STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET DE 19-120

IN THE MATTER OF: Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities
2019 Least Cost Integrated Resource Plan.

DIRECT TESTIMONY

OF

Kurt Demmer
Utility Analyst NHPUC

January 23, 2020

Q. Please state your full name.

A. Kurt Demmer.

Q. By whom are you employed and what is your business address?

A. I am employed as a Utility Analyst in the Electric Division of the New Hampshire Public Utilities Commission (Commission or PUC). My business address is 21 South Fruit St., Suite 10, Concord, NH, 03301.

Q. Please summarize your education and professional work experience.

A. I graduated from Merrimack College in North Andover, Massachusetts with a Bachelor of Science degree in Electrical Engineering in 1987. In 2002, I received a Master's degree in Electrical Engineering and Power Systems Management from Worcester Polytechnic Institute in Worcester, Massachusetts. Since 1996, I have been a registered professional engineer in the State of New Hampshire.

In June 1988, I joined Massachusetts Electric Company as an Operations Field Engineer. In 1996, I became a Senior Engineer for Massachusetts Electric Company. In 1999, my area of responsibility expanded to include distribution planning engineering. In 2000, I accepted a position as Area Supervisor for the Salem NH area of National Grid USA and was responsible for all distribution engineering, distribution overhead/underground/substation construction, substation operations, and warehousing in the Salem/Pelham area. In 2002, I was promoted to Superintendent of Electric Operations in the Salem/Beverly/Cape Ann Massachusetts area. As Superintendent, I was responsible for distribution engineering immediate oversight, distribution overhead/underground/substation construction, substation operations, and warehousing. From 2003 to 2004, I was a project manager for a 14-mile, $19 million subtransmission 34.5kV underground distribution project consisting of manhole and duct construction housing (1) 34.5kV distribution supply circuit and (1) 34.5kV distribution circuit connecting East Beverly substation to a downtown Gloucester distribution substation. In 2005, as Superintendent of electric overhead distribution operations, I was assigned to the Merrimack Valley district area in Massachusetts. In 2008, I was promoted to Manager of Electric Operations in New Hampshire for National Grid, responsible for the operations, construction, and maintenance functions for the electric distribution organization. In 2010, I was promoted to Acting Director of Electrical Operations in New Hampshire for National Grid. In 2012, I became Director of Electrical Operations in New Hampshire for Liberty Utilities (Liberty). My continued areas of responsibility were to oversee the construction, maintenance, and operation of the electric distribution system. Since 2017, I have been employed as a Utility Analyst in the Electric Division for the Commission.

Q. What is the purpose of your testimony?

A. My testimony in this proceeding will review and evaluate the Liberty Utilities (Liberty) limited Least Cost Integrated Resource Plan (LCIRP) submittal as required in Order No. 26,261. The evaluation will determine whether Liberty complied with the Commission order and recommend next steps to the Commission for the Company's January 15, 2021 full LCIRP submittal.

Q. Did Liberty file a Least cost Integrated Resource Plan (LCIRP) on July 15, 2019?

A. No. Liberty requested—and was granted—a waiver of the 2019 LCIRP requirements in Order No. 26,261 (June 14, 2019). That order stated, in pertinent part:

> While we will allow Liberty to delay its LCIRP filing, we will nonetheless require a more limited filing by the Company on or before July 15, 2019. The purpose of this filing will be to ensure that Liberty is adhering to certain commitments made in its prior approved LCIRP. Our approval of Liberty's 2016 LCIRP contained specific deliverables and we will require updates of those in Liberty's July 15 filing, as follows:
>
> - Confirmation that the utility is currently following the process of system planning using established procedures, criteria, and policies outlined in its 2016 LCIRP, and achieving the objectives included its 2016 LCIRP.
>
> - Copies of adopted standard operating procedures for employees and managers integrating day-to-day and long-term planning consistent with the Company's objectives of Least Cost Planning.

Instead of an LCIRP, Liberty provided a "more limited filing" pursuant to Order No. 26,261 (June 14, 2019). In the testimony below, I review the Company's more limited filing for consistency with the Commission's direction in Order No. 26,261, and make recommendations for the full LCIRP the Company must file on January 15, 2021.

<u>Procedures, criteria, and policies outlined in its 2016 LCIRP</u>

Q. Is the Company following the process of system planning utilizing the established procedures, criteria, and policies outlined in its 2016 LCIRP?

A. No. Overall the planning criteria for the 2016 LCIRP and the 2019 limited filing LCIRP describe similar design criteria, equipment rating criteria, and forecasting methodology, however, there are additional equipment rating criteria for distribution transformers that were new to the 2019 limited filing LCIRP planning criteria. There were also other strategies or procedures that were in the 2019 limited filing LCIRP that differ from the 2016 full LCIRP filing.

Q. What are the other procedures, policies, and criteria that are different from the 2016 LCIRP filing?

A. Items that were submitted in the 2019 limited LCIRP that are in addition to those submitted in the 2016 LCIRP include a comprehensive set of Distribution Construction Standards for overhead and underground equipment, electric operating procedures for distribution, strategy documents (DAS-1 through DAS-5),[1] and reliability based review processes and identification tools (DAM-012 and DAM-016).[2] These documents, numbered DAS-1 through DAS-15 provide Liberty employees guidance on Liberty's asset management strategy on numerous distribution field assets. Since most of the strategy documents are revised National Grid documents, Staff requested the original or pre-2016 versions of the strategy documents in Staff 3-15. A majority of the strategy documents have been revised in either 2018 or 2019 . It appears that DAS-010 is a new strategy document (Poor Performing Feeder Strategy) released in June 2019. In addition to the revised and new Strategy documents, DAM-012, Engineering Reliability Review Process is also a new strategy document released in June 2019.

<u>Standard Operating Procedures for Employees and Managers</u>

[1] Docket No. DE 19-120. Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities Least Cost Integrated Resource Plan, Attachment 1
[2] *Id*.

Q. Did the Company provide copies of adopted standard operating procedures for employees and managers integrating day-to-day and long-term planning consistent with the Company's objectives of Least Cost Planning?

A. The Company provided the documentation described in the answer above, however the Company's filing in Docket No. DE 19-120 is missing certain key documents which would have shown whether the Company's standards and operating procedures for employees and managers integrate day-to-day and long-term planning consistent with the Company's objectives of Least Cost Planning.

Q. Please describe the missing documentation.

A. As part of the construction standards, operating policies, and procedures, there are also substation maintenance procedures (SMP) and substation maintenance standards (SMS). These procedures and standards, which were developed by National Grid to adequately maintain substation assets, are an essential resource for Liberty to benchmark asset performance and gauge substation asset condition. During the Liberty Technical Session held November 26, 2019, the Company discussed the ongoing revisions or modifications to the original SMP and SMS documents as the substation department takes on more of the substation tasks.

Q. What is the significance of not receiving all of the 2019 Limited Filing LCIRP deliverables at this time?

A. As stated in Order No. 26,039, it is imperative for the Company to include adopted standard operating procedures for employees and managers integrating day-to-day and long-term planning consistent with the Company's objectives of Least Cost Planning.[3] The lack of updated or adopted SMS and SMP indicates a disconnect between substation asset evaluation and the least cost planning process. Furthermore, Order No 26,261 requires the Company to submit all of the Company's adopted standard operating procedures for employees and managers.

Q. Is there a concern with Liberty's existing planning criteria?

A. Liberty addresses a change in design criteria in its 2016 and limited 2019 filing.. It states "Liberty Utilities has refined the distribution planning criteria to better fit Liberty's strategy and scale of facilities. These refinements…reflect Liberty's strategy of having sufficient capacity available to meet changes in demand, including new customer demand, to improve operations during emergency conditions, and to allow more time for the planning, analysis and construction, as needed, of new facilities. In addition the refinements reflect the operating parameters of Liberty's smaller distribution footprint and resource base."[4]

Liberty's scale of facilities, similar to other New Hampshire Investor Owned Utilities (NH IOUs) is proportional to its customer base. Less customers typically equate to less distribution circuits, substations, and resources. Conversely, as the customer count increases and load increases, the distribution system that serves those customers also increases. This assumes a similar mix of geographical topography, customer class, and load density (i.e. rural vs. urban density). Liberty, Eversource, and Unitil have both rural and urban areas. Liberty's design criteria is significantly lower for normal loading than other NH investor owned utilities. Adopting a "take action" step at 75% rather than 100% of the equipment's continuous rating equates to a premature

[3] Order No. 26,039 at 5-6. (July 10, 2017)

[4] Docket No. DE 19-120. Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities Least Cost Integrated Resource Plan. Attachment 2, Bates page 0142.

replacement of distribution and substation equipment, which is not necessary as the equipment is rated for 25% more loading.

Liberty's assessment of the lowered design criteria as necessary to allow more time for planning, analysis, and construction of new facilities does not align with Liberty's PSA forecast at the system level or township level. Liberty's Final Seasonal Peak Forecast 2018-2034 dated January 2019 lists a summary of results for Liberty's NH service territory. Table 1 indicates a -0.42% average growth rate for 2013-2017 summer weather adjusted peak loads. Table 2 indicates a 0.36% average load growth rate for 2020-2024 summer peak loads assuming normal weather. The largest average load growth for 2020-2024 at the township level is 1.04% average load growth rate for 2020-2024 summer peak loads assuming normal weather in the Derry Township.[5] There are spot loads 300kVA and larger that Liberty adds to the future forecast when planning load forecasts annually, however considering that past spot loads are now embedded in the historical load growth, spot loads typically are not significantly changing the peak loads.

Q. Are there other criteria that Liberty should reevaluate as part of the normal loading concerns?

A. Liberty's equipment rating criteria also is more conservative than National Grid and the other NH IOUs. The Long Term Emergency (LTE) load rating relies on the type of asset that is limiting the circuit as well as the duration.

Q. Can Staff provide an example of these conservative rating criteria?

[5] Attachment KFD-1. Docket No. DE 19-120, Staff Data Request 1-003a3. Page (21) of (47)

A. For example, the LTE load rating for overhead conductors is based on a 24-hour duration with an elevated temperature of the conductor not to exceed 90°C, however, bare wire may accommodate a higher temperature without risking safety or reliability. For circuits where the LTE rating is based on an overhead conductor, the current LTE rating may not accurately represent available additional capacity for restoration during a first contingency event. While I recognize that other factors that may limit the temperature range of bare conductor (e.g. pole top insulator temperature restrictions and clearances to other conductors as the conductor sag increases), a higher temperature range and resultant increased LTE rating for applicable circuits during contingencies may result in less load at risk and fewer requirements to upgrade the infrastructure at a higher cost.

Q. What is the correlation between the risk assessment and Liberty's contingency load at risk design criteria?

Liberty presently does not utilize risk assessment software, however the Megawatt (MW) and Megawatt-hour (MWhr) contingency load at risk should, at a minimum, reflect the actual risk and impact that a substation transformer, subtransmission line, and distribution feeder contingency presents. The existing Liberty design criteria is more conservative than its predecessor, National Grid, and is far more conservative than the other NH IOUs. Refer to Table 1 below for planning criteria comparisons:[6]

[6] Docket No. DE 19- 064 Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities Petition for Permanent Rates Distribution Service Rate Case. Direct Testimony of Kurt Demmer, Bates page 000013, "Table 1".

