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NARRAGANSETT ELECTRIC COMPANY

2021 Electric Peak (MW) Forecast

15-Year Long-Term

2021 to 2035

January 2021

Rev2, 02/08/2021

Economics and Load Forecasting
Advanced Data & Analytics

nationalgrid

REVISION HISTORY & GENERAL NOTES

Revision History

Version	Date	Changes
Original	11/02/2020	- ORIGINAL
Rev1	01/06/2021	- Expand discussions on COVID
Rev2	02/08/2021	- Correct figures 12, 13, and 14

General Notes:

- Hourly load data through August 2020; projections from 2021 forward;
- Economic data is from Moody's vintage September 2020.
- No explicit long-term **Covid-19** post-model adjustments. It is assumed that the Moody's economic projections capture any long-term system level pandemic impacts.
- Energy Efficiency data is internal data vintage August 2020.
- Demand Response is internal data vintage August 2020.
- Solar PV data is internal data vintage July 2020.
- Electric Vehicle data is POLK data vintage May 2020.
- **Electric Heat Pumps added as an additional DER this year.**
- Peak MW and Energy GWH source is ISO-NE/MDS meter-reconciled data (Jan. 2003 to Jun. 2020), internal unreconciled **preliminary** data (Jul. 2020 to Aug. 2020).
- Peak load data is metered zonal load; but without ISO bulk system losses.
- **Likelihoods for each DER scenario new for this year.**
- **Climate scenarios new for 2020**

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Summary

National Grid's US electric system is comprised of four companies serving 3.5 million customers in Rhode Island, Massachusetts, and upstate New York. The four electric companies are: Narragansett Electric Company, serving 0.5 million customers Rhode Island, Massachusetts Electric Company and Nantucket Electric Company, serving 1.3 million customers in Massachusetts and Niagara Mohawk Power Company serving 1.7 million customers in upstate New York. Figure 1[1] shows the Company's service territory in the U.S.

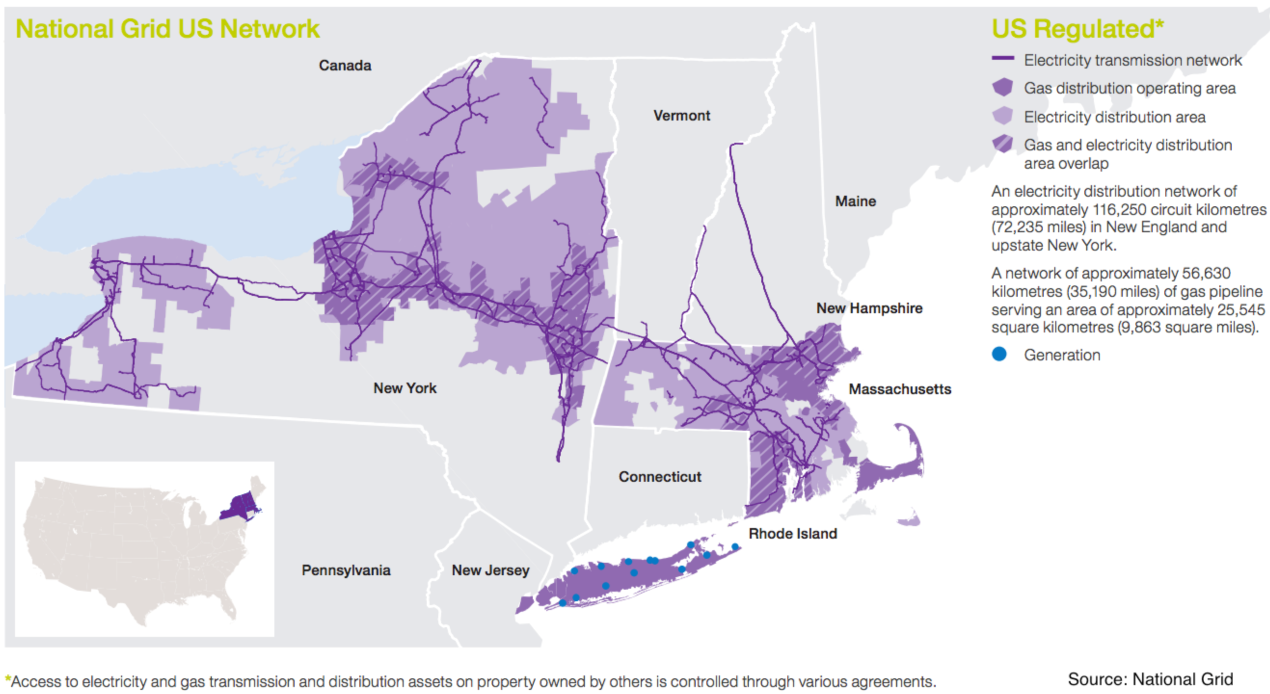

Figure 1: National Grid U.S. Service Territory

Forecasting peak electric load is necessary for the Company's capital planning process so the Company can assess the reliability of its electrical infrastructure, procure and build required facilities in a timely manner, and provide system planning with information to prioritize and focus their efforts.

The Company's[2] peak demand in 2020 was 1,855 MW on Tuesday, July 28 at hour-ending 15. This 2020 peak was 7% below the company's all-time high of 1,985 MW reached on Wednesday, August 2, 2006.

This summer's weather for the Company peak was considered warmer than 'normal' (or average). The peak weather fell in the 83 percentile of peak weather over the last 20 years. This means that only 17%

[1] National Grid also serves gas customers in these same states which are also shown on this map.
[2] Company refers to Narragansett Electric Company for the remainder of this report.

of summer peaks are expected to be warmer[3]. This year's peak is considered 106 MW above the peak the company would have experienced under normal weather. Thus, on an adjusted "normal" basis this year's peak was estimated to be 1,749 MW, a decrease of 1.8% compared to last year's adjusted peak.

The forecast indicates that the service territory will experience peak decrease of 0.5% annually in the next five years, primarily due to the impacts of distributed energy resources (DERs) offsetting any underlying economic growth. In the longer term, it will expect a peak increase of about 0.2% annually over the next fifteen years. Such growth is primarily due to the impacts of additional beneficial electrification including electric vehicles.

Figure 2 shows this forecast graphically.

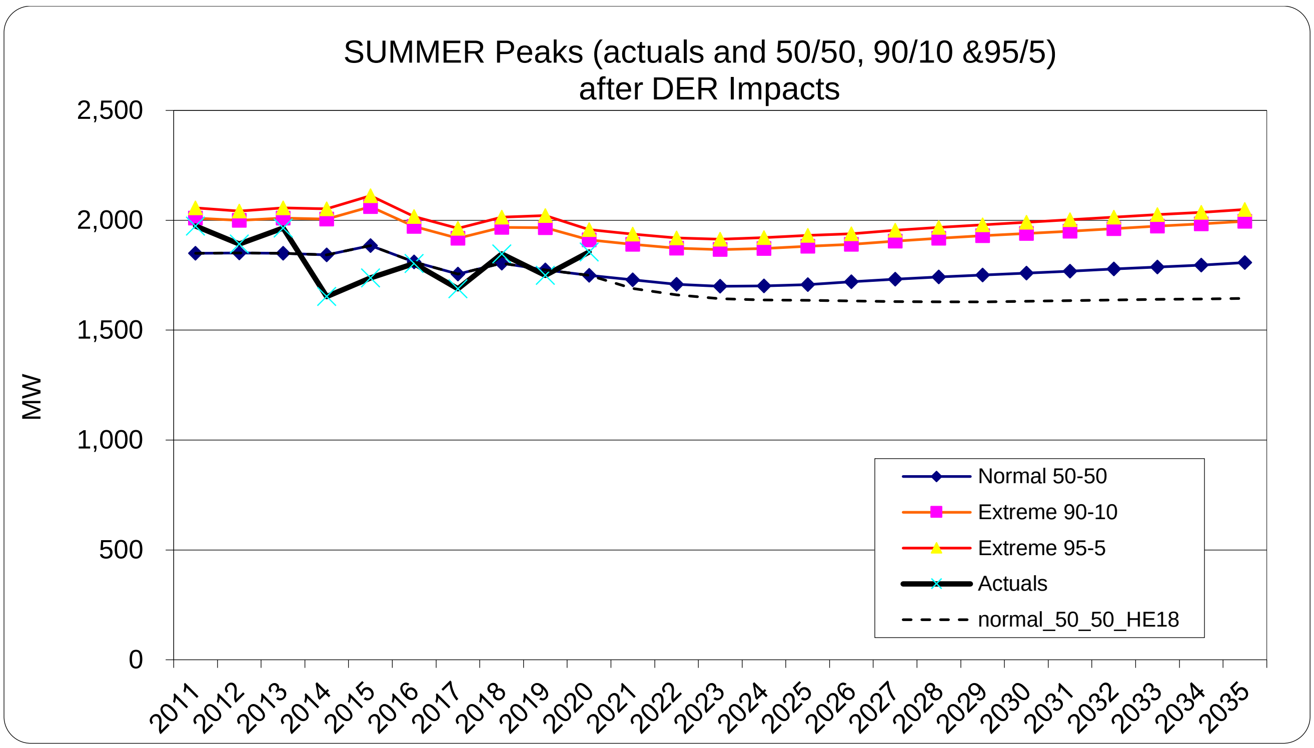

Figure 2: Historical (actual & weather-adjusted) and Projected Summer Peaks

This forecast incorporates the impacts of a changing hour of the peak over time. In general, due to increased solar photovoltaics (PV) and electric vehicles (EV) the hour of the peak moves from its current afternoon/early evening time to later in the evenining time. As this occurs, the impact of PV is less pronounced on the new peak hour. For comparison, the dasheds line in Figure 2 shows how the load at the 5-6 PM hour, where PV has more impact continues to decline over the planning horizon.

[3] For planning purposes, network strategy uses a 90/10 for transmission planning and a 95/5 for distribution planning for weather extremes.

Forecast Methodology

The overall approach to the peak forecast is to relate (or regress) peak MWs to aggregate system energy and economic indicators (if appropriate).

The model is developed based on a “reconstructed” model of past load. That is, claimed energy efficiency, installed solar PV and demand response impacts are added back to the historical data set before the models are run. Electric vehicle impacts are removed from the historical data set. Electric heat pumps both add or remove load depending on the season (removed in winter and added in the summer). The statistical forecast is made based on the “reconstructed” data set. Then, the future cumulative estimates of savings or additions for these DERs are taken out or added to the statistical forecast to arrive at the final forecast. Hourly profiles for the DERs are applied to the hourly profiles for the loads to determine the annual peaks.

The results of this forecast are used as input into various system planning studies. The forecast is presented for three weather scenarios. The transmission planning group uses the extreme 90/10 weather scenario for its planning purposes. Up until year 2019, distribution planning used the 95/5. The 50/50, or weather-normal scenario is used for capacity market, strategic scenarios, incentive mechanisms and other relevant work.

Weather Assumptions

Weather data is collected from the relevant weather stations located within the Company's New England service territory and used to weather-adjust peak demands. The Providence weather station is used for Rhode Island.

The weather variables used in the model include heating degree days for the winter months and a temperature-humidity index (THI)[4] for the summer months. Other variables such as maximum or minimum temperature on the peak day are also evaluated. These weather variables are from the actual days that each peak occurred in each season over the historical period. Summer THI uses a weighted three-day index (WTHI)[5] to capture the effects of prolonged heat waves that drive summer peaks. Weather adjusted peaks are derived for a normal (50/50) weather scenario and extreme weather scenarios (90/10 and 95/5)[6].

- Normal 50/50 weather is the average weather on the past 20 annual peak days.
- Extreme 90/10 weather is such that it is expected that 90% of the time it should not be exceeded. It is similarly inferred that it should occur no more than one time in a ten-year period on average.
- Extreme 95/5 weather is such that it is expected that 95% of the time it should not be exceeded. It is similarly inferred that it should occur no more than one time in a twenty-year period on average.

These normal and extremes are used to derive the weather-adjusted historical and forecasted values for each of the normal and extreme cases.

