure 26. Total distribution system power outage events from 2011-2019 by month.

The frequency of power outage events and their weather attribution shows a thunderstorm peak during summer, likely as a result of localized wind gusts from thunderstorms, whereas wet snowfall impacts are concentrated in the fall to early winter (Figure 27). Gradient wind event impacts were also highest in the fall season (October & November).

The severity of power outage impacts can be represented by the duration of power outages; in this analysis customer power outage hours are described in Figure 28. The fall and early winter season featured over 50% of all power outage severity impacts from a combination of wet snowfall and high wind storms. January and February featured a comparatively low impact compared to the higher frequency of weather hazards (Figure 25). This strong seasonal signal should be incorporated into planning and emergency preparedness to take storm systems during the fall and early winter with a higher level of potential risk.

Wind events (gradient wind or thunderstorm) accounted for 68% of all distribution power outage impacts, whereas wet snowfall was 28% and ice was 4% (Figure 29). The differences in the frequency and impacts of weather hazards was most dramatic for wet snowfall and thunderstorms. Thunderstorms generally featured a much lower impact while wet snowfall events featured a comparatively higher impact.

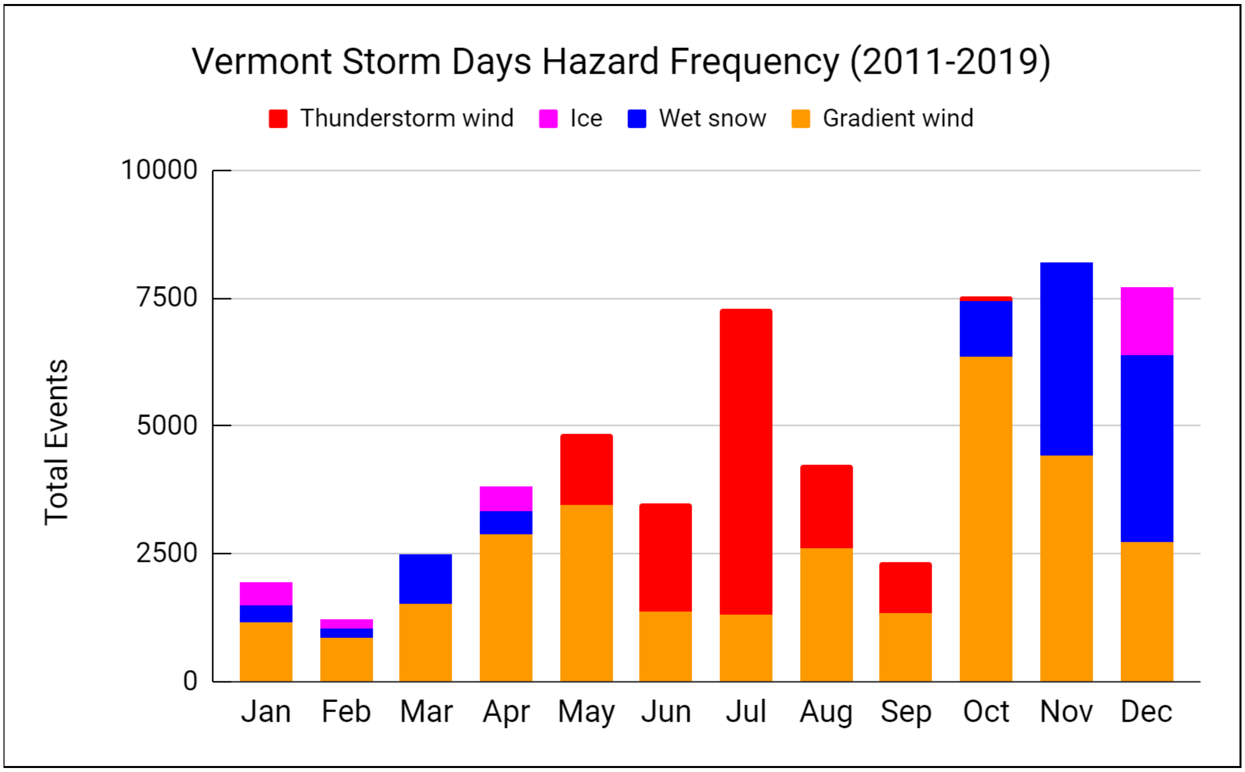

Figure 27. GMP and VEC storm days aggregated monthly according to type using total events.

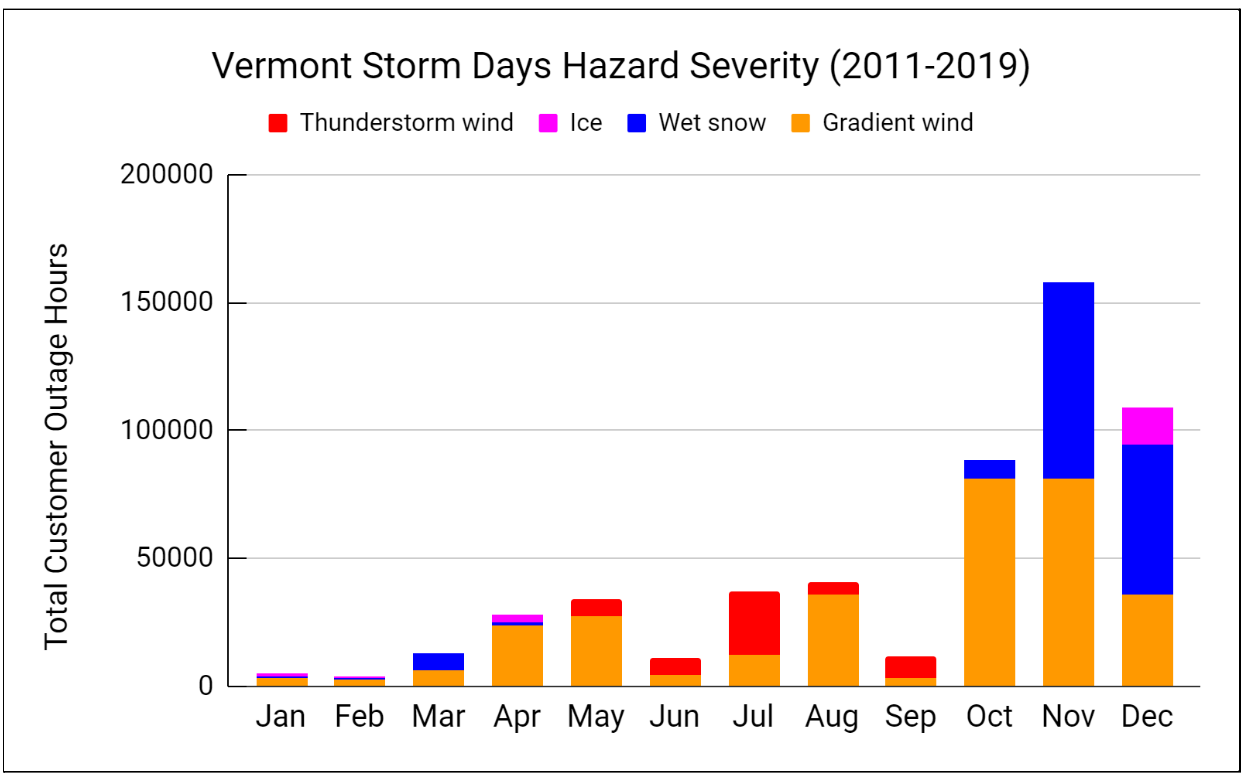

Figure 28. GMP and VEC storm days are aggregated monthly according to type using customer outage hours.

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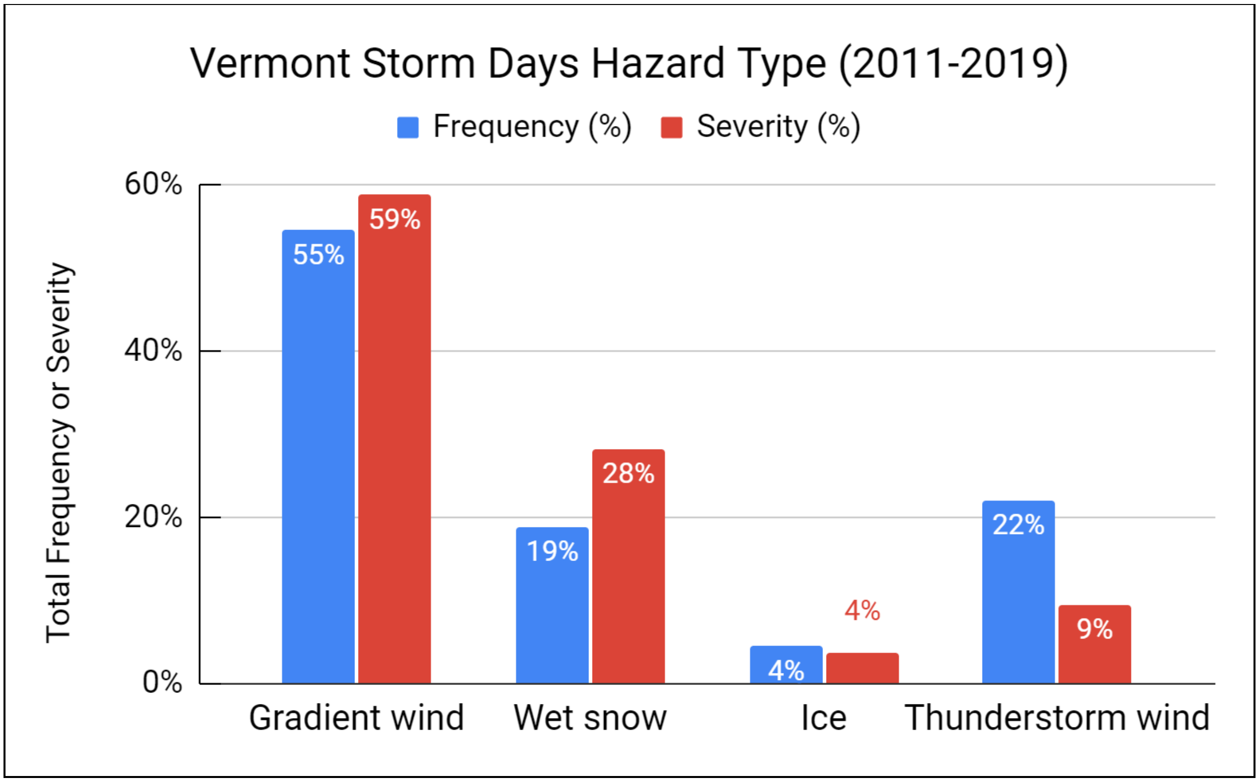

Figure 29. Event frequency percentage broken down according to hazard type.

c) Extreme Storm Examples

The top storms for each weather hazard and their respective customer outage profiles are described in Figure 30. The high wind storm of Oct 30, 2017 was the most significant storm, with nearly 100,000 customers without power at the storm's peak and a 5-day restoration. The wet snow and ice events had a lower peak customer value, but more sustained outages as wet snow and ice remained loaded on trees and overhead lines, continuing to cause outages as restoration was underway. By comparison, the top thunderstorm event (July 23, 2016) peaked around 25,000 customers without power with a full restoration around 2 days.

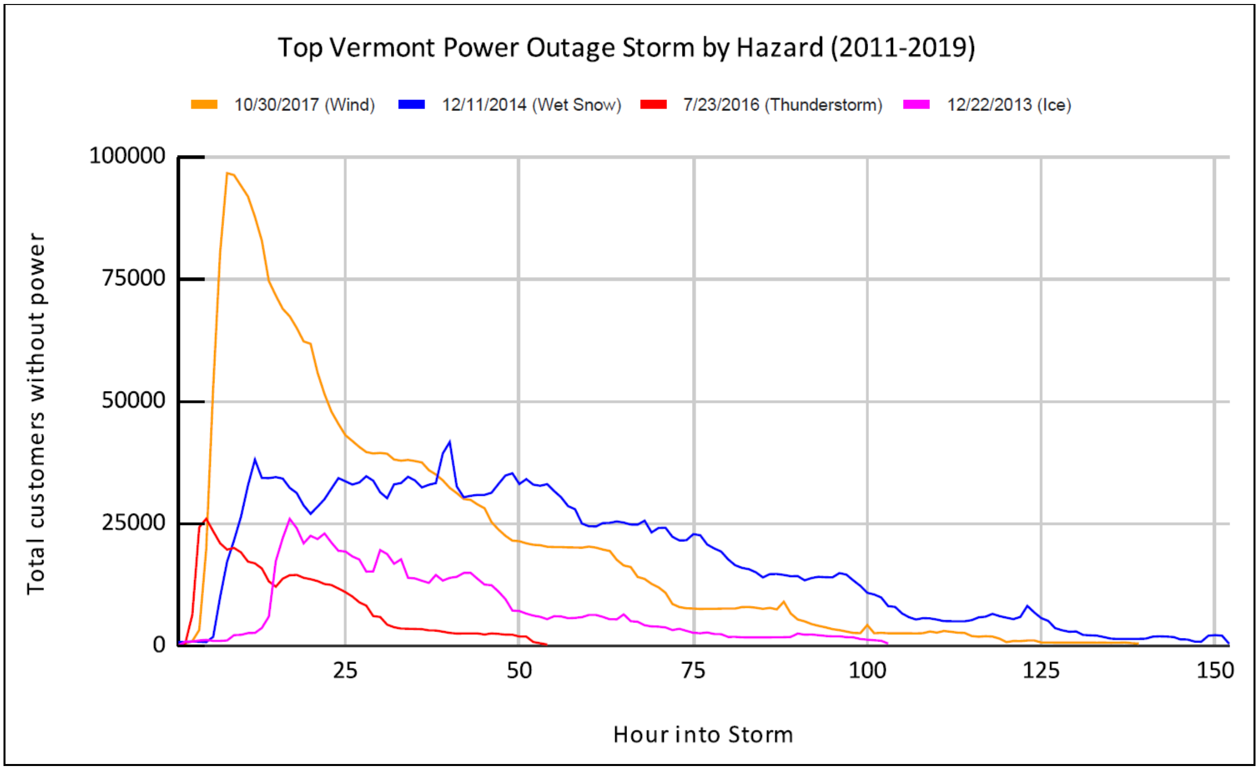

Figure 30. Top statewide power outage storm by storm class from 2011-2019.

d) Historic Power Outage Reconstruction and Trends

In order to describe long-term power outage variability a deep learning model was used to reconstruct or model outages outside of the observed outage window (2011-2019). Table 2 describes the variables used for the deep learning model. This reconstruction does not sample outages from thunderstorm events, and has a tendency to underestimate the most extreme storms; thus, the recreated values likely underestimate the total historic outages. This methodology also assumes stationarity with system infrastructure and doesn't take into account any system hardening over time. Nonetheless, this method can be used to understand general long-term weather impact variability.

The 2010s featured the highest number of simulated events (Figure 31), being the most active decade since 1980. The 2000s featured the most severe storm impacts. Thus, the last 20-years have seen, on average, an increase in both the frequency and severity of storm impacts. The most severe storms produced a higher fraction of overall impacts during the 2010s. In order to understand severe storm variability may be changing, this population is examined independently.

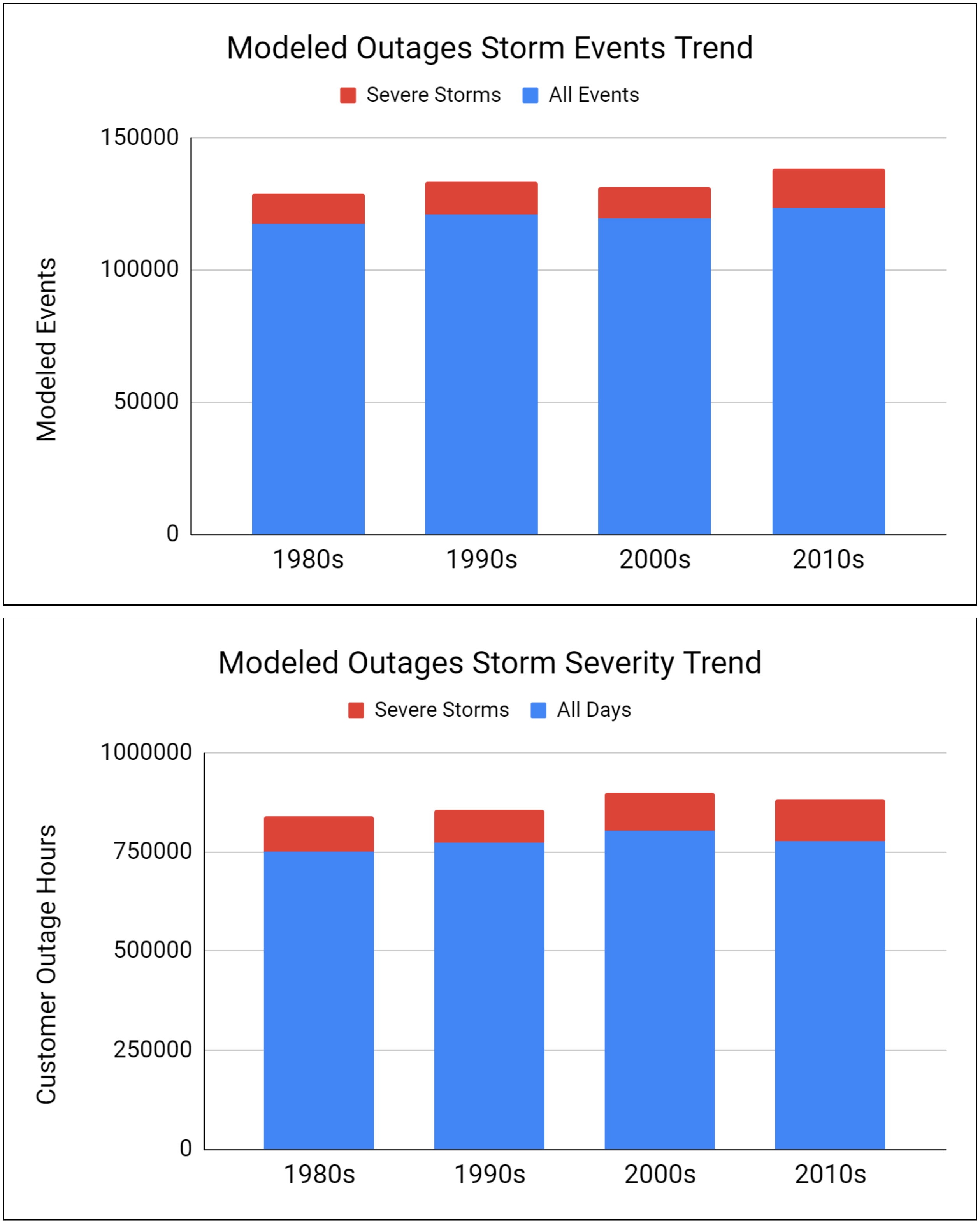

Figure 31. Historically modeled power outages using a deep learning model, top shows frequency variability while bottom describes the intensity variability. Severe storms are defined as being in the top 1% of storm days by total number of events.

e) Extreme Storm Analysis and Trends

In order to understand how the most extreme storms may be changing, the top most severe storms were subsetted. The top 1% of modeled storm days (defined around 100 statewide events or greater) represented around 15% of all modeled impacts. Decadal variability of the most extreme storms shows that both the frequency and intensity of these storms has increased from 1980 to 2019 (Figure 32). Overall modeled storm frequency has increased approximately 2% for all storms and increased 4% for storm severity (Table 3). However, the most extreme storms increased frequency by 14% and were 19% more severe (Table 3). This result suggests that the most severe or extreme storms are getting more frequent and intense, and their intensity has increased faster than their frequency.

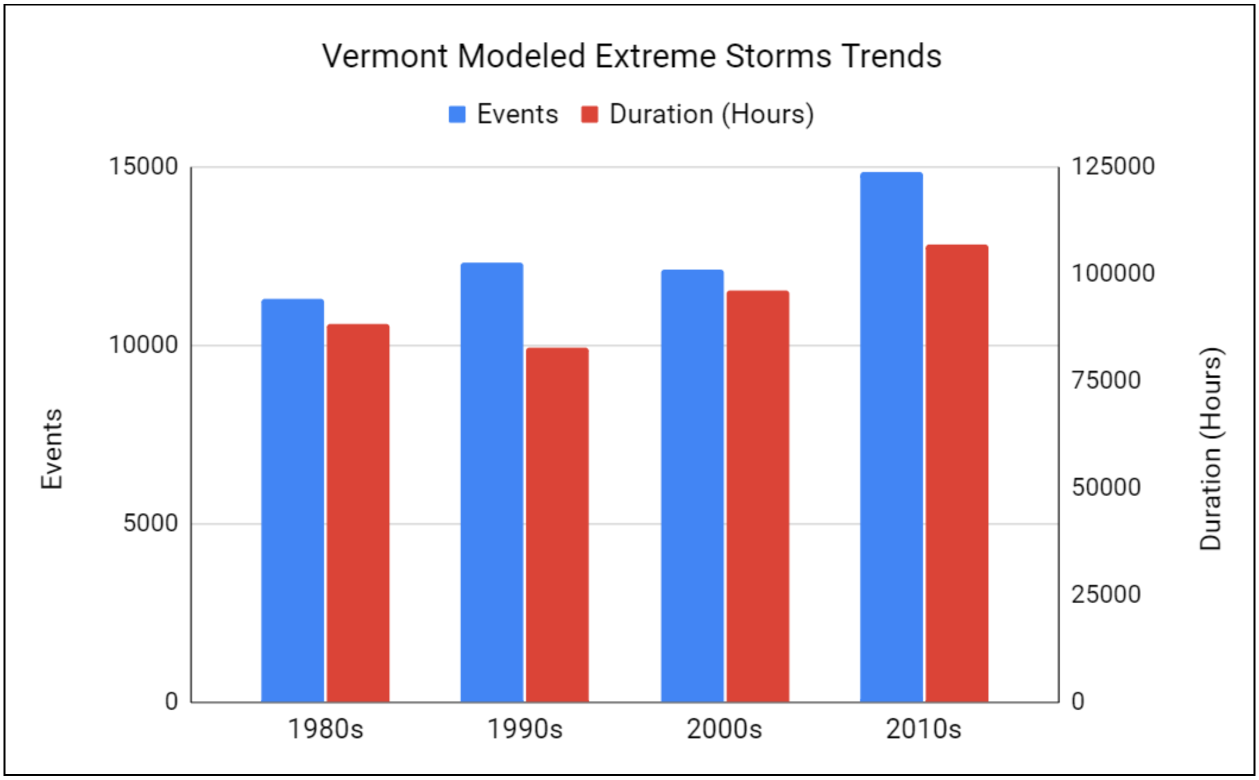

Figure 32. Most extreme reconstructed storm outage impacts by frequency (events) and severity (duration). Extreme storms represent the top 1% of overall events.