Table 1

Comparison of Planning Criteria and Forecasting Methodology

Liberty Utilities	National Grid	Eversource (See Note)	Unitil
Normal Operations			
Distribution feeders to remain within **75%** of normal ratings.	Distribution Feeder to remain within **100%** of normal ratings	Distribution Feeder to remain within **100%** of normal ratings	Distribution Feeder to remain within **100%** of normal ratings
Subtransmission lines to remain within **90%** of normal ratings.	Subtransmission lines to remain within **100%** of normal ratings	Subtransmission lines to remain within **100%** of normal ratings	Subtransmission lines to remain within **100%** of normal ratings
Substation transformers to remain within **75%** of normal ratings.	Substation transformers to remain within **100%** of normal ratings	Substation transformers to remain within **100%** of TFRAT ratings with an 85% TFRAT rating identification	Substation transformers to remain within **100%** of normal ratings
First Contingency (N-1) Operations			
For loss of a distribution feeder, with no more than **16MWhr** load at risk during peak loading	For loss of a distribution feeder, with no more than **16MWhr** load at risk during peak loading	N/A	N/A
For loss of a subtransmission line, load at risk after switching is no more than **1.5 MW**. No more than **36 MWhr** load at risk during peak loading	For loss of a subtransmission line, load at risk after switching is no more than **20 MW**. No more than **240 MWhr** load at risk during peak loading	For loss of a subtransmission line, load at risk after switching is no more than **30 MW**. No more than **720 MWhr** load at risk during peak loading	For loss of a subtransmission line, load at risk after switching is no more than **30 MW.** No more than **720 MWhr** load at risk during peak loading
For loss of a substation transformer, load at risk after switching is no more than **2.5 MW**. No more than **60 MWhr** load at risk during peak loading	For loss of a substation transformer, load at risk after switching is no more than **10 MW**. No more than **240 MWhr** load at risk during peak loading	For loss of a substation transformer, load at risk after switching is no more than **30 MW**. No more than **720 MWhr** load at risk during peak loading	For loss of a system supply substation transformer, load at risk after switching is no more than **30 MW**. No more than **720 MWhr** load at risk during peak loading
Other First Contingency (N-1) Design Criteria			
In general, and whenever practical, each distribution feeder should have 3 feeder ties to adjacent circuits	Circuits shall tie to neighboring circuits as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible	N/A	N/A
Distribution circuits should be limited to 2,500 customers and sectionailed such that the number of customers does not exceed 500 or 2,000 kVA of load between disconnecting devices	N/A	N/A	N/A
Load Forecasting Methodology			
Load forecast is based on econometric models and updated annually. It is developed on both weather normalized and weather probabalistic basis on both a system level and a Planning Study Area (PSA) level. The following year (Year 1) forecast is based on an extreme weather forecast which is a 95/5 forecast. Known spot loads are added to the PSA forecast after the forecast has been determined.	Load forecast is based on econometric models and updated annually. It is developed on both weather normalized and weather probabalistic basis on both a system level and a Planning Study Area (PSA) level. The following year (Year 1) forecast is based on an extreme weather forecast which is a 95/5 forecast. Known spot loads are added to the PSA forecast after the forecast has been determined	The maximum Peak Load Forecast shall be based upon the highest recorded peak within the previous five years where consecutive days of 17 cooling degree days occurred. Each Operating area has separate peak load forecast based on spot load increases and New Hampshire Coop / Unitil Load forecasts	Load forecasts are developed using a linear trend regression model that correlates a 10-year history of daily peak load versus daily average temperature and humidity. A Monte Carlo simulation is utilized to produce a range of peak load possibilities. Peak Design load is used for system infrastructure adequacy and contingenciy studies. Peak Design load is a 90/10 forecast.

Staff Recommendations and Expectations for the 2021 LCIRP

Q. Does Staff have any recommendations related to the Company's distribution capital projects and least cost planning?

A. For the next LCIRP due January 2021, Liberty should provide the level of detail and transparency into least cost planning, planned capital projects, circuit level load forecasts, and current system visibility that Unitil provided in its 2016 LCIRP and Attachments in Docket No. DE 16-463. This would include any recently completed capital plans, area planning studies, ten-year circuit level loading criteria and forecasts, and an evaluation of planned investments and potential least cost alternatives.

Q. How does the Company plan to satisfy its obligation under Order No. 26,207?

A. When asked whether the Company would provide a grid needs assessment within its next LCIRP, the Company stated that it would file such an assessment in it next LCIRP, which would be due to the Commission on or before June 19, 2020 absent intervening Commission action.[7]

Q. What is Staff's recommendation for risk evaluation in Liberty's planning and design criteria?

Liberty's planning and design criteria for the assets that have the probability for a larger impact should be consistent with the other NH IOUs while still evaluating the actual probability and impact of each significant contingency event. The 30MW/720MWh load at risk should be considered as a first step. Mitigation of contingencies such as portable transformers, emergency portable generation, and access enhancement should be considered before significant capital investment is employed.

Q. Does this recommendation extend to the 16MWh first contingency design criteria for distribution circuits?

[7] Attachment KFD-2, Docket No DE 19-120, Staff Data Request 1-001.

A. No, it does not. The impact and likelihood of a distribution circuit outage does not warrant a specific load at risk criteria. Distribution circuits vary too much in their layout and level of complexity to provide backup configurations, criticality of load, and circuit design. The 16MWh criteria is a guideline and should not be part of a criteria that requires a costly solution to resolve.

Q. What is Staff's position on the Company's planning criteria as it relates to this limited filing and the proposed January 2021 full LCIRP filing?

A. Staff does not support the planning criteria as submitted in the Company's 2016 LCIRP and 2019 limited filing. Staff recommends the following planning or design criteria changes:

- Liberty change the existing 75% "take action" criteria and use the 75% as a "take notice" criteria. The change will allow planners and engineers ample time to identify a future risk and plan accordingly. A "take notice" identified asset will be on an annual watch list to ensure that there is sufficient time to mitigate or eliminate a future issue if or when the asset approaches 100%.
- Rerate or adjust the LTE rating to reflect the contingency violation as well as evaluate any limiting asset for increased temperature capabilities.
- Outage contingency load at risk should accurately reflect the risk or probability of failure as well as impact and cost to either mitigate or eliminate that risk. This load at risk should align with other NH investor owned utilities (IOUs).
- Feeder criteria, such as number of customers per feeder and outage contingency load at risk, should be further evaluated as guidelines rather than investment planning criteria.

Staff recommends that the Commission require the Company to suspend any investments arising from the planning criteria and methodology changes that have been made in the 2016 LCIRP

Docket DE 16-097 and the 2019 limited filing until approval of the Company's next full LCIRP, which is due to be filed in January 2021. During that proceeding, the Company should provide Staff the necessary justification and documentation required for the modifications, additions, or deletions, to the planning criteria, policies, procedures, and methodologies.

Q. Does this conclude your testimony?

A. Yes.

Liberty Utilities New Hampshire

Final Seasonal Peak Forecasts
2018-2034

Prepared By

Business Economic Analysis and Research

January 2019

Summary of Results

The weather adjusted actual seasonal peaks appear in Table 1 below for Liberty Utilities New Hampshire (LUNH). Note that the peak load series reflects the historic impacts of both energy efficiency programs and distributed generation activities in the LUNH service territory. Since the forecast is based on normal weather conditions, weather adjusting actual peaks enhances comparisons between historic and forecasted peaks.

Table 1
Historic Weather Adjusted Peaks

year	Summer month	Wthr Adj Peak Mw	Growth	Winter month	Wthr Adj Peak Mw	Growth
2004	7	184.555		12	151.111	
2005	7	193.986	5.11%	12	162.349	7.44%
2006	7	186.673	-3.77%	1	152.805	-5.88%
2007	7	187.153	0.26%	12	152.433	-0.24%
2008	7	194.86	4.12%	12	146.156	-4.12%
2009	7	190.024	-2.48%	12	153.679	5.15%
2010	7	188.816	-0.64%	12	148.528	-3.35%
2011	8	200.696	6.29%	2	151.769	2.18%
2012	8	189.021	-5.82%	1	152.708	0.62%
2013	7	194.125	2.70%	12	155.566	1.87%
2014	7	200.63	3.35%	1	158.976	2.19%
2015	7	184.56	-8.01%	1	148.31	-6.71%
2016	7	187.134	1.39%	1	144.578	-2.52%
2017	8	185.065	-1.11%	12	144.559	-0.01%
2013-2017 Avg			-0.42%			-1.07%

The summer peak has dropped .42% per year over the past five years compared to the winter peak declining 1.07% annually over the same period.

Table 2 displays the LUNH 2018-2034 seasonal peak forecasts under normal peak day weather conditions. The forecasted peak values include the historic impacts from both energy efficiency programs and distributed generation activities in the LUNH service territory. The 2018 growth is based on the 2017 weather adjusted actual shown in Table 1.

Table 2
Forecasted Peaks Normal Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2018	7	193.324	4.46%	12	149.036	3.10%
2019	7	194.168	0.44%	12	149.322	0.19%
2020	7	194.898	0.38%	12	149.483	0.11%
2021	7	195.572	0.35%	12	149.636	0.10%
2022	7	196.27	0.36%	12	149.836	0.13%
2023	7	196.994	0.37%	12	150.047	0.14%
2024	7	197.702	0.36%	12	150.223	0.12%
2025	7	198.396	0.35%	12	150.4	0.12%
2026	7	199.093	0.35%	12	150.583	0.12%
2027	7	199.797	0.35%	12	150.771	0.12%
2028	7	200.508	0.36%	12	150.969	0.13%
2029	7	201.228	0.36%	12	151.175	0.14%
2030	7	201.957	0.36%	12	151.39	0.14%
2031	7	202.693	0.36%	12	151.61	0.15%
2032	7	203.433	0.37%	12	151.834	0.15%
2033	7	204.177	0.37%	12	152.063	0.15%
2034	7	204.927	0.37%	12	152.298	0.15%
2020-2024 Avg			0.36%			0.12%

The average annual summer growth rate in peak for 2020-2024 is .36% while the winter average annual growth rate is .12% over the same period.

Table 3 provides the LUNH 2018-2034 seasonal peak forecasts under extreme weather. Although the peaks are higher, the annual growth rates for 2020-2024 are just less than the growth rates using normal weather.

Table 3
Forecasted Peaks Extreme Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2018	7	212.317		12	155.069	
2019	7	213.19	0.41%	12	155.355	0.18%
2020	7	213.95	0.36%	12	155.516	0.10%
2021	7	214.653	0.33%	12	155.669	0.10%
2022	7	215.38	0.34%	12	155.87	0.13%
2023	7	216.133	0.35%	12	156.08	0.13%
2024	7	216.87	0.34%	12	156.256	0.11%
2025	7	217.593	0.33%	12	156.433	0.11%
2026	7	218.32	0.33%	12	156.616	0.12%
2027	7	219.052	0.34%	12	156.804	0.12%
2028	7	219.793	0.34%	12	157.002	0.13%
2029	7	220.542	0.34%	12	157.208	0.13%
2030	7	221.299	0.34%	12	157.423	0.14%
2031	7	222.064	0.35%	12	157.644	0.14%
2032	7	222.833	0.35%	12	157.867	0.14%
2033	7	223.607	0.35%	12	158.096	0.15%
2034	7	224.386	0.35%	12	158.331	0.15%
2020-2024 Avg			0.35%			0.12%

In previous peak day studies performed by National Grid, Eastern PSA and Western PSA hourly data was the source of historic peak day analysis and subsequent forecasts. In this study, LUNH system hourly data was the only source of historic peak day analysis. Once the LUNH system seasonal peak day forecasts were developed in this analysis, Eastern PSA and Western PSA forecasts were derived by using the average summer coincident peak Eastern and Western PSA percent contributions for 2014 through 2018 and the average winter coincident peak Eastern and Western PSA percent contributions for 2015 through 2018. Table 4 below reveals the Eastern PSA seasonal forecasts under normal weather conditions.

Table 4

Eastern PSA Peaks Normal Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2018	7	97.8993		12	71.0305	
2019	7	98.3267	0.44%	12	71.1669	0.19%
2020	7	98.6964	0.38%	12	71.2435	0.11%
2021	7	99.0377	0.35%	12	71.3165	0.10%
2022	7	99.391	0.36%	12	71.4118	0.13%
2023	7	99.7577	0.37%	12	71.5125	0.14%
2024	7	100.1162	0.36%	12	71.5963	0.12%
2025	7	100.4677	0.35%	12	71.6807	0.12%
2026	7	100.8208	0.35%	12	71.7679	0.12%
2027	7	101.1773	0.35%	12	71.8575	0.12%
2028	7	101.5373	0.36%	12	71.9518	0.13%
2029	7	101.9018	0.36%	12	72.05	0.14%
2030	7	102.271	0.36%	12	72.1524	0.14%
2031	7	102.6437	0.36%	12	72.2574	0.15%
2032	7	103.0185	0.37%	12	72.3641	0.15%
2033	7	103.3952	0.37%	12	72.4733	0.15%
2034	7	103.775	0.37%	12	72.5852	0.15%
2020-2024 Avg			0.36%			0.12%

Table 5 lists the Western PSA seasonal forecasts under normal weather conditions. The Eastern PSA numbers are slightly higher than the Western peak day values in the summer but somewhat lower in the winter months.