Figure 3 shows the historical, weather-normal, and weather-extreme values for WTHI for the Company.

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[4] THI is calculated as (0.55 * dry bulb temperature) + (0.20 dew point) + 17.5. Maximum values for each of the 24 hours in a day are calculated and the maximum value is used in the WTHI formula.
[5] WTHI is weighted 70% day of peak, 20% one day prior and 10% two days prior.
[6] Normal distribution is assumed to derive the extreme weather scenarios. This probabilistic approach employs Z-scores and standard deviations to calculate the extreme weather scenarios.

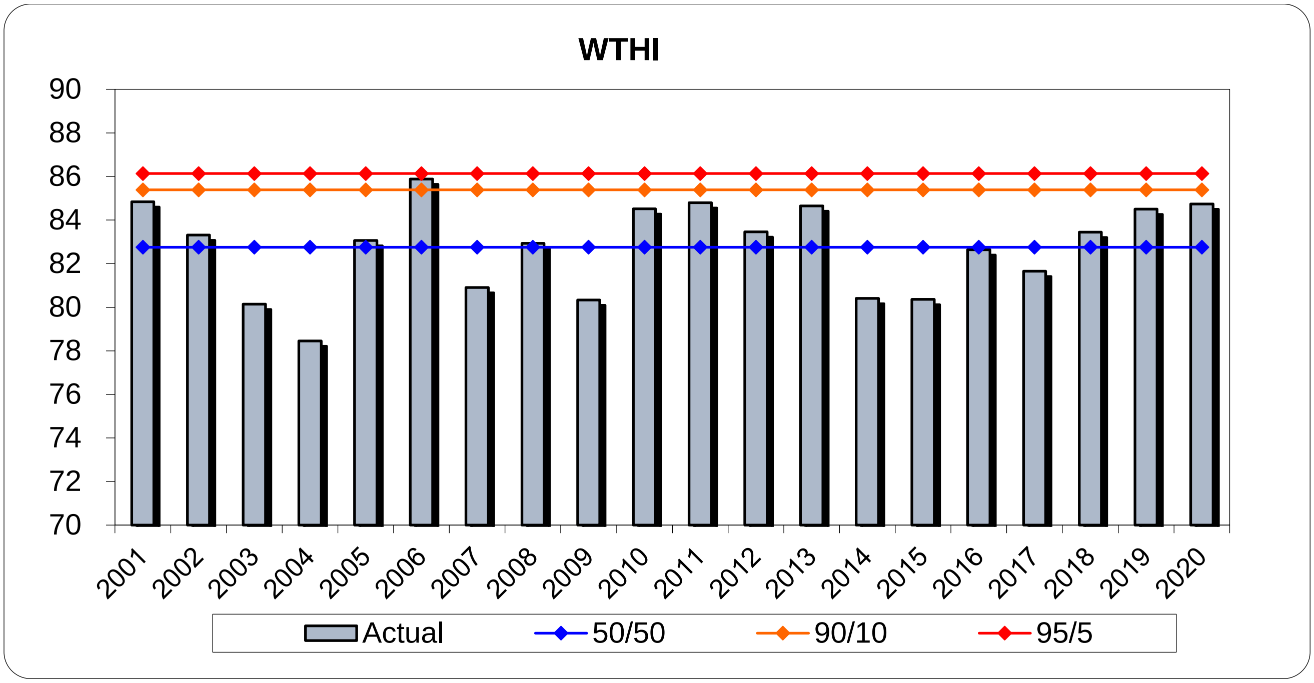


Figure 3: Actual, weather-normal and extreme WTHI

COVID-19

The COVID-19 pandemic led to behavior change (from stay at home orders, etc.) and economic impacts that affected load. It contributed to lower than expected loads throughout the summer in the Company's service territory. During the summer, the region had gone through a multi-phase re-opening plan. During the earlier part of the summer, weather adjusted loads were lower in general than they were later in the summer as the economy re-opened. Therefore, in addition to the standard WTHI weather variable that has been used in prior years, a weekly trend variable was also added to the weather normalization model. This trend variable was used to approximate these additional loads coming back on-line as the summer progressed. The Company's summer peak was on July 28th, about two-thirds through the full summer season. The weekly trend variable estimated (using the statistical modeling) that about 0.2% more load returned each week. Therefore, a COVID-19 adjusted peak was created that adjusted the July 28th peak for the load that returned by the end of the summer.

No explicit out-of-model future adjustments were made. The Moody's economic projections are assumed to account for future economic impacts of this pandemic, thereby capturing long-term impacts via the modeling process.

Distributed Energy Resources (DERs)

In Rhode Island there are a number of policies, programs, and technologies that impact customer loads. These include, but are not limited to energy efficiency (EE), solar photovoltaics (PV), electric vehicles (EV), demand response (DR), and electric heat pumps (EH). These collectively are termed distributed energy resources (DERs) because they impact the loads at the customer level, as opposed to traditional, centralized power supplies.

A base case forecast is developed for each of the DERs and is part of the official forecast. For each of the DERs, a higher case and a lower case are developed, if appropriate. The inclusion of multiple scenarios for each DER, as well as the different combinations of them, provides system and strategic planners with additional information to make informed decisions. The discussion below is based on the expected, or base case.

Figure 4 shows the expected loads and impacts for the DERs each year.

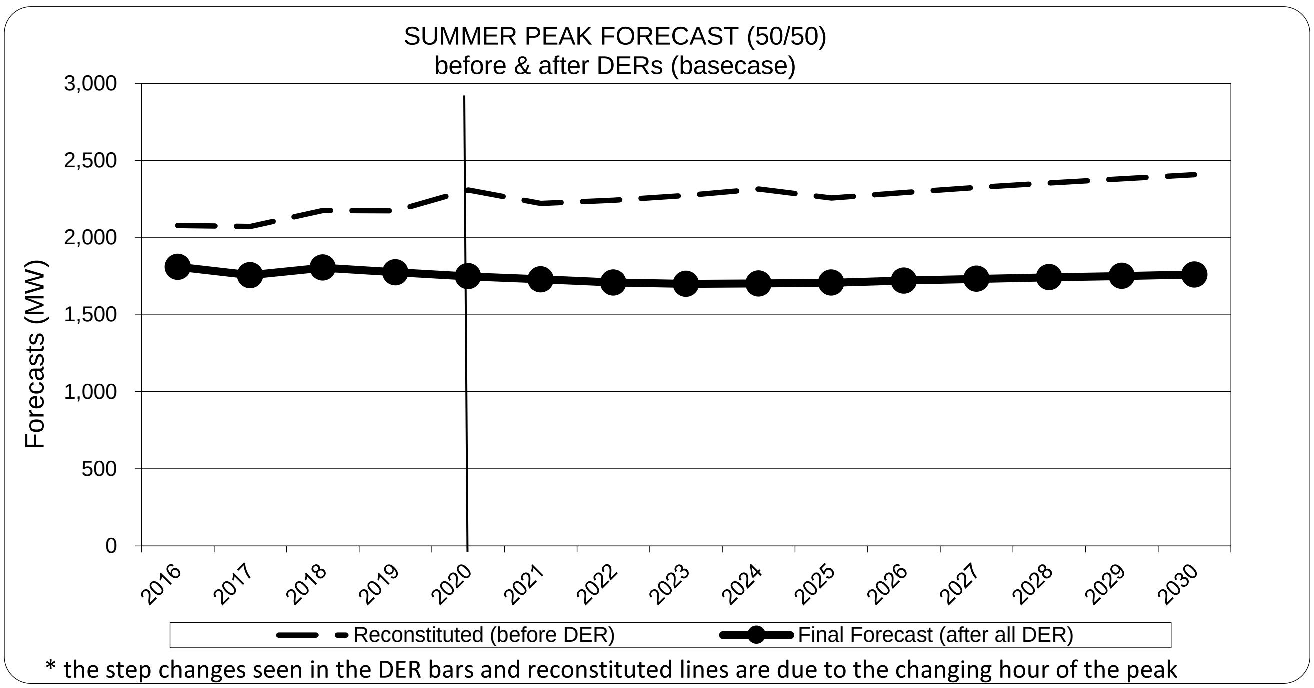


Figure 4: Annual loads before and after the impacts of DERs

Figure 5 shows the impacts for the DERs each year.

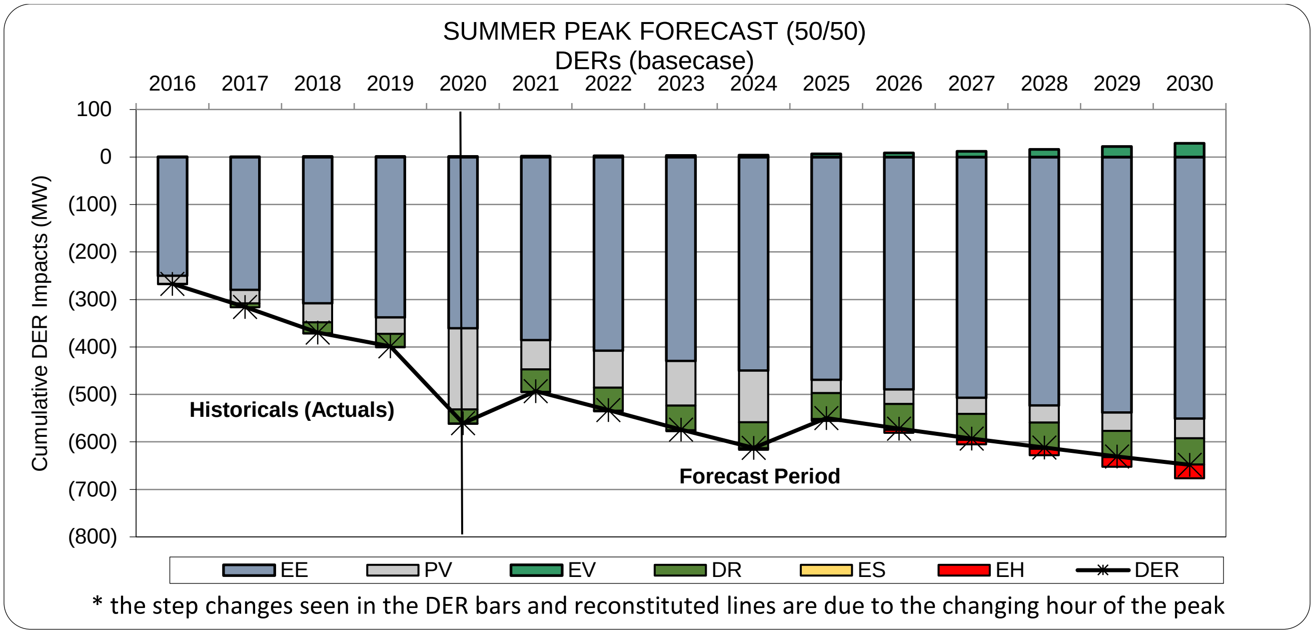


Figure 5: Annual impact of DERs

In general, DERs are expected to decrease future growth from 0.5% per year over the next fifteen years to 0.2% per year.

In addition to impacting the magnitude of the peak, the DERs change the peak-day load shape which shifts the peak hour over time. The significant increase of the PV impact this year is due to the shift of the peak hour from hour-ending 17 or 18 in the past two years to hour-eding 15 this year when more solar irradiance was available than the later hours of the day. In general, the peak hour shift to late of the days. The impacts of each DER on the peak hour change as the peak hour shifts[7]. In general, due to increased solar photovoltaics (PV) and electric vehicles (EV) the hour of the peak moves from its current time of 3-4 PM to 5-6-7 PM over the fifteen-year planning horizon. As this occurs, the impact of PV is less pronounced on the peak hour. The visible decreases in DERs shown in Figure 5 in 2021 and then in 2025 are due to this shift.

Each of the DERs is discussed next.