	All Modeled Days		Extreme Modeled Storms	
Timeframe	**Total Events**	**Total Duration**	**Total Events**	**Total Duration**
1980-1999	238651	1523726	23597	171128
2000-2019	242682	1580235	26993	203077
20-Year Trend	2%	4%	14%	19%

Table 3. Modeled power outage trends. Extreme storm days were defined as the top 1% of all modeled storm events.

6. Climate Projections

In order to determine the future climatic shifts and how the weather behavior may vary within changing climatic states, a combination of three information sources are relied upon. These include the current trends, climate simulations, and published literature. The trends are generally relied upon more than the simulations, with the literature being fairly limited for understanding extreme weather behavior. A general direction and level of risk are described to capture future risk and any adaption or resilience decisions that may be based on this analysis.

a) Base Climate States

Two climate simulations were run using two different emissions scenarios, the RCP4.5, which is considered a moderate greenhouse gas emissions mitigation pathway, and RCP8.5, which is considered the business as usual pathway with little mitigation of greenhouse gas emissions. Both simulations show limited variability with each other regarding future climate measures of temperature, precipitation, and solar radiation (Table 4). The simulations generally show a notable projected increase in temperatures, but relatively small changes to annual precipitation and solar radiation. The projected temperature increase was distributed fairly uniformly across all seasons and there were no significant seasonal changes to precipitation and solar radiation (not shown).

Variable	1990-2019 Baseline	RCP4.5 Simulation	RCP8.5 Simulation
Average Annual Temperature (°F)	39.7	41.1	41.3
Average Annual Precipitation (inches)	53.2	54.6	53.4
Average Total Daily Solar Radiation (Watts/m²)	3930	3818	3825

Table 4. Climate simulations and base states. Simulations were run from 2020-2049.

The official forecast from this analysis incorporates three primary information sources: the long-term trend from 1980-2019, the two dynamically downscaled climate simulations, and published literature. These three information sources are synthesized to produce a general direction and level of confidence of each weather hazard and climate state (Table 5). The two high confidence forecasts include increases to temperature and extreme precipitation events. Extreme precipitation events have been increasing about twice the rate of average annual precipitation. Climate simulations were unable to resolve extreme events, in particular wind storms; this is a known issue with simulating extreme midlatitude weather events. Annual temperatures and precipitation are projected to increase while there is no significant change for annual solar radiation.

Vermont Climate and Weather Forecast Changes: 1990-2019 to 2020-2049					
Variable	**1980 to 2019 Trend**	**Climate Simulations**	**Literature Consensus**	**Official Forecast Direction Change**	**Official Forecast Confidence**
Annual Temperature	++	+++	++	++	High
Annual Precipitation	+	0	+	+	Medium
Annual Solar Radiation	0	0	0	0	High
Wind Storms	+	-	+	+	Medium
Wet Snow Storms	+	0	NA	+	Medium
Ice Storms	0	+	0	0	Low
Heavy Precipitation Events	++	0	++	++	High

Sign Change Key		Annual Temperature	Annual Precipitation	Wind Storms	Wet Snow Storms	Ice Storms	Heavy Precipitation Events
+++	Strong increase	+2 to +3°F	+5 to 7"	+11 to 15%			
++	Moderate increase	+1 to +2°F	+3 to 5"	+6 to 10%			
+	Slight increase	+0.3 to 1°F	+1 to 2"	+2 to 5%			
0	Little to no change	-0.2 to +0.2°F	-1 to +1"	-2 to + 2%			
-	Slight decrease	-0.3 to -1°F	-1 to 2"	-2 to -5%			
--	Modderate decrease	-1 to -2°F	-3 to 5"	-6 to -10%			
---	Strong decrease	-2 to -3°F	-5 to 7"	-11 to -15%			

Table 5. Official forecasts and sign changes for each predicted variabile with accompanying forecast confidence.

b) Extreme weather events

Extreme weather events were examined in three major categories with respect to future projections. Hazards from thunderstorms (wind gusts and flash flooding) were not examined extensively, as there is limited literature in these areas and the scientific certainty is low given the complexities around convective processes. All three major large-scale storm classes (wind, wet snow, and ice) have distribution system outages that are anticipated to increase through 2049 (Table 6). The general fraction of outage risks is not projected to change significantly from historic values, with wind storms remaining the most significant threat to distribution system outages.

Increases in storm risk arise more from storms becoming more intense than frequent. A warming climate does generally provide more capacity for wind storms such as those related to tropical storms/hurricanes interacting with mid latitude storm systems to be more intense. A warming atmosphere also produces the potential for heavy precipitation events (Table 5). The low frequency of ice storms combined with the phase challenges makes ice storms a low confidence forecast. Overall distribution system power outages are projected to increase approximately 5% through 2049 compared to the prior thirty years with a moderate level of confidence.

Vermont Power Outage Risk Profile Projection: 2020 to 2049						
Hazard	**Fraction of Outage Risk**	**Frequency Change**	**Intensity Change**	**Projection Confidence**	**Overall Risk Change Sign**	**Overall Risk Change %**
Wind Storms	73%	0	+	Medium	+++	+3 to +5%
Wet Snow Storms	23%	+	+	Medium	++	+6 to +10%
Ice Storms	4%	+	0	Low	+	0 to +2%
				Overall Risk Change		+4 to +6%

Table 6. Distribution system power outage risk assessment projection.

The climate simulations generally show a higher number of wet snow and freezing rain ice events during the winter season (Figure 33), which is consistent with a warming climate producing more storms that cross precipitation type/phase as a result of varying temperatures throughout storm systems. These factors suggest that the winter storm season will feature greater outage impacts. Both climate simulations show similar behavior to the frequency of wet snow and ice events; these results also support the idea that the climate will still remain cold enough in Vermont to sustain wet snow and ice risks. However, as the climate warms there will be a tipping point sometime after these climate simulations end in 2049 where more rainfall dominates winter precipitation, reducing the frequency of snow and ice.

Figure 36 examines weather hazards and climate changes and their general sign changes and levels of confidence. High confidence changes occur with temperature, with extreme heat being more likely. For precipitation, extreme precipitation events, which are usually heavy rainfall, are increasing faster than annual precipitation with a fairly high degree of confidence. Low confidence forecast weather behavior includes ice storms and thunderstorms. The occurrence of drought is also likely to increase, despite increases in precipitation, thus the variability of precipitation both year to year and within seasons is likely to increase.

Influences on vegetation health and growth primarily arise from temperature and precipitation variability. The growing season is generally projected to increase, however, year-to-year precipitation variability and a variety of other factors (e.g., invasive species, species migration) make this work difficult to determine how vegetation management may be impacted. The climate generally appears fairly stable for vegetation health and growth through 2049, thus no substantial impacts on vegetation are able to be determined within this work. The asynchronous nature of tree growth responding to environmental stimuli and limited tree data sets prohibited more comprehensive results with how climate change may affect vegetation management. Figure 36 generally shows that most weather and climate risks are changing in a direction that increases overall risks to the distribution and transmission grids.

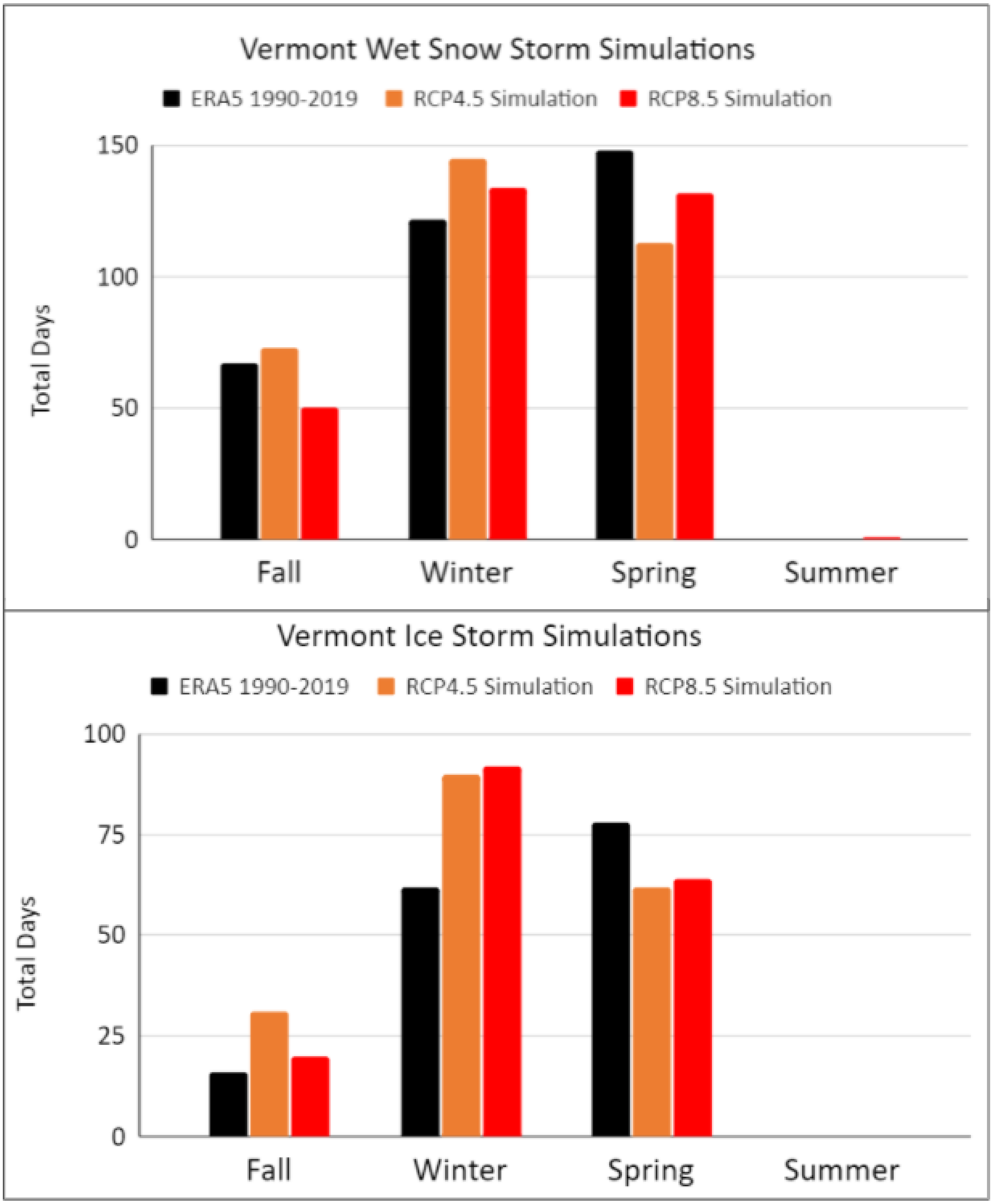

Figure 33. Climate simulations for significant wet snow and ice accumulation days from 2020 to 2049.

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c) Peak load management

Peak electricity demand correlates strongly with extreme temperatures in Vermont, largely due to significant cooling demands during summer heat and heating demand during winter cold. The highest loads typically occur during the hottest or coldest periods (over multiple days), and not necessarily the coldest single day of the year. Other factors such as the time of the day and day of the week have a strong influence on electricity demand. Trends in heat waves show a general increase in the last 60 years, with the 2010s featuring 71 events (Figure 34), or on average 7 events per year. Cold waves, on the other hand, have declined more steadily, with only 19 events (about two per year) during the 2010s, declining from around five to six per year in the 1970s. These trends are consistent with climate change trends of warming temperatures. The next thirty years will likely feature a trend toward more heat waves and fewer cold waves as the climate continues to warm. Additionally, the most extreme cold temperatures will also continue to decline in intensity slightly.

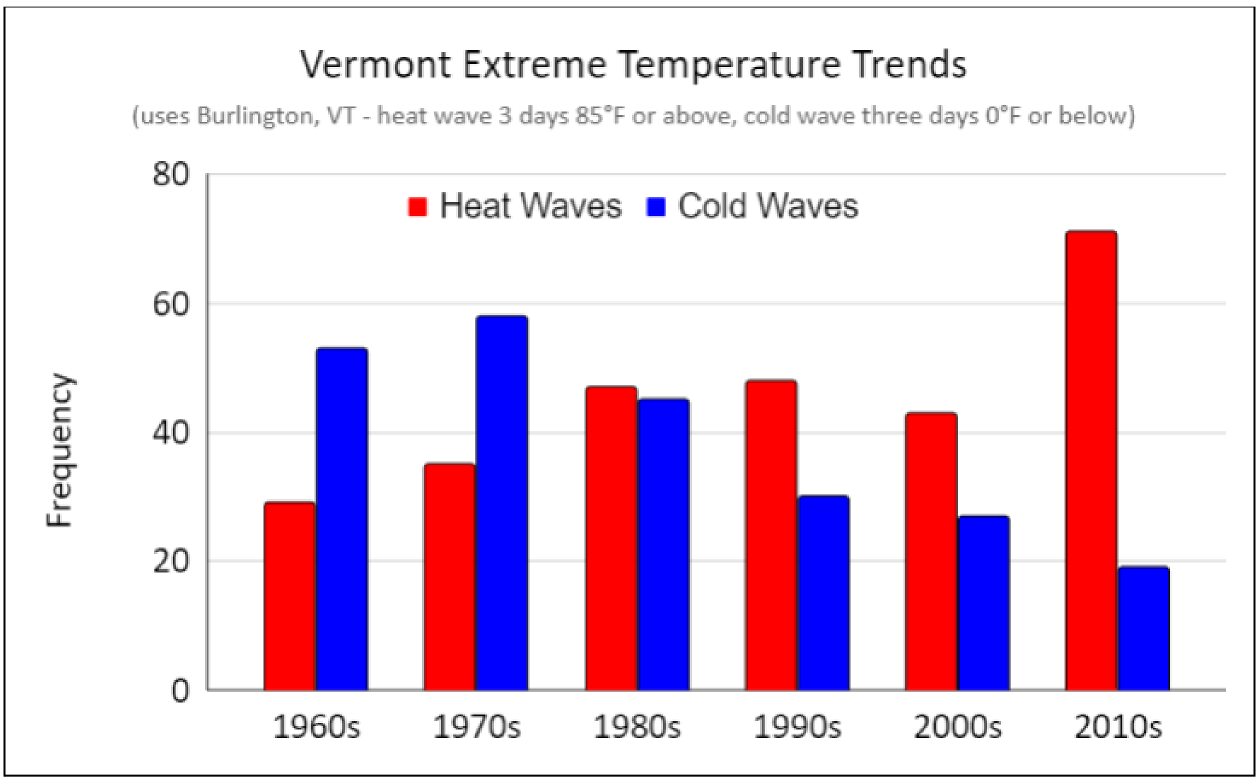
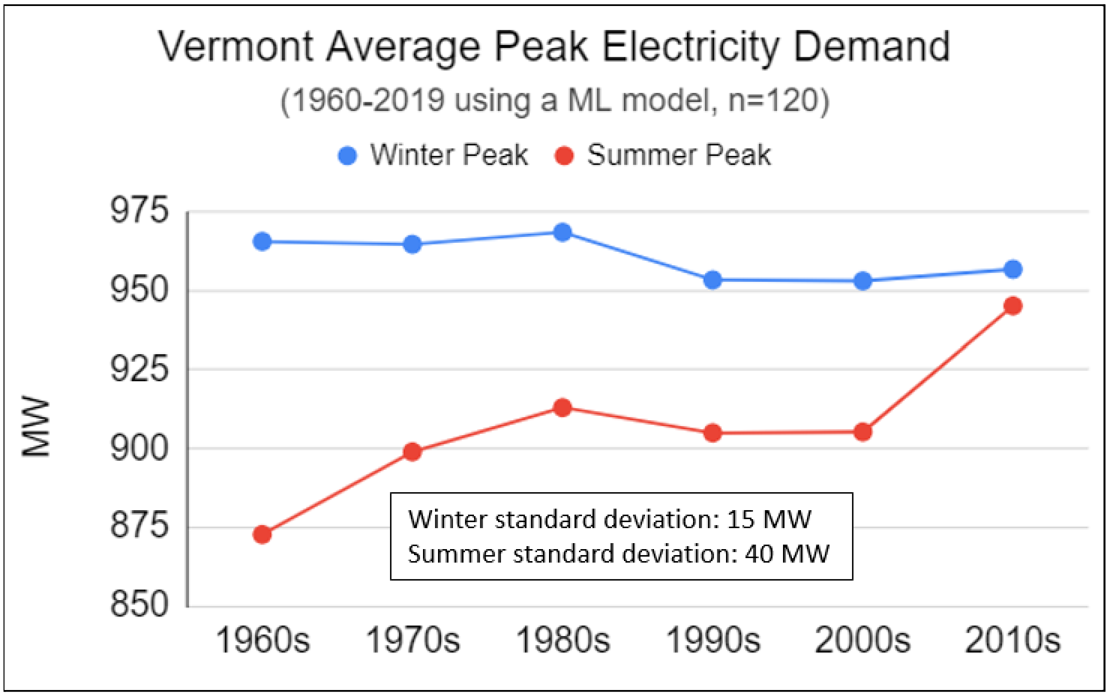


Figure 34. Extreme temperature trends across Vermont. Derived from Burlington, VT, observed air temperatures. A heat wave is defined as three consecutive days with a high temperature at or above 85°F. A cold wave is defined as three consecutive days with a low temperature of 0°F or colder.

In order to understand the effects of trends of warming on peak electricity demand, a machine learning model is used to reconstruct historical daily peak load. This model takes into consideration three years of observed peak load data for training provided by VELCO from 2017-2019, observed temperatures at Burlington, VT, and other variables such as the day of the week (workday, holiday) to develop a backward-looking model. This model shows a general reduction in winter peak demand while an increase in summer peaks (Figure 35). Variability with the summer peak is 2.5x higher than the winter peak variability. The trend of greater summertime peaks is likely to continue in a warming climate, which is anticipated to warm approximately 1.4°F to 1.6° F across Vermont by 2049. Additionally, the seasonality of peak loads during summer will likely continue to extend into late summer and early fall following warming temperature trends (Figure 35).



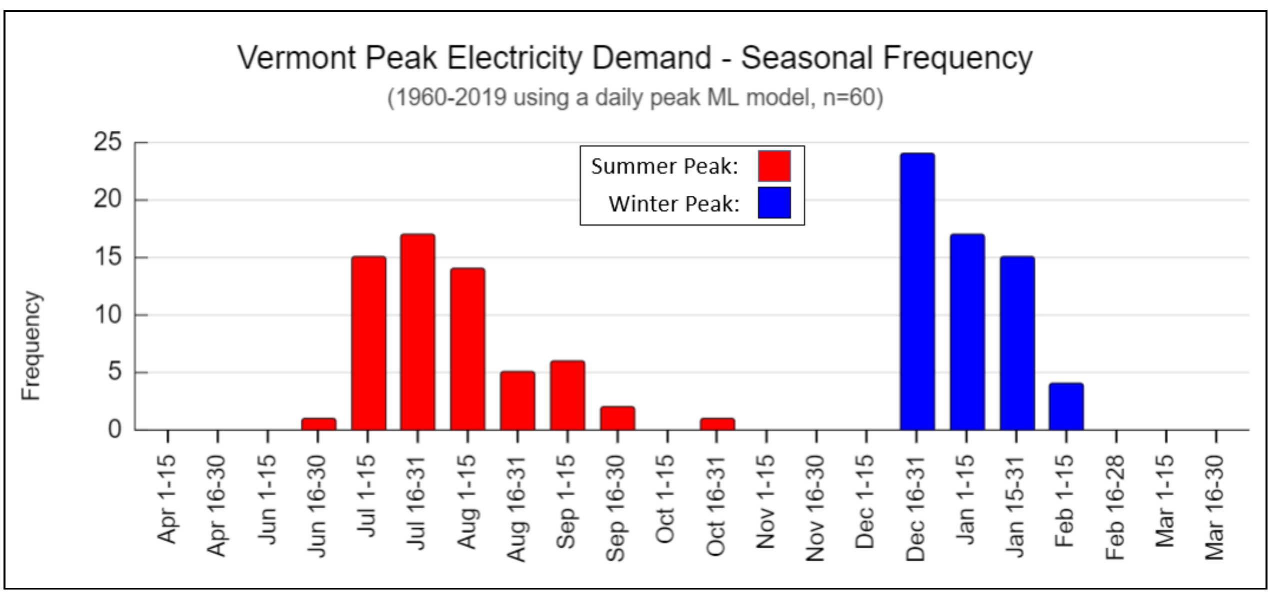


Figure 35. Top: Vermont peak load aggregated by decade using a machine-learning model trained on three years of observed Vermont-wide demand (2017-2019). Bottom: Modeled peak seasonal demand based on the same model.

d) Design Standards

VELCO asked that the specific extreme weather criteria in Table 7 be examined in more detail to help evaluate the efficacy of meeting current ASCE standards for ice and wind loading conditions. The primary intention of this analysis is to understand how climate change may affect wind and ice loading risks. This analysis starts with an historic simulation of all ice loading and wind across VELCO's system to establish a baseline or climatology. The period of record for this analysis extended from 1980-2019, at an hourly timescale and a native spatial resolution of 5km; this 40-year period is not sufficient to capture all extreme storm events that the current climate could support. However, this 40-year period can provide reasonable insight into identifying the location(s) of VELCO assets potentially at greater risk to ice and high wind.

Radial ice is the average ice thickness when uniformly distributed around a cylinder or conductor element. Thus, 0.5" of radial ice uniformly distributed around a conductor will measure 0.5" from the conductor to the edge of the ice at all radials. It takes at least 2.5 times the amount of freezing rain liquid to produce the equivalent radial ice thickness; thus, in order to get 0.5" of radial ice, at least 1.5" of freezing rain liquid precipitation is necessary (assuming nearly 100% efficiency converting freezing rain to ice). Given other efficiency factors of converting freezing rain to ice such as wind speed, air temperature, and precipitation rate (Sanders and Barjenbruch 2016), this efficiency factor of converting freezing rain to ice is lower (often ranging from 30-70%). This means that 2" to 3" of long-duration freezing rain liquid is likely needed to meet or exceed 0.5" of radial ice thickness.