Table 5

Western PSA Peaks Normal Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2018	7	95.4248		12	78.0054	
2019	7	95.8414	0.44%	12	78.1554	0.19%
2020	7	96.2016	0.38%	12	78.2394	0.11%
2021	7	96.5343	0.35%	12	78.3194	0.10%
2022	7	96.8789	0.36%	12	78.4242	0.13%
2023	7	97.2362	0.37%	12	78.5347	0.14%
2024	7	97.5858	0.36%	12	78.6266	0.12%
2025	7	97.9284	0.35%	12	78.7195	0.12%
2026	7	98.2723	0.35%	12	78.8148	0.12%
2027	7	98.6199	0.35%	12	78.9135	0.13%
2028	7	98.9709	0.36%	12	79.0173	0.13%
2029	7	99.3262	0.36%	12	79.1251	0.14%
2030	7	99.6859	0.36%	12	79.2376	0.14%
2031	7	100.0491	0.36%	12	79.3526	0.15%
2032	7	100.4148	0.37%	12	79.4698	0.15%
2033	7	100.7816	0.37%	12	79.5897	0.15%
2034	7	101.1519	0.37%	12	79.7129	0.15%
2020-2024 Avg			0.36%			0.12%

Tables 6 and 7 provide the Eastern PSA and Western PSA seasonal forecasts under extreme weather conditions. As the case with the normal weather forecasts, The Eastern PSA values are higher than the Western PSA numbers in the summer but lower during the winter period.

Table 6

Eastern PSA Peaks Extreme Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2018	7	107.5173		12	73.9059	
2019	7	107.9595	0.41%	12	74.0422	0.18%
2020	7	108.3443	0.36%	12	74.119	0.10%
2021	7	108.7002	0.33%	12	74.1918	0.10%
2022	7	109.0684	0.34%	12	74.2877	0.13%
2023	7	109.4498	0.35%	12	74.3876	0.13%
2024	7	109.823	0.34%	12	74.4716	0.11%
2025	7	110.189	0.33%	12	74.556	0.11%
2026	7	110.5572	0.33%	12	74.6433	0.12%
2027	7	110.9279	0.34%	12	74.7328	0.12%
2028	7	111.3032	0.34%	12	74.8272	0.13%
2029	7	111.6825	0.34%	12	74.9254	0.13%
2030	7	112.0658	0.34%	12	75.0278	0.14%
2031	7	112.4532	0.35%	12	75.1331	0.14%
2032	7	112.8427	0.35%	12	75.2394	0.14%
2033	7	113.2346	0.35%	12	75.3486	0.15%
2034	7	113.629	0.35%	12	75.4606	0.15%
2020-2024 Avg			0.35%			0.12%

Table 7

Western PSA Peaks Extreme Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2018	7	104.7997		12	81.1631	
2019	7	105.2306	0.41%	12	81.3128	0.18%
2020	7	105.6058	0.36%	12	81.3971	0.10%
2021	7	105.9527	0.33%	12	81.4771	0.10%
2022	7	106.3115	0.34%	12	81.5821	0.13%
2023	7	106.6833	0.35%	12	81.6922	0.13%
2024	7	107.047	0.34%	12	81.7843	0.11%
2025	7	107.4041	0.33%	12	81.8771	0.11%
2026	7	107.7628	0.33%	12	81.9728	0.12%
2027	7	108.1243	0.34%	12	82.0713	0.12%
2028	7	108.4899	0.34%	12	82.175	0.13%
2029	7	108.8596	0.34%	12	82.2826	0.13%
2030	7	109.2332	0.34%	12	82.3951	0.14%
2031	7	109.6111	0.35%	12	82.5109	0.14%
2032	7	109.9904	0.35%	12	82.6275	0.14%
2033	7	110.3723	0.35%	12	82.7473	0.14%
2034	7	110.7569	0.35%	12	82.8704	0.15%
2020-2024 Avg			0.35%			0.12%

The report describes the analytical approach employed in developing the seasonal LUNH forecasts and details the data available for the analysis.

Introduction

This report presents the Liberty Utilities New Hampshire (LUNH) seasonal peak forecasts for 2018-2034 under both normal and extreme weather. Regression analysis was used to estimate the LUNH historic monthly peak day model. The historic monthly peaks were net of all energy efficiency and distributed generation load impacts. The monthly peak day model coefficients were then employed to develop seasonal peak forecasts at the LUNH system level. The LUNH system seasonal peak forecasts were then split into Eastern and Western jurisdictions using LUNH township sales information as well the average summer coincident peak Eastern and Western PSA percent contributions for 2014 through 2018 and the average winter coincident peak Eastern and Western PSA percent contributions for 2015 through 2018.

The remainder of this report is organized as follows. First, the data used in the analysis is described. Second, the regression model specifications are provided. Third, the results from the regression models are discussed. Finally, the 2018-2034 seasonal forecast process is detailed.

Data

There were three data sources employed to perform the historic peak day modeling. These sources include LUNH hourly load and annual township sales, economic drivers for the LUNH service area, and daily weather information.

Hourly system load for LUNH from October 2000 through April 2014 was supplied by National Grid while historic system loads from May 2014 through October 2018 was provided by LUNH staff. LUNH also supplied hourly Eastern and Western PSA loads for March 2014 through October 2018. The historic peak load data includes the impacts of energy efficiency programs as well as distributed generation activities. Also, National Grid supplied annual sales data for 21 townships from 1996 through 2013 and 2014-2017 township volumes came from LUNH. The 2014-2017 township volumes collapsed 2 small townships into larger ones so the 1996 through 2013 data was aggregated as well down to 19 townships.

The system load and annual township sales information was utilized to create the dependent variables for the various regression models estimated. For the monthly peak day analysis, the maximum hourly load for each month from October 2000 through October 2018 was identified as the dependent variable (LUNH staff requested not using 2002-2003 peak day values). A total of 193 months of peaks are used in the peak day analysis. Each of the 19 townships has 22 years of annual sales in the annual usage analysis. Appendix A contains the historic monthly peak values for LUNH.

Annual employment and number of households for Rockingham and Grafton counties from 1970 through 2043 was purchased from Moody's Economy.com to develop an economic variable for the monthly peak model. Employment and household values were summed across the two counties. Each series was then divided by the 2017 employment and household value to create annual ratios. The annual ratios were then combined using a 60% weight for employment and 40% weight for households based on previous work performed by National Grid. The annual ratios were converted to monthly numbers over the historic and forecast period by spreading the annual growth rate into 12 equal parts. Appendix B reveals the annual total employment and total households for Rockingham and Grafton counties from 2000 to 2034 along with the development of the annual employment/household ratio term.

Weather information came from NOAA. Daily high temperature, low temperature, and dew point temperature information from the Concord New Hampshire Airport (WBAN #14745) was obtained for March 1994 through October 2018. Using the above mentioned weather elements, the temperature humidity index (THI) and heating degree days (HDD) were used in the peak day modeling analysis while annual cooling degree days (CDD) was used when modeling annual township sales. The discussion of how each specific weather element is computed resides in the model specification section of this report.

Specification of Models

This section first provides the specification of the peak day model followed by a description of the annual township sales models.

Peak Day Model Specification

The monthly peak day usage was primarily driven by weather conditions. The most important weather term was the temperature humidity index (THI). The daily THI was defined as follows:

THI = .55 * maximum temperature + .2 * average dew point temperature + 17.5

A weighted THI variable (WTHI) was used in the model to account for the heat buildup impact on energy usage. The WTHI equaled:

WTHI = .7 * THI on the peak day + .2 * THI day before + .1 * THI two days before

In addition to the WTHI term, a summer period (June through September) indicator was interacted with the WTHI as follows:

WTHI_SUMMER = WTHI * summer period

To account for the increased saturation of air conditioning in the service territory, the WTHI_SUMMER term defined above was also interacted with a time trend term (the value of the trend started at 1 in year 2000 and increased to 19 in year 2018) as described below:

WTHI_SUMMER_T = WTHI_SUMMER * time trend

The coefficient values of three THI terms defined above are expected to be positive in the regression model based on the assumption that the higher the WTHI value, the higher the peak day value will be. To account for peaks during the winter period, a heating degree day (HDD) term was added based on the maximum daily temperature on the peak day, the day before the peak, and two days prior to the peak (WTMAX). WTMAX equaled:

WTMAX = .7*max temp on peak day + 2*max temp day before +.1*max temp 2 days before

The term HDD was defined as

HDD = (55 – WTMAX), or 0 if the value of WTMAX was greater than or equal to 55

The expected value of the HDD coefficient in the regression equation is greater than zero which suggests the peak day use rises as the temperature becomes colder. The economic variable included in the peak day model was the weighted employment and household (EMP_HH) index variable discussed in the previous section of this report. EMP_HH was defined as

EMP_HH = .6 * employment index + .4 * household index

The index portion of this variable was computed by dividing the actual employment and household count variables by the 2017 values. It is expected that a positive relationship exists between peak day use and the value of the index. The remaining variables included in the peak day model were monthly indicators. These indicators take the value of one for a particular month, zero otherwise. The monthly indicators included are as follows:

FEB = one if month is February, zero otherwise

MAR = one if month is March, zero otherwise

APR = one if month is April, zero otherwise

MAY = one if month is May, zero otherwise

JUN = one if month is June, zero otherwise

JUL = one if month is July, zero otherwise

AUG = one if month is August, zero otherwise

SEP = one if month is September, zero otherwise

OCT = one if month is October, zero otherwise

NOV = one if month is November, zero otherwise

DEC = one if month is December, zero otherwise

The final LUNH peak day model expressed in mathematical terms is as follows:

PeakDay Mw = a + b * WTHI + c * WTHI_SUMMER + d * WTHI_SUMMER_T
+ e * HDD + f * EMP_HH + g * FEB + h * MAR + i * APR + j * MAY
+ k * JUN + l * JUL + m * AUG + n * SEP + o * OCT + p * NOV
+ q * DEC

Values of the estimated coefficients (a, b …, q) will be presented and discussed in the next section of the report.

Annual Township Sales Model Specification

The principal factor that influences annual sales at the township level has been a time trend that takes the value of one in 1996 and increases to twenty two in 2017. In order to flatten the change in township usage over the historic period, the time trend variable was expressed as a log function. The trend term variable was expressed as follows:

TIME = log(time trend value + 1)

The value of TIME is expected to have a positive coefficient value if the township experienced sales growth from 1996 through 2017 and a negative value if township sales declined from 1996 through 2017. The other term included in the annual township sales models was annual cooling degree days (CDD). CDD was based on the average daily temperature (daily maximum temperature plus daily minimum temperature divided by two). Daily cooling degree days was defined as:

CDD = (average temp – 60), or 0 if the average temp was less than or equal to 60.

The daily CDD values were then summed for the entire calendar year for final inclusion into the township models. It was expected that a positive relationship existed between CDD and annual sales. Township regression models that generated a negative coefficient for CDD had that variable removed from the analysis. The final LUNH annual township models expressed in mathematical terms are as follows:

Annual kWh = a + b * TIME + c * CDD

Values of the estimated coefficients (a, b, and c) will be presented and discussed in the next section of the report.

Regression Results

This section provides the overall model statistics as well as estimated coefficient values for the peak day and annual township models. The peak day model adjusted R-Squared value was .8750 which means that almost 88% of the monthly historic peak day variation was explained by the model coefficients. The monthly peak day Mw model coefficients are as follows:

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|
INTERCEPT	64.86846	23.20202	2.8	0.0058
WTHI	0.85693	0.20588	4.16	<.0001
WTHI_SUMMER	3.1535	0.46812	6.74	<.0001
WTHI_SUMMER_T	0.00632	0.00306	2.06	0.0406
HDD	0.96711	0.23931	4.04	<.0001
EMP_HH	24.462	21.59604	1.13	0.2589
FEB	-4.66736	2.84739	-1.64	0.103
MAR	-8.22188	3.20446	-2.57	0.0111
APR	-17.97462	4.53312	-3.97	0.0001
MAY	-2.41446	5.41104	-0.45	0.656
JUN	-239.189	36.00799	-6.64	<.0001
JUL	-234.42314	36.64564	-6.4	<.0001
AUG	-234.567	36.24369	-6.47	<.0001
SEP	-241.3816	35.23254	-6.85	<.0001
OCT	-13.51145	4.82839	-2.8	0.0057
NOV	-5.35602	4.05034	-1.32	0.1878
DEC	2.16819	2.96977	0.73	0.4663

The values of the WTHI terms have the expected positive coefficient signs and significant. The HDD term also has a significant expected positive coefficient sign. Likewise, the EMP_HH term has an insignificant expected positive coefficient sign and the coefficient value is smaller than in previous models. Only the MAY, NOV and DEC monthly terms are not significant at the 80% level. The JUN through SEP indicators have large negative values to offset the impact of the WTHI_SUMMER and WTHI_SUMMER_T terms.