Energy Efficiency (EE)

National Grid has run EE programs in its Rhode Island jurisdiction for many years and will continue to do so for the foreseeable future. In the short-term, EE targets are based on approved company programs. Over the longer term, the Company assumes the market begins to saturate and the rate of new EE is assumed to decline. This allows continued cumulative growth of EE over time, however at a lower rate of incremental EE each year to account for long-term saturation, higher marginal costs,

[7] While the figure shows a step function drop in DERs as the hour shifts, in practice each DER would have a smoother impact. This table only shows each 'hour-ending' value.

and a lower load base to capture savings from as long-term EE lowers overall load. (This practice of declining EE over time is similar to what each regional ISO does).

Figure 5 above shows the expected load and energy efficiency program impacts to peaks by year for the base case. As of 2020, it is estimated that these EE programs have reduced load by 361 MW, or 15.6% compared to the counterfactual with no EE programs. By 2035, it is expected that this reduction will grow to 599 MW or 24.1% of what load would have been had these programs not been implemented. Over the fifteen-year planning horizon these reductions lower annual peak growth from 0.5% to negative 0.2% per year. Figure 6 presents the annual incremental (left) and cumulative (right) EE summer MWs.

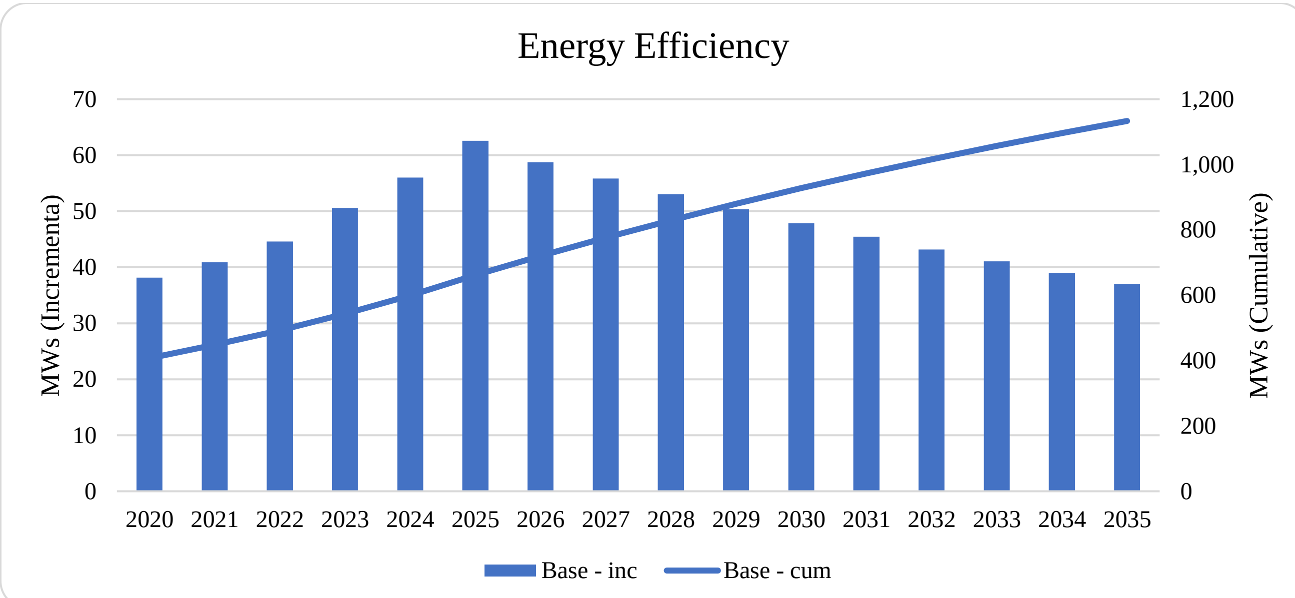


Figure 6: Energy efficiency summer MWs by year

Solar Photovoltaic (PV)[8]

There has been a rapid increase in the adoption of PV throughout the state. Actual installed PV is tracked by the Company and used for the historical values in Figure 7. The projection for the future is based on an estimate of installations for units already in the application queue for the first two years, then a continuation of those levels until year 2023, and then a slowly declining number of new annual installations to account for saturation.

Figure 7 shows the projected connected PV installations. As of 2020, it is estimated about 289 MWs will have been connected, growing to 1,476 MW by the end of the planning period.

[8] This discussion is limited to PV which is expected to reduce loads and would not include those PV installations considered to be supply by the ISO. This can include both 'behind-the-meter" and in "front-of-the-meter" (e.g. community solar which is allocated back to customers).

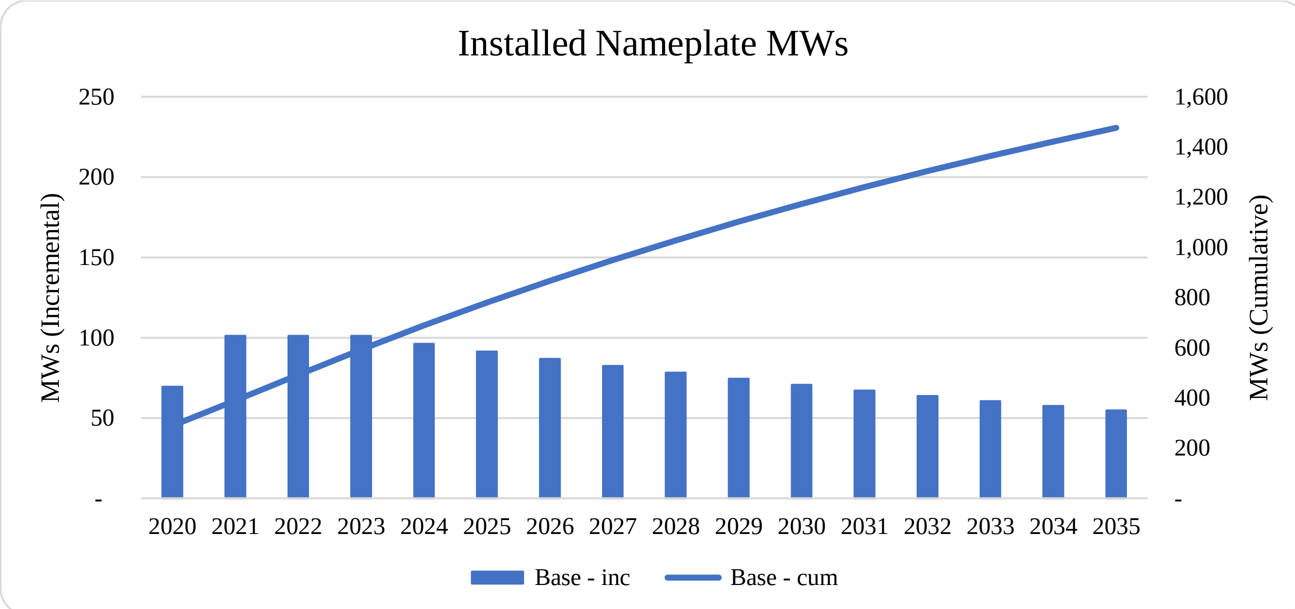


Figure 7: Solar-PV connected nameplate (AC) MW by year

While installed PV continues to grow, suppressing peak load, its impact drops off considerably as the peak hour shifts later in the day when there is less daylight.

Electric Vehicles (EV)

EVs increase peak load over time. Electric vehicles of interest are those that "plug-in" to the electric system and include "plug-in hybrid electric vehicles" (PHEVs) and "plug-in battery-only electric vehicles" (BEVs). These two types are those that could have potential impacts on the electric network.

The Company has been tracking EV adoption in its service territory for several years. Each year, the rate of electric vehicle adoption has increased. The base case forecast for the number of newly registered electric vehicles within the Company's service territory uses the recent trend showing this increased rate of adoption yielding an increasing number of new EVs each year.

Figure 8 shows the future estimated number of EVs in the Company's Rhode Island service territory. As of the end of 2020, it is estimated that almost 2,654 EVs will be on the roads in the service territory, growing to about 128,000 by the end of the fifteen-year planning horizon.

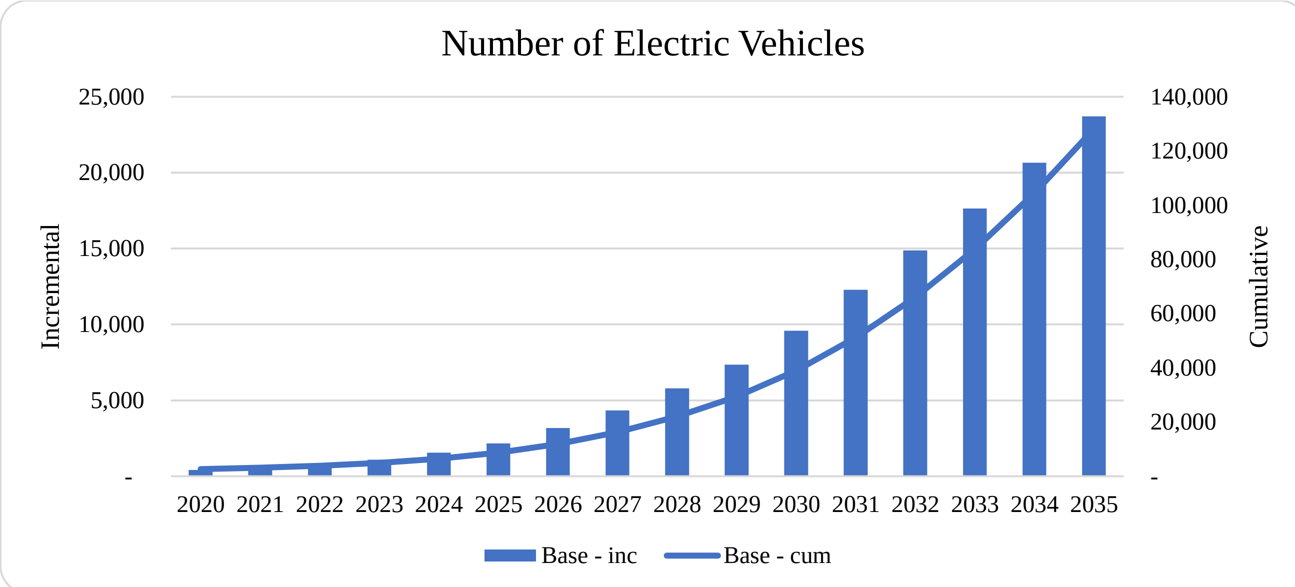


Figure 8: Number of Incremental and Cumulative EVs

It is estimated that these vehicles may have increased cumulative summer peak loads by about 1.1 MW as of 2020, increasing to 94.8 MW of cumulative peak load increase in 2035. While EVs do add to both peak and energy loads over time, they are considered 'beneficial'[9] electrification.

Demand Response (DR)

DR programs actively target reductions to peak demand during hours of high expected demand and/or reliability problems. These resources must be dispatched, unlike the more passive energy efficiency programs that provide savings throughout the year. The DR programs enable utilities and the Independent System Operator (ISO) to act in response to a system reliability concern or economic (pricing) signal. During these events, customers can actively participate by either cutting their load or by turning on a generator to displace load from behind the customer's meter.

In general, there are two categories of Demand Response programs in Rhode Island. These are ISO programs and Company retail level programs.

The ISO programs, referred here as "wholesale DR", have been active for several years and were activated multiple times over that period. There were no ISO activations this year. The company's policy has been to add-back reductions from these dispatches to its reported system peak numbers. This is because the Company cannot dispatch the ISO resources so there is no guarantee that these ISO DR events would be at the times of Company peaks. Therefore, the company must plan assuming they are not called.

The Company recently began to run its own DR program at the 'retail', or customer level over the last few years. In contrast to the wholesale level DR programs implemented by the ISO, these programs are activated by the Company.

[9] Beneficial electrification is based on an overall portfolio of lowered carbon emissions from the transportation sector coupled with lower/carbon free generation of electricity in the power sector to support the charging of the EVs.

In 2020, estimated impact of the retail DR program was about 29 MW and is expected to grow to about 55 MW, or 2.2% of summer peak load by year 2035.