Evaluation Condition	Wind Speed (3-second gust)	Radial Ice Thickness (inches)
Condition #1	40 mph	0.50"
Condition #2	40 mph	0.75"
Condition #3	40 mph	1.0"
Condition #4	40 mph	1.5
Condition #5	75 mph	0
Condition #6	90 mph	0

Table 7. Simultaneous extreme weather states that were evaluated for design standards across the 1980-2019 simulation of all weather systems..

When analyzing 24-hour duration accumulations of radial ice thickness from 1980-2019, no locations in Vermont met or exceeded radial ice thickness values of 0.5", or conditions #1 to #4 in Table 7 were not exceeded. Long-duration freezing rain events can extend beyond 24-hour duration, thus a 48-hour accumulation or duration period was analyzed. The 24-hour and 48-hour accumulation assumes that there is no melting of ice, which results in a high bias. Figure 36 shows the maximum radial ice accretion across Vermont from 1980-2019 as accumulated during a 48-hour period (this was a 48-hour summation of hourly values and assumes no melting). The maximum statewide radial ice accretion was just over 0.5” in the highest elevations of Bennington and Windham County. Higher radial ice accumulations generally correlate with elevation to the east of the Green Mountain crest (higher values at higher elevations), but are more variable with elevation west of the Green Mountains. Low-level cold air masses can persist within storms to the west of the Green Mountains in the Champlain Valley, potentially resulting in lower elevation icing.

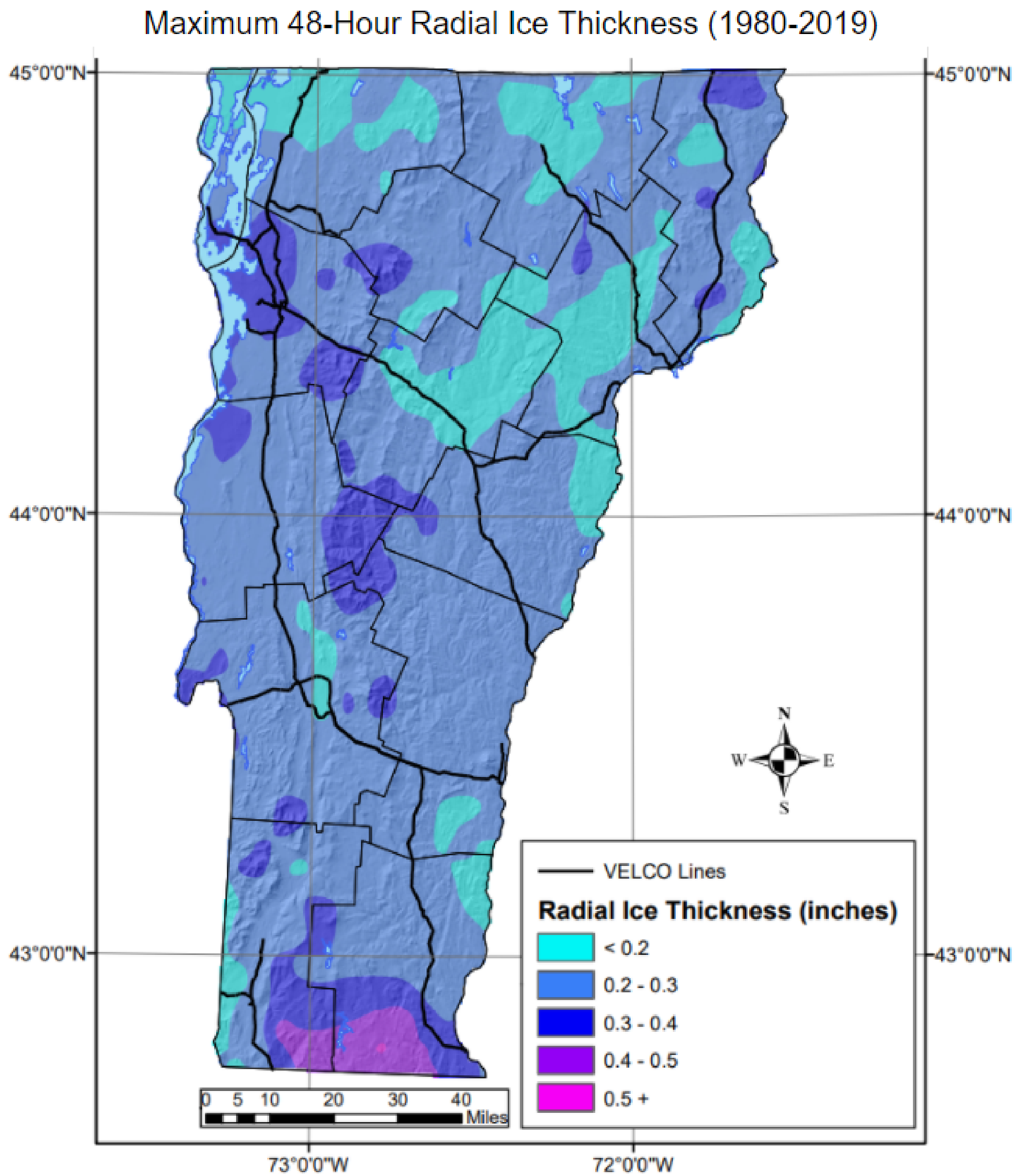


Figure 36. Maximum 48-hour duration radial ice thickness (inches), 1980-2019. Created using hourly data at a native spatial resolution of 5 km.

This analysis does not incorporate ice loading from wet snowfall. There are no published wet snowfall icing ASCE standards for lines or towers. Rather, snow loading design standards are often applied for building construction to meet minimum criteria for total snow mass accumulating on roofs. Wet snowfall icing occurs when partially melted snowflakes accrete or stick onto elevated objects, and occurs in a narrow range of temperatures just below freezing. Wet snowfall can occur during a storm cycle featuring freezing rain, and may be a secondary factor, but most storm systems with icing feature either freezing or wet snowfall and not a combination of the two. Examination of wet snow icing shows 48-hour maximum values that are equal to or greater than the equivalent radial ice accretion (not shown). This magnitude suggests that wet snow icing could be one of the design standards to evaluate. However, since there are no published standards or models to apply wet snow accretion efficiency (the fraction of wet snow that accretes to lines or towers), the unknowns remain too high to fully evaluate without moderate to high uncertainty.

Based on climate simulations and other literature on ice storm risk and climate change, there does not exist strong evidence to show that future climate states through 2050 would support long-duration freezing rain events that would be greater than the current climate state. VELCO's current standards as in Table 7 for ice accretion from freezing rain appear sufficient.

In order to investigate conditions #5 and #6 from Table 7, the peak wind gusts observed over the last decade (2010-2020) were used to create a peak wind speed model based on elevation. Peak wind speeds within mid latitude climates show an increase of wind with elevation. Reduced friction, local terrain accelerations over barriers, and increasing pressure gradients result in stronger winds occurring generally with elevation.

Table 8 shows the peak wind gusts observed from 2010 to 2020, with Mt. Washington the highest at 160 mph, while Mt. Mansfield experienced a wind gust of 103 mph. The highest valley locations were between 65 and 70 mph (Bennington, Morrisville and Lake Champlain). Using a linear regression equation of the data within Table 8, a peak wind elevation model was derived (peak wind gust = 0.0157*(elevation ft)+52.795. This model is shaded in Figure 36, showing peak values above 75 mph at elevations of 1500' and higher (condition #5 - Table 7), and 90 mph around 2,400' elevation and higher (condition #6 - Table 7). This eleven-year period did not, however, feature an extreme wind storm. Some reasonable multiplier of these 11-year peak wind gust values to account for the most extreme storms would be one approach to examining the possible bounds the current climate could support. However, available data and methods to accomplish this are beyond the capabilities of this project.

The most extreme wind storms that the VELCO system could experience would likely be from a landfalling tropical storm or Hurricane (e.g., Hurricane of 1938). A warmer and wetter climate does increase the potential intensity of gradient wind storms and Hurricanes, with Hurricanes and Tropical Storms maintaining their strength longer at higher latitudes. Additional research would be needed to estimate how much stronger a potential wind storm could be, but reasonable estimates suggest an increase of 10-25% of current peak wind gust values as those shown in Figure 36 and Table 8.

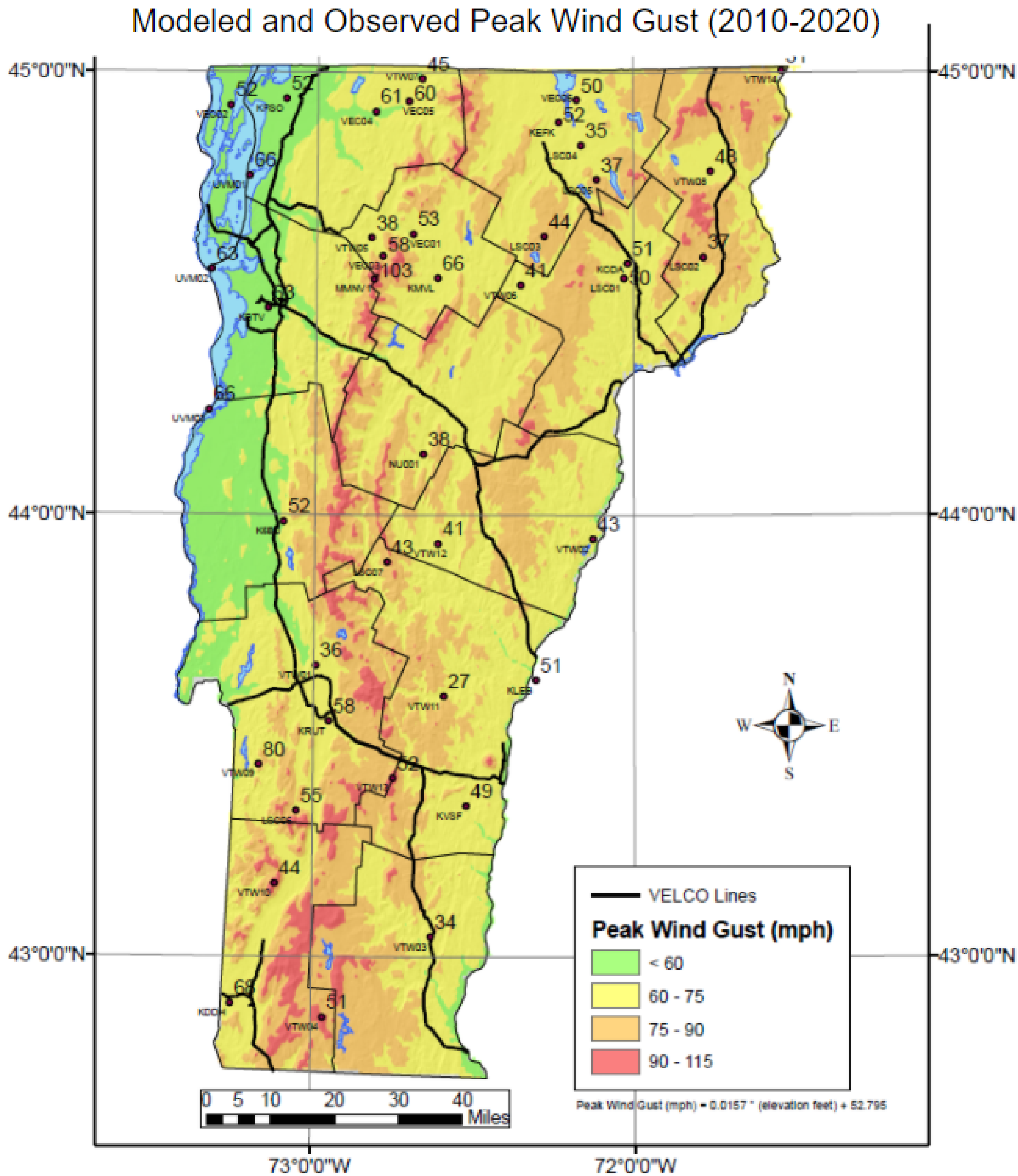


Figure 36. Maximum 48-hour duration radial ice thickness (inches), 1980-2019. Created using hourly data at a spatial resolution of 5 km.

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Station ID	Peak Wind (mph)	Latitude	Longitude
KMWN	160	44.27086	-71.30337
MMNV1	103	44.53330	-72.81670
VTW09	80	43.43532	-73.16679
KDDH	68	42.89355	-73.24860
KMVL	66	44.53589	-72.61625
UVM01	66	44.76660	-73.21340
UVM03	66	44.23680	-73.33340
KBTV	63	44.46806	-73.15028
UVM02	63	44.55510	-73.32920
VEC04	61	44.91145	-72.81442
VEC05	60	44.93532	-72.70930
KRUT	58	43.53333	-72.95000
VEC03	58	44.58542	-72.78916
LSC06	55	43.33107	-73.04978
VEC01	53	44.63528	-72.69424
K6B0	52	43.98480	-73.09590
KEFK	52	44.88846	-72.23593
KFSO	52	44.94028	-73.09746
VEC02	52	44.92445	-73.27516
VTW13	52	43.40507	-72.75024
KCDA	51	44.56911	-72.01798
KLEB	51	43.62710	-72.30537
VTW04	51	42.86236	-72.96412
LSC01	50	44.53572	-72.02860
VEC06	50	44.93859	-72.17940
KVSF	49	43.34250	-72.52167
VTW08	48	44.77756	-71.75471
VTW07	45	44.98638	-72.66776
LSC03	44	44.63067	-72.28083
VTW10	44	43.16624	-73.11467
LSC07	43	43.89400	-72.77150
VTW02	43	43.94631	-72.12769
VTW06	41	44.52034	-72.35455
VTW12	41	43.93490	-72.61227

Table 8. Peak wind gusts observed from 2010-2020 from National Weather Service and VTWAC stations (https://mesowest.utah.edu/cgi-bin/droman/stn_mnet.cgi?mnet=201). Values below 40 mph are excluded, but are shown in Figure 36.

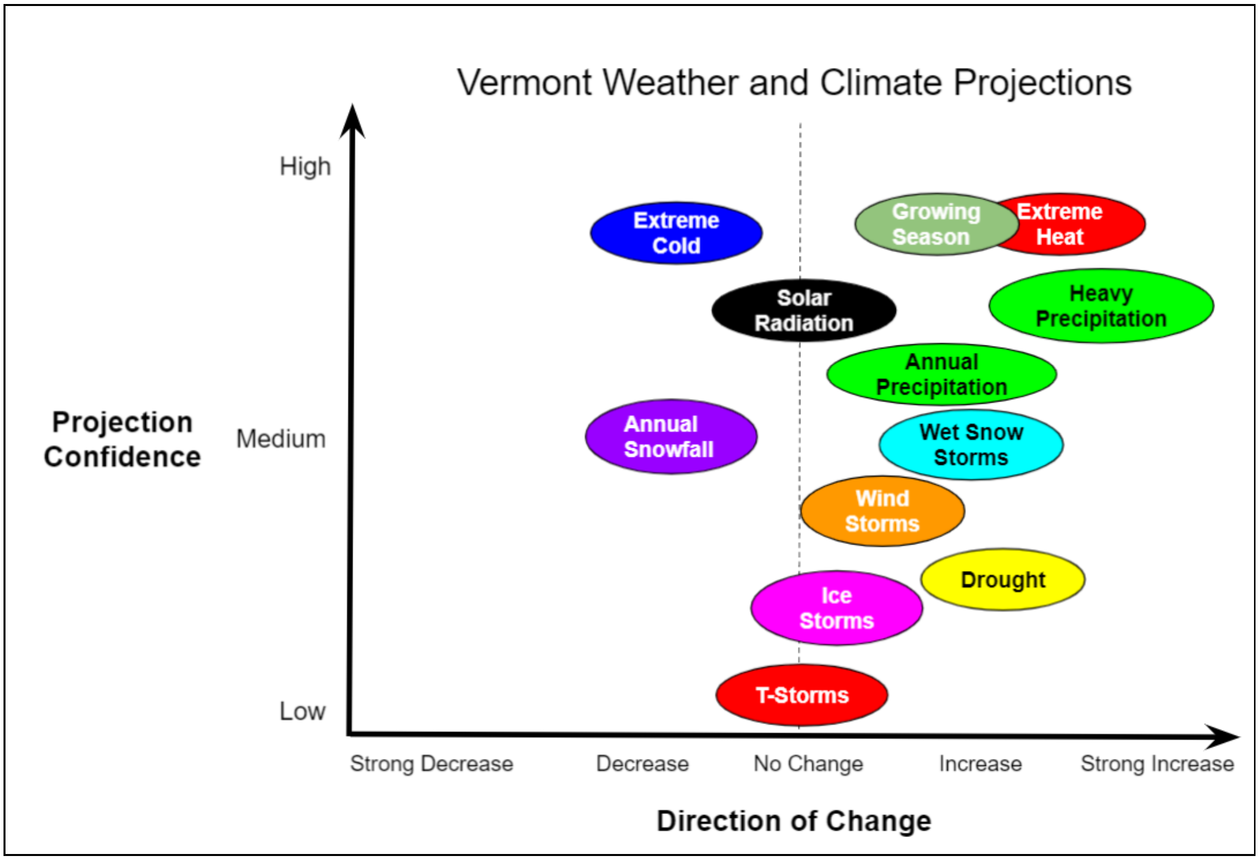

Figure 36. Vermont weather hazards and climate states directionality with projection confidence referenced from 1990-2019 to 2020-2049.

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7. Summary and Conclusions

This report describes how climate change may present itself through the behavior of weather systems and climate states and how these collective changes may affect the reliable operation of Vermont's electric grid through 2049. Overall risk to operating the electric grid does appear to increase primarily as a result of potentially more intense storm systems. Wind storms represent the greatest risk, with over 70% of all weather-caused distribution system outages produced by wind that may cause tree conflicts within or from outside right of ways, or when extreme winds exceed rated design standards. Secondary risk factors such as wind direction and soil moisture were also examined, but given asynchronous effects and data limitations, this analysis was based primarily on one-variable synchronous impacts. Trends in power outage impacts show an increase of weather-caused power outages of approximately +2 to +4% for the 20-year trend (1980-1990 vs. 2000-2019). The most severe storms have increased their outage impacts by +10% to +15% (1980-1990 vs. 2000-2019), and account for a large fraction of overall outage risk. An increase of distribution system power outages around +5% is projected with a moderate degree of confidence for overall statewide aggregated power outage risk through 2049 (1990-2019 to 2020-2049).

There is a high degree of confidence that Vermont's climate is warming and becoming wetter, both of which will likely continue to increase into the future. Warmer and wetter storm systems generally produce storms that are more intense (not necessarily more frequent). Seasonal changes to the warm season show a widening of the summer into early fall, which is expected to continue. This warm season widening will have the effect of lengthening the fall storm season into early winter (over 50% of all power outage impacts occur October to December). The most extreme storms (e.g., Superstorm Sandy, Tropical Storm Phillippe extratropical transition) still appear most likely during the mid-fall season from approximately mid October to early November when the climatological nexus of tropical moisture and mid latitude temperature gradients creates significant energy for storm development. Widespread extreme precipitation and resulting flooding also peaks for these mid-fall storms when surface runoff is greater. Despite a warming winter, this work also shows that the winter season will remain cold enough to sustain wet snow and ice storm risks through 2049, with wet snowfall risks continuing to increase. Midwinter will likely feature fewer quieter outage impact periods as a result of warmer winters.

The transmission system likely features slightly greater risk from low-frequency, high-impact storms as potential storm intensity increases; this more than likely would be from inland-tracking tropical storms or hurricanes. Given the low frequency of such extreme wind risks, however, it is difficult to determine the "storm intensity speed limit" of future storms as regulated by temperature increases and storm behavior changes.

Regarding peak load system management, more extreme high temperatures will tend to shift annual peak loads to summertime. Extreme cold will still occur but the distribution of temperatures will tend to grow to the right hand tail (heat extremes) faster and move slowly away from the left hand tail (cold extremes). The seasonality of peak demand will likely feature greater late-summer season and early fall peak events associated with seasonal warming and an extension of the warm season. Solar energy impacts from changes in incoming solar radiation did not appear to be significant when aggregated annually. However, seasonal changes of a warmer late summer and early fall period will likely produce sunnier conditions, resulting in midday behind-the-meter solar PV load minimums continuing well into the fall shoulder season. Annual yields of solar energy do not appear to vary significantly through 2049 from current year-to-year variability.

With respect to design standards, the evaluation of radial ice loading shows that current standards are likely sufficient through the next 30 years. There are competing effects that result in a low confidence understanding of long-duration freezing rain icing; winter will continue to get wetter producing winter storms that could have more freezing rain, but at the same time storms will be warmer and thus may not have as much cold air to sustain freezing long-duration rain. Peak wind gusts from Hurricanes likely have the potential to produce stronger storms with higher wind gusts at higher latitudes if they are able to track inland. The ice and wind climatology show that there may be an opportunity to geographically and topographically evaluate standards as they relate to future system design.

Heavy precipitation events are expected to continue to increase around twice as fast as annual precipitation. A higher frequency of heavy precipitation events may result in greater widespread flooding risks, especially during the fall season. More irregular precipitation patterns are also likely, potentially leading to more intense drought conditions. However, vegetation health and growth analysis show no clear or strong indications as to how precipitation changes may affect future tree health and growth. The availability of soil moisture will continue to be the most important control of seasonal tree growth. Future work could examine vegetation management applications, but the time and effort required to investigate this may yield few results for the investment.

Information and insights provided within the report suggests that additional investments are likely needed to maintain reliability as the effects of climate change produce increased system risks. Increasing system resilience through more aggressive vegetation management, replacing aging infrastructure, and/or hardening existing assets may all be effective strategies in responding to climate change risks.

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1.0 Transmission & Distribution System Analysis

In 2023, WEC developed a Long Range Plan (LRP) in accordance with the USDA Rural Utility Services (RUS) requirements. This study analyzed WEC's system as it currently exists and also considered a ten-year planning horizon, accounting for anticipated increases in load and distributed generation. This was a detailed and comprehensive study of WEC's Transmission and Distribution (T&D) system, including the sub-transmission lines that serve the distribution substations.