The Eastern area annual kWh models by township appear as follows:

Eastern Township Regression Results

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Derry					R-Square	0.1887
INTERCEPT	-1835369	2055463	-0.89	0.3831		
TIME	693431	390994	1.77	0.0922		
CDD	2451.71302	2090.285	1.17	0.2553		
Town=Pelham					R-Square	0.843
INTERCEPT	23190627	7417272	3.13	0.0056		
TIME	12696638	1410926	9	<.0001		
CDD	16722	7542.929	2.22	0.039		
Town=Salem, NH					R-Square	0.3481
Intercept	260455731	18672477	13.95	<.0001		
TIME	4661243	3489929	1.34	0.1983		
CDD	23524	19167	1.23	0.2355		
YEAR 2005	27801238	10711572	2.6	0.0183		
Town=Windham					R-Square	0.7684
INTERCEPT	8359128	1308965	6.39	<.0001		
TIME	1749608	248994	7.03	<.0001		
CDD	2533.59809	1331.141	1.9	0.0723		

Note that the Salem Township had a year 2005 indicator variable added to capture a spike in annual usage for that year. All the CDD terms were significant at the 75% confidence level which is reasonable for a twenty two year historic series.

Western area annual kWh models by township are displayed below. The Grafton Township had a year 2002 indicator variable to capture a spike in usage for that year and Monroe Township had inserted a year 2015 indicator variable to capture a sharp decline in usage for that year.

Western Township Regression Results #1

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Acworth					R-Square	0.2872
INTERCEPT	1138893	40922	27.83	<.0001		
TIME	51619	16782	3.08	0.006		
Town=Alstead					R-Square	0.2703
INTERCEPT	9911652	279550	35.46	<.0001		
TIME	339631	114640	2.96	0.0077		
Town=Bath					R-Square	0.6263
INTERCEPT	-24230	18148	-1.34	0.1976		
TIME	16396	3452.176	4.75	0.0001		
CDD	34.64262	18.45562	1.88	0.0759		
Town=Canaan					R-Square	0.5829
INTERCEPT	10109160	992313	10.19	<.0001		
TIME	939189	188760	4.98	<.0001		
CDD	626.87929	1009.124	0.62	0.5418		
Town=Charlestown, NH					R-Square	0.662
INTERCEPT	1341700	7090630	0.19	0.8519		
TIME	7708582	1348792	5.72	<.0001		
CDD	7084.15717	7210.754	0.98	0.3382		
Town=Cornish					R-Square	0.2728
INTERCEPT	737101	125034	5.9	<.0001		
TIME	60214	23784	2.53	0.0203		
CDD	106.30368	127.1522	0.84	0.4135		

Western Township Regression Results #2

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Enfield					R-Square	0.696
INTERCEPT	14777186	1182050	12.5	<.0001		
TIME	1424926	224852	6.34	<.0001		
CDD	816.14872	1202.076	0.68	0.5054		
Town=Grafton, NH					R-Square	0.2885
INTERCEPT	58659	6089.404	9.63	<.0001		
TIME	1831.8423	2481.113	0.74	0.4693		
YEAR 2002	25472	7934.861	3.21	0.0046		
Town=Hanover, NH					R-Square	0.7912
INTERCEPT	71690818	10136017	7.07	<.0001		
TIME	15531554	1928091	8.06	<.0001		
CDD	9687.25295	10308	0.94	0.3591		
Town=Lebanon					R-Square	0.8205
INTERCEPT	75964275	26385845	2.88	0.0096		
TIME	41806548	5019161	8.33	<.0001		
CDD	54227	26833	2.02	0.0576		
Town=Marlow					R-Square	0.1333
INTERCEPT	27954	7196.082	3.88	0.001		
TIME	2734.8391	1368.851	2	0.0602		
CDD	2.38771	7.31799	0.33	0.7478		

Western Township Regression Results #3

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Monroe, NH					R-Square	0.0412
INTERCEPT	1749590	49783	35.14	<.0001		
TIME	10203	20693	0.49	0.6276		
YEAR 2015	-112537	66177	-1.7	0.1053		
Town=Plainfield					R-Square	0.4926
INTERCEPT	4730329	569497	8.31	<.0001		
TIME	417108	108331	3.85	0.0011		
CDD	691.89342	579.1449	1.19	0.2469		
Town=Surry					R-Square	0.5655
INTERCEPT	126126	47772	2.64	0.0161		
TIME	44633	9087.18	4.91	<.0001		
CDD	18.33472	48.58082	0.38	0.7101		
Town=Walpole					R-Square	0.4369
INTERCEPT	22018299	1526600	14.42	<.0001		
TIME	1065108	290392	3.67	0.0016		
CDD	1156.39317	1552.462	0.74	0.4655		

Except for Grafton, all the western area townships had significant time trend coefficients at the 90% confidence level. All of the larger usage Western Townships had CDD coefficients significant at the 70% confidence level.

An explanation of how the peak day and township model coefficients are employed to generate seasonal peak day forecasts appears in the next section.

Seasonal Forecast Development for 2018-2034

The peak day model coefficients detailed in the previous section of the report are used along with the economic driver forecast (shown in Appendix B) and normal/extreme weather to estimate seasonal peak forecasts for 2018 through 2034. The normal monthly WTHI and HDD values were computed by taking the average values for those terms during the October 2000 through September 2018 LUNH system monthly peak days. The extreme monthly WTHI and HDD values were extracted by taking the maximum values for those monthly terms during the October 2000 through September 2018 LUNH system monthly peak days. The normal and extreme monthly WTHI and HDD values appear below.

	Weather Values Used in Forecast			
Month	Normal WTHI	Extreme WTHI	Normal HDD	Extreme HDD
January	30.315	21.9	34.7444	45
February	34.0047	26.995	29.9167	38.1
March	39.7611	30.86	22.3111	32.6
April	62.9111	78.18	5.0389	25.1
May	75.9147	81.925	0	0
June	80.3658	84.525	0	0
July	81.8786	86.475	0	0
August	80.9872	84.61	0	0
September	78.1219	82.16	0	0
October	67.4789	75.035	1.3737	10.7
November	48.2356	37.26	12.0667	23.8
December	37.5533	21.37	25.8222	46.4

The normal and extreme LUNH system seasonal peak day forecasts appear in Tables 2 and 3 in the Summary of Results section of the report. The system peak day values were allocated to the Eastern and Western PSA regions by using the average summer coincident peak Eastern and Western PSA percent contributions for 2014 through 2018 and the average winter coincident peak Eastern and Western PSA percent contributions for 2015 through 2018. The summer Eastern coincident peak proportion was 50.64% while the Western proportion was 49.36%. The winter Eastern coincident peak contribution was 46.66% compared to the Western value of 53.34%. Appendix C lists the Eastern and Western coincident peak contributions for March 2014 through October 2018.

The individual township peaks were then calculated by utilizing the annual township sales regression models. For townships with CDD in the model, normal CDD value equaled 1057 and the extreme CDD took the value of 1265 which were computed based upon 1998 through 2017 Concord weather data. Once the annual township forecasts were completed, they were totaled so that individual township annual proportions under normal and extreme weather could be applied to the area peak values.

The Derry township results are shown below. The annual growth rates for 2020-2024 are much larger than the overall system average.

Derry Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.7228		0.5244		0.9092		0.625	
2019	0.7314	1.19%	0.5294	0.95%	0.9186	1.03%	0.63	0.80%
2020	0.7394	1.09%	0.5337	0.81%	0.9273	0.95%	0.6344	0.70%
2021	0.747	1.03%	0.5379	0.79%	0.9355	0.88%	0.6385	0.65%
2022	0.7545	1.00%	0.5421	0.78%	0.9437	0.88%	0.6428	0.67%
2023	0.762	0.99%	0.5463	0.77%	0.9519	0.87%	0.6469	0.64%
2024	0.7693	0.96%	0.5502	0.71%	0.9598	0.83%	0.6508	0.60%
2025	0.7764	0.92%	0.5539	0.67%	0.9675	0.80%	0.6546	0.58%
2026	0.7834	0.90%	0.5576	0.67%	0.9751	0.79%	0.6584	0.58%
2027	0.7903	0.88%	0.5613	0.66%	0.9827	0.78%	0.662	0.55%
2028	0.7971	0.86%	0.5648	0.62%	0.9901	0.75%	0.6656	0.54%
2029	0.8038	0.84%	0.5684	0.64%	0.9975	0.75%	0.6692	0.54%
2030	0.8105	0.83%	0.5718	0.60%	1.0048	0.73%	0.6727	0.52%
2031	0.8172	0.83%	0.5753	0.61%	1.0121	0.73%	0.6762	0.52%
2032	0.8238	0.81%	0.5786	0.57%	1.0193	0.71%	0.6796	0.50%
2033	0.8303	0.79%	0.582	0.59%	1.0264	0.70%	0.683	0.50%
2034	0.8367	0.77%	0.5853	0.57%	1.0335	0.69%	0.6864	0.50%
2020-2024 Avg		1.04%		0.79%		0.90%		0.66%

The Pelham township results are provided next. The 2020-2024 annual growth rates for Pelham are not as large as Derry but larger than the overall system.

Pelham Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	19.8326		14.3895		22.193		15.2552	
2019	20.006	0.87%	14.4799	0.63%	22.3766	0.83%	15.3466	0.60%
2020	20.1645	0.79%	14.5557	0.52%	22.545	0.75%	15.4232	0.50%
2021	20.3145	0.74%	14.6283	0.50%	22.7043	0.71%	15.4965	0.48%
2022	20.4642	0.74%	14.7034	0.51%	22.8634	0.70%	15.5725	0.49%
2023	20.6143	0.73%	14.7776	0.50%	23.0226	0.70%	15.6473	0.48%
2024	20.7604	0.71%	14.8464	0.47%	23.1777	0.67%	15.7169	0.44%
2025	20.903	0.69%	14.9137	0.45%	23.329	0.65%	15.7849	0.43%
2026	21.044	0.67%	14.9799	0.44%	23.4787	0.64%	15.8518	0.42%
2027	21.1839	0.66%	15.0451	0.44%	23.627	0.63%	15.9177	0.42%
2028	21.3228	0.66%	15.1099	0.43%	23.7745	0.62%	15.9832	0.41%
2029	21.4611	0.65%	15.1742	0.43%	23.9211	0.62%	16.0482	0.41%
2030	21.599	0.64%	15.2381	0.42%	24.067	0.61%	16.1128	0.40%
2031	21.7361	0.63%	15.3014	0.42%	24.2123	0.60%	16.1769	0.40%
2032	21.8725	0.63%	15.3641	0.41%	24.3567	0.60%	16.2402	0.39%
2033	22.008	0.62%	15.4262	0.40%	24.5003	0.59%	16.303	0.39%
2034	22.1431	0.61%	15.4879	0.40%	24.6432	0.58%	16.3654	0.38%
2020-2024 Avg		0.75%		0.51%		0.72%		0.48%

Salem forecasts are displayed next. The Salem annual growth rates are lower than the overall system rates and since Salem contributes the most to Eastern PSA total, Salem pushes down the Eastern PSA numbers that appear in Tables 4 through 7 in the Summary of Results section.