Electric Heat Pumps (EH):

The base case for years 2020 to 2029 are based on the ISO-NE estimates. Subsequent to this and through the end of the planning cycle in year 2035, incremental heat pumps continue to grow, but at a smaller amount each year to reflect a level of saturation. Figure 9 shows the annual number of electric heat pumps assumed for the forecast.

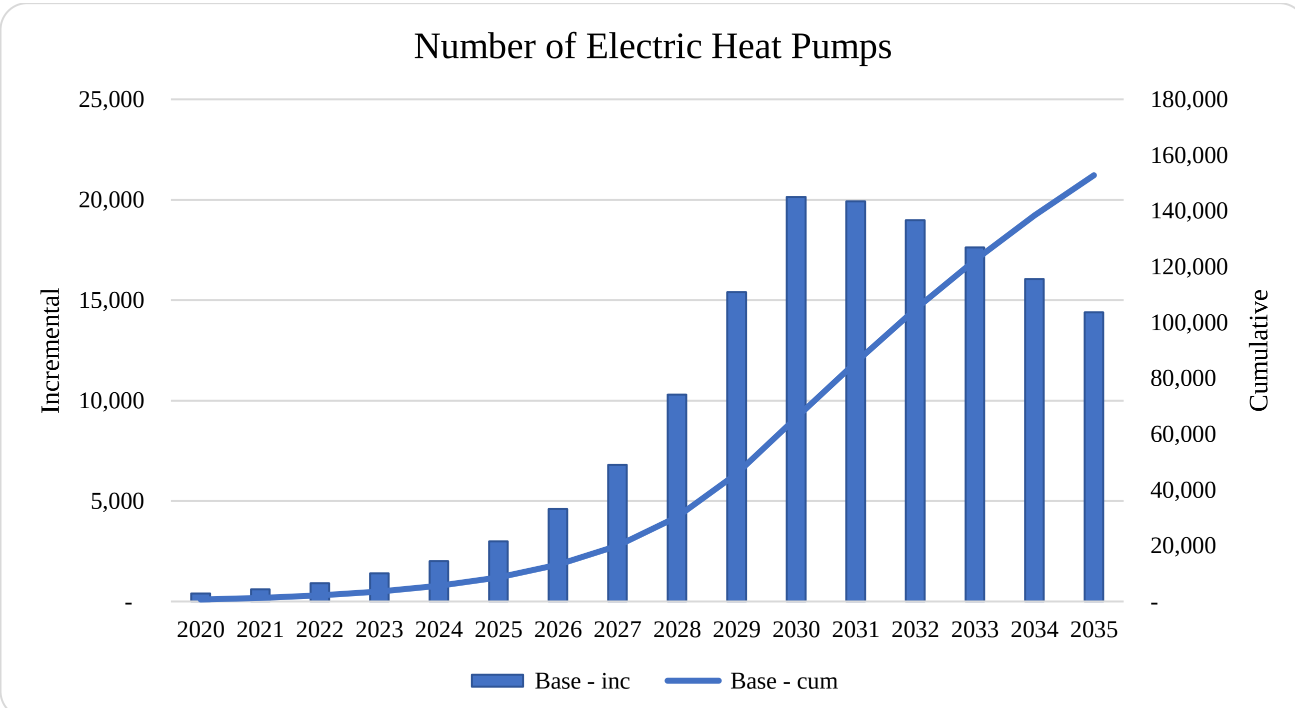


Figure 9: Number of electric heat pumps

All prior discussion on load & DERs above is limited to the base case. Additional higher and lower scenarios are provided later in this section (see 'DER scenarios') and in the Appendices.

Peak Day 24 Hourly Curves

While the single summer peak values discussed above are of major importance, the estimated impacts due to DERs on the load profile on these peak days is also significant. A 24-hour peak day load profile is provided below. This allows the Company to look beyond the traditional approach of predicting only the 'single' highest seasonal system peak each year. The process looks at the hourly load shape of all 24 hours of each peak day for each year of the planning horizon to determine the load and impact of DERs. This is useful to show the changing hours of the peaks as more DERs are added. For example, as more and more PV is added to the system, the summer peak hour will shift away from afternoon hours where solar irradiation is highest to evening hours as the solar reductions taper off. As more electric vehicles chargers are installed, evening and nighttime loads can go up.

Figure 10 shows the impact of the "24 hour" peak summer day for selected years over the planning horizon for the base case DERs.

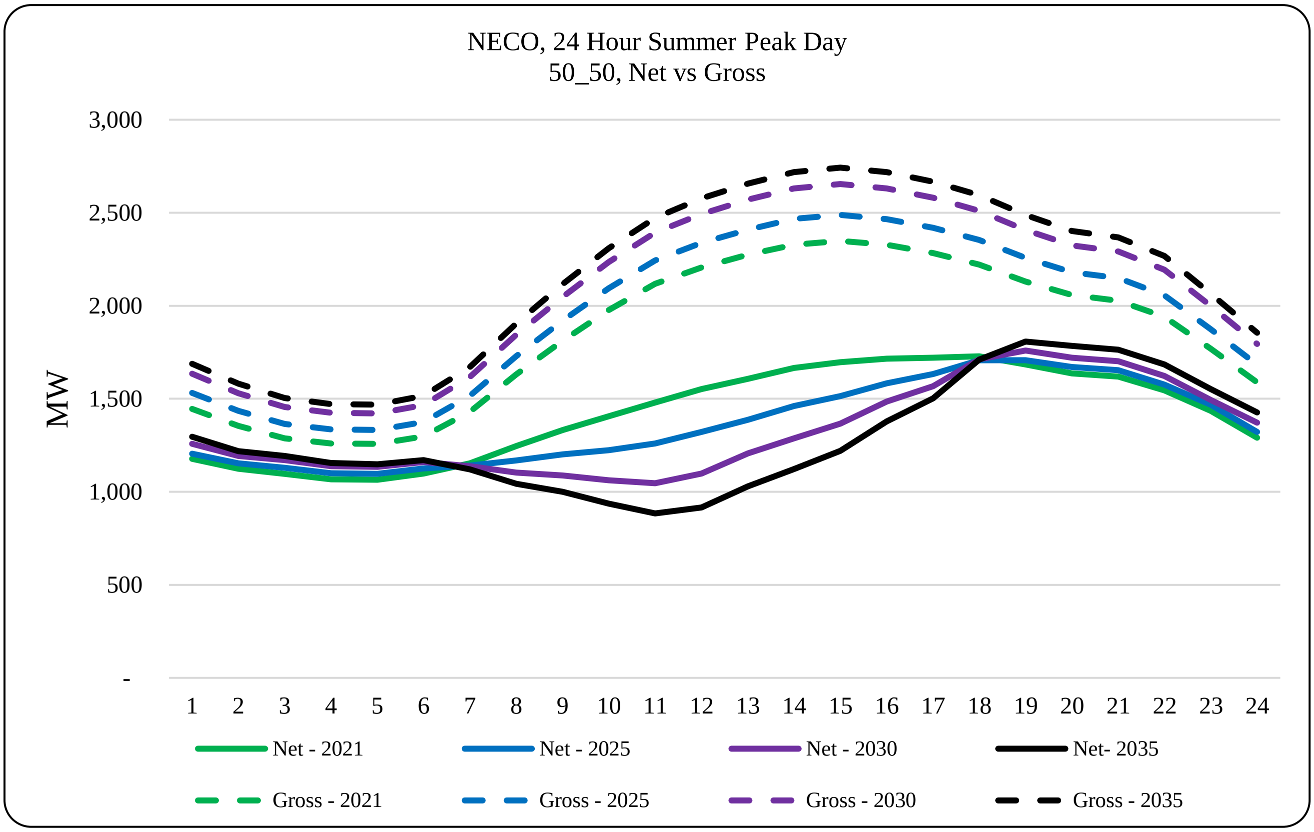


Figure 10: Peak Summer day hourly load, pre and post DERs

Figure 10 clearly shows how the expected DERs not only lower the loads, but also shift the hour of the peaks. "Gross" refers to loads before DER impacts and "Net' refers to loads after DER. The selected years are 2021, 2025, 2030 and 2035.

Figure 11 shows the impact of the "24 hour" peak winter day for selected years over the planning horizon with the base case DERs.

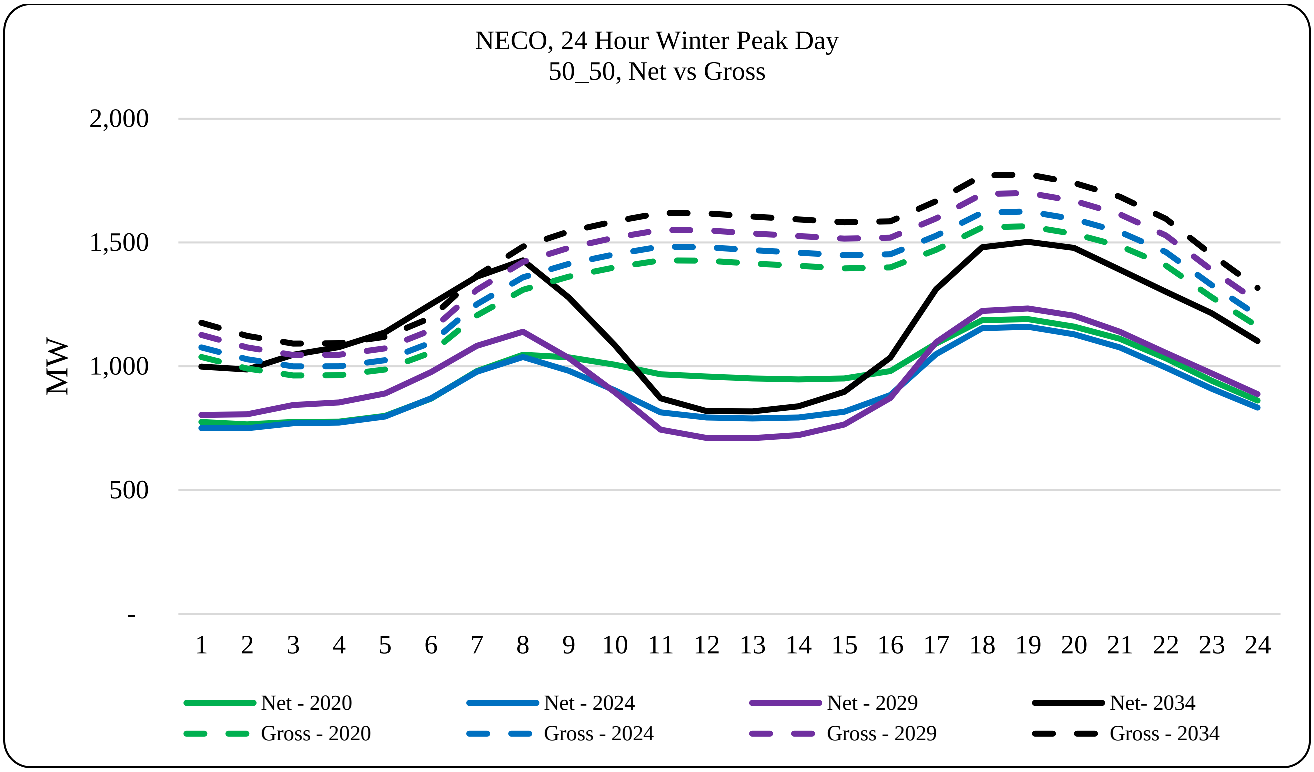


Figure 11: Peak Winter day hourly load, pre and post DERs

Figure 11 shows the dual peaks associated with winter days as well as the very low load hours during the daytime hours due to solar and the rapid ramp ups needed as the sun sets. The increasing penetration of electric heat pumps will significantly increase the usage in later years. The figures above show the Gross and Net load profiles for the base case DERs.

Appendix C contains additional load shapes for other day types including: summer, winter and shoulder month average weekdays and weekends. These show the varying seasonal patterns as well as the lower load shoulder months which are mostly comprised of base load with minimal impacts of cooling or heating. Weekend load patterns also provide insight to lower load profiles since there is no weekday business load. One item of note is that where the highest peaks tend to drop over time for the system summer peaks, in the average day profiles one can see some growth in the evening and early night time hours. One reason for this is that demand response is not considered to be implemented in shoulder periods and on average days.