Through the course of the study, it became apparent that the WEC T&D system will be facing some unprecedented challenges in the coming years. Due to increasing electrification and addition of new members, WEC is now experiencing significant load growth and a high rate of Distributed Energy Resource (DER) deployment. At the same time, there is a need to replace aging and thermally limited assets such as the #8 Jackson Corners and #3 Mount Knox substations. Presently, all of WEC's circuits experience their peak loading during the winter months. WEC's circuit loading data is currently monitored using thermal demand ammeters that are checked monthly, so it is not possible to determine what time of day the peak load is occurring. However, it is very likely that the peak load occurs when solar photovoltaic (PV) arrays are at minimal to no output, such as when they are covered with snow, or the sun has set. Therefore, the addition of solar PV generation is not anticipated to provide a reduction in peak load growth on the WEC system. The current level of DER penetration is approaching, and in some cases exceeding, the load carrying capability of some assets. A prime example is the #8 Jackson Corners substation transformer, which is at risk of overload due to reverse power flow from DER during times of high solar output and also during peak load times due to normal system loads.

Reliability remains a chief concern for both WEC and its members. In order to continue to provide safe and reliable service while accommodating the increases in load and distributed generation, WEC's T&D system must be made stronger and more resilient with greater redundancy and connectivity. These needs are further emphasized by the increasing frequency of extreme weather events.

1.1 Overview

1.1.1 Sub-Transmission

WEC owns five sub-transmission lines. Four are radial and serve the distribution circuits. The fifth serves the Coventry Landfill Gas Generating Station. See table below for more details.

Line	Station Served	Operating Voltage	Line Miles
East Montpelier to Maple Corners Line	Maple Corners	34.5 kV	8.99
Graniteville to Jackson Corners Line	Jackson Corners	34.5 kV	4.45
GMP 3319 Tap to Walden Feed	South Walden	34.5 kV	2.26
VELCO Chelsea to Tunbridge Line	North Tunbridge	46 kV	2.6
Coventry	Coventry Landfill Gas Generating Station	46 kV	7.3

Table 1: WEC Owned Sub-Transmission Lines

The ratings of the sub-transmission lines that serve the WEC distribution substations are listed below. In the analysis, each of the listed lines was evaluated for thermal loading over the next 10 years.

Line	Limiting Element		
	Description	Rating (Amps)	MVA
East Montpelier to Maple Corners Line	4/0 ACSR Conductor	357	21.31
Graniteville to Jackson Corners Line	4/0 ACSR Conductor	357	21.31

GMP 3319 Tap to Walden Feed	2/0 ACSR[1]	276	16.48
VELCO Chelsea to Tunbridge Line	4/0 ACSR Conductor	357	21.31

Table 2: WEC Owned Sub-Transmission Line ratings that supply Distribution Substations

1.1.2 Substations

The Supply Transformers at each of the WEC distribution substations and the name plate rating of each are listed below.

Substation Transformer	Transformer Nameplate Rating (kVA)
#1 East Montpelier	(3) - 1,667, Total 5,001
#2 Jones Brook (Metering Point)	N/A[2]
#3 Mount Knox	(3) – 1,250, Total 3,750
#4 West Danville	(3) – 500, Total 1,500
#5 South Walden	(3) – 1,250, Total 3,750
#8 Jackson Corners	(1) - 3,750
#9 Moretown	(3) – 1,250, Total 3,750
#10 Maple Corners	(3) – 833 Total 2,499
#11 North Tunbridge	(3) – 1,250, Total 3,750

Table 3: Existing Supply Transformers

The limiting element for each of the distribution substations is shown below.

[1] This line has approximately 10,953 feet of 2/0ACSR and approximately 1,006 feet of 4/0AAAC.
[2] Substation Transformer is located at the GMP #27 Mountain View Substation.

Substation	Limiting Element		
	Device	Rating (Amps)	Rating (kVA)
#1 East Montpelier	Transformer Bank - (3) 1,667 kVA	231.5	5,001
#2 Jones Brook (Metering Point) Single Phase Circuit	50H Single phase recloser	50	360
#3 Mount Knox	Bus Regulators - (3) 150A *Transformer Bank - (3) 1,250 kVA*	150	3,240
#4 West Danville	Transformer Bank - (3) 500 kVA	69	1,500
#5 South Walden	Transformer Bank - (3) 1,250 kVA	174	3,750
#8 Jackson Corners	Transformer Bank – (1) – 3,750 kVA *Bus Regulators – (3) – 219A*	174	3,750
#9 Moretown	Transformer Bank – (3) – 1,250 kVA	174	3,750
#10 Maple Corners	Transformer Bank - (3) 833 kVA	116	2,499
#11 North Tunbridge	Bus Regulators - (3) 150A *Transformer Bank - (3) 1,250 kVA*	150	3,240

Table 4: Distribution Substation – Limiting Element

1.1.3 Substations in 100 and 500 year flood plains

WEC reviewed effective Flood Insurance Rate Maps (FIRMS) available through the Flood Map Service Center (MSC) for each substation location. The FIRM maps are the official public source for flood hazard information produced in support of the National Flood Insurance Program.

For locations where a FEMA flood map was available each location was mapped using a street addressing and or coordinate based search to find the most current (if available) flood map for the local area. An evaluation of each location was completed to determine if the site was located within the 100- or 500-year flood plain.

FHA Zone Definitions:

- **<u>Zone A:</u>** Areas that have a 1% probability of flooding every year (also known as the 100-year flood plain) and where predicted flood water elevations above mean sea level have not been established.

- **<u>Zone C and X:</u>** Area of minimal flood hazard, usually depicted as above the 500-year flood level. Zone C may have ponding or drainage problems that are not designated as flood plains. Zone X is the area determined to be outside the 500-year floodplain.

The table below lists WEC substations and whether or not they fall within the 100- and 500-year flood plains and the FHA associated with each of these locations.

Substation	100 Year	500 Year	FHA Zone
#1 East Montpelier	No	No	X
#3 Mount Knox	No	No	X
#4 West Danville	N/A	N/A	N/A
#5 South Walden	N/A	N/A	N/A
#8 Jackson Corners	N/A	N/A	N/A
#9 Moretown	No	No	X
#10 Maple Corners	Yes*	Yes*	A
#11 North Tunbridge	No	No	C

Table 4A: Existing Supply Transformers

FIRM maps were not available for three WEC substations listed above; #4 West Danville, #5 South Walden and #8 Jackson Corners. These substations are located at higher elevations that would not be affected by any flood waters.

*Flood maps show the southeast corner of the Maple Corners substation yard within Zone A. WEC believes this is due to the potential for the Curtis Pond dam, which is located 0.43 miles to the northeast of the substation, to fail during times of extremely high rainfall. WEC noted during the July 2023 flood event, flood waters did not reach the southeast corner of the substation.

1.1.4 Distribution System

The existing WEC Distribution system has approximately 1,233 miles of overhead lines and 33 miles of underground lines, for a total of 1,266 miles, see detail in Table 5. The Distribution system operates at 12.47/7.2 kV, with four wire, grounded-wye radial circuits that are voltage regulated at each substation. The majority of substations are served by radial 34.5 kV sub-transmission lines served by Green Mountain Power (GMP). WEC-owned sub-transmission lines feed the #5 South Walden, #8 Jackson Corners, and #10 Maple Corners via radial 34.5 kV lines, and the #11 South Tunbridge substation is fed by a radial 46 kV line. Additional distribution loads are served by the # 2 Jones Brook circuit which is supplied by a GMP 12.47 kV primary metering point.

The limiting element for each of the distribution circuits, at the substation, is listed in Table 6.

Circuit Conductor & Meter Counts				
Substation	**Circuit**	**Overhead** *(Approximate Miles)*	**Underground** *(Approximate Miles)*	**Meters**
#1 East Montpelier	#1 Cabot	44.2	1.6	280
	#2 Orange	87.9	2.0	890
	#3 County Rd	57.1	2.7	612
#2 Jones Brook ***Metering Point***	#1 Jones Brook	10.0	0.0	80
#3 Mt. Knox	#1 Peacham	63.9	0.9	555

	#2 Corinth	155.5	2.1	1447
#4 West Danville	#1 Hookerville (AØ) #2 West Danville (BØ) #3 Peacham (CØ)	42.6	2.6	461
#5 South Walden	#1 Greensboro	59.8	0.5	455
	#2 East Cabot	54.8	0.7	498
	#3 West Hill Pond	40.9	0.3	324
#8 Jackson Corners	#1 Topsham	42.7	0.9	455
	#2 Chelsea	60.8	0.6	352
	#3 Northfield	123.3	4.2	1385
#9 Moretown	#1 Middlesex	45.6	1.7	503
	#2 Moretown Common	17.7	1.4	164
	#3 Fayston	67.9	5.7	892
#10 Maple Corners	#1 North Calais	35.3	1.0	298
	#2 Middlesex	58.0	0.7	603
#11 North Tunbridge	#1 Corinth	86.6	1.9	705
	#2 South Tunbridge	38.8	0.6	241
	#3 Brookfield	39.5	0.6	267
Totals	23	1,233	32.6	11,467

Table 5: WEC Substations & Circuits Line miles & Meter count

Substation	Circuit	Device	Limiting Element	
			Amps	kVA
#1 East Montpelier	#1 Cabot	Voltage Regulators – (3) 150A Recloser Bypass – (3) 150A	150	3,240
	#2 Orange	Voltage Regulators – (3) 150A Recloser Bypass – (3) 150A	150	3,240
	#3 County Road	Voltage Regulators – (3) 150A Recloser Bypass – (3) 150A	150	3,240
#2 Jones Brook (Metering Point)	#2 Jones Brook	50H Single phase recloser	50	360
#3 Mount Knox	#1 Peacham	Recloser Bypass – 100K	150	3,240
	#2 Corinth	Recloser Bypass – 100K	150	3,240
#4 West Danville *(Single Phase Circuits)*	#1 Hookerville *(A Phase)*	Circuit Regulator – (3) 100A	100	720
	#2 West Danville *(B Phase)*	Circuit Regulator – (3) 100A	100	720
	#3 Peacham	Circuit Regulator – (3) 100A	100	720

Substation	Circuit	Device	Limiting Element	
			Amps	kVA
	(C Phase)			
#5 South Walden	#1 Greensboro	Voltage Regulators – (3) 150A Recloser Bypass – (3) 150A	150	3,240
	#2 Cabot	Voltage Regulators – (3) 150A Recloser Bypass – (3) 150A	150	3,240
	#3 West Hill Pond	Voltage Regulators – (3) 150A Recloser Bypass – (3) 150A	150	3,240
#8 Jackson Corners	#1 Topsham	Recloser Bypass	150	3,240
	#2 Chelsea	Recloser Bypass	150	3,240
	#3 Northfield	Recloser Bypass	150	3,240
#9 Moretown	#1 Middlesex	Voltage Regulators – (3) 150A Recloser Bypass – (3) 150A	150	3,240
	#2 Moretown	Circuit Recloser 70 V4L	70	1,512
	#3 Fayston	Circuit Regulator – (3) 75A	75	1,620
#10 Maple Corners	#1 North Calais	Circuit Regulator – (3) 100A	100	2,160
	#2 Middlesex	Circuit Regulator – (3) 100A	100	2,160
#11 North Tunbridge	#1 Corinth	Recloser Bypass – (3) 150A	150	3,240
	#2 South Tunbridge	Overhead Line – 6/8 CWC	100	720
	#3 Brookfield	Recloser Bypass – (3) 150A	150	3,240

Table 6: Distribution Circuit – Limiting Element

1.3 RUS Long Range Plan

WEC borrows money from the United States Department of Agriculture (USDA) Rural Utility Service (RUS) for its electrical system improvements. The Long Range Plan (LRP) is a periodic study that RUS borrowers are required to perform in order to qualify for funds. The LRP is based on USDA RUS Bulletin 1724D-101A, and its purpose is to develop plans for serving existing and future system loads while maintaining customer satisfaction and meeting environmental requirements. WEC's latest LRP was completed in 2023 and evaluated present peak load conditions, and minimum load conditions with and without DER exporting power. Load growth was forecast for the next ten years, and load flows were reviewed at projected load levels at four years and ten years to determine what upgrades would be necessary to continue to support load, voltage, power quality, existing level of fault duty, and improve reliability with least cost options. Asset condition and operational considerations were taken into account. Most upgrades did not have a viable alternative solution, with two notable exceptions:

1.) Improving reliability at Fayston Village - a strategic study was recommended for the next Construction Work Plan to determine if a new substation, a non-wires alternative, or another solution would be the best fit.
2.) Re-conductoring the #9 Moretown #1 Middlesex circuit with 477 kcmil ACSR or 4/0 AAAC - this upgrade is proposed in the 2032-2033 time frame. Due to equipment cost volatility, it was decided to defer the selection of conductor size until the upgrade is more imminent.

Protection was reviewed at the substation and circuit main line level. Aggregate DER was analyzed for negative effects on the system, and it was determined that Transmission Ground Fault Overvoltage (TGFOV) protection will be required at all the distribution substations (see section 8.2.10 for more details). An Arc Flash review was performed, and an updated collection of distribution Substation one-lines was drawn. The following sub-sections detail the work and findings in the LRP that are relevant to the IRP.

The RUS requires that its borrowing members provide a Construction Work Plan (CWP) which is a four-year plan of the proposed upgrades that the borrower is seeking to finance. The CWP is usually prepared every four years, so analysis for the LRP was done for existing or "Year 0", four years out or "Year 4", and at "Year 10" which is the furthest point that load is projected for.

The RUS recommends regular review of the LRP to ensure that the recommendations proposed are still relevant.

1.3.1 Study Criteria

The following Planning Criteria were used for the LRP analysis for normal and contingency (N-1) conditions and are based on RUS requirements and industry best practices:

- Thermal Criteria:
  - Substation Transformers: ≤ 100% of Top Nameplate Rating
  - Fuses, Reclosers, Switches: ≤ 100% of Top Nameplate Rating
  - Voltage Regulators: ≤ 100% of Top Nameplate Rating (without load bonus)
  - Overhead & Underground Conductors: ≤ 90% of Nominal Rating
- Protection Criteria:
  - Device pickups shall be 150% of the maximum current flow through the device.
  - Device Reach or Pickup Amps shall be ≥ 3 for bolted three-line and single line-to-ground faults.
- Voltage Criteria:
  - Within ANSI Range A (0.95 – 1.05 per-unit) [3]
  - Phase Imbalance < 3% between all phases
- Phase Balance:
  - Total phase imbalance should be < 50A.
- Transmission Ground Fault Overvoltage (TGFOV) Criteria:
  - Load-to-Generation Ratio < 2 on applicable transformer winding configurations.
- Power factor correction in the form of capacitors can reduce losses and improve voltage, provided that the capacitor is sized and placed judiciously. The criteria for installing a capacitor bank to reduce losses is for circuits with a power factor less than 95%.
- Asset Conditions

[3] ANSI C84.1 is the national standard for utilization voltage. ANSI Range A is the normal operating voltage which spans from 105% to 95% of nominal. ANSI Range B is the acceptable range for contingency conditions and spans from 106% to 91% of nominal.

- Sub-transmission Poles >50 years of age will be considered near end-of-life[4].
- Based on field information, testing, and/or WEC Operations consultation.

1.3.2 Load Data

The 2023 LRP load forecast was developed based on historical thermal demand ammeter data and, where available, Vermont Electric Power Company (VELCO) and GMP supervisory control and data acquisition (SCADA) data going back to January 1, 2018. Load data was not available for some circuits, so ratios were developed based on connected kVA or SCADA data was approximated to a circuit level using ratios of thermal demand ammeter data between circuits. It should be noted that thermal demand ammeter data is based on a manual reading of a device that reports the maximum demand that occurred over the time period since the device was last reset. Therefore, the data is neither coincidental nor does it provide insight as to the exact date and time the maximum demand occurred. The timeframe of reference for this data is the interval in which it is collected, typically on a monthly basis.

Historically, the WEC peak loading has occurred in the winter. In 2019/2020 and 2020/2021, some circuits had summer peaks. However, in the past two years (2021/2022 and 2022/2023), all circuits have been winter peaking. Peak loads observed on available SCADA data occurred between 5:45 PM and 11:00 PM, when solar PV would not have been generating. Since the majority of WEC's DER is PV, no load masking was assumed due to DER.

WEC load data was based on thermal demand ammeter data, which is collected at each substation monthly. Historical data for use in this study goes back to January 1st, 2018. Most of the WEC circuits have individual thermal demand ammeter data. At some substations, only bus load data is available. In those cases, the connected aggregate distribution transformer kVA ratings were used to determine the percentage loading for each circuit. GMP was able to provide 15-minute interval SCADA data for some of the 34.5 kV substation supply lines, and VELCO was also able to supply hourly interval data for the 46 kV sub-transmission line that serves the WEC #11 North Tunbridge substation. Interval data was used with the thermal demand ammeter data to determine peak loading for each substation and circuit. Kilowatthour consumption data from WEC's advanced metering infrastructure (AMI) system was also incorporated into the load flows which added another layer of granularity to loading across the system.

A 96% Power Factor was assumed for all circuit loads, except the #11 Tunbridge loads, which was based off one of the few locations where VAR data was available, from VELCO. In aggregate, the 96% load Power Factor matched the peak VAR demand recorded by the GMP feed to #1 East Montpelier and #10 Maple Corners substations.

The #11 Tunbridge substation load Power Factor was assumed to be 99.8%, which is not atypical for mostly residential circuits. This load Power Factor created a VAR demand at the head of the 46 kV sub-transmission line from VELCO Chelsea that matched VELCO's recorded peak loading for the line.

[4] USDA RUS Bulletin 1724D-101A RD-GD-2017-85

Note, load power factors refer to the individual loads on a circuit, the overall circuit will have a different power factor based on aggregate loads, losses, and the VARs supplied by capacitors connected to the circuit.

Minimum daytime loading was assumed to be 30% of peak load. This assumption is based on typical industry practice and has been found to be fairly accurate provided that the circuit is not a dedicated industrial feeder. Since this percentage is based on a peak load that occurred after the sun had set, there is a high level of confidence in the assumption since the loads do not include any inadvertent masking from DER which could make the minimum load appear even lower.

In order to more accurately monitor the load and generation across the WEC system, SCADA monitoring is recommended on each circuit. More accurate data could help WEC determine when an upgrade is needed more definitively. From an operational perspective, in the event of an outage SCADA can be used to determine if feeder backup is a viable option to restore members without risking additional members being taken out of service.

1.3.3 Load Forecast

As part of the LRP, a 10-year load forecast that was circuit and substation specific was developed in order to determine the need for system upgrades over a period extending to 2033. Two load forecasts were developed one that used the trend of existing historical loads, and another that applied publicly available load growth factors provided by ISO-NE (that were specific to Vermont) to account for electrification of transportation and heating.

The load forecast based on historic loading predicts a peak load of 21.53 MW in 10 years, while the forecast that factors in electrification efforts predicts a peak load of 26.493 MW in 10 years. Both projections are based on a current peak load of 17.839 MW. Historically, WEC has experienced minimal load growth, so the historical forecast is already a significant increase of 3.691 MW or 2.06% over a ten-year period. The electrification forecast is even more significant, projecting an increase of 8.657 MW or 4.85% over the same period.

These projections mean that several infrastructure upgrades are anticipated to be required to support WEC members' greater reliance on electricity to reduce their fossil fuel consumption. Due to WEC members increasingly anchoring their fundamental needs on electricity, reducing carbon also creates a push for more reliability-based upgrades such as feeder backup capability improvements including reconductoring and/or extending new three phase lines. These improvements can also strengthen the system for future growth. Since growth is likely to be more uneven than predicted, having greater connectivity across the system and higher capacity main lines will increase the flexibility of the WEC system to adapt to its members' needs.

Load Forecast Based on Historic Load Only												
Sub/Circuit	**LGR[5]**	Seasonal Year[6] Loads (kW)										
		2022-2023	**2023-2024**	**2024-2025**	**2025-2026**	**2026-2027**	**2027-2028**	**2028-2029**	**2029-2030**	**2030-2031**	**2031-2032**	**2032-2033**
#1 East Montpelier 12 kV	2.12%	3.314	3.385	3.456	3.530	3.604	3.681	3.759	3.838	3.920	4.003	4.087
#1 Cabot		0.566	0.578	0.590	0.602	0.615	0.628	0.642	0.655	0.669	0.683	0.698
#2 Orange		1.561	1.594	1.627	1.662	1.697	1.733	1.770	1.807	1.846	1.885	1.925
#3 County Rd		1.188	1.213	1.239	1.265	1.292	1.319	1.347	1.376	1.405	1.435	1.465
#2 Jones Brook Metering Point	0.00%	0.143	0.143	0.143	0.143	0.143	0.143	0.143	0.143	0.143	0.143	0.143
#3 Mount Knox	1.12%	2.796	2.827	2.859	2.891	2.923	2.956	2.989	3.023	3.056	3.091	3.125
#1 Peacham		0.755	0.763	0.772	0.781	0.789	0.798	0.807	0.816	0.825	0.834	0.844
#2 Corinth		2.041	2.064	2.087	2.110	2.134	2.158	2.182	2.207	2.231	2.256	2.281
#4 West Danville	1.48%	0.616	0.625	0.634	0.644	0.653	0.663	0.673	0.683	0.693	0.703	0.713
#1 Hookerville - AØ		0.153	0.156	0.158	0.160	0.163	0.165	0.167	0.170	0.172	0.175	0.178
#2 W. Danville - BØ		0.262	0.266	0.270	0.274	0.278	0.282	0.286	0.290	0.294	0.299	0.303
#3 Peacham - CØ		0.201	0.204	0.207	0.210	0.213	0.216	0.219	0.223	0.226	0.229	0.233
#5 S. Walden	0.30%	1.575	1.580	1.585	1.589	1.594	1.599	1.604	1.609	1.613	1.618	1.623
#1 Greensboro		0.518	0.520	0.521	0.523	0.524	0.526	0.527	0.529	0.531	0.532	0.534
#2 Cabot		0.599	0.601	0.603	0.604	0.606	0.608	0.610	0.612	0.614	0.615	0.617
#3 West Hill Pond		0.458	0.459	0.461	0.462	0.464	0.465	0.466	0.468	0.469	0.471	0.472
#8 Jackson Corners	1.76%	3.476	3.537	3.600	3.663	3.728	3.794	3.861	3.929	3.998	4.069	4.140
#1 Topsham		0.660	0.672	0.684	0.696	0.708	0.721	0.734	0.746	0.760	0.773	0.787
#2 Chelsea		0.521	0.531	0.540	0.549	0.559	0.569	0.579	0.589	0.600	0.610	0.621
#3 Northfield		2.294	2.335	2.376	2.418	2.460	2.504	2.548	2.593	2.639	2.685	2.733
#9 Moretown	4.36%	2.906	3.032	3.165	3.303	3.447	3.597	3.754	3.918	4.089	4.267	4.453
#1 Middlesex		1.117	1.166	1.217	1.270	1.325	1.383	1.443	1.506	1.572	1.640	1.712
#2 Moretown		0.292	0.305	0.318	0.332	0.346	0.361	0.377	0.394	0.411	0.429	0.447
#3 Fayston		1.497	1.562	1.630	1.701	1.775	1.853	1.934	2.018	2.106	2.198	2.294
#10 Maple Corners	2.12%	0.990	1.011	1.032	1.054	1.077	1.099	1.123	1.146	1.171	1.195	1.221
#1 North Calais		0.423	0.432	0.442	0.451	0.460	0.470	0.480	0.490	0.501	0.511	0.522
#2 Middlesex		0.567	0.579	0.591	0.603	0.616	0.629	0.642	0.656	0.670	0.684	0.699
#11 Tunbridge	0.00%	2.023	2.023	2.023	2.023	2.023	2.023	2.023	2.023	2.023	2.023	2.023

[5] LGR = Load Growth Rate

[6] Seasonal Year is from October 1st to September 31st, this keeps winter peaks of the same season together.