Salem Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	73.2909		53.176		79.9279		54.9413	
2019	73.5093	0.30%	53.2046	0.05%	80.1487	0.28%	54.9687	0.05%
2020	73.6882	0.24%	53.1915	-0.02%	80.3308	0.23%	54.9548	-0.03%
2021	73.8492	0.22%	53.1784	-0.02%	80.4952	0.20%	54.9409	-0.03%
2022	74.0223	0.23%	53.1845	0.01%	80.6718	0.22%	54.9464	0.01%
2023	74.2081	0.25%	53.1969	0.02%	80.8613	0.23%	54.9575	0.02%
2024	74.3905	0.25%	53.199	0.00%	81.0475	0.23%	54.9588	0.00%
2025	74.5701	0.24%	53.2035	0.01%	81.2311	0.23%	54.9625	0.01%
2026	74.7531	0.25%	53.212	0.02%	81.4187	0.23%	54.9702	0.01%
2027	74.9408	0.25%	53.224	0.02%	81.6104	0.24%	54.9814	0.02%
2028	75.1331	0.26%	53.2412	0.03%	81.8076	0.24%	54.9978	0.03%
2029	75.3306	0.26%	53.2627	0.04%	82.0097	0.25%	55.0185	0.04%
2030	75.5332	0.27%	53.2889	0.05%	82.2167	0.25%	55.0439	0.05%
2031	75.7401	0.27%	53.3182	0.05%	82.4283	0.26%	55.0727	0.05%
2032	75.9499	0.28%	53.3501	0.06%	82.6431	0.26%	55.1034	0.06%
2033	76.1627	0.28%	53.385	0.07%	82.8612	0.26%	55.1375	0.06%
2034	76.379	0.28%	53.4231	0.07%	83.0826	0.27%	55.1748	0.07%
2020-2024 Avg		0.24%		0.00%		0.22%		0.00%

The last Eastern PSA township, Windham, forecasts are displayed next. The annual growth rate in peaks for Windham from 2020-2024 are somewhat higher than the overall system average.

Windham Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	4.053		2.9406		4.4872		3.0844	
2019	4.08	0.67%	2.953	0.42%	4.5156	0.63%	3.0969	0.41%
2020	4.1043	0.60%	2.9626	0.33%	4.5412	0.57%	3.1066	0.31%
2021	4.127	0.55%	2.9719	0.31%	4.5652	0.53%	3.1159	0.30%
2022	4.15	0.56%	2.9818	0.33%	4.5895	0.53%	3.126	0.32%
2023	4.1733	0.56%	2.9917	0.33%	4.614	0.53%	3.1359	0.32%
2024	4.196	0.54%	3.0007	0.30%	4.638	0.52%	3.1451	0.29%
2025	4.2182	0.53%	3.0096	0.30%	4.6614	0.50%	3.154	0.28%
2026	4.2403	0.52%	3.0184	0.29%	4.6847	0.50%	3.1629	0.28%
2027	4.2623	0.52%	3.0271	0.29%	4.7078	0.49%	3.1717	0.28%
2028	4.2843	0.52%	3.0359	0.29%	4.731	0.49%	3.1806	0.28%
2029	4.3063	0.51%	3.0447	0.29%	4.7542	0.49%	3.1895	0.28%
2030	4.3283	0.51%	3.0536	0.29%	4.7773	0.49%	3.1984	0.28%
2031	4.3503	0.51%	3.0625	0.29%	4.8005	0.49%	3.2073	0.28%
2032	4.3723	0.51%	3.0713	0.29%	4.8236	0.48%	3.2162	0.28%
2033	4.3942	0.50%	3.0801	0.29%	4.8467	0.48%	3.2251	0.28%
2034	4.4162	0.50%	3.0889	0.29%	4.8697	0.47%	3.234	0.28%
2020-2024 Avg		0.57%		0.32%		0.54%		0.31%

The Western Township forecasts are shown next starting with Acworth. The Acworth annual growth rates are much lower than the overall system for 2020-2024.

Acworth Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.242		0.1979		0.258		0.1998	
2019	0.2422	0.08%	0.1975	-0.20%	0.2581	0.04%	0.1995	-0.15%
2020	0.2422	0.00%	0.197	-0.25%	0.2581	0.00%	0.199	-0.25%
2021	0.2421	-0.04%	0.1965	-0.25%	0.2581	0.00%	0.1985	-0.25%
2022	0.2422	0.04%	0.1961	-0.20%	0.2581	0.00%	0.1981	-0.20%
2023	0.2423	0.04%	0.1957	-0.20%	0.2582	0.04%	0.1977	-0.20%
2024	0.2424	0.04%	0.1953	-0.20%	0.2583	0.04%	0.1974	-0.15%
2025	0.2425	0.04%	0.195	-0.15%	0.2585	0.08%	0.197	-0.20%
2026	0.2427	0.08%	0.1946	-0.21%	0.2586	0.04%	0.1967	-0.15%
2027	0.2429	0.08%	0.1943	-0.15%	0.2588	0.08%	0.1964	-0.15%
2028	0.2431	0.08%	0.1941	-0.10%	0.259	0.08%	0.1962	-0.10%
2029	0.2433	0.08%	0.1938	-0.15%	0.2592	0.08%	0.1959	-0.15%
2030	0.2436	0.12%	0.1936	-0.10%	0.2595	0.12%	0.1957	-0.10%
2031	0.2439	0.12%	0.1934	-0.10%	0.2598	0.12%	0.1955	-0.10%
2032	0.2442	0.12%	0.1932	-0.10%	0.2601	0.12%	0.1954	-0.05%
2033	0.2445	0.12%	0.1931	-0.05%	0.2604	0.12%	0.1952	-0.10%
2034	0.2449	0.16%	0.193	-0.05%	0.2608	0.15%	0.1951	-0.05%
2020-2024 Avg		0.02%		-0.22%		0.02%		-0.21%

Alstead township forecast appears next. As the case with Acworth, Alstead annual growth in peak is much lower than the system average.

Alstead Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	2.0418		1.6691		2.1768		1.6858	
2019	2.042	0.01%	1.6652	-0.23%	2.1768	0.00%	1.682	-0.23%
2020	2.0414	-0.03%	1.6603	-0.29%	2.1761	-0.03%	1.6772	-0.29%
2021	2.0406	-0.04%	1.6555	-0.29%	2.1751	-0.05%	1.6726	-0.27%
2022	2.0403	-0.01%	1.6516	-0.24%	2.1747	-0.02%	1.6688	-0.23%
2023	2.0405	0.01%	1.6481	-0.21%	2.1748	0.00%	1.6654	-0.20%
2024	2.0409	0.02%	1.6444	-0.22%	2.1751	0.01%	1.6618	-0.22%
2025	2.0413	0.02%	1.6409	-0.21%	2.1755	0.02%	1.6584	-0.20%
2026	2.042	0.03%	1.6377	-0.20%	2.1761	0.03%	1.6553	-0.19%
2027	2.043	0.05%	1.6348	-0.18%	2.177	0.04%	1.6524	-0.18%
2028	2.0442	0.06%	1.6321	-0.17%	2.1781	0.05%	1.6498	-0.16%
2029	2.0457	0.07%	1.6297	-0.15%	2.1796	0.07%	1.6474	-0.15%
2030	2.0475	0.09%	1.6275	-0.13%	2.1812	0.07%	1.6453	-0.13%
2031	2.0495	0.10%	1.6255	-0.12%	2.1832	0.09%	1.6434	-0.12%
2032	2.0517	0.11%	1.6237	-0.11%	2.1853	0.10%	1.6416	-0.11%
2033	2.054	0.11%	1.6221	-0.10%	2.1876	0.11%	1.64	-0.10%
2034	2.0565	0.12%	1.6206	-0.09%	2.19	0.11%	1.6386	-0.09%
2020-2024 Avg		-0.01%		-0.25%		-0.02%		-0.24%

The Bath township forecasts are displayed below. The annual growth in the Bath peaks from 2020-2024 is higher than the system average although the peaks are very small.

Bath Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.012		0.0098		0.0142		0.011	
2019	0.0121	0.83%	0.0099	1.02%	0.0143	0.70%	0.0111	0.91%
2020	0.0122	0.83%	0.0099	0.00%	0.0144	0.70%	0.0111	0.00%
2021	0.0123	0.82%	0.01	1.01%	0.0145	0.69%	0.0112	0.90%
2022	0.0124	0.81%	0.01	0.00%	0.0146	0.69%	0.0112	0.00%
2023	0.0125	0.81%	0.0101	1.00%	0.0147	0.68%	0.0113	0.89%
2024	0.0126	0.80%	0.0101	0.00%	0.0148	0.68%	0.0113	0.00%
2025	0.0127	0.79%	0.0102	0.99%	0.0149	0.68%	0.0114	0.88%
2026	0.0127	0.00%	0.0102	0.00%	0.015	0.67%	0.0114	0.00%
2027	0.0128	0.79%	0.0103	0.98%	0.0151	0.67%	0.0115	0.88%
2028	0.0129	0.78%	0.0103	0.00%	0.0152	0.66%	0.0115	0.00%
2029	0.013	0.78%	0.0104	0.97%	0.0153	0.66%	0.0115	0.00%
2030	0.0131	0.77%	0.0104	0.00%	0.0154	0.65%	0.0116	0.87%
2031	0.0132	0.76%	0.0104	0.00%	0.0154	0.00%	0.0116	0.00%
2032	0.0133	0.76%	0.0105	0.96%	0.0155	0.65%	0.0117	0.86%
2033	0.0133	0.00%	0.0105	0.00%	0.0156	0.65%	0.0117	0.00%
2034	0.0134	0.75%	0.0106	0.95%	0.0157	0.64%	0.0118	0.85%
2020-2024 Avg		0.83%		0.40%		0.70%		0.36%

Forecasts for the Canaan Township appear below. The annual growth rate in Canaan is less than the system average during the 2020-2024 years.

Canaan Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	2.5555		2.089		2.7503		2.13	
2019	2.5597	0.16%	2.0874	-0.08%	2.7545	0.15%	2.1284	-0.08%
2020	2.5627	0.12%	2.0842	-0.15%	2.7575	0.11%	2.1254	-0.14%
2021	2.5652	0.10%	2.0812	-0.14%	2.7601	0.09%	2.1225	-0.14%
2022	2.5683	0.12%	2.079	-0.11%	2.7632	0.11%	2.1204	-0.10%
2023	2.5719	0.14%	2.0773	-0.08%	2.7669	0.13%	2.1187	-0.08%
2024	2.5756	0.14%	2.0752	-0.10%	2.7706	0.13%	2.1167	-0.09%
2025	2.5792	0.14%	2.0733	-0.09%	2.7743	0.13%	2.1149	-0.09%
2026	2.5831	0.15%	2.0716	-0.08%	2.7782	0.14%	2.1133	-0.08%
2027	2.5872	0.16%	2.0702	-0.07%	2.7824	0.15%	2.112	-0.06%
2028	2.5915	0.17%	2.0691	-0.05%	2.7869	0.16%	2.1109	-0.05%
2029	2.5962	0.18%	2.0682	-0.04%	2.7916	0.17%	2.11	-0.04%
2030	2.601	0.18%	2.0675	-0.03%	2.7965	0.18%	2.1094	-0.03%
2031	2.6061	0.20%	2.067	-0.02%	2.8017	0.19%	2.109	-0.02%
2032	2.6114	0.20%	2.0667	-0.01%	2.807	0.19%	2.1087	-0.01%
2033	2.6168	0.21%	2.0665	-0.01%	2.8125	0.20%	2.1086	0.00%
2034	2.6224	0.21%	2.0666	0.00%	2.8182	0.20%	2.1086	0.00%
2020-2024 Avg		0.12%		-0.12%		0.12%		-0.11%

The Charlestown township forecasts are shown next below. The annual growth rate in peak forecasts is higher than the system average during the 2020-2024 years.

Charlestown Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	6.1913		5.0611		6.8924		5.3379	
2019	6.2426	0.83%	5.0906	0.58%	6.9461	0.78%	5.3673	0.55%
2020	6.2892	0.75%	5.1149	0.48%	6.9951	0.71%	5.3916	0.45%
2021	6.3331	0.70%	5.1381	0.45%	7.0412	0.66%	5.4147	0.43%
2022	6.3769	0.69%	5.1622	0.47%	7.0872	0.65%	5.4387	0.44%
2023	6.4208	0.69%	5.1858	0.46%	7.1333	0.65%	5.4623	0.43%
2024	6.4634	0.66%	5.2077	0.42%	7.178	0.63%	5.4841	0.40%
2025	6.5049	0.64%	5.2289	0.41%	7.2216	0.61%	5.5053	0.39%
2026	6.5458	0.63%	5.2498	0.40%	7.2647	0.60%	5.5261	0.38%
2027	6.5864	0.62%	5.2703	0.39%	7.3073	0.59%	5.5466	0.37%
2028	6.6268	0.61%	5.2907	0.39%	7.3497	0.58%	5.567	0.37%
2029	6.6669	0.61%	5.3109	0.38%	7.3918	0.57%	5.5872	0.36%
2030	6.7068	0.60%	5.3311	0.38%	7.4338	0.57%	5.6073	0.36%
2031	6.7466	0.59%	5.351	0.37%	7.4755	0.56%	5.6273	0.36%
2032	6.7861	0.59%	5.3706	0.37%	7.5169	0.55%	5.6469	0.35%
2033	6.8253	0.58%	5.3901	0.36%	7.5581	0.55%	5.6664	0.35%
2034	6.8644	0.57%	5.4095	0.36%	7.5991	0.54%	5.6858	0.34%
2020-2024 Avg		0.71%		0.46%		0.67%		0.44%

The Cornish township forecast numbers are displayed next. The annual growth in Cornish peaks is less than the 2020-2024 system average growth.