DER Scenarios

So far, this report has shown results for the peak forecast with the base case DERs scenario. The Company has also looked at a number of scenarios where each of the DERs (EE, PV, EV, DR, and EH) also has a higher case and a lower case scenario, if appropriate. Looking at a range of scenarios can provide planners with additional information on what loads might be under various combinations of DER scenarios[10].

Each of the various combinations of DERs scenarios – base, high and low – were modeled. This creates thousands of combinations. In order to assess the probabilities of any one of these scenarios occurring, each DER case was assigned a 'probability level. For example, for the three EE cases, these were assigned 80% likelihood for the base case, 10% for the low case, 5% for the high case, and 5% for the high2 case. These assignments are based on group consensus with the SMEs for the DER and sum to 100%. For this report, the probabilities for each DER are assumed to be independent of each other. This process is repeated for each DER. Table 1 shows the probabilities used in the forecast.

Table 1, Probabilities for each DER case

DER	Low	Base	High	High2
Energy Efficiency	10%	80%	5%	5%
Solar - PV	5%	60%	35%	n.a.
Electric Vehicles	5%	80%	10%	5%
Demand Response	5%	90%	5%	n/a
Electric Heat Pumps	20%	75%	5%	n/a

Figure 12 shows the basecase (which is the most likely) in black dashed line and the maximum and minimum cases in red solid lines which provide the highest and lowest bounds for planning purposes. It also shows the other more likely cases besides the basecase.

[10] In this forecast, five DERs, each with three scenarios (EV and EE with four) – base, high and low, creates 432 cases for each weather scenario. With three weather scenarios 1,296 cases are generated for the Company.

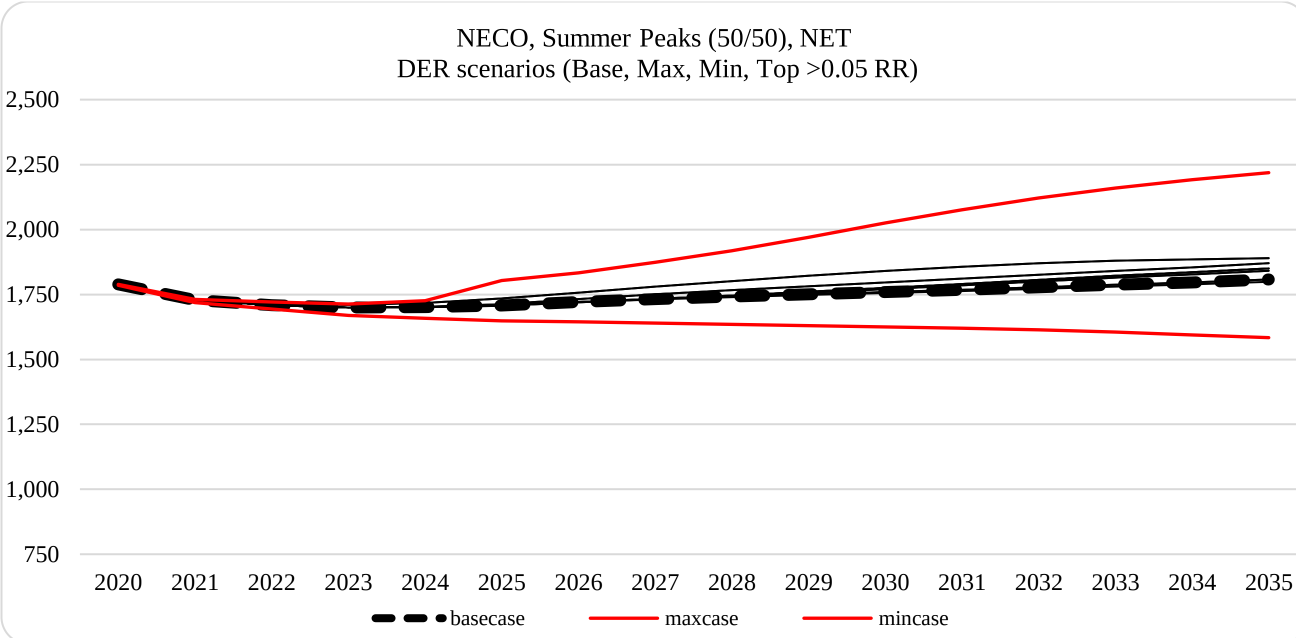


Figure 12: Summer Peaks (50/50), NET, selected DER scenarios

Figure 12 shows that the peak load five years from now or in year 2025, ranges from about 1,648 MW to 1,803 MW - a 155 MW spread, with the base case at 1,707 MW. The uncertainty increases over time, so that fifteen years from now or in year 2035, the range expands to from about 1,584 MW to 2,219 MW, or almost a 635 MW spread, with the base case at 1,808 MW. It is noted that while the maximum and minimum cases are shown to provide bounds for the forecast, those specific scenarios are very, very unlikely, with relative ranking of less than 0.000001.

Table 2 shows the relative rankings of the basecase, max/min cases and the DER scenarios with the higher rankings (>= 0.5). For reference, any case that is at least 5% as likely as the base case and higher is shown. An example of how to interpret each case is as follows. The basecase is assumed to be the most likely and assigned a relative ranking of 1.0. Other cases are shown relative to the basecase. Thus, in the graph above, case _ee_B_pv_H_ev_B_dr_B_es_B_eh_B_[11] is shown with a relative ranking of 0.58. That means that this case is only 27%, or a little over one-quarter as likely as the basecase.

[11] ee, pv, ev, dr, es, eh are the individual DERS; B, H, L are the base, high or low case used in the subject scenario. Please note, RI does not have ES considered yet, the ES is just a placeholder.

Table 2 Relative rankings of selected scenarios

Relative Rankings		
case	relative_rank	prob
basecase (ee_B_pv_B_ev_B_dr_B_es_B_eh_B_)	**1.00**	**19.4%**
maxcase (ee_L_pv_L_ev_H2_dr_L_es_L_eh_L_)	0.00	0.0%
mincase (ee_H2_pv_H_ev_L_dr_H_es_H_eh_H_)	0.00	0.0%
ee_B_pv_H_ev_B_dr_B_es_B_eh_B_	0.58	11.3%
ee_B_pv_B_ev_B_dr_B_es_B_eh_L_	0.27	5.2%
ee_B_pv_H_ev_B_dr_B_es_B_eh_L_	0.16	3.0%
ee_B_pv_B_ev_H_dr_B_es_B_eh_B_	0.13	2.4%
ee_L_pv_B_ev_B_dr_B_es_B_eh_B_	0.13	2.4%
ee_B_pv_L_ev_B_dr_B_es_B_eh_B_	0.08	1.6%
ee_L_pv_H_ev_B_dr_B_es_B_eh_B_	0.07	1.4%
ee_B_pv_H_ev_H_dr_B_es_B_eh_B_	0.07	1.4%
ee_B_pv_B_ev_B_dr_B_es_B_eh_H_	0.07	1.3%
ee_H_pv_B_ev_B_dr_B_es_B_eh_B_	0.06	1.2%
ee_B_pv_B_ev_H2_dr_B_es_B_eh_B_	0.06	1.2%
ee_H2_pv_B_ev_B_dr_B_es_B_eh_B_	0.06	1.2%

While Figure 12 above show what the longer term annual single summer peaks look like, Figures 13 and 14 show what the 24-hour peak day profiles might be for selected years.