Load Forecast Based on Historic Load Only												
Sub/Circuit	LGR[5]	Seasonal Year[6] Loads (kW)										
		2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033
#1 Corinth		1.052	1.052	1.052	1.052	1.052	1.052	1.052	1.052	1.052	1.052	1.052
#2 South Tunbridge		0.364	0.364	0.364	0.364	0.364	0.364	0.364	0.364	0.364	0.364	0.364
#3 Brookfield		0.607	0.607	0.607	0.607	0.607	0.607	0.607	0.607	0.607	0.607	0.607

Table 7: Load Forecast Based on Historic Load Only

Load Forecast with Electrification												
Sub/Circuit	LGR[7]	Seasonal Year[8] Loads (kW)										
		2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033
#1 East Montpelier 12 kV	2.12%	3.314	3.425	3.534	3.662	3.807	3.965	4.137	4.325	4.526	4.733	4.955
#1 Cabot		0.566	0.585	0.604	0.625	0.650	0.677	0.707	0.739	0.773	0.808	0.846
#2 Orange		1.561	1.614	1.665	1.725	1.793	1.868	1.949	2.037	2.132	2.230	2.334
#3 County Rd		1.188	1.228	1.267	1.313	1.365	1.421	1.483	1.550	1.623	1.697	1.776
#2 Jones Brook Metering Point	0.00%	0.143	0.145	0.146	0.149	0.152	0.155	0.159	0.164	0.169	0.175	0.180
#3 Mount Knox	1.12%	2.796	2.862	2.925	3.003	3.094	3.196	3.308	3.434	3.568	3.707	3.857
#1 Peacham		0.755	0.773	0.790	0.811	0.836	0.863	0.893	0.927	0.964	1.001	1.042
#2 Corinth		2.041	2.089	2.135	2.192	2.259	2.333	2.415	2.506	2.605	2.706	2.816
#4 West Danville	1.48%	0.616	0.633	0.649	0.668	0.691	0.716	0.743	0.773	0.806	0.839	0.875
#1 Hookerville - AØ		0.153	0.157	0.161	0.166	0.172	0.178	0.185	0.192	0.200	0.208	0.217
#2 W. Danville - BØ		0.262	0.269	0.276	0.284	0.294	0.304	0.316	0.329	0.343	0.357	0.372
#3 Peacham - CØ		0.201	0.206	0.212	0.218	0.225	0.234	0.242	0.252	0.263	0.274	0.285
#5 S. Walden	0.30%	1.575	1.599	1.622	1.652	1.690	1.734	1.783	1.840	1.902	1.965	2.035
#1 Greensboro		0.518	0.526	0.533	0.543	0.556	0.570	0.587	0.605	0.625	0.646	0.669
#2 Cabot		0.599	0.608	0.617	0.628	0.643	0.659	0.678	0.700	0.723	0.747	0.774
#3 West Hill Pond		0.458	0.465	0.472	0.480	0.492	0.504	0.519	0.535	0.553	0.571	0.592
#8 Jackson Corners	1.76%	3.476	3.580	3.681	3.802	3.940	4.091	4.256	4.438	4.633	4.833	5.048
#1 Topsham		0.660	0.680	0.699	0.722	0.748	0.777	0.808	0.843	0.880	0.918	0.959
#2 Chelsea		0.521	0.537	0.552	0.570	0.591	0.613	0.638	0.665	0.694	0.724	0.757
#3 Northfield		2.294	2.363	2.429	2.509	2.600	2.700	2.809	2.929	3.058	3.190	3.332
#9 Moretown	4.36%	2.906	3.069	3.233	3.419	3.625	3.847	4.086	4.345	4.620	4.907	5.213
#1 Middlesex		1.117	1.180	1.243	1.314	1.393	1.479	1.570	1.670	1.776	1.886	2.004
#2 Moretown		0.292	0.308	0.325	0.344	0.364	0.387	0.411	0.437	0.464	0.493	0.524
#3 Fayston		1.497	1.581	1.666	1.761	1.867	1.982	2.105	2.238	2.380	2.528	2.686
#10 Maple Corners	2.12%	0.990	1.045	1.102	1.165	1.235	1.310	1.392	1.480	1.574	1.672	1.776
#1 North Calais		0.423	0.447	0.471	0.498	0.528	0.560	0.595	0.632	0.673	0.714	0.759
#2 Middlesex		0.567	0.599	0.631	0.667	0.707	0.751	0.797	0.848	0.902	0.958	1.017
#11 Tunbridge	0.00%	2.023	2.048	2.071	2.104	2.147	2.197	2.254	2.320	2.393	2.469	2.553

[7] LGR = Load Growth Rate

[8] Seasonal Year is from October 1st to September 31st, this keeps winter peaks of the same season together.

Load Forecast with Electrification												
Sub/Circuit	LGR[7]	Seasonal Year[8] Loads (kW)										
		2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031	2031-2032	2032-2033
#1 Corinth		1.052	1.065	1.077	1.094	1.116	1.142	1.172	1.207	1.245	1.284	1.327
#2 South Tunbridge		0.364	0.369	0.373	0.379	0.386	0.395	0.406	0.417	0.431	0.444	0.459
#3 Brookfield		0.607	0.615	0.621	0.631	0.644	0.659	0.676	0.696	0.718	0.741	0.766

Table 8: Load Forecast with Electrification

1.3.4 Thermal

Thermal evaluations were performed on the WEC sub-transmission lines, substations, circuits, and line equipment that serve distribution loads. Evaluations were performed for the following load conditions:

- Most recent Peak
- Minimum Loads with full DER output
- Four-year Projected Peak Loads
- 10-year Projected Peak Loads

1.3.4.1 Sub-Transmission (for Distribution Substations) Thermal Evaluation

WEC owns four sub-transmission lines that serve distribution loads, none of the lines had thermal violations for the ten-year period evaluated.

1.3.4.2 Distribution Substations – Thermal Evaluation

WEC has eight distribution substations and one distribution primary metering point served by another Utility, which are thermally evaluated below.

Present Loading

Analysis was done for two existing load scenarios Peak with no DER output and Minimum loads with full DER output determined that the following substation thermal limits are close to being exceeded:

- #3 Mount Knox – Bus Regulators – 150A
    - Due to Peak Loads
- #8 Jackson Corners – (1) Transformer Bank – 3,750 kVA
    - Due to Peak loads
    - Due to Minimum Load with full DER Output (reverse power)

Due to asset conditions (Section 8.2.6) and old wooden pole structures, these substations are already planned to be rebuilt. To ensure the substations infrastructure is sized to serve the loads forecasted in the next 10 years and provide feeder backup capacity (Section 8.2.2.4) the following are recommended:

- #3 Mount Knox – Substation Rebuild
    - Replace Circuit Regulators – 328A units.
        - Or Install Bus Regulators – 546A.
    - Replace Substation Transformer – 7.5/10.5 MVA

- #8 Jackson Corners - Substation Rebuild
    - Replace Circuit Regulators – 328A units.
        - Or Install Bus Regulators – 546A.
    - Replace Substation Transformer – 7.5/10.5 MVA

Year 4 Peak Loading

The year four analysis shows that the following substation thermal limits will be exceeded, assuming prior thermal issues have been addressed:

- #9 Moretown Substation Transformer Bank – (3) – 1,250 kVA

To ensure the substations infrastructure is sized to serve the loads forecasted in the next 10 years and provide feeder backup capacity (Section 8.2.2.4) the following are recommended:

- #9 Moretown
  - Replace Substation Transformer – 7.5/10.5 MVA

Year 10 Peak Loading

The year ten analysis shows that the following substation thermal limits will be exceeded, assuming prior thermal issues have been addressed:

- #1 East Montpelier Substation Transformer Bank – (3) – 1,667 kVA

To ensure the substation infrastructure is sized to serve the loads forecast in the next 10 years and provide feeder backup capacity (Section 8.2.2.4) the following are recommended:

- #1 East Montpelier
  - Replace Substation Transformer – 7.5/10.5 MVA

1.3.4.3 Distribution Circuits – Thermal Evaluation

WEC has twenty-three distribution circuits, which are thermally evaluated below for the load conditions described above.

Present Loading

Year 0 analysis determined that the following circuit thermal limits are close to being exceeded:

- #9 Moretown – #3 Fayston Circuit
  - Circuit Regulators - 75A
    - Due to Peak Loads
- #8 Jackson Corners – #3 Northfield Circuit
  - Recloser Bypass Fuses – 100K Fuses – 150A
    - Minimum Load with full DER Output

The following Recommendations will address the above issues for current and the forecasted loads:

- #9 Moretown – #3 Fayston Circuit
  - Replace Circuit Regulators – 219A units.

- #8 Jackson Corners - #3 Northfield Circuit

  - Circuit Recloser Bypass Fuses – 150K Fuses – 225A Rating

Year 4 Peak Loading

At the four-year peak it appears that the following circuit thermal limits are close to being exceeded:

- #9 Moretown - #2 Moretown Common – Single Phase Circuit
  - Circuit Recloser – 704L – Continuous Current Rating

This circuit is single phase with a load of close to 70A, and the industry practice is to limit single phase loading to 50A or less. The recommendation is to extend three phase to split up the load rather than increasing the size of the recloser.

The following Recommendations will address the above issues for current and the forecast loads:

- #9 Moretown - #2 Moretown Common – Extend three phase.

Year 10 Peak Loading

Year 10 analysis shows that the following circuit thermal limits are close to or are being exceeded:

- #3 Mount Knox - #2 Corinth
  - Recloser Bypass 100K fuse – 150A – Continuous Amp Rating
- #9 Moretown - #2 Moretown Common – Single Phase Circuit
  - Circuit Recloser – 704L – Continuous Amps Rating

The above circuit is single phase with a load of close to 70A, and the industry practice is to limit single phase loading to 50A or less. The recommendation is to extend three phase to split up the load rather than increasing the size of the recloser. This was included in the four-year peak load observation as well, but it is possible that if load growth is slower, the recommendation may be deferred to just after Year Four.

The following recommendations will address the above issues for current and forecast loads:

- #3 Mount Knox - #2 Corinth – Replace Recloser Bypass
  - Circuit Recloser Bypass Fuses – 150K Fuses – 225A Rating
- #9 Moretown - #2 Moretown Common – Extend three Phase

1.3.4.4 Distribution Transformers

Historically, WEC used 5 kVA transformers to serve single family homes. WEC is now finding that significantly larger transformers are needed for modern homes. Currently, the increased electrical demand is more often used by Members with more disposable income, who may have higher and increasing electrical demands. Determining an “average” transformer size for single family homes is an ongoing process, especially as homeowners may plan to add additional electric vehicles but, in the future, may also decide to reduce their demand with on-site batteries. In the meantime, there are approximately 2,700 - 5 kVA transformers on the WEC system. Based on load flows, approximately 24 are presently overloaded. It is anticipated that

WEC will be making significant efforts to replace overloaded distribution transformers in the next few years. This will be a challenge, considering increasing equipment costs and decreasing availability due to supply chain constraints. Even 10, 15, and 25 kVA transformers might not be sufficient in some cases, and those transformer sizes make up a majority of the WEC distribution transformer population.

1.3.4.5 Line Devices

WEC has several circuit line devices that are currently overloaded or are expected to reach their thermal limits over the next 10 years. This is due to increasing loads on the WEC system and these items need to be addressed in a timely fashion to prevent equipment failure and to strengthen the system for future growth.

Present Loading

Based on current peak loads, with no DER output, there are some discrete circuit line devices that need to be upgraded for thermal loads. The existing devices and their recommended replacements are shown below. There are no circuit line devices that are overloaded at current minimum loads when DER is at full output.

- #1 East Montpelier - #1 Cabot – Device # RC13306
    - Existing - 50H Line Recloser
    - Recommended Upgrade – 70 V4H Line Recloser
- #3 Mount Knox - #2 Corinth – Device # RC24581
    - Existing – 50L Line Recloser
    - Recommended Upgrade – Triple-Single Line Recloser
- #8 Jackson Corners - #3 Northfield – Device # REG24076
    - Existing – (3) 150A Line Regulators
    - Recommended Upgrade – (3) 219A Line Regulators
- #10 Maple Corners - #2 Middlesex – Device # RC09580
    - Existing - 35H Line Recloser
    - Recommended Upgrade – 100 4H Line Recloser

Year 4 Peak Loading

No line devices are forecast to reach their thermal limit at the four-year horizon once the year 0 overloads are addressed.

Year 10 Peak Loading

At the ten-year peak, two device locations need to be upgraded due to thermal limits, they are listed below.

- #3 Mount Knox - #2 Corinth – Device # REG24676
    - Existing – (3) 75A Line Regulators
    - Recommended Upgrade – (3) 150A Line Regulators
- #9 Moretown - #3 Fayston – Substation Getaway Cable
    - Existing – 1/0AL Cables

- Recommended Upgrade – 4/0AL Cables

1.3.5 Asset Condition Sub-Transmission (serving Distribution Substations) & Substations

Through review of documentation and discussions with WEC, it was determined that multiple existing WEC assets need to be rebuilt or replaced due to age.

All of the WEC-owned sub-transmission lines that feed distribution substations are close to or well over 50 years of age. Per the RUS LRP Bulletin, poles over 50 years old are considered deteriorated. In the next four years WEC plans to finish upgrading the 3319, 34.5kV Transmission Line that feeds the #5 South Walden Substation. This line was previously partially upgraded for VELCO fiber make-ready work. Additionally, WEC inspects each sub-transmission line annually and corrects any issues discovered during each inspection.

Line	Station Served	Operating Voltage	Distance Miles	Install Date of Line
East Montpelier to Maple Corners Line	#10 Maple Corners	34.5 kV	8.99	1973
Graniteville to Jackson Corners Line	#8 Jackson Corners	34.5 kV	4.45	1958
GMP 3319 Tap to Walden Feed	#5 South Walden	34.5 kV	2.26	1967
VELCO Chelsea to Tunbridge Line	#11 North Tunbridge	46 kV	2.6	1975

Table 9: WEC Sub-transmission lines that feed Distribution Substations

The Distribution Substations below are aged wood frame structures that are close to the end of life and should be rebuilt with steel structures within the next ten years. These older wood pole structures have cross arms that are bent under the weight of the equipment mounted on them. Replacement of equipment at the older substations is difficult due to the structure layouts. In addition to that, the #3 Mount Knox substation transformers are mis-matched in that they have significantly different impedance values, which can lead to excess circulating current that can reduce their life expectancy. Some substations will be at their thermal limits over the next 10 years.

Distribution Substation	Age of Substation	Thermal Limit Reached			
		Existing issue	0 – 4 Year	4-10 Years	Not Reached within 10 Years[9]
#3 Mount Knox	1971		X		
#4 West Danville	1988 – Rebuilt 2002				X
#5 South Walden	1967 – Rebuilt 2004				X
#7 Graniteville (Feeds #8 Sub)	1968				X
#8 Jackson Corners	1968	X			
#11 North Tunbridge	1975				X

Table 10: Distribution Substations – Age versus Thermal

1.3.6 Sub-Transmission

WEC owns four sub-transmission lines that serve distribution substations. None of the lines had thermal violations for the ten-year period evaluated in the LRP (Section 8.2.5.1). To address asset conditions, (Section 8.2.6) WEC plans to finish upgrading the 3319, 34.5kV Transmission Line that feeds the #5 South Walden Substation. This line was previously partially upgraded for VELCO fiber make-ready work.

1.3.7 Substations

The substations, listed below, require the following upgrades per the LRP due to DER, existing and proposed loads, and asset condition (see Section 8.2.5.2 & 8.2.6). Upgrades take into account existing and potential feeder backup capability (Section 8.2.2.4).

- #3 Mount Knox – Substation Rebuild
  - Replace Circuit Regulators – 328A units.
    - Or Install Bus Regulators – 546A.
  - Replace Substation Transformer – 7.5/10.5 MVA

- #8 Jackson Corners - Substation Rebuild
  - Replace Circuit Regulators – 328A units.
    - Or Install Bus Regulators – 546A.

[9] Substations to be upgraded from wood to steel in the 4-10 year time frame due to asset condition.

- Replace Substation Transformer – 7.5/10.5 MVA

- #9 Moretown
  - Replace Substation Transformer – 7.5/10.5 MVA

- #1 East Montpelier
  - Replace Substation Transformer – 7.5/10.5 MVA

1.3.8 Incentives & Storage

One potential way to reduce the thermal loading on the WEC system would be to incentivize Members to spread their electrical consumption more evenly across the day and possibly employ storage to mitigate those peak demand hours.

1.3.9 Transmission Ground Fault Overvoltage

WEC, like many utilities, has enough aggregate small DER on its distribution system that Transmission Ground Fault Overvoltage (TGFOV) is a concern. Essentially, without enough load to offset the output of aggregate DER on the distribution system, overvoltage can occur on the sub-transmission system in the event of a line-to-ground fault. The DER cannot sense this type of fault due to the substation transformer configuration, which is typically high side delta, low side grounded-wye. The WEC distribution substations' Load to Generation Ratios (LGR) are shown in the table below. An LGR of less than 2 indicates there is a risk of a damaging TGFOV event. Based on the results below, all of the WEC distribution substations should have TGFOV protection installed to prevent the possibility of damaging overvoltages occurring on the sub-transmission lines. Only two distribution circuits already have TGFOV protection, and these are shown in the Table below as well. The best protection scheme for each substation is still under review but will most likely consist of a communications-based scheme or a set of voltage sensing transformers installed on the high voltage side of the substation that will trip the circuit reclosers and prevent the DER from backfeeding on to the sub-transmission line during a fault. It is likely that all of the circuit reclosers will need to be replaced in order to implement TGFOV protection.

Substation	**Min Load kW**	**Connected Generation kW**	**Pending Generation kW**	**Total DER kW**	**Net Power kW**	**LGR** *If <2 TGFOV Protection Required*	**TGFOV required?**
1 - East Montpelier	339.11	3325.4	115.52	3440.92	-3101.81	0.099	Yes
3 - Mount Knox	624.00	671.95	65.2	737.15	-113.15	0.847	Yes
4 - W Danville	141.00	168.3	23.9	192.2	-51.20	0.734	Yes
5 - S. Walden	267.00	474.3	64.79	539.09	-272.09	0.495	Yes
8 - Jackson Corners	1042.8	4756.9	103.13	4860.03	-3817.23	0.215	Yes
9 - Moretown[10]	871.70	2985.4	367	3352.4	-2480.70	0.260	Yes

[10] The #1 Middlesex and #3 Fayston Moretown substation circuits already have TGFOV protection, the #2 Moretown Common circuit needs to be included in the scheme.

10 - Maple Corners	101.29	660.85	105.6	766.45	-665.16	0.132	Yes
11 - Tunbridge	503.00	559.8	197.9	757.7	-254.70	0.664	Yes

Table 11: TGFOV Evaluation

1.3.10 Phase Balancing

Phase balancing was reviewed on any circuit or bus, at current peak loads, where the total phase imbalance exceeded 50A. This is considered good industry practice.

Present Loading

Four locations violated this criterion and two more were added to the review list to better diversify reliability. Since WEC employs triple-single circuit reclosers which operate independently on each phase, balancing customer counts and loading between phases can help reliability by reducing the number of customers affected by outages. The following table shows all six circuits or buses that were considered in order of greatest to least imbalance. The imbalance at four of the locations can be addressed by changing the phase of single-phase taps. However, for two locations, it will be necessary to extend three phase as detailed below:

#11 North Tunbridge - #3 Brookfield Circuit

On this circuit, there is a single-phase tap that has approximately 68.5A of load at peak (approximately 500 kVA). This tap is very long, at approximately 46,328 feet or 8.77 miles. With this much load on a single-phase tap, it becomes difficult to support voltage. This is further exacerbated by the presence of #8 copperweld-copper (CWC) conductor, which has a very high impedance. The tap includes 6,723' of #8 CWC which is obsolete (likely installed in the early 1900s) and prone to embrittlement and breakage which presents a safety concern.

It is proposed to rebuild this tap to three phase utilizing 4/0 AAAC conductors. Extending three phase down this tap will provide the added benefit of increasing the ability of the #3 Brookfield circuit to serve some load, even single phase, from the #8 Jackson Corners #2 Chelsea circuit. This will also better balance the load on the #11 Tunbridge substation to help extend the capacity of the substation.

#1 East Montpelier - #1 Cabot Circuit

This circuit is almost entirely single phase and has approximately 54.8A at peak. There are no taps that can improve the circuit balance, so three phase must be extended. This three-phase extension will not only improve the balance, but it will also replace 6/8 CWC conductor and may make it possible to move the line roadside and out of a wetland, which would make the circuit more capable of accepting new loads and strengthen the single-phase tie to the #5 South Walden substation. Although there will still be an 8.57 mile gap between the three phase from both substations, this is still seen as a worthwhile investment since the #5 South Walden substation does not have any existing three phase connections to the rest of the WEC distribution system.

Substation	Circuit	Current Peak Loading			Average Amps	Max Amps	Min Amps	Max Amp Deviation	Maximum Unbalance
		A	B	C					
#11 North Tunbridge	Bus Load	111	23	108	80.67	111	23	**88**	109%
#8 Jackson Corners	Bus Load	166	102	157	141.67	166	102	**64**	45%
#3 Mount Knox	Bus Load	114	103	157	124.67	157	103	**54**	43%
#1 East Montpelier	#1 Cabot	5.6	15.1	57.9	26.2	57.9	5.6	**52.3**	200%
#5 South Walden	#2 Cabot	47	5	36	29.33	47	5	42	143%
#10 Maple Corners	#2 Middlesex	61.7	34.9	20	38.87	61.7	20	41.7	107%

Table 12: Current Peak – Phase Imbalance violations[11]

[11] Items in bold **red** lettering are over the thermal limits or very close.