Cornish Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.1934		0.1581		0.2105		0.163	
2019	0.1936	0.10%	0.1579	-0.13%	0.2107	0.10%	0.1628	-0.12%
2020	0.1937	0.05%	0.1576	-0.19%	0.2109	0.09%	0.1625	-0.18%
2021	0.1938	0.05%	0.1573	-0.19%	0.211	0.05%	0.1622	-0.18%
2022	0.194	0.10%	0.1571	-0.13%	0.2111	0.05%	0.162	-0.12%
2023	0.1942	0.10%	0.1569	-0.13%	0.2113	0.09%	0.1618	-0.12%
2024	0.1944	0.10%	0.1566	-0.19%	0.2116	0.14%	0.1616	-0.12%
2025	0.1946	0.10%	0.1565	-0.06%	0.2118	0.09%	0.1614	-0.12%
2026	0.1949	0.15%	0.1563	-0.13%	0.212	0.09%	0.1613	-0.06%
2027	0.1951	0.10%	0.1561	-0.13%	0.2122	0.09%	0.1611	-0.12%
2028	0.1954	0.15%	0.156	-0.06%	0.2125	0.14%	0.161	-0.06%
2029	0.1957	0.15%	0.1559	-0.06%	0.2128	0.14%	0.1609	-0.06%
2030	0.196	0.15%	0.1558	-0.06%	0.2131	0.14%	0.1608	-0.06%
2031	0.1963	0.15%	0.1557	-0.06%	0.2135	0.19%	0.1607	-0.06%
2032	0.1967	0.20%	0.1556	-0.06%	0.2138	0.14%	0.1606	-0.06%
2033	0.197	0.15%	0.1556	0.00%	0.2142	0.19%	0.1606	0.00%
2034	0.1974	0.20%	0.1556	0.00%	0.2145	0.14%	0.1605	-0.06%
2020-2024 Avg		0.08%		-0.16%		0.09%		-0.15%

Enfield Township seasonal peak forecasts are listed next. Much like Cornish, the annual 2020-2024 growth in Enfield peaks is lower than the system average numbers.

Enfield Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	3.7467		3.0627		4.0279		3.1195	
2019	3.7532	0.17%	3.0606	-0.07%	4.0345	0.16%	3.1175	-0.06%
2020	3.7579	0.13%	3.0562	-0.14%	4.0393	0.12%	3.1133	-0.13%
2021	3.7619	0.11%	3.0521	-0.13%	4.0434	0.10%	3.1093	-0.13%
2022	3.7667	0.13%	3.0492	-0.10%	4.0483	0.12%	3.1066	-0.09%
2023	3.7723	0.15%	3.0468	-0.08%	4.0541	0.14%	3.1044	-0.07%
2024	3.778	0.15%	3.044	-0.09%	4.0598	0.14%	3.1017	-0.09%
2025	3.7836	0.15%	3.0414	-0.09%	4.0656	0.14%	3.0993	-0.08%
2026	3.7895	0.16%	3.0392	-0.07%	4.0716	0.15%	3.0972	-0.07%
2027	3.7959	0.17%	3.0374	-0.06%	4.0781	0.16%	3.0954	-0.06%
2028	3.8025	0.17%	3.0359	-0.05%	4.0849	0.17%	3.0941	-0.04%
2029	3.8095	0.18%	3.0348	-0.04%	4.092	0.17%	3.093	-0.04%
2030	3.8169	0.19%	3.034	-0.03%	4.0995	0.18%	3.0923	-0.02%
2031	3.8246	0.20%	3.0334	-0.02%	4.1074	0.19%	3.0919	-0.01%
2032	3.8326	0.21%	3.0332	-0.01%	4.1154	0.19%	3.0916	-0.01%
2033	3.8407	0.21%	3.0331	0.00%	4.1238	0.20%	3.0916	0.00%
2034	3.8491	0.22%	3.0333	0.01%	4.1323	0.21%	3.0919	0.01%
2020-2024 Avg		0.13%		-0.11%		0.13%		-0.10%

Grafton Township forecast results are provided below. Annual growth in Grafton peaks is lower than the system average.

Grafton Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.012		0.0098		0.0128		0.0099	
2019	0.012	0.00%	0.0098	0.00%	0.0128	0.00%	0.0099	0.00%
2020	0.012	0.00%	0.0097	-1.02%	0.0128	0.00%	0.0098	-1.01%
2021	0.012	0.00%	0.0097	0.00%	0.0128	0.00%	0.0098	0.00%
2022	0.012	0.00%	0.0097	0.00%	0.0128	0.00%	0.0098	0.00%
2023	0.012	0.00%	0.0097	0.00%	0.0128	0.00%	0.0098	0.00%
2024	0.012	0.00%	0.0096	-1.03%	0.0128	0.00%	0.0097	-1.02%
2025	0.012	0.00%	0.0096	0.00%	0.0128	0.00%	0.0097	0.00%
2026	0.012	0.00%	0.0096	0.00%	0.0128	0.00%	0.0097	0.00%
2027	0.012	0.00%	0.0096	0.00%	0.0128	0.00%	0.0097	0.00%
2028	0.012	0.00%	0.0096	0.00%	0.0128	0.00%	0.0097	0.00%
2029	0.012	0.00%	0.0096	0.00%	0.0128	0.00%	0.0097	0.00%
2030	0.012	0.00%	0.0095	-1.04%	0.0128	0.00%	0.0096	-1.03%
2031	0.012	0.00%	0.0095	0.00%	0.0128	0.00%	0.0096	0.00%
2032	0.012	0.00%	0.0095	0.00%	0.0128	0.00%	0.0096	0.00%
2033	0.012	0.00%	0.0095	0.00%	0.0128	0.00%	0.0096	0.00%
2034	0.012	0.00%	0.0095	0.00%	0.0128	0.00%	0.0096	0.00%
2020-2024 Avg		0.00%		-0.41%		0.00%		-0.40%

The Hanover township forecasts appear next. As one of the larger Western PSA townships, the Hanover annual growth rate from 2020-2024 is slightly lower than the system average growth.

Hanover Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	24.3897		19.9375		26.401		20.4465	
2019	24.4794	0.37%	19.9621	0.12%	26.4937	0.35%	20.472	0.12%
2020	24.5554	0.31%	19.9706	0.04%	26.5731	0.30%	20.4816	0.05%
2021	24.6251	0.28%	19.9786	0.04%	26.646	0.27%	20.4907	0.04%
2022	24.6984	0.30%	19.9935	0.07%	26.7225	0.29%	20.5065	0.08%
2023	24.7754	0.31%	20.0103	0.08%	26.8027	0.30%	20.524	0.09%
2024	24.851	0.31%	20.0229	0.06%	26.8813	0.29%	20.5374	0.07%
2025	24.9253	0.30%	20.0361	0.07%	26.9587	0.29%	20.5514	0.07%
2026	25.0003	0.30%	20.0504	0.07%	27.037	0.29%	20.5665	0.07%
2027	25.0767	0.31%	20.0658	0.08%	27.1163	0.29%	20.5825	0.08%
2028	25.1543	0.31%	20.0829	0.09%	27.197	0.30%	20.6002	0.09%
2029	25.2333	0.31%	20.1013	0.09%	27.279	0.30%	20.6192	0.09%
2030	25.3138	0.32%	20.1212	0.10%	27.3624	0.31%	20.6396	0.10%
2031	25.3955	0.32%	20.1421	0.10%	27.447	0.31%	20.6611	0.10%
2032	25.478	0.32%	20.1637	0.11%	27.5324	0.31%	20.683	0.11%
2033	25.5612	0.33%	20.1863	0.11%	27.6186	0.31%	20.706	0.11%
2034	25.6454	0.33%	20.2098	0.12%	27.7057	0.32%	20.7299	0.12%
2020-2024 Avg		0.30%		0.06%		0.29%		0.06%

Lebanon township seasonal peak forecasts are listed next. As the largest Western PSA township, Lebanon peak growth from 2020-2024 is somewhat higher than the overall system growth.

Lebanon Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	49.4416		40.4163		54.9438		42.5517	
2019	49.7017	0.53%	40.53	0.28%	55.2134	0.49%	42.664	0.26%
2020	49.9308	0.46%	40.608	0.19%	55.4519	0.43%	42.7403	0.18%
2021	50.1438	0.43%	40.6822	0.18%	55.674	0.40%	42.813	0.17%
2022	50.3613	0.43%	40.7679	0.21%	55.9007	0.41%	42.8976	0.20%
2023	50.5842	0.44%	40.8552	0.21%	56.1328	0.42%	42.9834	0.20%
2024	50.8016	0.43%	40.9318	0.19%	56.3593	0.40%	43.0588	0.18%
2025	51.0141	0.42%	41.0076	0.19%	56.5811	0.39%	43.1334	0.17%
2026	51.2263	0.42%	41.0839	0.19%	56.8028	0.39%	43.2086	0.17%
2027	51.4393	0.42%	41.1607	0.19%	57.0247	0.39%	43.2844	0.18%
2028	51.6531	0.42%	41.2393	0.19%	57.248	0.39%	43.3621	0.18%
2029	51.8683	0.42%	41.3192	0.19%	57.4725	0.39%	43.4412	0.18%
2030	52.085	0.42%	41.4009	0.20%	57.6982	0.39%	43.5221	0.19%
2031	52.3027	0.42%	41.4832	0.20%	57.9253	0.39%	43.604	0.19%
2032	52.5208	0.42%	41.5659	0.20%	58.1526	0.39%	43.6857	0.19%
2033	52.7391	0.42%	41.6494	0.20%	58.3806	0.39%	43.7686	0.19%
2034	52.9584	0.42%	41.7339	0.20%	58.6093	0.39%	43.8526	0.19%
2020-2024 Avg		0.44%		0.20%		0.42%		0.19%

Marlow township forecast values are shown next. The Marlow growth is much lower than the system average during the 2020-2024 years.

Marlow Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.0073		0.0059		0.0079		0.0061	
2019	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.0061	0.00%
2020	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.0061	0.00%
2021	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.0061	0.00%
2022	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.0061	0.00%
2023	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.0061	0.00%
2024	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.006	-1.64%
2025	0.0073	0.00%	0.0059	0.00%	0.0079	0.00%	0.006	0.00%
2026	0.0074	1.37%	0.0059	0.00%	0.0079	0.00%	0.006	0.00%
2027	0.0074	0.00%	0.0059	0.00%	0.008	1.27%	0.006	0.00%
2028	0.0074	0.00%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2029	0.0074	0.00%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2030	0.0074	0.00%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2031	0.0074	0.00%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2032	0.0074	0.00%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2033	0.0075	1.35%	0.0059	0.00%	0.008	0.00%	0.006	0.00%
2034	0.0075	0.00%	0.0059	0.00%	0.0081	1.25%	0.006	0.00%
2020-2024 Avg		0.00%		0.00%		0.00%		-0.33%

Monroe township peak forecasts are shown below. The annual growth in Monroe Township is smaller than the system average during the 2020-2024 years.