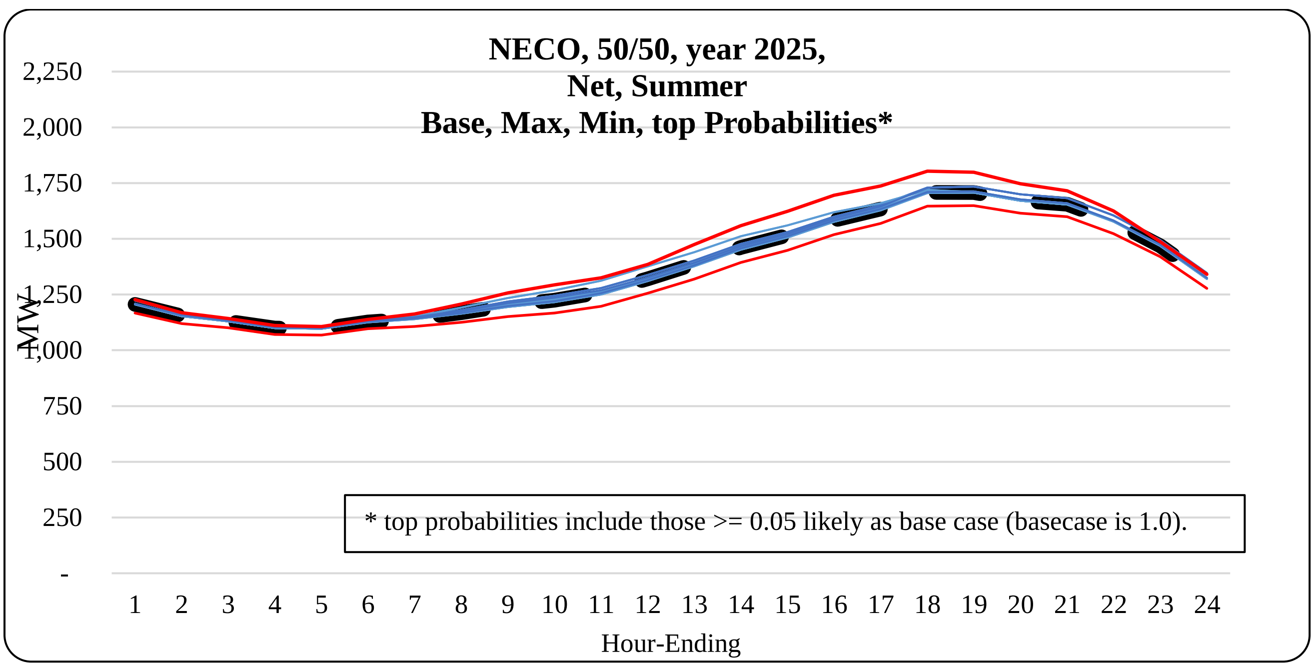


Figure 13: 50/50 case, net summer peak, w/range of DER scenarios, year 2025

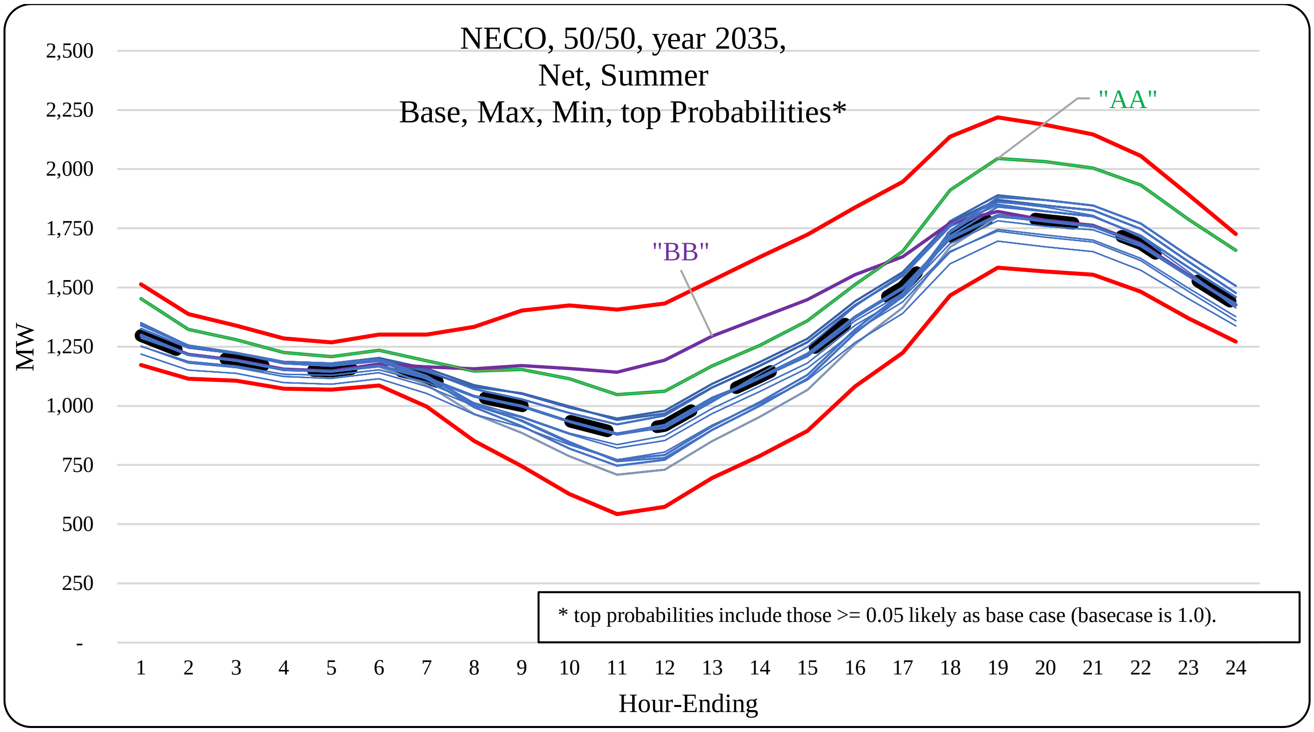


Figure 14: 50/50 case, net summer peak, w/range of DER scenarios, year 2035

What becomes apparent is that the range of possible outcomes in the early years (Figure 13), quickly increases fifteen years out (Figure 14). Note that the mid-day hours have a wider range of possible loads than other times of the day. While most scenarios tend to stay close to the basecase for the selected (higher ranked) scenarios, two of them towards the higher-demand side stand out as different. The case “AA” is from the high2 EV scenario and base scenarios for other DERs. The usage ramps up in the late afternoon / early evening due to the EV charging demand. The case “BB” is from the low PV scenario and base scenarios for other DERs. The usage during the day is high due to low PV impact. However, according to Table 2, both cases are not very likely to occur.

Appendices D and E describe the process for determining these scenarios and what the input cases look like.

The base case DER projections included in this forecast are based on current trends, approved programs, and existing state policy targets. They are considered the most probable scenario at this time. The higher and lower scenarios are provided to give additional insights into what loads could look like under different scenarios. These are not meant to be all-inclusive and may or may not capture some of the more ambitious and aspirational type DER scenarios associated with more renewables due to climate and other regional discussions. These can include, among other things, additional electrification of the transportation and heating sectors. The Company is actively monitoring these processes and will incorporate, as appropriate, new policies and scenarios as they become more likely.

The Company is also part of Grid Modernization, more specifically in Rhode Island termed Power Sector Transformation (PST), and considers scenarios and work in that arena in this forecast as appropriate.

Climate Scenarios

The Company provides a climate change scenario based on possible changes in weather over time. This scenario shows potential changes to peak loads should average temperatures and volatility increase over time. Figure 15 compares the basecase, 50/50 summer peak forecast vs. alternative loads with higher average weather values.

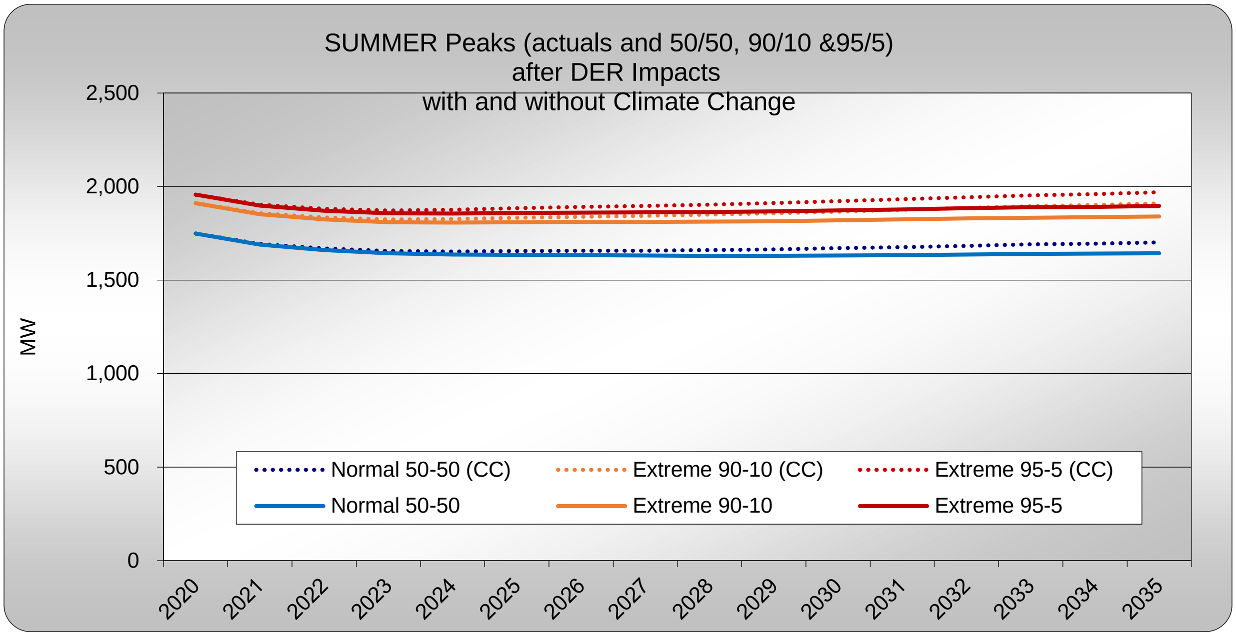


Figure 15 Summer loads basecase and with climate change

The input assumption is a 0.7 degree rise in average temperatures per each ten years and a five percent increase in volatility over that same period. These increases are evenly divided across each year. No regional specific climate study was aware of, so the scenario was developed based on a study that the NYISO performed relative to climate change.[12] Average temperature is a factor in each of the three weather scenarios. The volatility value of 5% is currently a placeholder. The NYISO report did not assume a value for this, however, since the 90/10 and 95/5 scenarios in this report do include variance in the modeling, a placeholder value was assumed for this exercise.

Table 3 shows the differences between the loads in the basecase and the potential higher loads with the climate change assumptions for the three weather scenarios.

[12] NYISO Climate Change Phase II Study, page 4, dated April 23,2020

Table 3 Comparison of loads between Basecase and Climate Change scenario for year 2035[13]

	50-50		90-10		95-5	
	Base	w/CC	Base	w/CC	Base	w/CC
Year 2035 (MWs)	1,644	1,702	1,840	1,910	1,896	1,970
Delta (MWs)		58		70		74
Delta (%)		3.5%		3.8%		3.9%

[13] Please note, the numbers are based on the peak load at a fixed hour of the day and may not necessarily be the same as the predicted annual peak.

Comparison of 2020 Forecast to 2019 Forecast

Figure 16 provides a comparison of this year's summer peak forecast to last year's.

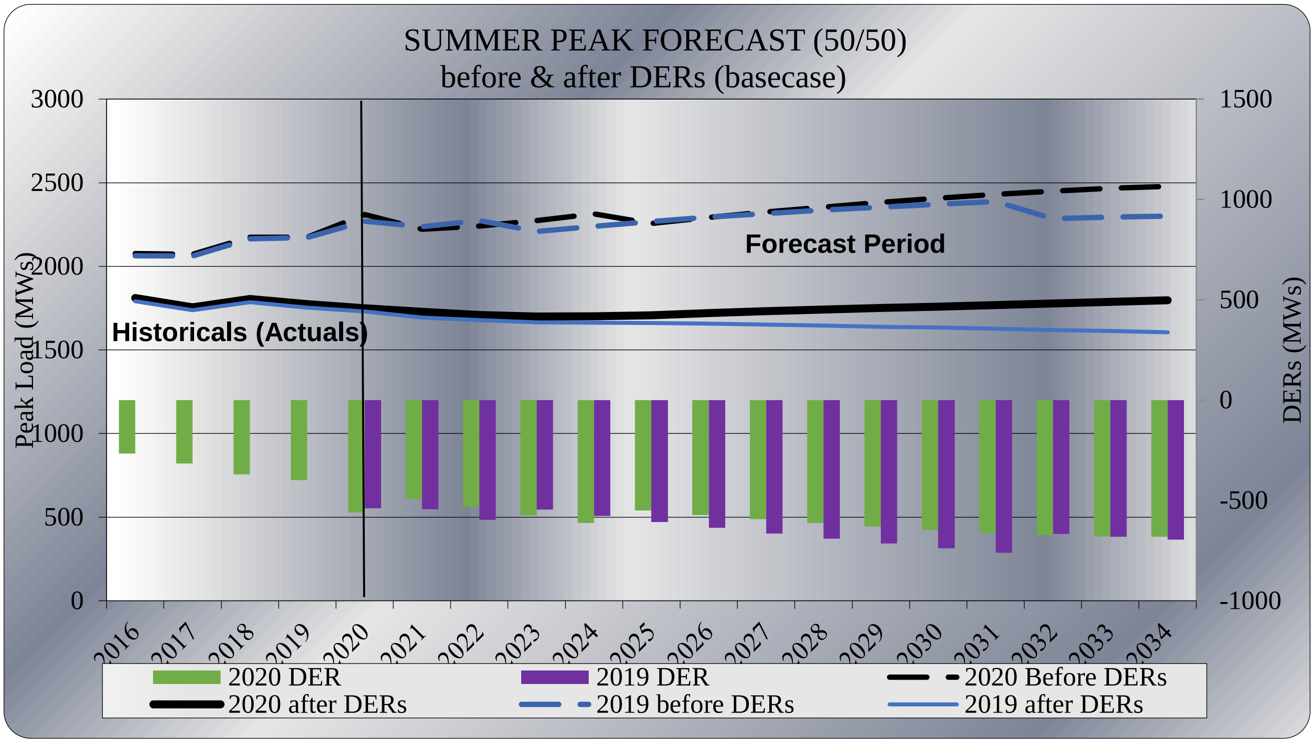


Figure 16 Comparison of current forecast to prior forecast, Gross and Net, Summer 50-50

Generally speaking, there is very little difference in the "Gross" forecasts (the forecast with the DERs reconstituted) in the first ten years. Only in the last five years do the two begin to differ. It is mainly due to the shift of the peak hour: they were predicted to be hour-ending 21 last year but are now predicted to be hour-ending 19.

For the "Net" forecast, there is no significant difference in the first five years, then the current forecast moves higher for the remainder of the planning period. The main reason for the higher net values is markedly more electric vehicles in the current forecast are expected than in the prior forecast that take hold in the late 2020's and into the 2030's.