Substation	Circuit	Phase Balancing Solution
#11 North Tunbridge	#3 Brookfield	**Extend 3Ø** 2.22 miles from Pole #11-3-47A outside the VELCO Chelsea substation off East Randolph Rd, Chelsea, to Pole #11-3-84 Hook Rd, Chelsea, with 1/0 AAAC. **Phase Balance Taps** • Change tap to #11-3-84 on Hook Rd to B phase. • Change tap at Pole #11-3-63 on East Randolph Rd going toward Brook Rd to B phase. **Line Regulator** - REG28951 - change connection to B phase, change settings.
#8 Jackson Corners	#1 Topsham	Change tap at Pole #8-1-36 on Tower Rd, Williamstown, fed by F24208, feeding south on Tower Rd, from C to B phase.
	#3 Northfield	Change tap at Pole #8-3-79 on Rood Pond Rd, Williamstown, that feeds RC24088 (south on Rood Pond Road) from C to B phase.
#3 Mount Knox	#2 Corinth	Change tap at Pole #3-2-101 off VT Rte. 25, Topsham, tap that feeds RC24582 from C to A phase.
#1 East Montpelier	#1 Cabot	**Extend 3Ø** 1.08 miles from Pole #1-1-57A on Lightning Ridge Rd to Pole #1-1-73 off Max Gray Rd, Calais, with 4/0 AAAC. **Phase Balance** Change tap at Pole #1-1-73 off Max Gray Rd, Calais, that feeds down the ROW via fuse F13303, from C to A phase.
#5 South Walden	#2 Cabot	**Phase Balance Taps** Change the following taps from A to B phase: • Pole #5-2-65 at the corner of Bricketts Crossing & Upper Harrington Hill Road, Walden, fed by fuse F08901 to Upper Harrington Hill Rd. • Pole #5-2-56 at the corner of Bricketts Crossing & Lyford West Shore, Walden, fed by fuse F07681 to Lyford West Shore Rd. • Pole #5-2-22 ROW off Grand Army of the Republic Hwy (Rte. 15), Walden, fed by fuse F07627 to Sawmill Rd, Walden.
#10 Maple Corners	#2 Middlesex	Pole #10-2-100 on West Hill Road, Worcester - Swap A & C phases fed by this pole (Taps to West Hill Rd, Hampshire Hill Rd, & Minister Brook Rd)

Table 13: Present Phase Balance Recommendations

Substation	Circuit	Current Peak Loading			Average Amps	Max Amps	Min Amps	Max Amp Deviation	Maximum Unbalance
		A	B	C					
#11 North Tunbridge	Bus Load	86	73	83	79.5	86	73	13	16%
#8 Jackson Corners	Bus Load	146	142	137	144	146	142	4	3%
#3 Mount Knox	Bus Load	114	133	127	123.5	133	114	19	15%
#1 East Montpelier	#1 Cabot	25.6	25.1	27.9	25.35	25.6	25.1	0.5	2%
#5 South Walden	#2 Cabot	27	25	36	26	27	25	2	8%
#10 Maple Corners	#2 Middlesex	41.7	34.9	40	38.3	41.7	34.9	6.8	18%

Table 14: Phase Balance Load, post Recommendations

Year 4 Loading

No phase balancing recommendations were made for Year 4.

Year 10 Loading

The following phase balancing tap changes are recommended for Year 10 loading. Note, for the recommended three phase extension projects, additional phase balancing tap changes are recommended as well but are not listed here. Those taps are listed under the "Extending Three Phase" section.

Substation	Circuit	Recommendation Description
#3 Mount Knox	#2 Corinth	**Phase Balance Taps** Change tap at Pole #3-2-146 on Pike Hill Rd, Topsham, from C to B phase, fed via F24654.
#5 South Walden	#2 Cabot	**Phase Balance Taps** Change tap at Pole #5-2-82 on Bricketts Crossing Rd, Cabot, tap that feeds RC08907, from C to B phase
#9 Moretown	#1 Middlesex	**Phase Balance Taps** • Change tap at Pole #9-1-162 on Molly Supple Hill Road, Middlesex, fed by RC11180, from B to A phase. • Change tap at Pole #9-1-129 in ROW, tap toward South Bear Swamp Road, Middlesex, fed by F12901, from A to B phase. • Change tap at Pole #9-1-102 in ROW off Center Rd, Middlesex, tap fed by F12908, from A to B phase

Table 15: 10 Year Peak Load – Phase Balancing Recommendation

1.3.11 Power Factor

Because there was limited VAR data available for the WEC system, some very broad assumptions were made on power factor (see section 8.2.3). Most of the distribution circuits had a load power factor of 96%, which was the assumed power factor for the actual loads and not the circuits. The #11 Tunbridge loads had a higher power factor of 99.8% based on SCADA load data from VELCO, which directly serves the substation.

Note: "load power factor" refers to the individual loads on a circuit. The overall circuit will have a different power factor when accounting for aggregate loads, line losses, and the VARs supplied by capacitors connected to the circuit.

There are quite a few existing capacitor banks on the WEC system, so the circuit power factors based on load flows range from 96% to -95% during peak loads, and from 97% to -48% at minimum loads (this is with the DER turned off in the load flow software). All of the existing WEC cap banks are fixed (on at all times, with no controller or switches). Due to occurrences of high voltage and leading power factors (supplying vars to the transmission system) for a significant portion of the year, it was decided to remove several capacitor banks, especially single phase banks toward the ends of lines (single phase capacitors at the end of lines tend to create unbalanced voltage issues which are exacerbated by local DER).

The proposed capacitor changes listed below will help to reduce system losses, improve voltage, and make the system more able to accommodate DER and load.

Present Loading

Based on the analysis of Present loads, several new capacitor installations are recommended; see Table 16.

Substation	Circuit	Recommendation	
		Location	Description
#1 East Montpelier	#2 Orange	Pole #1-2-154R11, Cutler Corner Rd, Barre	Remove Capacitor CAP19051 (3)-100 kVAR/300 kVAR Fixed Total Cap Bank
		Pole #1-2-66, Upper Rd, Plainfield	Replace Capacitor CAP17176 Existing – (3)-50 kVAR Fixed Cap Bank, 150 kVAR Total New – (3)-100 kVAR/300 kVAR Fixed Total Cap Bank
#3 Mount Knox	#2 Corinth	Pole #3-2-210R61, Brook Rd, Corinth	Remove Capacitor CAP28026 (1)-50 kVAR Fixed Cap Bank
		Pole #3-2-210R10, Brook Rd, Corinth	Remove Capacitor CAP26477 (1)-50 kVAR Fixed Cap Bank
		Pole #3-2-236, off Israel Lane, Corinth	Remove Capacitor CAP26476 (1)-50 kVAR Fixed Cap Bank
		Pole #3-2-93, Main St, Topsham	Remove Capacitor CAP24525 (3)-200 kVAR/600 kVAR Fixed Total Cap Bank
#4 West Danville *(Single Ø Circuits)*	#1 Hookerville *(A Phase)*	Pole #4-1H-116, Theodore Roosevelt Hwy (Rte. 2), Cabot	Remove Capacitor CAP11826 (1)-50 kVAR Fixed Cap Bank
	#3 Peacham *(C Phase)*	Pole #4-1P-52, Bayley Hazen Rd, Peacham	Remove Capacitor CAP10351 (1)-50 kVAR Fixed Cap Bank
#5 South Walden	#2 Cabot	Pole #5-2-45L25, Grand Army of the Republic Hwy (Rte. 15), Walden	Remove Capacitor CAP07751 (1)-50 kVAR Fixed Cap Bank
		Pole #5-2-107, Dubray Rd, Cabot, Walden	Remove Capacitor CAP08876 (1)-50 kVAR Fixed Cap Bank
		Pole #5-2-43 – Off of VT Rte. 125 (Behind the Emergency Services building) Walden	Install Capacitor (3)-150 kVAR/450 kVAR Total Cap Bank
#8 Jackson Corners	#2 Chelsea	Pole #8-2-114, VT Rte. 110, Chelsea	Remove Capacitor CAP27676 (2)-100 kVAR/200 kVAR Total Cap Bank
	#3 Northfield	Pole #8-3-89R104, Hebert Rd, Barre	Remove Capacitor CAP20751 (3)-50 kVAR/150 kVAR Total Cap Bank

Substation	Circuit	Recommendation	
		Location	Description
		Pole #8-3-122R76, Onion River Rd, Northfield	Remove Capacitor CAP22401 (1)-50 kVAR Fixed Cap Bank
		Pole #8-3-89R63, Hebert Rd, Williamstown	Remove Capacitor CAP22501 (3)-50 kVAR/150 kVAR Total Cap Bank
		Pole #8-3-207R51A, Bailey Rd, Northfield	Remove Capacitor CAP23951 (1)-50 kVAR Fixed Cap Bank
		Pole #8-3-209, Ladd Rd, Roxbury	Remove Capacitor CAP25601 (2)-50 kVAR/100 kVAR Total Cap Bank
#10 Maple Corners	#2 Middlesex	Pole #10-2-6L3 off County Rd, Calais	Install Capacitor (3)-50 kVAR/150 kVAR Total Cap Bank
#11 North Tunbridge	#1 Corinth	Pole #11-1-262, Chelsea Rd, Corinth	Remove Capacitor - CAP29301 (1)-50 kVAR Fixed Cap Bank
	#3 Brookfield *Single Ø Circuit*	Pole #11-3-139, Chelsea Rd, Vershire	Remove Capacitor - CAP27576 (1)-50 kVAR Fixed Cap Bank

Table 16: Present Load – Proposed Capacitor Changes

Year 4 Loading

No capacitor changes were recommended for Year 4 loading.

Year 10 Loading

Only two capacitor installations were recommended for Year 10 loads, see Table 17.

Substation	Circuit	Recommendation	
		Location	Description
#3 Mount Knox	#2 Corinth	Pole #3-2-79, Main St (Rte. 25), Topsham	Install Capacitor (3)-50 kVAR/150 kVAR Total Cap Bank
#9 Moretown	#1 Middlesex	Pole #9-1-82, Center Rd, Middlesex	Install Capacitor Bank (3)-100 kVAR/300 kVAR Total Cap Bank

Table 17: Year 10 Loading – Proposed Capacitor Changes

1.3.12 Voltage Regulation

The LRP also reviewed circuit and bus regulator settings. It was found that the majority of substation regulators and several line regulators require settings changes due to a significant increase in DER since the previous review of the settings. Note, these setting changes were recommended purely for voltage support, other upgrades such as extending three phase or re-conductoring also call for adding or changing regulator settings as part of the upgrade.

The existing regulator settings were generally chosen for conservation voltage reduction (CVR) in the forward direction (load flowing into the circuit) with a set voltage in the reverse direction (power flowing into the transmission system). In developing the new settings, most of the regulators were able to maintain CVR settings, but the settings were carefully selected to work at peak and minimum loads with and without DER. However, some locations could not retain CVR settings due to the existing DER causing such low currents that adequate voltage at the end of the line could not be maintained, or DER was causing high voltage when the circuit was experiencing reverse power during minimum loads.

Present Loading

For the present loading conditions, the following recommendations were made:

- 14 sets of substation regulators, bus and circuit, require setting changes.
    - Some of these regulators are called to be replaced due to thermal loading, see Section 8.2.5
- 9 sets of line regulators require setting changes.
    - Some of these regulators are called to be replaced due to thermal loading, see Section 8.2.5
- Install 1 new line regulator.

Substation	Circuit	Recommendation	
		Location	Description
#1 East Montpelier	#1 Cabot	Sub	Change circuit regulator settings
	#2 Orange	Sub	Change circuit regulator settings
	#3 County Road	Sub	Change circuit regulator settings
#3 Mount Knox	#2 Corinth	Pole #3-2-210R67, Brook Rd	Change line regulator settings - REG28076
		Pole #3-2-158, Main St, Topsham	Change line regulator settings – REG24676
	Bus	Sub	Change bus regulators Settings[12]
#4 West Danville *(Single Ø Circuits)*	Bus	Sub	Change bus regulators Settings
#5 South Walden	#2 Cabot	Sub	Change circuit regulator settings
	#3 West Hill Pond	Sub	Change circuit regulator settings
#8 Jackson Corners	#1 Topsham	Pole #8-1-112, Tucker Rd, Orange	Change line regulators Settings - REG22726
	#3 Northfield	Pole #8-3-207R2A, East Roxbury Rd, Roxbury	Change line regulator settings - REG25601[13]
	Bus	Sub	Change bus regulator settings[12]
#9 Moretown	#1 Middlesex	Sub	Change circuit regulator Settings

[12] Per the thermal evaluation these regulators also need to be replaced, Section 8.2.5.2.
[13] Per the thermal evaluation these regulators also need to be replaced, Section 8.2.5.5.

Substation	Circuit	Recommendation	
		Location	Description
		Pole #9-1-152, Molly Supple Hill Rd, Middlesex	Change line regulator Settings – REG12926
		Pole #9-1-164, French Rd, Middlesex	Change line regulator Settings – REG11176
	#2 Moretown Common *Single Ø Circuit*	Sub	Change circuit regulator Settings
	#3 Fayston	Sub	Change circuit regulator Settings[12]
		Pole #9-3-72A, VT Rte. 100, Duxbury	Change line regulator Settings – REG14551
#10 Maple Corners	#1 North Calais	Sub	Change circuit regulator Settings
	#2 Middlesex	Sub	Change circuit regulator Settings
		Pole #10-2-125 West Hill Rd, Worcester	Install 100A - Line regulator
#11 North Tunbridge	#1 Corinth	Pole #11-1-173R26, VT Rte. 113, Vershire	Change line regulator Settings - REG30501
		Pole #11-1-200, Goose Green Rd, Vershire	Change REG29201 settings change
	Bus	Sub	Change bus regulators settings

Table 18: Present Loads – Voltage Regulator Recommendations

Year 4 Loading

No regulator changes were recommended for Year 4 loads.

Year 10 Loading

For the Year 10 loading conditions the following recommendations were made:

- 3 sets of substation regulators, bus and circuit, require setting changes.
  - Some of these regulators are called to be replaced due to thermal loading, see Section 8.2.5
- 1 line regulator requires setting changes.
  - Some of these regulators are called to be replaced due to thermal loading, see Section 8.2.5
- Install 6 new line regulators.
- Remove 2-line regulators.

Substation	Circuit	Recommendation	
		Location	Description
#1 East Montpelier	#2 Orange	Pole #1-2-156 Bisson Rd, Orange	Install (1)-100A Line Regulator
#3 Mount Knox	#2 Corinth	Pole #3-2-227R17, Fairground Rd, Corinth	Install (1)-100A Line Regulator
#8 Jackson Corners	#2 Chelsea	Pole #8-2-137R19, Bobbinshop Rd, Chelsea, VT	Change Line Regulator Settings - REG28901
	#3 Northfield	Pole #8-3-207R38 Bailey Rd, Northfield	Install (1)-75A Line Regulator
#9 Moretown	#1 Middlesex	Sub	Circuit Regulator Change Settings

Substation	Circuit	Recommendation	
		Location	Description
		Pole #9-1-118 Center Rd, Middlesex	Install (3)-328A Line Regulators
		Pole #9-1-164, French Rd, Middlesex	Remove Line Regulator REG11176
		Pole #9-1-152, Molly Supple Hill Road, Middlesex	Remove Line Regulator REG12926
#10 Maple Corners	#1 North Calais	Sub	Change circuit reg settings
	#2 Middlesex	Sub	Change circuit reg settings

Table 19: 10 Year Peak – Voltage Regulator Recommendation

1.3.13 Re-Conductoring

Re-conductoring is a costly upgrade that is used when other voltage support measures such as capacitors and voltage regulators are not sufficient to support system voltage. This upgrade strengthens the circuit to accept future loads and additional DER. If in an appropriate location, the upgraded circuit can also be used to support load transfers and feeder backup. WEC also has some very old and brittle conductors, such as 3/12 CWC and 6/8 CWC, that require replacement due to safety and reliability concerns. Proposed projects considered all of the above factors, and a higher priority was placed on projects which are expected to provide multiple benefits. In one case, there is a decision to be made at a later date on whether to re-conductor the #9 Moretown #1 Middlesex circuit's mainline using 477 kcmil ACSR or 4/0 AAAC. These are known as options "78a" and "78b" respectively. This decision will be deferred until the upgrade is imminent and will consider the economics of the conductor size.

Note, this section excludes re-conductoring projects that are recommended purely for feeder backup, see Section 8.2.2.4.

Present Loading

No re-conductoring projects were recommended for Present Loading conditions.

Year 4 Loading

Only one re-conductoring project was recommended for Year 4 Loading conditions.

Substation	Circuit	Recommendation
#8 Jackson Corners	#3 Northfield	<u>**Re-conductor**</u> • From Pole #8-3-207 to Pole #8-3-207R3 East Roxbury Rd, Roxbury - replace 3/12 CWC with 1/0 AAAC, ~0.19 miles. • From Pole #8-3-207R12 to Pole #8-3-207R14 East Roxbury Rd, Roxbury – replace #6 CWC with 1/0 AAAC, ~0.11 miles. • From Pole #8-3-207R17 VT Rte. 12S to Pole #8-3-207R37 Bailey Rd, Northfield, VT – replace 3/12CWC with 1/0 AAAC, ~1.14 miles. • Remove Regulator REG25601 Pole #8-3-207R2A, East Roxbury Rd, Roxbury, VT

Table 20: Year 4 – Re-conductoring Recommendations

Year 10 Loading

As loads significantly increase over the next ten years, re-conductoring becomes more vital for voltage support. There are 8 re-conductoring projects recommended for voltage support at Year 10 loads.

Substation	Circuit	Recommendation Description
#1 East Montpelier	#2 Orange	**Re-conductor 3Ø** – From Pole #1-2-45R23 ROW off Lower Rd, Plainfield, to Pole #1-2-45R32 Lower Rd, Plainfield - replace 3/12 CWC with 1/0AAAC, approximately 0.57 miles
#3 Mount Knox	#2 Corinth	**Re-conductor 3Ø** From Sub to Pole #3-2-33, William Scott Memorial Hwy (Rte. 302), Topsham - replace. 2/0 ACSR with 4/0 AAAC, approximately 1.77 miles
		Re-conductor 3Ø From Pole #3-2-33, William Scott Memorial Hwy (US Rte. 302), Topsham, to Pole #3-2-54 in ROW off Kimball Hill Rd, Topsham – replace 2/0 ACSR & two spans of 1/0 ACSR with 4/0 AAAC, approximately 1.19 miles
#9 Moretown	#1 Middlesex	**Replace substation getaway cable.** From Sub to Pole #9-1-1, Moretown Common Rd, Moretown – replace 1/0 AL cable with 4/0 AL cable, approximately 110 feet
		78a Option – Re-conductor 3Ø – From Pole #9-1-1, Moretown Common Rd, Moretown, (by Sub riser) to Pole #9-1-73 on Center Road, Middlesex – replace 1/0 ACSR with 477 ACSR, approximately 3.93 miles
		78b Option Re-conductor 3Ø – From Pole #9-1-1, Moretown Common Rd, Moretown, (by Sub riser) to Pole #9-1-124A on Leland Farm Rd, Middlesex – replace 1/0 ACSR with 4/0 AAAC, approximately 6.69 miles
	#3 Fayston	**Replace substation getaway cable** From Sub to Pole #9-3-1, Moretown Common Road, Middlesex – replace 1/0 AL cable with 4/0 AL cable, approximately 110 feet
#11 North Tunbridge	#3 Brookfield *Single Ø Circuit*	**Re-conductor 1Ø** - From Pole #11-3-84 on Hood Rd, Chelsea, (beyond F28951) to Pole #11-3-84L41 in ROW off Dickerman Hill Rd, Tunbridge, replace 3/12 CWC with 1/0 AAAC, approximately 2.68 miles

Table 21: Year 10 – Re-conductoring Recommendations

1.3.14 Extending Three Phase

Extending three phase is another costly upgrade and is considered when a single phase is carrying greater than 50 A of load and voltage can't be supported by the addition of line regulators. Single phase capacitors located a significant distance from the substation can cause overvoltages, especially when in the presence of DER. They can also cause voltage imbalances outside the ANSI C84.1 requirements. Since WEC employs triple-single circuit reclosers which operate independently on each phase, upgrading lines to three phase and balancing customer counts and loading between phases can help reliability by reducing the number of customers affected by outages. This upgrade can also create opportunities for feeder backup and increases the circuit capacity to accommodate additional DER and loads. Three phase extension projects can also involve multiple sub-projects such as phase balancing, re-conductoring, substation work, capacitor and regulator changes. Note, three phase extension recommendations based purely on improving feeder backup are listed in Section 8.2.2.4, and Phase Balancing are located in Section 8.2.11.

Present Loading

No three phase extension projects were recommended for voltage support for Present Loading conditions.

Year 4 Loading

No three phase extension projects were recommended for voltage support for Year 4 Loading conditions.

Year 10 Loading

There are 8 three phase extension projects recommended for Year 10 Loading conditions.