Monroe Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.331		0.2706		0.3529		0.2733	
2019	0.3307	-0.09%	0.2697	-0.33%	0.3526	-0.09%	0.2724	-0.33%
2020	0.3303	-0.12%	0.2686	-0.41%	0.3521	-0.14%	0.2714	-0.37%
2021	0.3299	-0.12%	0.2676	-0.37%	0.3516	-0.14%	0.2704	-0.37%
2022	0.3295	-0.12%	0.2667	-0.34%	0.3512	-0.11%	0.2695	-0.33%
2023	0.3293	-0.06%	0.2659	-0.30%	0.3509	-0.09%	0.2687	-0.30%
2024	0.329	-0.09%	0.2651	-0.30%	0.3507	-0.06%	0.2679	-0.30%
2025	0.3289	-0.03%	0.2643	-0.30%	0.3505	-0.06%	0.2672	-0.26%
2026	0.3287	-0.06%	0.2636	-0.26%	0.3503	-0.06%	0.2665	-0.26%
2027	0.3286	-0.03%	0.2629	-0.27%	0.3502	-0.03%	0.2658	-0.26%
2028	0.3286	0.00%	0.2623	-0.23%	0.3501	-0.03%	0.2652	-0.23%
2029	0.3286	0.00%	0.2617	-0.23%	0.3501	0.00%	0.2646	-0.23%
2030	0.3286	0.00%	0.2612	-0.19%	0.3501	0.00%	0.2641	-0.19%
2031	0.3287	0.03%	0.2607	-0.19%	0.3502	0.03%	0.2636	-0.19%
2032	0.3288	0.03%	0.2603	-0.15%	0.3503	0.03%	0.2631	-0.19%
2033	0.329	0.06%	0.2598	-0.19%	0.3504	0.03%	0.2627	-0.15%
2034	0.3292	0.06%	0.2594	-0.15%	0.3506	0.06%	0.2623	-0.15%
2020-2024 Avg		-0.10%		-0.34%		-0.11%		-0.33%

Plainfield township forecasts appear next. The Plainfield growth rate is peak from 2020-2024 is much lower than the system average over this time frame.

Plainfield Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	1.2609		1.0307		1.3727		1.0631	
2019	1.2626	0.13%	1.0296	-0.11%	1.3744	0.12%	1.062	-0.10%
2020	1.2637	0.09%	1.0278	-0.17%	1.3755	0.08%	1.0602	-0.17%
2021	1.2646	0.07%	1.026	-0.18%	1.3764	0.07%	1.0584	-0.17%
2022	1.2658	0.09%	1.0247	-0.13%	1.3776	0.09%	1.0571	-0.12%
2023	1.2673	0.12%	1.0236	-0.11%	1.3791	0.11%	1.056	-0.10%
2024	1.2688	0.12%	1.0223	-0.13%	1.3806	0.11%	1.0548	-0.11%
2025	1.2704	0.13%	1.0212	-0.11%	1.3821	0.11%	1.0536	-0.11%
2026	1.272	0.13%	1.0201	-0.11%	1.3837	0.12%	1.0526	-0.09%
2027	1.2738	0.14%	1.0192	-0.09%	1.3855	0.13%	1.0517	-0.09%
2028	1.2757	0.15%	1.0185	-0.07%	1.3874	0.14%	1.0509	-0.08%
2029	1.2777	0.16%	1.0178	-0.07%	1.3895	0.15%	1.0503	-0.06%
2030	1.2799	0.17%	1.0173	-0.05%	1.3917	0.16%	1.0497	-0.06%
2031	1.2821	0.17%	1.0169	-0.04%	1.394	0.17%	1.0493	-0.04%
2032	1.2845	0.19%	1.0166	-0.03%	1.3964	0.17%	1.049	-0.03%
2033	1.2869	0.19%	1.0163	-0.03%	1.3988	0.17%	1.0487	-0.03%
2034	1.2895	0.20%	1.0162	-0.01%	1.4014	0.19%	1.0486	-0.01%
2020-2024 Avg		0.10%		-0.14%		0.09%		-0.14%

Surry Township forecast values are listed next. The annual growth in the Surry peak from 2020-2024 is higher than the system average.

Surry Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	0.0534		0.0436		0.0577		0.0447	
2019	0.0537	0.56%	0.0438	0.46%	0.058	0.52%	0.0448	0.22%
2020	0.0539	0.37%	0.0438	0.00%	0.0582	0.34%	0.0449	0.22%
2021	0.0541	0.37%	0.0439	0.23%	0.0584	0.34%	0.0449	0.00%
2022	0.0544	0.55%	0.044	0.23%	0.0587	0.51%	0.045	0.22%
2023	0.0546	0.37%	0.0441	0.23%	0.0589	0.34%	0.0451	0.22%
2024	0.0548	0.37%	0.0442	0.23%	0.0592	0.51%	0.0452	0.22%
2025	0.0551	0.55%	0.0443	0.23%	0.0594	0.34%	0.0453	0.22%
2026	0.0553	0.36%	0.0443	0.00%	0.0597	0.51%	0.0454	0.22%
2027	0.0555	0.36%	0.0444	0.23%	0.0599	0.34%	0.0455	0.22%
2028	0.0557	0.36%	0.0445	0.23%	0.0601	0.33%	0.0455	0.00%
2029	0.056	0.54%	0.0446	0.22%	0.0604	0.50%	0.0456	0.22%
2030	0.0562	0.36%	0.0447	0.22%	0.0606	0.33%	0.0457	0.22%
2031	0.0564	0.36%	0.0448	0.22%	0.0609	0.50%	0.0458	0.22%
2032	0.0567	0.53%	0.0448	0.00%	0.0611	0.33%	0.0459	0.22%
2033	0.0569	0.35%	0.0449	0.22%	0.0613	0.33%	0.046	0.22%
2034	0.0571	0.35%	0.045	0.22%	0.0616	0.49%	0.0461	0.22%
2020-2024 Avg		0.41%		0.18%		0.41%		0.18%

The final township, Walpole forecasts of peak appear below. The Walpole average annual growth is less than the system average for the 2020-2024 years.

Walpole Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2018	4.9462		4.0433		5.3208		4.1208	
2019	4.9486	0.05%	4.0354	-0.20%	5.3228	0.04%	4.113	-0.19%
2020	4.9489	0.01%	4.0249	-0.26%	5.3229	0.00%	4.1027	-0.25%
2021	4.9485	-0.01%	4.0148	-0.25%	5.3222	-0.01%	4.0928	-0.24%
2022	4.9494	0.02%	4.0066	-0.20%	5.3229	0.01%	4.0847	-0.20%
2023	4.9516	0.04%	3.9993	-0.18%	5.3249	0.04%	4.0775	-0.18%
2024	4.954	0.05%	3.9915	-0.20%	5.327	0.04%	4.0699	-0.19%
2025	4.9565	0.05%	3.9843	-0.18%	5.3294	0.05%	4.0628	-0.17%
2026	4.9596	0.06%	3.9776	-0.17%	5.3324	0.06%	4.0562	-0.16%
2027	4.9633	0.07%	3.9716	-0.15%	5.336	0.07%	4.0503	-0.15%
2028	4.9677	0.09%	3.9661	-0.14%	5.3402	0.08%	4.0449	-0.13%
2029	4.9726	0.10%	3.9613	-0.12%	5.345	0.09%	4.0401	-0.12%
2030	4.9781	0.11%	3.957	-0.11%	5.3504	0.10%	4.0359	-0.10%
2031	4.9841	0.12%	3.9531	-0.10%	5.3564	0.11%	4.0321	-0.09%
2032	4.9906	0.13%	3.9496	-0.09%	5.3628	0.12%	4.0287	-0.08%
2033	4.9974	0.14%	3.9466	-0.08%	5.3696	0.13%	4.0256	-0.08%
2034	5.0047	0.15%	3.944	-0.07%	5.3768	0.13%	4.023	-0.06%
2020-2024 Avg		0.02%		-0.22%		0.02%		-0.21%

APPENDIX A

	LUNH Historic Peak Day Values			
year	month	day	hour	Mw
2000	10	30	18	120.587
2000	11	21	18	132.537
2000	12	14	18	133.21
2001	1	10	18	130.276
2001	2	22	19	131.967
2001	3	1	19	117.486
2001	4	24	14	125.857
2001	5	11	16	134.29
2001	6	27	16	159.728
2001	7	24	15	168.319
2001	8	6	14	173.866
2001	9	10	15	142.882
2001	10	4	14	121.58
2001	11	29	18	126.458
2001	12	17	18	137.219
2004	1	14	19	150.948
2004	2	17	19	138.039
2004	3	16	19	135.111
2004	4	30	15	126.933
2004	5	12	16	137.766
2004	6	9	15	166.476
2004	7	22	14	172.492
2004	8	3	15	169.516
2004	9	17	14	141.094
2004	10	8	15	124.583
2004	11	17	18	140.077
2004	12	21	19	151.159
2005	1	18	19	148.961
2005	2	21	19	137.439
2005	3	9	19	141.04
2005	4	20	13	125.3
2005	5	11	15	127.421
2005	6	27	15	184.603
2005	7	19	14	191.871
2005	8	10	16	179.92
2005	9	14	16	158.878
2005	10	25	19	145.312

2005	11	23	18	135.463
2005	12	13	18	161.546
2006	1	23	19	149.003
2006	2	8	19	139.41
2006	3	1	19	134.011
2006	4	4	20	123.651
2006	5	31	17	147.724
2006	6	19	13	181.58
2006	7	18	16	191.959
2006	8	2	15	195.419
2006	9	18	16	138.005
2006	10	4	20	126.699
2006	11	30	18	132.703
2006	12	4	18	146.719
2007	1	26	18	141.539
2007	2	5	19	146.216
2007	3	6	19	144.084
2007	4	4	19	130.327
2007	5	25	16	148.856
2007	6	27	14	187.416
2007	7	27	14	178.707
2007	8	3	15	187.522
2007	9	7	16	165.591
2007	10	22	19	150.267
2007	11	26	18	139.867
2007	12	5	18	152.389
2008	1	3	18	144.175
2008	2	1	18	139.664
2008	3	5	19	132.501
2008	4	23	16	127.896
2008	5	27	14	135.302
2008	6	10	15	195.262
2008	7	8	15	186.04
2008	8	18	16	159.613
2008	9	5	15	163.176
2008	10	9	20	127.515
2008	11	5	18	133.241
2008	12	8	18	146.578
2009	1	14	18	147.427
2009	2	5	19	142.883
2009	3	2	19	138.703
2009	4	28	15	140.767
2009	5	21	16	145.009

2009	6	26	13	145.615
2009	7	29	15	176.68
2009	8	18	14	190.698
2009	9	3	16	139.939
2009	10	28	19	131.489
2009	11	30	18	136.288
2009	12	17	18	154.02
2010	1	12	18	143.943
2010	2	4	19	140.447
2010	3	3	19	131.958
2010	4	7	20	124.039
2010	5	26	16	174.742
2010	6	28	14	171.967
2010	7	7	16	196.543
2010	8	31	17	187.363
2010	9	1	16	186.389
2010	10	1	10	139.359
2010	11	29	18	138.456
2010	12	15	18	149.16
2011	1	24	19	150.041
2011	2	2	18	155.316
2011	3	21	20	144.149
2011	4	28	12	140.458
2011	5	31	16	162.456
2011	6	9	15	183.139
2011	7	22	15	205.939
2011	8	1	15	186.77
2011	9	14	14	157.534
2011	10	10	16	139.923
2011	11	28	18	138.63
2011	12	19	18	146.848
2012	1	16	18	150.194
2012	2	29	19	139.924
2012	3	1	19	140.808
2012	4	16	18	142.882
2012	5	31	14	149.487
2012	6	21	16	192.762
2012	7	17	17	191.846
2012	8	3	16	188.008
2012	9	7	16	165.842
2012	10	15	19	137.546
2012	11	7	18	141.017
2012	12	16	18	149.861

2013	1	24	18	154.659
2013	2	5	19	146.904
2013	3	7	19	139.796
2013	4	12	14	130.322
2013	5	31	16	182.108
2013	6	24	12	191.469
2013	7	19	13	203.761
2013	8	21	17	181.325
2013	9	11	16	191.313
2013	10	2	15	140.756
2013	11	25	18	145.9
2013	12	17	19	159.28
2014	1	2	18	161.33
2014	2	11	19	145.35
2014	3	3	19	144.09
2014	4	15	14	122.63
2014	5	12	16	133.566
2014	6	30	17	172.905
2014	7	23	16	193.21
2014	8	27	16	175.731
2014	9	2	15	177.966
2014	10	16	12	134.995
2014	11	18	18	135.778
2014	12	8	18	143.234
2015	1	8	18	148.541
2015	2	16	19	144.885
2015	3	5	19	137.502
2015	4	2	11	123.717
2015	5	27	16	159.605
2015	6	23	17	149.229
2015	7	30	14	184.893
2015	8	18	14	186.141
2015	9	9	16	187.326
2015	10	13	19	153.086
2015	11	30	18	131.008
2015	12	29	18	133.603
2016	1	9	18	142.592
2016	2	15	18	142.576
2016	3	3	19	129.165
2016	4	4	12	125.539
2016	5	31	16	152.579
2016	6	20	16	167.76
2016	7	28	15	185.985