Appendix A: Forecast Details

NECO
SUMMER Peaks

AFTER DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 90-10 (MW)	Extreme 90-10 (% Grwth)	Extreme 95-5 (MW)	Extreme 95-5 (% Grwth)	WTHI ACTUAL
2004	1,628		1,868		2,016		2,058		78.5
2005	1,805	10.8%	1,801	-3.6%	1,948	-3.4%	1,990	-3.3%	83.1
2006	1,985	10.0%	1,830	1.6%	1,962	0.7%	1,997	0.4%	85.9
2007	1,777	-10.5%	1,881	2.8%	2,030	3.5%	2,072	3.7%	80.9
2008	1,824	2.6%	1,845	-1.9%	1,987	-2.1%	2,027	-2.2%	82.9
2009	1,713	-6.1%	1,848	0.2%	2,012	1.3%	2,059	1.6%	80.3
2010	1,872	9.3%	1,831	-0.9%	1,994	-0.9%	2,040	-0.9%	84.5
2011	1,974	5.5%	1,850	1.0%	2,011	0.9%	2,056	0.8%	84.8
2012	1,892	-4.2%	1,852	0.1%	2,000	-0.5%	2,042	-0.7%	83.5
2013	1,965	3.9%	1,850	-0.1%	2,010	0.5%	2,056	0.7%	84.7
2014	1,653	-15.9%	1,843	-0.4%	2,006	-0.2%	2,052	-0.2%	80.4
2015	1,738	5.1%	1,885	2.3%	2,062	2.8%	2,112	2.9%	80.4
2016	1,803	3.8%	1,810	-4.0%	1,972	-4.4%	2,018	-4.5%	82.6
2017	1,688	-6.4%	1,756	-3.0%	1,918	-2.7%	1,964	-2.7%	81.7
2018	1,847	9.4%	1,805	2.8%	1,968	2.6%	2,015	2.6%	83.4
2019	1,750	-5.3%	1,775	-1.7%	1,967	-0.1%	2,021	0.3%	84.5
2020	1,855	6.0%	1,749	-1.5%	1,911	-2.8%	1,957	-3.2%	84.7
2021	-	-	1,728	-1.2%	1,891	-1.1%	1,937	-1.0%	-
2022	-	-	1,709	-1.1%	1,873	-1.0%	1,919	-0.9%	-
2023	-	-	1,700	-0.5%	1,867	-0.3%	1,914	-0.3%	-
2024	-	-	1,702	0.1%	1,872	0.3%	1,921	0.4%	-
2025	-	-	1,708	0.3%	1,882	0.5%	1,931	0.5%	-
2026	-	-	1,721	0.8%	1,891	0.5%	1,939	0.4%	-
2027	-	-	1,732	0.7%	1,905	0.8%	1,954	0.8%	-
2028	-	-	1,742	0.6%	1,918	0.7%	1,968	0.7%	-
2029	-	-	1,751	0.5%	1,929	0.6%	1,980	0.6%	-
2030	-	-	1,760	0.5%	1,940	0.6%	1,991	0.6%	-
2031	-	-	1,768	0.5%	1,951	0.6%	2,003	0.6%	-
2032	-	-	1,778	0.5%	1,962	0.6%	2,015	0.6%	-
2033	-	-	1,788	0.6%	1,974	0.6%	2,027	0.6%	-
2034	-	-	1,797	0.5%	1,984	0.5%	2,037	0.5%	-
2035	-	-	1,808	0.6%	1,996	0.6%	2,049	0.6%	-

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg, last 15 yrs	-0.2%	-0.1%	-0.1%
Avg. last 10 yrs	-0.5%	-0.4%	-0.4%
Avg. last 5 yrs	-1.5%	-1.5%	-1.5%
BASE 2019			
Avg. next 5 yrs	-0.5%	-0.3%	-0.3%
Avg. next 10 yrs	0.1%	0.2%	0.2%
Avg. next 15 yrs	0.2%	0.3%	0.3%

WTHI

NORMAL	82.8
EXTREME 90/10	85.4
EXTREME 95/5	86.1

**** impacts include energy efficiency, solar pv, electric vehicles, energy storage and company demand response***

NECO — SUMMER 50/50 Peaks (MW) (before & after DERs)

	SYSTEM PEAK								DER IMPACTS						
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2004	1,890	1,868	1,890	1,890	1,890	1,890	1,890	**1,868**	(21)	(0)	0.0	0.0	0.0	0.0	(21)
2005	1,832	1,801	1,832	1,832	1,832	1,832	1,832	**1,801**	(30)	(0)	0.0	0.0	0.0	0.0	(30)
2006	1,872	1,831	1,871	1,872	1,872	1,872	1,872	**1,830**	(41)	(0)	0.0	0.0	0.0	0.0	(41)
2007	1,932	1,882	1,932	1,932	1,932	1,932	1,932	**1,881**	(51)	(0)	0.0	0.0	0.0	0.0	(51)
2008	1,907	1,845	1,906	1,907	1,907	1,907	1,907	**1,845**	(61)	(0)	0.0	0.0	0.0	0.0	(62)
2009	1,925	1,849	1,925	1,925	1,925	1,925	1,925	**1,848**	(77)	(0)	0.0	0.0	0.0	0.0	(77)
2010	1,920	1,832	1,920	1,920	1,920	1,920	1,920	**1,831**	(89)	(1)	0.0	0.0	0.0	0.0	(89)
2011	1,952	1,851	1,951	1,952	1,952	1,952	1,952	**1,850**	(102)	(1)	0.0	0.0	0.0	0.0	(102)
2012	1,974	1,854	1,973	1,975	1,974	1,974	1,974	**1,852**	(121)	(2)	0.0	0.0	0.0	0.0	(122)
2013	2,005	1,857	1,997	2,005	2,005	2,005	2,005	**1,850**	(148)	(7)	0.1	0.0	0.0	0.0	(155)
2014	2,038	1,851	2,030	2,038	2,038	2,038	2,038	**1,843**	(187)	(8)	0.2	0.0	0.0	0.0	(195)
2015	2,118	1,898	2,105	2,118	2,118	2,118	2,118	**1,885**	(220)	(13)	0.2	0.0	0.0	0.0	(233)
2016	2,077	1,827	2,060	2,078	2,077	2,077	2,077	**1,810**	(250)	(17)	0.3	(0.1)	0.0	0.0	(267)
2017	2,072	1,792	2,043	2,072	2,064	2,072	2,072	**1,756**	(280)	(28)	0.5	(8.3)	0.0	0.0	(316)
2018	2,175	1,866	2,135	2,176	2,152	2,175	2,175	**1,805**	(309)	(40)	0.8	(22.7)	0.0	(0.1)	(370)
2019	2,174	1,835	2,139	2,175	2,146	2,174	2,173	**1,775**	(338)	(35)	1.4	(27.5)	0.0	(0.2)	(399)
2020	2,309	1,948	2,138	2,310	2,280	2,309	2,309	**1,749**	(361)	(171)	1.1	(29.4)	0.0	(0.4)	(560)
2021	2,222	1,836	2,160	2,224	2,175	2,222	2,221	**1,728**	(386)	(61)	2.0	(47.3)	0.0	(0.7)	(493)
2022	2,242	1,833	2,164	2,244	2,193	2,242	2,241	**1,709**	(408)	(77)	2.4	(48.8)	0.0	(1.1)	(533)
2023	2,274	1,844	2,181	2,277	2,222	2,274	2,272	**1,700**	(430)	(93)	3.1	(52.0)	0.0	(1.8)	(574)
2024	2,314	1,864	2,206	2,318	2,259	2,314	2,311	**1,702**	(450)	(108)	4.1	(55.1)	0.0	(2.8)	(612)
2025	2,257	1,787	2,230	2,264	2,202	2,257	2,253	**1,708**	(470)	(27)	6.4	(55.1)	0.0	(3.9)	(550)
2026	2,293	1,803	2,262	2,302	2,238	2,293	2,287	**1,721**	(490)	(30)	8.8	(55.1)	0.0	(5.9)	(572)
2027	2,325	1,817	2,292	2,337	2,270	2,325	2,316	**1,732**	(508)	(33)	12.0	(55.1)	0.0	(9.0)	(593)
2028	2,354	1,831	2,318	2,371	2,299	2,354	2,341	**1,742**	(524)	(36)	16.3	(55.1)	0.0	(13.6)	(612)
2029	2,382	1,844	2,343	2,404	2,327	2,382	2,361	**1,751**	(538)	(39)	21.7	(55.1)	0.0	(20.6)	(631)
2030	2,408	1,857	2,367	2,437	2,353	2,408	2,378	**1,760**	(551)	(41)	28.8	(55.1)	0.0	(29.6)	(648)
2031	2,430	1,868	2,387	2,468	2,375	2,430	2,392	**1,768**	(563)	(43)	37.9	(55.1)	0.0	(38.6)	(662)
2032	2,450	1,877	2,405	2,499	2,395	2,450	2,403	**1,778**	(574)	(46)	48.9	(55.1)	0.0	(47.1)	(672)
2033	2,467	1,884	2,419	2,529	2,412	2,467	2,412	**1,788**	(583)	(48)	62.0	(55.1)	0.0	(55.1)	(679)
2034	2,478	1,887	2,428	2,555	2,423	2,478	2,416	**1,797**	(592)	(50)	77.3	(55.1)	0.0	(62.3)	(681)
2035	2,488	1,889	2,436	2,583	2,433	2,488	2,419	**1,808**	(599)	(52)	94.8	(55.1)	0.0	(68.8)	(680)

Avg, last 15 yrs	1.6%	0.5%	1.0%	1.6%	1.5%	1.6%	1.6%	**-0.2%**
Avg. last 10 yrs	1.9%	0.6%	1.1%	1.9%	1.7%	1.9%	1.9%	**-0.5%**
Avg. last 5 yrs	1.7%	0.5%	0.3%	1.8%	1.5%	1.7%	1.7%	**-1.5%**
BASE 2019								
Avg. next 5 yrs	-0.5%	-1.7%	0.8%	-0.4%	-0.7%	-0.5%	-0.5%	**-0.5%**
Avg. next 10 yrs	0.4%	-0.5%	1.0%	0.5%	0.3%	0.4%	0.3%	**0.1%**
Avg. next 15 yrs	0.5%	-0.2%	0.9%	0.7%	0.4%	0.5%	0.3%	**0.2%**

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
EH: Electric Heating Pump Cooling (reduces load)

NECO
WINTER Peaks

after DER Impacts *

YEAR	Actuals (MW)	Actuals (% Grwth)	Normal 50-50 (MW)	Normal 50-50 (% Grwth)	Extreme 10-90 (MW)	Extreme 10-90 (% Grwth)	Extreme 05-95 (MW)	Extreme 05-95 (% Grwth)	HDD_wtd ACTUAL
2004	1,394		1,433		1,481		1,494		36.7
2005	1,329	-4.6%	1,329	-7.3%	1,373	-7.3%	1,385	-7.3%	45.0
2006	1,329	0.0%	1,322	-0.5%	1,366	-0.5%	1,379	-0.5%	45.5
2007	1,352	1.7%	1,332	0.8%	1,375	0.7%	1,387	0.6%	44.8
2008	1,305	-3.5%	1,322	-0.8%	1,369	-0.5%	1,382	-0.4%	40.0
2009	1,294	-0.8%	1,334	0.9%	1,383	1.1%	1,397	1.1%	35.0
2010	1,315	1.6%	1,268	-4.9%	1,323	-4.4%	1,338	-4.2%	53.1
2011	1,243	-5.5%	1,256	-1.0%	1,306	-1.3%	1,320	-1.4%	41.6
2012	1,320	6.2%	1,295	3.1%	1,344	3.0%	1,358	2.9%	51.9
2013	1,328	0.7%	1,329	2.6%	1,379	2.6%	1,394	2.6%	43.9
2014	1,275	-4.0%	1,232	-7.3%	1,287	-6.7%	1,303	-6.5%	52.2
2015	1,223	-4.1%	1,205	-2.2%	1,252	-2.7%	1,265	-2.9%	55.0
2016	1,239	1.3%	1,284	6.5%	1,340	7.1%	1,356	7.2%	35.9
2017	1,277	3.1%	1,210	-5.7%	1,282	-4.3%	1,303	-3.9%	53.8
2018	1,301	1.9%	1,255	3.7%	1,318	2.8%	1,336	2.5%	51.0
2019	1,183	-9.1%	1,195	-4.7%	1,260	-4.4%	1,279	-4.3%	42.4
2020	-	-	1,190	-0.4%	1,257	-0.3%	1,276	-0.2%	-
2021	-	-	1,177	-1.1%	1,245	-0.9%	1,265	-0.9%	-
2022	-	-	1,169	-0.7%	1,239	-0.5%	1,258	-0.5%	-
2023	-	-	1,162	-0.6%	1,233	-0.4%	1,254	-0.4%	-
2024	-	-	1,159	-0.2%	1,232	-0.1%	1,253	-0.1%	-
2025	-	-	1,160	0.0%	1,234	0.1%	1,255	0.2%	-
2026	-	-	1,163	0.3%	1,239	0.4%	1,261	0.5%	-
2027	-	-	1,175	1.0%	1,253	1.1%	1,275	1.1%	-
2028	-	-	1,198	1.9%	1,276	1.9%	1,299	1.9%	-
2029	-	-	1,233	3.0%	1,314	2.9%	1,337	2.9%	-
2030	-	-	1,283	4.0%	1,365	3.9%	1,388	3.8%	-
2031	-	-	1,335	4.1%	1,419	4.0%	1,443	3.9%	-
2032	-	-	1,390	4.1%	1,475	4.0%	1,499	3.9%	-
2033	-	-	1,446	4.0%	1,533	3.9%	1,557	3.9%	-
2034	-	-	1,503	3.9%	1,591	3.8%	1,616	3.8%	-