Substation	Circuit	Recommendation
#1 East Montpelier	#1 Cabot	**Extend 3Ø** From Pole #1-1-73 off Max Gray Rd, Calais, to Pole #1-1-92, E. Hill Rd, Plainfield, approximately 1.542 miles, using 4/0 AAAC conductors. **Phase Balance Taps** • Change tap from Pole #1-1-92, E. Hill Rd, Plainfield, Tap on ROW to Hollister Hill Rd, from C to B Phase. • Change tap from Pole #1-1-92, E. Hill Rd, Plainfield, - Tap headed north, from C to A Phase. • Change tap from Pole #1-1-73 off Max Gray Rd, Calais - Tap headed toward the ROW fed by fuse F13303 from A to C Phase **Circuit Regulator Setting Change** **Remove Regulator - REG13301** Pole #1-1-70, Max Gray Rd, Calais **Install 100A Line Regulator** Pole #1-1-119A, E. Hill Rd, Calais
#9 Moretown	#2 Moretown Common *Single Ø Circuit*	**Extend 3Ø** – From sub to Pole #9-2-50, Moretown Mountain Rd, Moretown, approximately 2.6 miles, using 1/0 AAAC conductors. **Sub Work** – Convert circuit to 3Ø - Circuit regulators, reclosers, getaway cables, buswork, etc. **Phase Balancing** • Pole #9-2-50, Moretown Mountain Rd, Moretown – Change tap fed by Fuse F16577 from C to A phase. • Pole #9-2-50, Moretown Mountain Rd, Moretown – Change tap fed by Fuse F16576 from C to B phase
	#2 Moretown Common *Single Ø Circuit*	**Extend 3Ø** – From sub to Pole #9-2-50, Moretown Mountain Rd, Moretown, approximately 2.6 miles, using 1/0 AAAC conductors. **Sub Work** – Convert circuit to 3Ø - Circuit regulators, reclosers, getaway cables, buswork, etc. **Phase Balancing** • Pole #9-2-50, Moretown Mountain Rd, Moretown – Change tap fed by Fuse F16577 from C to A phase. • Pole #9-2-50, Moretown Mountain Rd, Moretown – Change tap fed by Fuse F16576 from C to B phase
	#3 Fayston	**Extend 3Ø** – From Pole #9-3-66R5 VT Rte. 100, Duxbury, to Pole #9-3-66R33, Crossett Hill Rd, Duxbury, approximately 1.43 miles, using 1/0 AAAC conductors. **Phase Balancing** – Change tap at Pole #9-3-66R33, Crossett Hill Rd, Duxbury – fed by Fuse F12678 from A to C phase. **Replace Capacitor Bank** CAP14576 – Pole #9-3-58 – Stevens Brook Rd, Duxbury – Remove (1)50 kVAR Fixed Cap Bank and Install (3) 150 kVAR/450 kVAR Total Cap Bank

Substation	Circuit	Recommendation
#10 Maple Corners	#1 North Calais	**Extend 3Ø** – From Pole #10-1-8 Old West Church, Calais, to Pole #10-1-8R73 Lightning Ridge Rd, Calais, approximately 3.39 miles, using 1/0 AAAC conductors. **Phase Balancing** Change tap at Pole #10-1-8R73, George Rd, Calais, fed by F13228, from C to B phase
#11 North Tunbridge	#1 Corinth	**Extend 3Ø** - From Pole #11-1-173, Rte. 113, Vershire, to Pole #11-1-173R44, VT Rte. 113, Vershire, approximately 2.38 miles, using 1/0 AAAC conductors. **Install Line Regulator** - Add two more regulators to the existing line regulator location REG30501 at Pole #11-1-173R26, VT Rte. 113, Vershire. **Phase Balancing** Change tap at Pole #11-1-173R44, VT Rte. 113, Vershire, heading east on VT Rte. 113, from C to B phase
	#2 South Tunbridge	**Sub work** – Convert circuit to 3Ø - regulation, protection, getaway, switches, etc. **Extend 3Ø** - From substation to Pole #11-2-20L1 Strafford Rd, Tunbridge, approximately 1.43 miles, using 1/0 AAAC conductors. **Phase Balancing** Change tap at Pole #11-2-20, Strafford Rd, Tunbridge, towards SW31679-A-A west on Strafford Road, from A to C phase.
	#3 Brookfield *Single Ø Circuit*	**Re-conductor & Extend 3Ø -** From Pole #11-3-84 Hood Rd, Chelsea, to Pole #11-3-110 Macredy Rd, Chelsea, replace #8 CWC with 4/0 AAAC conductors, approximately 1.62 miles

Table 22: 10 Year Peak Load – Three Phase Extension Recommendations

1.3.15 Losses

Losses were recorded for the distribution circuits and substations during the analysis for the LRP. Note, for Year 10 loading there are two entries, "78a" and "78b" - the difference between these two is the selection of either 477 kcmil ACSR or 4/0 AAAC for re-conductoring of the #9 Moretown #1 Middlesex circuit's mainline. The selection of conductor type will be deferred until the upgrade is more imminent, at which time the economics of the conductor size will be evaluated. The losses tabulated below are based on assumptions made that are detailed in Section 8.2.3. Most of the WEC data is gathered through thermal demand ammeters as detailed in section 8.2.3. Load data gathered by SCADA would provide greater accuracy in future analysis.

	Existing			All Recommendations in Place		Loss Delta	
Load Scenario	Peak	Min - No DER	Min - Connected & Proposed DER	Peak	Min - Connected & Proposed DER	Peak	Min - Connected & Proposed DER
Present - Year "0"	258.14	57.97	317.90	213.84	328.87	44.29	-10.96
Years 0-4 - Year "4"	267.99			254.49		13.50	
Years 4-10 - Year "10" 78a	524.30			410.58		113.72	
Years 4-10 - Year "10" 78b	524.30			405.04		119.26	

Table 23: Loss Results from LRP Analysis

1.3.16 Reliability

The reliability or protection portion of the LRP review considered substation high side fusing, WEC-owned sub-transmission reclosers (that serve distribution substations), coordination between circuit reclosers and the downstream line reclosers and largest fuses, impacts of increasing loads and fault duty, reliability data, and operational impacts.

Existing feeder backup ties were evaluated, and new ones proposed. Thermal impacts from new and proposed feeder ties were reviewed, and major substation upgrades recommended as part of the LRP took feeder backup into account.

1.3.16.1 Substation HS Fuses

The high side fuses at the WEC-owned distribution substations were reviewed for coordination with the substation transformer inrush and damage curves as well as coordination with the upstream and downstream devices. Analysis showed that almost all the substation HS fuses need to be replaced due to existing miscoordinations and increasing loads - see Table 24. These

Recommendations will need to be reviewed with any affected upstream utilities before implementation.

Substation	Substation Transformer	Existing HS Fuses			Recommended HS Fuses for Existing Substation Transformers			
		Manufacturer	Model	Size	Rec. #	Manufacturer	Model	Size
#1 East Montpelier	EM-T1, EM-T2, EM-T3	S&C	SMD-20	125E	257	S&C	SMD-20	**150E**
#3 Mount Knox	MK-T1, MK-T2, MK-T3	S&C	SMU-20	80E	145	S&C	SMU-20	**100E**
#4 West Danville	WD-T1, WD-T2, WD-T3	S&C	S.E.C	30E	152	S&C	S.E.C	**50E**
#5 South Walden	SW-T1, SW-T2, SW-T3	S&C	SMU-20	65E	147	S&C	SMU-20	**100E**
#8 Jackson Corners	JC-T1	S&C	SMD-20	80E	155	S&C	**SMU-20**	**100E**
#9 Moretown	MO-T1, MO-T2, MO-T3	S&C	SMU-20	65E	120	S&C	SMU-20	**100E**
#10 Maple Corners	MC-T1, MC-T2, MC-T3	S&C	SMU-20	65E	168	S&C	SMU-20	**80E**
#11 North Tunbridge	TU-T1, TU-T2, TU-T3	S&C	SMD2A	100E	129	S&C	SMD2A	**80E**

Table 24: Substation Transformer HS Fuse – Recommendations

1.3.16.2 Sub-Transmission Reclosers

With the proposed changes to substation high side fuses, changes will also need to be made to the #7 Graniteville and #1 East Montpelier sub-transmission reclosers that serve the #8 Jackson Corners and #10 Maple Corners substations respectively.

WEC is also looking to add a 34.5 kV recloser to the 3319 tap that feeds the #5 South Walden substation in order to improve reliability and gain a three-phase interrupting device to facilitate work at the substation.

All setting changes and new devices will be discussed with the transmission provider.

1.3.16.3 Circuit Protection

Due to increasing load, DER, and fault duty, there are quite a few protection upgrades that are required.

Per the TGFOV analysis (Section 8.2.10) it is likely that all of the circuit reclosers will need to be replaced in order to implement TGFOV protection. This will be approximately 20 new circuit reclosers that will be capable of monitoring load data that could be collected via a SCADA system to improve future analysis.

Over the years, the Vermont sub-transmission system has strengthened. That, along with the increasing DER, has increased the available fault current seen by the WEC system. There are 8 reclosers that will need to be upgraded for the increase in fault duty.

Coordination between the High Side fuses, circuit reclosers, line reclosers and largest downstream fuses was reviewed as part of the LRP. The following recommendations were made:

- Of the 23 WEC distribution circuits, 19 circuit reclosers need setting changes.
- Eleven new line reclosers are needed to improve coordination, unrelated to replacements for fault duty.
- Four line reclosers need setting changes.
- One detailed coordination study is recommended for the #11 Tunbridge #2 South Tunbridge circuit.

Thermal evaluations in Section 8.2.5.5 indicate that four additional line reclosers will also need to be upgraded to accommodate increasing loads.

1.3.16.4 Reliability Data

As part of the LRP, the WEC reliability data was reviewed, which included the SAIFI and CAIDI indices for the past 12 years - see Figure 1 and Figure 2. A general downward trend can be seen in the SAIFI, but an upward trend in CAIDI is indicated. A number of coordination improvements were suggested in Section 8.2.2.2 which will help reduce the number of Members affected by outages. The ten most operated devices from 2016 to 2022 were reviewed to determine what recommendations could be made to improve reliability. In addition to these frequently operated devices, WEC has several locations where outages are typically of a long duration due to inaccessibility. WEC also has several locations where adding a new device could reduce the number of Members affected by outages. All of these recommendations are listed in Table 25, but four in particular are described below:

#8 Jackson Corners - #3 Northfield Circuit

For the 90 Members downstream of line recloser RC25611, it can take over two hours to restore outages due to the line running through a heavily treed right of way (ROW). Between 2016 and 2022, there were seven outages, which lasted an average of an hour and fifteen minutes. The longest outages were almost three hours. Two options were proposed to address this situation:

1. Significantly increase tree trimming

2. Extend three phase across the highway I-89 by directional boring under the highway from Pole #8-3-122R17 on VT Rte. 64, Williamstown VT to Pole #8-3-207R88R5R1 on VT Rte. 64, Northfield VT. This extension will include approximately 450 cable feet of 4/0 AL cable and 2,215 conductor feet of 4/0 AL conductor.

Due to the cost and limited number of Members that would benefit WEC will be going with Option 1.

#9 Moretown - #3 Fayston Circuit

Due to terrain, the load served by WEC in the Town of Fayston, downstream of line recloser RC16415, is very isolated from the rest of the WEC system, and it can be difficult to restore power in the event of an outage. There have been seven outages on this line section from 2016 to 2022, ranging from 15 minutes to 8.5 hours in duration. There are approximately 247 Members affected by this situation, with about 500 kVA of peak load at this time and less than 700 kVA of load projected in 10 years. It is recommended that engineering analysis be performed to develop a Strategic Study to determine the best way to improve reliability. This might be a good case for a non-wires alternative, but a more traditional solution such as a substation could be beneficial.

#11 Tunbridge - #2 South Tunbridge Circuit

The fuse F33330 on Button Hill Road in Tunbridge is one of the most operated devices from 2016-2022. The proposed solution is a new line recloser and adjustment of the existing circuit recloser settings.

#5 South Walden – 3319 Transmission Line

Currently, the 3319 kV Tap that serves the #5 South Walden Substation is protected by fuses. To provide reclosing and to make coordination more flexible, it is recommended to replace the fuses with a new 35 kV line recloser. This device will need to be coordinated with the GMP and Morrisville 35 kV devices that provide the primary protection for the 3319 line.

Substation	Feeder	Device ID	Location	Outage Data from 2016-2022		Recommendation Detail
				# of Outages	Average Duration (hours)	
#9 Moretown	#3 Fayston	Circuit Recloser 9-3-RC	Substation	28	4.75	Change Circuit Recloser Settings
#11 North Tunbridge	#1 Corinth	F27951	Pole #11-1-208L10, Ryder Rd, Corinth	26	3.78	Increased Tree Trimming
#11 North Tunbridge	#2 South Tunbridge	F31603	Pole #11-2-13, Bicknell Rd, Tunbridge	20	3.87	Increased Tree Trimming & maybe upgrade fuse to a line recloser like a 50 V4H, only 11 Members affected.
#11 North Tunbridge	#2 South Tunbridge	F33330	Pole #11-2-108, Button Hill Rd, Tunbridge	17	2.93	Coordination Study
#2 Jones Brook	#1 Jones Brook	Circuit Recloser	Corner of Three Mile Bridge Rd & Jones Brook Rd, Berlin	17	5.45	Upgrade GMP 65T to 140T or Line Recloser
#9 Moretown	#1 Middlesex	RC11181	Pole #9-1-163, French Rd, Middlesex	17	6.28	Existing line recloser does not coordinate with largest downstream fuse upgrade to 50 H
#5 South Walden	#2 East Cabot	F07783	Pole #5-2-45L37R12, Cobb Rd, Walden	16	2.18	Increased Tree Trimming
#10 Maple Corners	#2 Middlesex	F11326	Pole #10-2-16L12A, Robinson Hill Rd, Calais	16	0.57	F11326 is a 15K fuse which does not coordinate with other existing devices. Recommend that RC09761 be upgraded from a 50 H to a 70 V4H and that fuses get re-coordinated
#11 North Tunbridge	#3 Brookfield	F27502	Pole #11-3-167, Cemetery St, Brookfield	16	1.66	Increased Tree Trimming
#3 Mount Knox	#2 Corinth	F28176	Pole #3-2-227R51L5R1, South Rd, Corinth	16	6.79	Increased Tree Trimming
#8 Jackson Corners	#3 Northfield	RC25611	Pole #8-3-207, East Roxbury Rd, Roxbury	10	4	Extend 3Ø across the highway I-89 by directional boring under the highway from Pole #8-3-122R17 on VT Rte. 64, Williamstown VT to Pole #8-3-207R88R5R1 on VT Rte. 64, Northfield VT. This extension will include ~450' of 4/0 AL cable and ~2,215' of 4/0 AL conductor
#9 Moretown	#3 Fayston	RC16415	Pole #9-3-109, VT Rte. 100, Duxbury	2	247	Strategic Study
#9 Moretown	#3 Fayston	New Line Recloser	Pole #9-3-69, VT Rte. 100, Duxbury	28	4.75	Add line recloser to reduce number of Members affected by faults.
#5 South Walden	3319	New 35 kV Line Recloser	3319 35 kV feed to #5 South Walden Substation	7[14]	1.5	Replace 3319 tap fuses with a 35 kV recloser. Operations requested this upgrade to reduce outage time, facilitate switching, tagging for clearance, and monitoring.

Table 25: Reliability Recommendations

[14] These are outages that a new line recloser could have reduced the duration of.

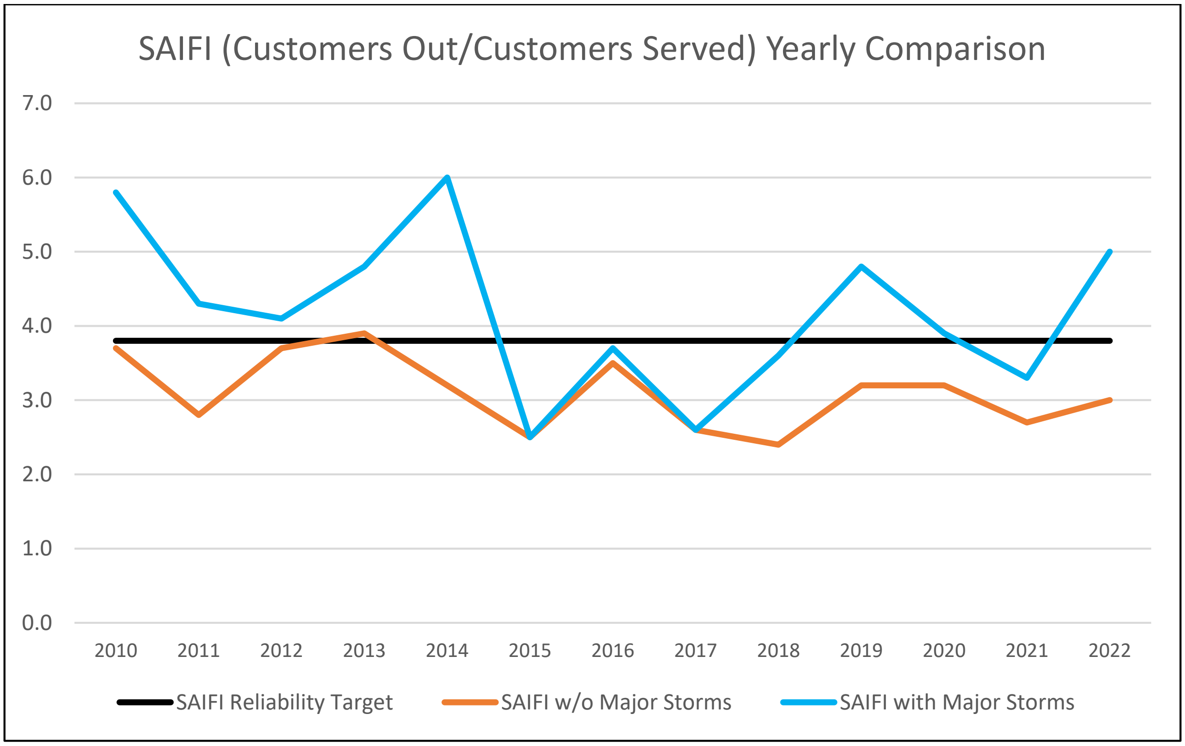

Figure 1: WEC SAIFI 2010-2022

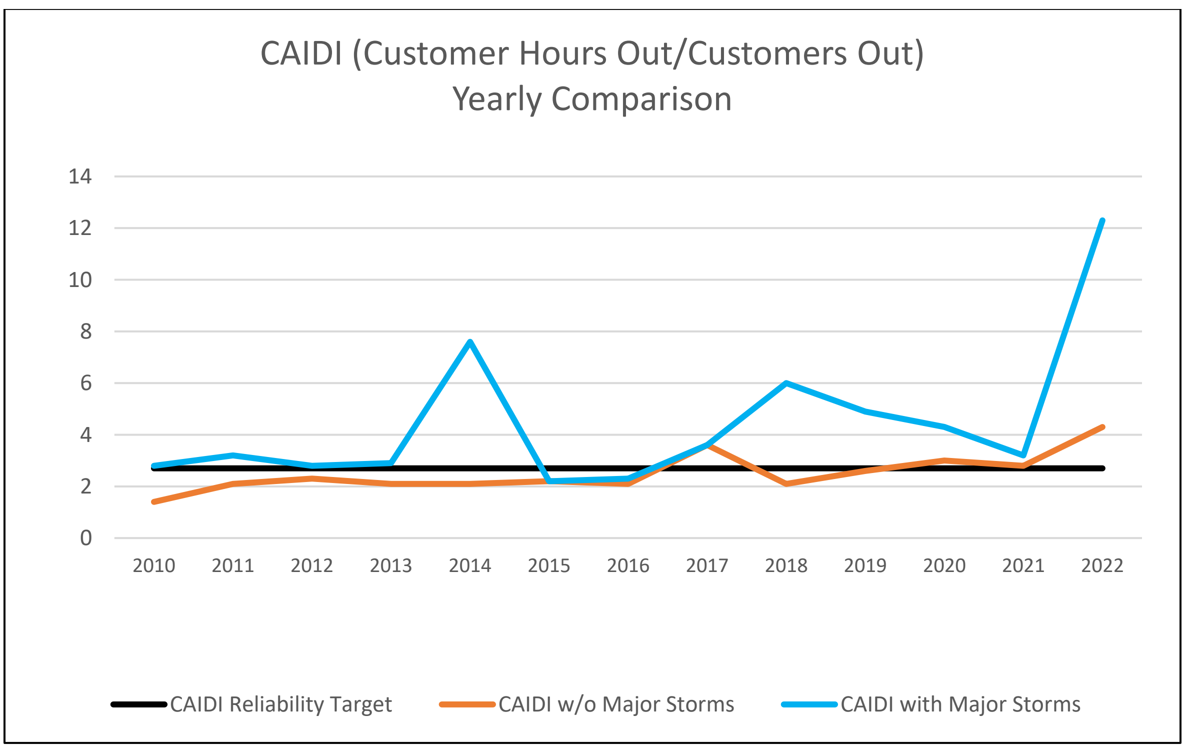

Figure 2: WEC CAIDI 2010-2022

1.3.16.5 Feeder Backup

The WEC distribution system has several existing feeder backup ties. These were thermally evaluated for existing peak loads and projected loads at 10 years with electrification initiatives. In addition to the existing ties, the LRP performed a strategic review of the system to consider new three phase ties, and line and substation upgrades to accommodate future ties. Strengthening the connectivity of the WEC system will increase reliability and its flexibility to accommodate new loads.

Existing Feeder Backup Capability

The existing feeder backup ties are shown in Figure 3 and Figure 4. These existing ties are also listed and thermally evaluated for current peak and load forecasted out to 10 years, for the limiting elements in the substations, in Table 26. Note, no load flows were performed to confirm if the circuits could support voltage for this much load. This analysis was done to establish high level capability and then identify locations for strategic upgrades.