2016	8	12	16	193.151
2016	9	9	16	176.143
2016	10	17	19	125.149
2016	11	21	18	128.994
2016	12	19	18	143.2
2017	1	9	18	143.485
2017	2	7	19	134.572
2017	3	4	19	127.668
2017	4	11	16	124.478
2017	5	18	16	162.931
2017	6	12	17	181.34
2017	7	20	15	179.727
2017	8	22	17	179.089
2017	9	25	16	172.378
2017	10	9	19	136
2017	11	28	18	129.146
2017	12	28	18	150.426
2018	1	2	18	154.265
2018	2	7	18	135.615
2018	3	7	18	127.866
2018	4	16	12	121.766
2018	5	31	18	145.275
2018	6	18	16	170.718
2018	7	3	14	194.416
2018	8	29	15	197.82
2018	9	5	16	185.689
2018	10	10	16	141.038

Appendix B

Rockingham and Grafton Economic Variabls

Year	Employment	Households	Ratio Employment	Ratio Households	EMP_HH
2000	187.909556	136.67992	0.883437547	0.868487589	0.878499
2001	190.210754	138.994921	0.894256394	0.883197501	0.890603
2002	188.792392	141.139531	0.88758811	0.89682472	0.890639
2003	188.11389	142.7048	0.884398203	0.906770707	0.891788
2004	192.798123	144.091146	0.906420645	0.915579786	0.909446
2005	195.972244	145.783314	0.92134345	0.926332111	0.922991
2006	198.973063	147.631915	0.935451493	0.938078438	0.936319
2007	200.824353	148.693788	0.944155144	0.944825761	0.944377
2008	200.732851	150.063565	0.943724956	0.953529558	0.946964
2009	194.529293	150.820776	0.914559563	0.958341006	0.929022
2010	195.290864	151.627674	0.918140011	0.963468174	0.933113
2011	196.932633	151.990988	0.92585862	0.965776733	0.939045
2012	199.207744	153.358134	0.936554822	0.974463813	0.949077
2013	201.188058	154.136489	0.945865066	0.979409614	0.956946
2014	203.497594	153.967144	0.956723113	0.978333567	0.963862
2015	206.784935	154.604545	0.97217821	0.982383722	0.975549
2016	209.789856	155.970247	0.986305539	0.991061626	0.987877
2017	212.702705	157.376941	1	1	1
2018	216.594529	159.020301	1.018297012	1.010442191	1.015702
2019	219.530696	160.178698	1.032101101	1.017802843	1.027378
2020	220.939724	161.212455	1.038725502	1.024371512	1.033984
2021	222.306633	162.130018	1.045151885	1.030201864	1.040214
2022	224.20116	163.196886	1.054058809	1.036980926	1.048418
2023	226.155081	164.359214	1.063244969	1.044366557	1.057009
2024	227.736127	165.42675	1.070678095	1.051149863	1.064227
2025	229.310686	166.501942	1.078080723	1.057981817	1.071442
2026	230.937906	167.622535	1.085730931	1.065102257	1.078917
2027	232.615046	168.783076	1.093615833	1.072476533	1.086633
2028	234.367337	169.997032	1.10185405	1.080190217	1.094698
2029	236.235999	171.209275	1.110639373	1.087893016	1.103126
2030	238.188653	172.464594	1.119819576	1.095869528	1.111908
2031	240.21632	173.724622	1.129352445	1.103875961	1.120937
2032	242.281408	174.98734	1.139061245	1.111899487	1.130089
2033	244.416009	176.245366	1.149096853	1.1198932	1.13945
2034	246.633113	177.497101	1.159520341	1.127846938	1.149058

Appendix C

year	month	day	hour	system mw	psa total	mw_e	mw_w	Eastern %	Western %
2014	3	3	19	144.09	144.0875	66.7299	77.3576	46.31%	53.69%
2014	4	15	14	122.63	122.6254	50.2352	72.3902	40.96%	59.04%
2014	5	12	16	133.566	133.5654	57.9524	75.613	43.39%	56.61%
2014	6	30	17	172.905	156.8357	69.5198	87.3159	40.21%	59.79%
2014	7	23	16	193.213	193.2128	96.326	96.8868	49.85%	50.15%
2014	8	27	16	175.731	175.7307	87.134	88.5967	49.58%	50.42%
2014	9	2	15	177.966	177.966	87.896	90.07	49.39%	50.61%
2014	10	16	12	134.995	134.9956	54.57	80.4256	40.42%	59.58%
2014	11	18	18	135.892	135.8918	62.217	73.6748	45.78%	54.22%
2014	12	8	18	143.321	143.3214	68.071	75.2504	47.50%	52.50%
2015	1	8	18	148.451	148.4504	69.655	78.7954	46.92%	53.08%
2015	2	16	19	144.833	144.8328	68.698	76.1348	47.43%	52.57%
2015	3	5	19	137.502	137.5021	63.046	74.4561	45.85%	54.15%
2015	4	2	11	123.717	123.7167	53.196	70.5207	43.00%	57.00%
2015	5	27	16	173.241	173.2414	80.931	92.3104	46.72%	53.28%
2015	6	23	17	163.897	163.8974	76.974	86.9234	46.96%	53.04%
2015	7	30	14	185.508	185.5081	88.65	96.8581	47.79%	52.21%
2015	8	18	14	186.141	186.141	90.612	95.529	48.68%	51.32%
2015	9	9	16	187.326	187.3256	90.746	96.5796	48.44%	51.56%
2015	10	13	19	126.066	126.0657	54.757	71.3087	43.44%	56.56%
2015	11	30	18	131.179	131.1792	61.125	70.0542	46.60%	53.40%
2015	12	29	18	135.02	135.0195	64.717	70.3025	47.93%	52.07%
2016	1	19	18	142.656	142.6563	66.52	76.1363	46.63%	53.37%
2016	2	15	18	142.576	142.576	66.849	75.727	46.89%	53.11%
2016	3	3	19	129.165	129.1652	58.534	70.6312	45.32%	54.68%
2016	4	4	12	125.627	125.6264	55.789	69.8374	44.41%	55.59%
2016	5	31	16	152.932	152.9326	72.016	80.9166	47.09%	52.91%
2016	6	20	16	168.23	168.2302	80.188	88.0422	47.67%	52.33%

2016	7	28	15	187.268	187.268	92.677	94.591	49.49%	50.51%
2016	8	12	16	193.773	193.7728	101.455	92.3178	52.36%	47.64%
2016	9	9	16	176.143	176.1425	88.094	88.0485	50.01%	49.99%
2016	10	17	19	125.149	125.1491	54.943	70.2061	43.90%	56.10%
2016	11	21	18	128.994	128.9941	59.783	69.2111	46.35%	53.65%
2016	12	19	18	143.2	143.2006	68.277	74.9236	47.68%	52.32%
2017	1	9	18	143.485	143.4859	67	76.4859	46.69%	53.31%
2017	2	7	19	134.572	134.5725	62.075	72.4975	46.13%	53.87%
2017	3	4	19	127.668	127.6675	59.331	68.3365	46.47%	53.53%
2017	4	11	16	124.478	124.4777	53.157	71.3207	42.70%	57.30%
2017	5	18	16	162.931	162.9316	80.043	82.8886	49.13%	50.87%
2017	6	12	17	181.34	181.3401	93.591	87.7491	51.61%	48.39%
2017	7	20	15	179.727	179.7268	89.606	90.1208	49.86%	50.14%
2017	8	22	17	179.089	179.0891	88.946	90.1431	49.67%	50.33%
2017	9	25	16	172.378	172.378	80.833	91.545	46.89%	53.11%
2017	10	9	19	136	136.0002	59.58	76.4202	43.81%	56.19%
2017	11	28	18	129.146	129.1464	60.506	68.6404	46.85%	53.15%
2017	12	28	18	150.426	150.4257	73.259	77.1667	48.70%	51.30%
2018	1	2	18	154.265	154.265	73.013	81.252	47.33%	52.67%
2018	2	7	18	135.615	135.6153	62.193	73.4223	45.86%	54.14%
2018	3	7	18	127.866	127.8662	58.701	69.1652	45.91%	54.09%
2018	4	16	12	121.766	121.7653	54.945	66.8203	45.12%	54.88%
2018	5	31	18	145.275	145.2743	67.507	77.7673	46.47%	53.53%
2018	6	18	16	170.718	170.718	83.684	87.034	49.02%	50.98%
2018	7	3	14	194.416	194.4155	95.599	98.8165	49.17%	50.83%
2018	8	29	15	197.82	197.8195	100.733	97.0865	50.92%	49.08%
2018	9	5	16	185.689	185.6899	90.481	95.2089	48.73%	51.27%
2018	10	10	16	141.038	141.0376	62.74	78.2976	44.48%	55.52%

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 19-120
Least Cost Integrated Resource Plan

Staff Data Requests - Set 1

Date Request Received: 10/10/19 Date of Response: 10/24/19
Request No. Staff 1-1 Respondent: Heather M. Tebbetts

REQUEST:

Reference Order No. 26,207 page 10 stating "Non-wires alternatives may be reviewed in various other dockets (rate cases, Least Cost Integrated Resource Plan (LCIRP) reviews, grid modernization proceedings) and, in each Electric Utilities' next LCIRP filing, each company will provide a grid needs assessment," and Order No. 26,209 stating " the settling parties acknowledge that [']the optimal venue for analyzing an electric distribution utility's planned capital investments for NWA candidates would be the review of its least cost integrated resource or similar plan ("LCIRP").['] Id. Under the Settlement Agreement, Liberty would provide a [']detailed grid needs assessment['] covering a number of specific topics within its next LCIRP," and a related DE 17-189 settlement agreement defining a Grid Needs Assessment as a filing "describe[ing] all forecasted grid needs related to distribution system capital investments of $250,000 or more over a five-year planning horizon at the circuit level. The grid needs assessment shall be available in spreadsheet format and shall include the following attribute-based columns and content: (1) Substation, Circuit, and/or Facility ID: identify the location and system granularity of grid need; (2) Distribution service required: capacity, reliability, and resiliency; (3) Anticipated season or date by which distribution upgrade must be installed; (4) Existing facility/equipment rating: MW, kVA, or other; and (5) Forecasted percentage deficiency above the existing facility/equipment rating over five years. Upon filing of the LCIRP and associated grid needs assessment, Commission Staff, the OCA, and Liberty will review planned capital investments to identify candidates that may be appropriate for NWA opportunities."

a. Please provide the above-described grid needs assessment or explain why the Company does not plan to comply with Orders No. 26,209 and 26,207 within this LCIRP.

b. If the Company does not plan to provide a grid needs assessment with this LCIRP, please explain whether the Company plans to comply with this requirement through its next LCIRP, pursuant to Order No. 26,261 which states "RSA 378:38 also contains a five-year filing requirement that runs from the date that a utility's prior LCIRP was filed. Liberty filed its prior LCIRP on January 15, 2016. Thus, the five-year filing requirement would compel a Liberty LCIRP filing on or before January 15, 2021. This five-year requirement ensures that LCIRP filings occur at regular intervals regardless of the timing of the review and approval process at the Commission. We do not find good cause to waive the five-year requirement at this time." If the Company does not plan to comply with its commitment to file a grid needs assessment in its next LCIRP, please explain why this is the case.

<u>RESPONSE:</u>

a. The Company will comply with Order Nos. 26,207 and 26,209 when it files its next LCIRP. Order No. 26,261, which gave rise to the filing in this docket, provided that, in lieu of an LCIRP, the Company was to make a more limited filing containing only the information specified in that Order, which was the filing that gave rise to this docket. Order No. 26,261 explicitly said that the filing in this docket is not an LCIRP ("While we will allow Liberty to delay its LCIRP filing, we will nonetheless require a more limited filing by the Company on or before July 15, 2019."). Order No. 26,261 did not require a grid needs assessment in this "more limited filing."

b. This filing is not an LCIRP, as discussed in part a above. The Company's next LCIRP is currently due January 15, 2021. The Company will file what is required at the time of its next LCIRP.