							10 Year Forecasted		
Sub	Circuit Providing Back Up	Circuit Being Backed Up	Limiting Element	Limiting Element Present Loading (Amps)	Combined Peak Amps Loading	Present Load for combined circuits (KW)	Loading for Combined Circuits (kW)	Ratio of combined circuits current to 10 year forecasted load	Peak Load Combined Circuit (Amps)
#1 East Montpelier	#1 Cabot	#1 East Montpelier - #3 County Road	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A	150	116.9	1,754	2,622	1.49	**174.75**
	#2 Orange	#8 Jackson Corners - #1 Topsham	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A	150	**141.3**	2,221	3,293	1.48	**209.50**
	#3 County Rd	#10 Maple Corners - #2 Middlesex	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A 4/0 ACSR- OH Line - Rated 357A	150	120.7	1,755	2,793	1.59	**192.09**
		#1 East Montpelier - #2 Cabot			116.9	1,754	2,165	1.23	**144.29**
#5 South Walden	#1 Greensboro	#5 South Walden - #3 West Hill Pond	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A 1/0AAAC - OH Line - Rated at 256A	150	109	976	1,261	1.29	**140.83**
	#3 West Hill Pond	#5 South Walden - #1 Greensboro	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A 1/0ACSR - OH Line - Rated 242A	150	109	976	1,261	1.29	**140.83**
#8 Jackson Corners	#1 Topsham	#1 East Montpelier - #2 Orange	Recloser Bypass 2/0 ACSR - OH Line - Rated 276A	150	**141.3**	2,221	3,293	1.48	**209.50**

Sub	Circuit Providing Back Up	Circuit Being Backed Up	Limiting Element	Limiting Element Present Loading (Amps)	Combined Peak Amps Loading	Present Load for combined circuits (KW)	10 Year Forecasted: Loading for Combined Circuits (kW)	10 Year Forecasted: Ratio of combined circuits current to 10 year forecasted load	10 Year Forecasted: Peak Load Combined Circuit (Amps)
	#2 Chelsea	#11 North Tunbridge - #1 Corinth	Recloser Bypass 1/0AAAC - OH Line - Rated 256A	150	83.7	1,573	2,084	1.32	**110.89**
#10 Maple Corners	#2 Middlesex	#1 East Montpelier - #3 County Rd	Circuit Regulators Recloser Bypasses - 150A 4/0 ACSR- OH Line - Rated 357A	100	**120.7**	1,755	2,793	1.59	**192.09**
#11 North Tunbridge	#1 Corinth	#8 Jackson Corners - #2 Chelsea	Circuit Regulators 4/0 ACSR- OH Line - Rated 357A	150	83.7	1,573	2,084	1.32	110.89

Table 26: Existing Feeder Backup Ties – Current & 10 Year Forecasted Thermal Evaluation

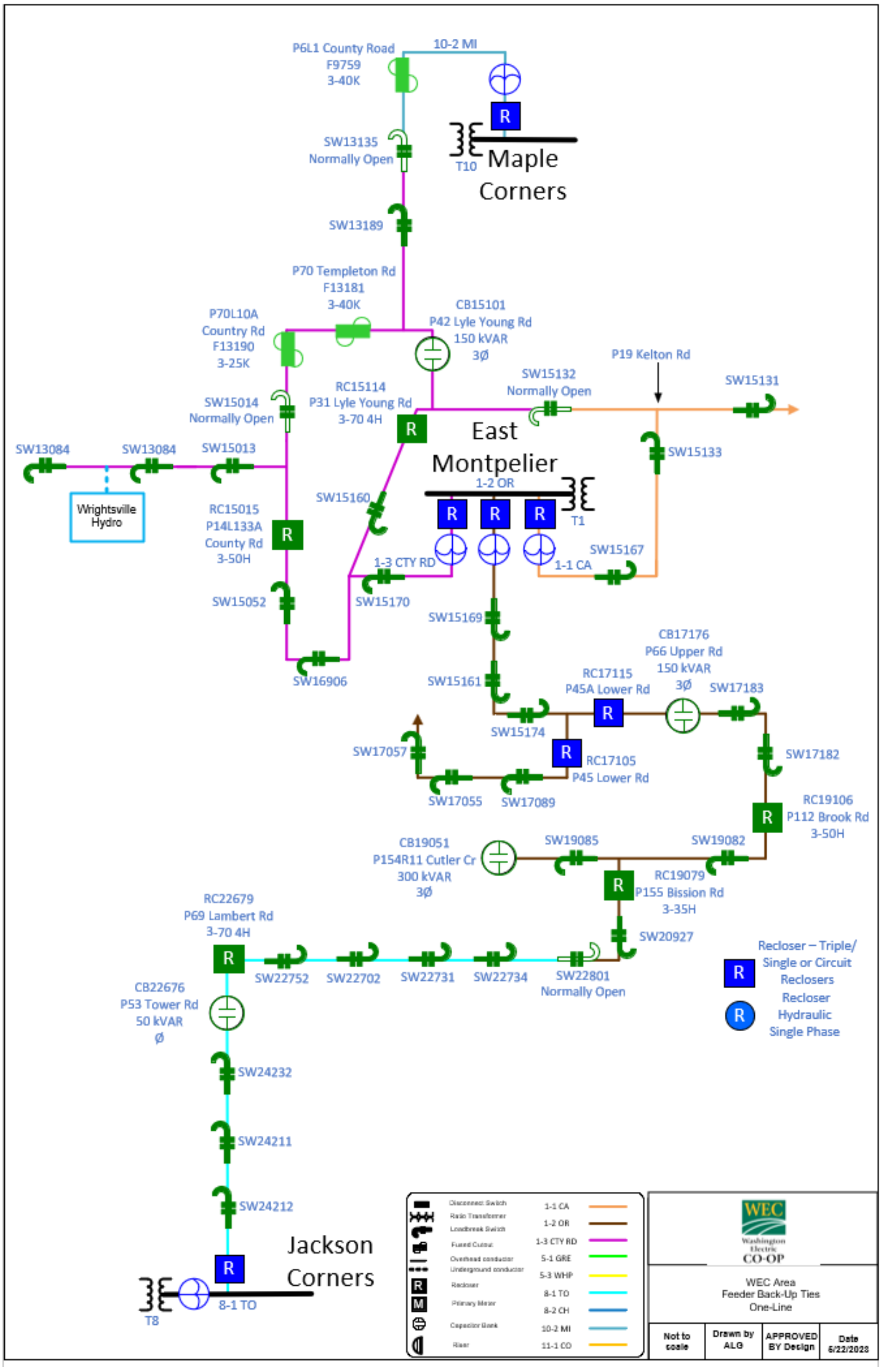

Figure 3: Existing Feeder Backup Ties – Page 1

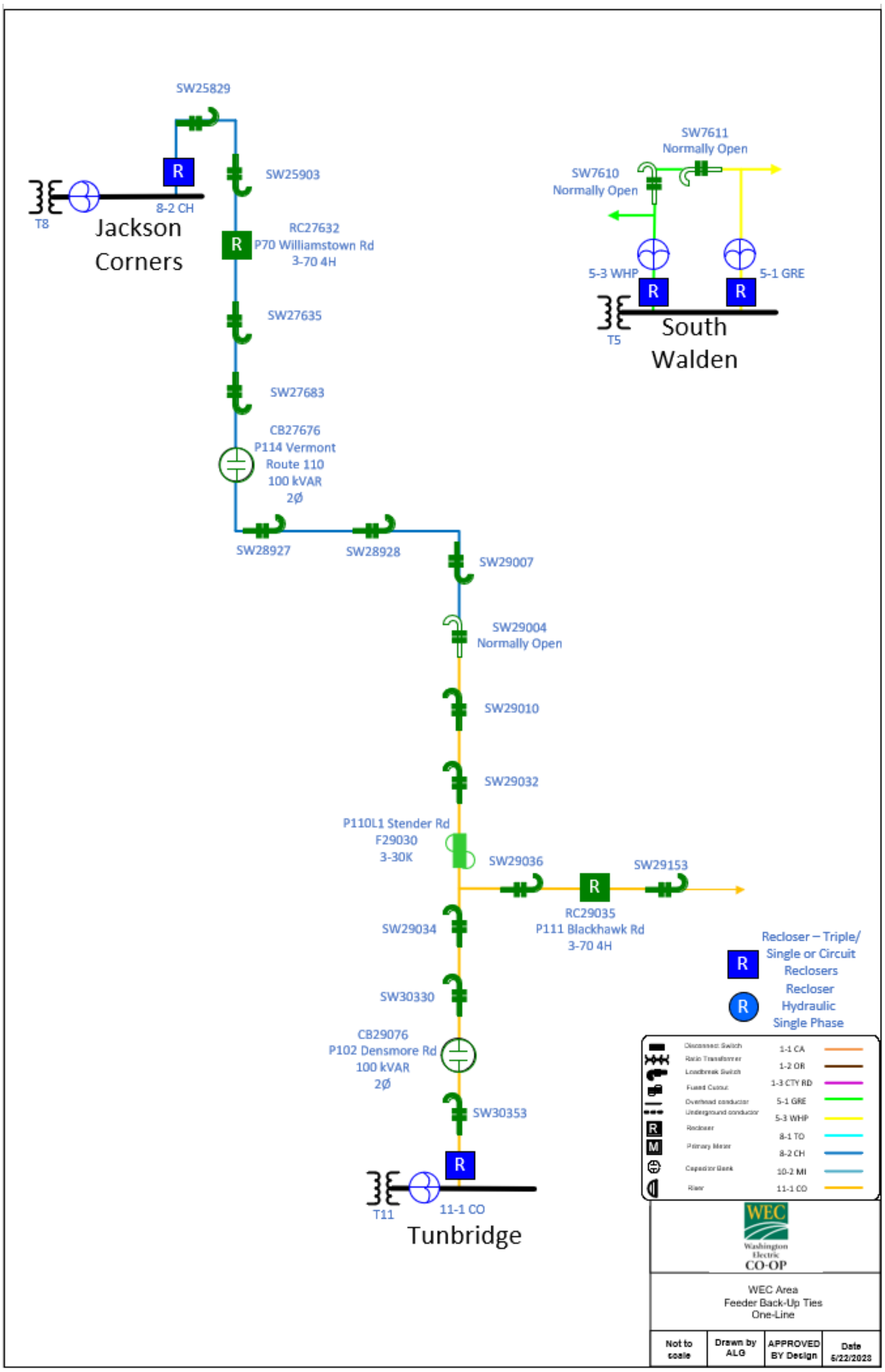

Figure 4: Existing Feeder Backup Ties – Page 2

Strategic Feeder Backup Upgrades[15]

In addition to the existing feeder backup ties identified in the prior section, several locations were identified as being prime locations to create or strengthen ties, see Table 27. Several substations such as #3 Mount Knox, #4 West Danville, #5 South Walden, and #9 Moretown do not have three phase distribution ties to other substations. Building these ties not only improves reliability for an increasing amount of load and members, but also builds in more flexibility for future growth by allowing the possibility of load transfers to better balance load across the system and allow more efficient use of existing assets, as well as allowing for temporary relief of overloads while new infrastructure is being built to accommodate increasing loads. The #11 Tunbridge substation already has a tie with #8 Jackson Corners, but it is very limited given the small and fragile conductor between the substations.

An expanded list of existing and proposed feeder backup ties and their thermal impacts to the circuit limiting elements for current and ten-year peak loads is shown in Table 28.

The upgrades necessary to address the thermal violations for existing and future ties is shown in Table 29.

Another factor in feeder backup is substation transformer capacity. Recommended substation transformer sizes based on feeder backup are shown in Table 30. Note, Table 30 is a suggested size based on Feeder Backup for all the substation transformers regardless of whether they are slated to be replaced in the next ten years for other reasons such as thermal or asset concerns.

One-lines showing the existing and strategic feeder backup Upgrades are shown in Figure 5, Figure 6, and Figure 7.

[15] Any proposed feeder backup tie is highlighted in light green in this section.

Substation	Circuit	Description	Ties that are Created/Strengthened	From Pole, Road, Town	To Pole, Road, Town	Distance (Feet)
#4 West Danville	#1 Hookerville	Extend 3Ø & RC[16] #4HDC	Creates West Danville-S. Walden Tie	Pole #4-1H-1, Woodward Rd, Danville	Pole #5-2-82L45, West Shore Rd, Cabot	6616
#5 S. Walden	#2 Cabot	Extend 3Ø & RC #4HDC	Creates West Danville-S. Walden Tie	Pole #5-2-82 Cabot Plains Rd, Cabot	Pole #5-2-82L45, West Shore Rd, Cabot	10017
#8 Jackson Corners	#2 Chelsea	RC #2ACSR	Jackson Corners - Tunbridge	Pole #8-2-41, Chelsea Rd, Williamstown	Pole #8-2-68, Williamstown Rd, Washington	9591
				Pole #8-2-71, Williamstown Rd, Washington	Pole #8-2-70, Williamstown Rd, Washington	205
				Pole #8-2-79 ROW off VT Rte. 110, Chelsea	Pole #8-2-86, VT Rte. 110, Chelsea	1660
				Pole #8-2-144, ROW off VT Rte. 110, Chelsea	Pole #8-2-164, Washington Turnpike, Chelsea	7427
#9 Moretown	#1 Middlesex	Extend 3Ø	Creates Moretown #1 Middlesex to East Montpelier #3 County Rd circuit tie	Pole #9-1-163, French Road, Middlesex	Pole #9-1-215, Horn of the Moon Rd, Middlesex	17386
#10 Maple Corners	#1 North Calais	Extend 3Ø	Creates 2nd tie between #10 Maple Corners and #1 East Montpelier Substations	Pole #11-1-173R17, George Rd, Calais	Pole #1-1-54, Lightening Ridge Rd, Calais	19780
#11 North Tunbridge	#1 Corinth	RC 6/8CWC	Jackson Corners - Tunbridge	Pole #11-1-110, ROW off Blackhawk Road, Chelsea	Pole #11-1-110L27, Upper Village Road, Chelsea	6526
#3 Mount Knox	#2 Corinth	Extend 3Ø	Creates three phase tie to #8 Jackson Corners #1 Topsham circuit	Mount Knox Pole #3-2-33 William Scott Memorial Hwy US Rte. 302, Topsham, VT	Pole #3-2-33R13 US Rte. 302, Orange, VT	3696
#8 Jackson Corners	#1 Topsham	Extend 3Ø	Creates a three-phase tie to #3 Mount Knox #2 Corinth circuit	Pole #8-1-131, Rte. 302, Orange, VT	Pole #3-2-33R13, US Rte. 302, Orange, VT	21089

Table 27: Strategic Feeder Backup Upgrades

[16] RC = Re-Conductor

							10 Year Forecasted		
Sub	Circuit Providing Back Up	Circuit Being Backed Up	Limiting Element	Limiting Element Present Loading (Amps)	Combined Peak Amps Loading	Present Load for combined circuits (KW)	Loading for Combined Circuits (kW)	Ratio of combined circuits current to 10 year forecasted load	Peak Load Combined Circuit (Amps)
#1 East Montpelier	#1 Cabot	#1 East Montpelier - #3 County Road	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A	150	116.9	1,754	2,622	1.49	**174.75**
		#10 Maple Corners - #1 North Calais		150	**141**	989	1,605	1.62	**228.82**
	#2 Orange	#8 Jackson Corners - #1 Topsham	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A	150	**141.3**	2,221	3,293	1.48	**209.50**
	#3 County Rd	#1 East Montpelier - #2 Cabot	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A 4/0 ACSR- OH Line - Rated 357A	150	116.9	1754.00	2,165	1.23	**144.29**
		#9 Moretown - #1 Middlesex			115	2,305	3,780	1.64	**188.59**
		#10 Maple Corners - #2 Middlesex			120.7	1,755	2,793	1.59	**192.09**
#3 Mount Knox	#2 Corinth	#8 Jackson Corners - #1 Topsham	Recloser Bypass 2/0 ACSR - OH Line - Rated 276A	150	**159**	2,701	3,775	1.40	**222.22**
#4 West Danville	#1 Hookerville	#5 South Walden - #2 Cabot	Voltage Regulators 100A	100	81	813	991	1.22	**98.73**

							10 Year Forecasted		
Sub	Circuit Providing Back Up	Circuit Being Backed Up	Limiting Element	Limiting Element Present Loading (Amps)	Combined Peak Amps Loading	Present Load for combined circuits (KW)	Loading for Combined Circuits (kW)	Ratio of combined circuits current to 10 year forecasted load	Peak Load Combined Circuit (Amps)
#5 South Walden	#1 Greensboro	#5 South Walden - #3 West Hill Pond	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A 1/0AAAC - OH Line - Rated at 256A	150	109	976	1,261	1.29	**140.83**
	#2 Cabot	#4 West Danville - #1 Hookerville	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A	150	81	813	991	1.22	98.73
	#3 West Hill Pond	#5 South Walden - #1 Greensboro	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A 1/0ACSR - OH Line - Rated 242A	150	109	976	1,261	1.29	**140.83**
#8 Jackson Corners	#1 Topsham	#1 East Montpelier - #2 Orange	Recloser Bypass 2/0 ACSR - OH Line - Rated 276A	150	**141.3**	2,221	3,293	1.48	**209.50**
		#3 Mount Knox - #2 Corinth		150	**159**	2,701	3,775	1.40	**222.22**
	#2 Chelsea	#11 North Tunbridge - #1 Corinth	Recloser Bypass 1/0AAAC - OH Line - Rated 256A	150	83.7	1,573	2,084	1.32	**110.89**

Sub	Circuit Providing Back Up	Circuit Being Backed Up	Limiting Element	Limiting Element Present Loading (Amps)	Combined Peak Amps Loading	Present Load for combined circuits (KW)	10 Year Forecasted Loading for Combined Circuits (kW)	Ratio of combined circuits current to 10 year forecasted load	Peak Load Combined Circuit (Amps)
#9 Moretown	#1 Middlesex	#1 East Montpelier - #3 County Rd	Recloser Bypass & Voltage Regulators 1/0 AL UG Getaway - Rated 155A	150	115	2,305	3,780	1.64	**188.59**
#10 Maple Corners	#1 North Calais	#1 East Montpelier - #1 Cabot	Circuit Regulators Recloser Bypasses - 150A 1/0 AL UG Getaway - Rated 155A 1/0ACSR - OH Line - Rated 242A	100	141	989	1,605	1.62	**228.82**
	#2 Middlesex	#1 East Montpelier - #3 County Rd	Circuit Regulators Recloser Bypasses - 150A 4/0 ACSR- OH Line - Rated 357A	100	**120.7**	1,755	2,793	1.59	**192.09**
#11 North Tunbridge	#1 Corinth	#8 Jackson Corners - #2 Chelsea	Circuit Regulators 4/0 ACSR- OH Line - Rated 357A	150	83.7	1,573	2,084	1.32	110.89

Table 28: Existing & Proposed Feeder Backup Ties – Current & Future Thermal Evaluation[17]

[17] Items in bold **red** lettering are over the thermal limits or very close.

		Recommendation	
Sub	Circuit Providing Back Up	#	Feeder Backup Upgrades
#1 East Montpelier	#1 Cabot	264	Upgrade Recloser Bypass to 150K, Voltage Regulators 328A, & UG Getaway Cable to 350 MCM CU 412A
	#2 Orange	265	Upgrade Recloser Bypass to 150K, Voltage Regulators 328A, & UG Getaway Cable to 350 MCM CU 412A
	#3 County Rd	266	Upgrade Recloser Bypass to 150K, Voltage Regulators 328A, & UG Getaway Cable to 350 MCM CU 412A
#3 Mount Knox	#2 Corinth	267	Upgrade Recloser Bypass to 150K
#4 West Danville	#1 Hookerville	268	Upgrade circuit regulators to 219A
#5 South Walden	#1 Greensboro	269	Upgrade Recloser Bypass to 150K, Voltage Regulators 219A, & UG Getaway Cable to 4/0 AL UG Cable 260A
	#3 West Hill Pond	270	Upgrade Recloser Bypass to 150K, Voltage Regulators 219A, & UG Getaway Cable to 4/0 AL UG Cable 260A
#8 Jackson Corners	#1 Topsham	271	Upgrade Recloser Bypass to 150K
	#2 Chelsea	272	Upgrade Recloser Bypass to 150K
#10 Maple Corners	#1 North Calais	273	Upgrade Recloser Bypass to 150K, Voltage Regulators 328A, & UG Getaway Cable to 350 MCM CU 412A
	#2 Middlesex	274	Upgrade Circuit Regulator to 328A & Recloser Bypass to 150K

Table 29: Circuit Upgrades at the substation for Feeder Backup [18]

[18] Highlighted circuits are upgrades for proposed ties.

Feeder Backup Source		Substation Being Backed up						
Substation Name	**10 YR Forecasted Load MVA with Electrification**	**Substation Name**	**10 YR Forecasted Load MVA with Electrification**	**Total MVA**	**Existing Transformation Capacity MVA**	**Delta between Transformation Capacity & Feeder Backup Total** ***(Negative indicates that there is insufficient capacity)***	**Min Suggested Transformer Size MVA**	**Notes**
#1 East Montpelier	4.995	#8 Jackson Corners	5.048	10.043	5	-5.043		Jackson Corners has other stronger and potential ties that are closer, load would be split during feeder backup.
	4.995	#10 Maple Corners	1.776	6.771	5	-1.771		
	4.995	#9 Moretown	5.213	10.208	5	-5.208	7.5/10.5	There is a 17,386' gap on the Middlesex circuit that is currently single phase and mostly 3/12CWC, note most of the Middlesex main line is 1/0ACSR which needs to be re-conductored for voltage and load support reasons. Moretown doesn't have any potential feeder backup options
	4.995	#5 S. Walden	2.035	7.03	5	-2.03		There will be a 7-mile gap even with the all the upgrades planned for the next 10 years
#2 Jones Brook	0.18	No Ties		0.18	N/A			No Ties
#3 Mount Knox	3.857	#8 Jackson Corners	5.048	8.905	3.75	-5.155	7.5/10.5	Jackson Corners substation load would be at minimum split between Mount Knox and Tunbridge
#4 West Danville	0.875	#5 S. Walden	2.035	2.91	1.5	-1.41	5	Three phase tie would need to be built, ~3.15 miles
#5 South Walden	2.035	#1 East Montpelier	4.995	7.03	3.75	-3.28	5	There will be a 7-mile gap even with the all the upgrades planned for the next 10 years. Jackson Corners and potentially Moretown would split up this load.
	2.035	#4 West Danville	0.875	2.91	3.75	0.84	5	Three phase tie would need to be built ~3.15 miles

Feeder Backup Source		Substation Being Backed up						
Substation Name	**10 YR Forecasted Load MVA with Electrification**	**Substation Name**	**10 YR Forecasted Load MVA with Electrification**	**Total MVA**	**Existing Transformation Capacity MVA**	**Delta between Transformation Capacity & Feeder Backup Total** ***(Negative indicates that there is insufficient capacity)***	**Min Suggested Transformer Size MVA**	**Notes**
#8 Jackson Corners	5.048	#1 East Montpelier	4.995	10.043	3.75	-6.293	**7.5/10.5**	East Montpelier substation load would be split between Jackson Corners and Maple Corners at minimum. Recommend 219A circuit regulators, or 546A bus regulators (non-standard item).
	5.048	#3 Mount Knox	3.857	8.905	3.75	-5.155		
	5.048	#11 Tunbridge	2.553	7.601	3.75	-3.851		
#9 Moretown	5.213	#1 East Montpelier	4.995	10.208	3.75	-6.458	**7.5/10.5**	There is a 17,386' gap on the Middlesex circuit that is currently single phase and mostly 3/12CWC, note most of the Middlesex main line is 1/0ACSR which needs to be re-conductored for voltage and load support reasons. East Montpelier substation load would likely be split between Moretown, Maple Corners and Jackson Corners
#10 Maple Corners	1.776	#1 East Montpelier	4.995	6.771	2.5	-4.271	**7.5/10.5**	East Montpelier substation load would likely be split between Moretown, Maple Corners and Jackson Corners
#11 Tunbridge	2.553	#8 Jackson Corners	5.048	7.601	3.24	-4.361	**7.5/10.5**	

Table 30: Recommended Substation Transformer Sizes Based on Feeder Backup

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