	Normal 50-50	Extreme 10-90	Extreme 05-95
Avg, last 15 yrs	-1.2%	-1.1%	-1.0%
Avg. last 10 yrs	-1.1%	-0.9%	-0.9%
Avg. last 5 yrs	-0.6%	-0.4%	-0.4%
BASE 2018			
Avg. next 5 yrs	-0.6%	-0.4%	-0.4%
Avg. next 10 yrs	0.3%	0.4%	0.4%
Avg. next 14 yrs	1.6%	1.7%	1.7%

HDD_wtd

NORMAL	44.3
EXTREME 90/10	54.5
EXTREME 95/5	57.4

**** impacts include energy efficiency, solar pv, electric vehicles, energy storage and company demand response***
(solar and demand response are zero at times of winter peak)

NECO	WINTER 50/50 Peaks (MW) (before & after DERs)														
	SYSTEM PEAK								DER IMPACTS						
Calendar Year	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)	EE	PV	EV	DR	ES	EH	DER
2004	1,455	1,433	1,455	1,455	1,455	1,455	1,455	**1,433**	(22)	0	0.0	0.0	0.0	0.0	(22)
2005	1,363	1,329	1,363	1,363	1,363	1,363	1,363	**1,329**	(35)	0	0.0	0.0	0.0	0.0	(35)
2006	1,368	1,322	1,368	1,368	1,368	1,368	1,368	**1,322**	(46)	0	0.0	0.0	0.0	0.0	(46)
2007	1,388	1,332	1,388	1,388	1,388	1,388	1,388	**1,332**	(56)	0	0.0	0.0	0.0	0.0	(56)
2008	1,387	1,322	1,387	1,387	1,387	1,387	1,387	**1,322**	(66)	0	0.0	0.0	0.0	0.0	(65)
2009	1,413	1,334	1,413	1,413	1,413	1,413	1,413	**1,334**	(79)	0	0.0	0.0	0.0	0.0	(79)
2010	1,359	1,268	1,359	1,359	1,359	1,359	1,359	**1,268**	(91)	0	0.0	0.0	0.0	0.0	(91)
2011	1,360	1,256	1,360	1,360	1,360	1,360	1,360	**1,256**	(104)	0	0.0	0.0	0.0	0.0	(104)
2012	1,418	1,295	1,418	1,419	1,418	1,418	1,418	**1,295**	(124)	0	0.1	0.0	0.0	0.0	(123)
2013	1,482	1,329	1,482	1,482	1,482	1,482	1,482	**1,329**	(153)	0	0.1	0.0	0.0	0.0	(153)
2014	1,431	1,232	1,431	1,431	1,431	1,431	1,431	**1,232**	(199)	0	0.3	0.0	0.0	0.0	(199)
2015	1,439	1,205	1,439	1,439	1,439	1,439	1,439	**1,205**	(234)	0	0.5	0.0	0.0	0.0	(233)
2016	1,549	1,283	1,549	1,549	1,549	1,549	1,549	**1,284**	(266)	0	0.6	0.0	0.0	0.0	(265)
2017	1,508	1,209	1,508	1,509	1,508	1,508	1,508	**1,210**	(299)	0	1.1	0.0	0.0	0.0	(298)
2018	1,583	1,253	1,583	1,584	1,583	1,583	1,583	**1,255**	(330)	0	1.4	0.0	0.0	0.2	(328)
2019	1,550	1,193	1,550	1,553	1,550	1,550	1,551	**1,195**	(358)	0	2.1	0.0	0.0	0.6	(355)
2020	1,566	1,186	1,566	1,568	1,566	1,566	1,567	**1,190**	(379)	0	2.5	0.0	0.0	1.4	(375)
2021	1,581	1,172	1,581	1,584	1,581	1,581	1,583	**1,177**	(409)	0	3.0	0.0	0.0	2.6	(403)
2022	1,595	1,161	1,595	1,599	1,595	1,595	1,600	**1,169**	(435)	0	3.7	0.0	0.0	4.4	(426)
2023	1,610	1,150	1,610	1,615	1,610	1,610	1,618	**1,162**	(460)	0	4.7	0.0	0.0	7.2	(448)
2024	1,625	1,142	1,625	1,632	1,625	1,625	1,637	**1,159**	(483)	0	6.2	0.0	0.0	11.2	(466)
2025	1,640	1,134	1,640	1,649	1,640	1,640	1,658	**1,160**	(506)	0	8.3	0.0	0.0	17.2	(481)
2026	1,655	1,126	1,655	1,667	1,655	1,655	1,682	**1,163**	(530)	0	11.3	0.0	0.0	26.4	(492)
2027	1,670	1,120	1,670	1,686	1,670	1,670	1,710	**1,175**	(550)	0	15.4	0.0	0.0	40.0	(495)
2028	1,685	1,116	1,685	1,706	1,685	1,685	1,746	**1,198**	(569)	0	20.9	0.0	0.0	60.6	(488)
2029	1,700	1,114	1,700	1,728	1,700	1,700	1,792	**1,233**	(586)	0	27.9	0.0	0.0	91.4	(467)
2030	1,715	1,114	1,715	1,752	1,715	1,715	1,847	**1,283**	(601)	0	37.0	0.0	0.0	131.7	(433)
2031	1,730	1,115	1,730	1,779	1,730	1,730	1,902	**1,335**	(615)	0	48.7	0.0	0.0	171.5	(395)
2032	1,745	1,118	1,745	1,808	1,745	1,745	1,955	**1,390**	(627)	0	62.8	0.0	0.0	209.5	(355)
2033	1,760	1,122	1,760	1,840	1,760	1,760	2,005	**1,446**	(638)	0	79.6	0.0	0.0	244.7	(314)
2034	1,775	1,127	1,775	1,874	1,775	1,775	2,052	**1,503**	(648)	0	99.2	0.0	0.0	276.8	(272)

	Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Forecast w/ EH only	Final Forecast (after all DER)
	-							
Avg, last 15 yrs	0.4%	-1.2%	0.4%	0.4%	0.4%	0.4%	0.4%	**-1.2%**
Avg. last 10 yrs	0.9%	-1.1%	0.9%	0.9%	0.9%	0.9%	0.9%	**-1.1%**
Avg. last 5 yrs	1.6%	-0.7%	1.6%	1.6%	1.6%	1.6%	1.6%	**-0.6%**
BASE 2019								
Avg. next 5 yrs	0.9%	-0.9%	0.9%	1.0%	0.9%	0.9%	1.1%	**-0.6%**
Avg. next 10 yrs	0.9%	-0.7%	0.9%	1.1%	0.9%	0.9%	1.5%	**0.3%**
Avg. next 15 yrs	0.9%	-0.4%	0.9%	1.3%	0.9%	0.9%	1.9%	**1.5%**

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
EH: Electric Heating/Cooling (ADDs to load)

Appendix B: Historical Peaks Days and Hours

Summer Peaks

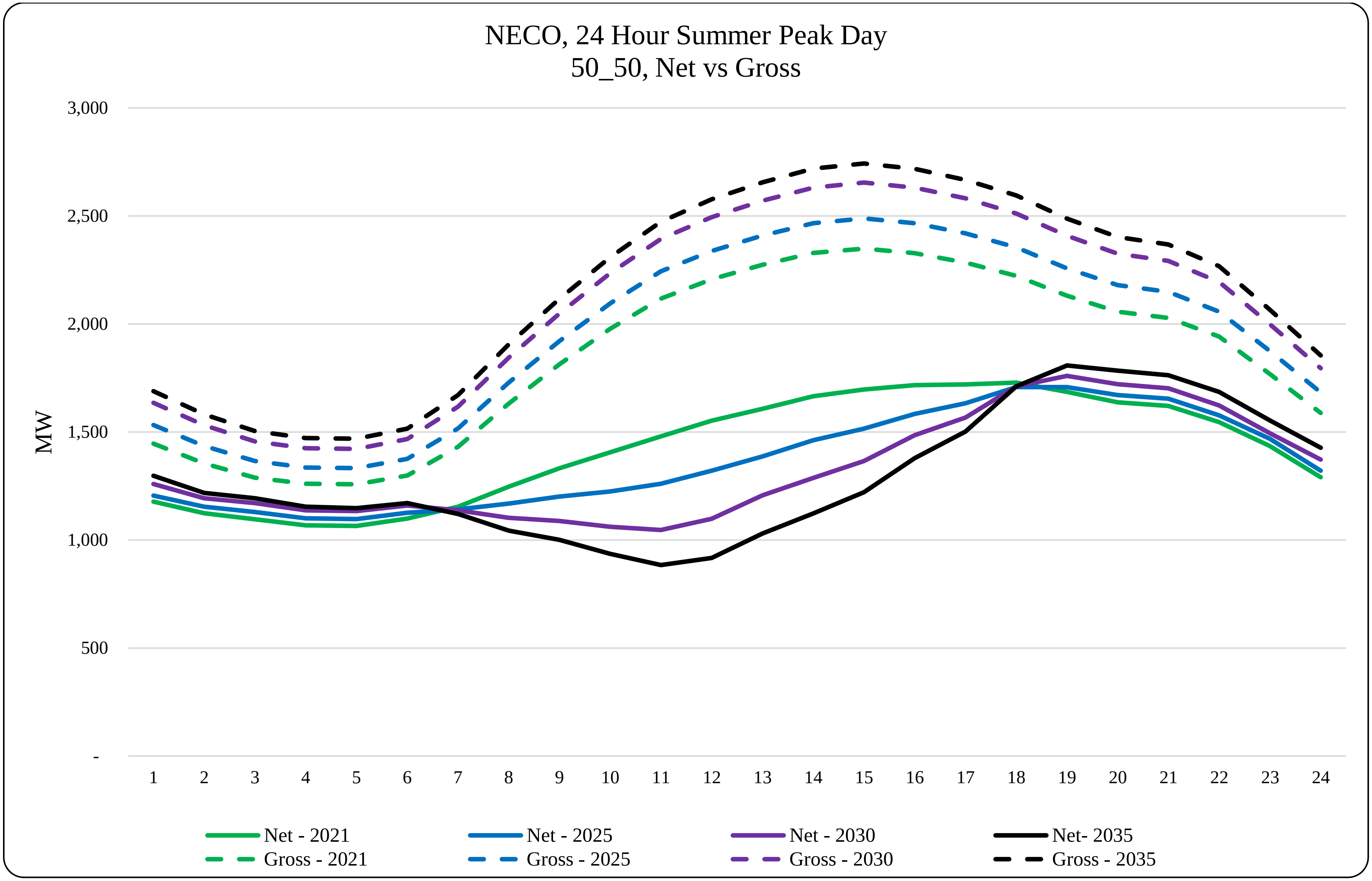
year	date	hour
2003	8/22/2003	15
2004	8/30/2004	15
2005	8/5/2005	15
2006	8/2/2006	15
2007	8/3/2007	15
2008	6/10/2008	15
2009	8/18/2009	15
2010	7/6/2010	15
2011	7/22/2011	16
2012	7/18/2012	15
2013	7/19/2013	15
2014	9/2/2014	16
2015	7/20/2015	15
2016	8/12/2016	16
2017	7/20/2017	16
2018	8/29/2018	17
2019	7/21/2019	18
2020	7/28/2020	15

Winter Peaks

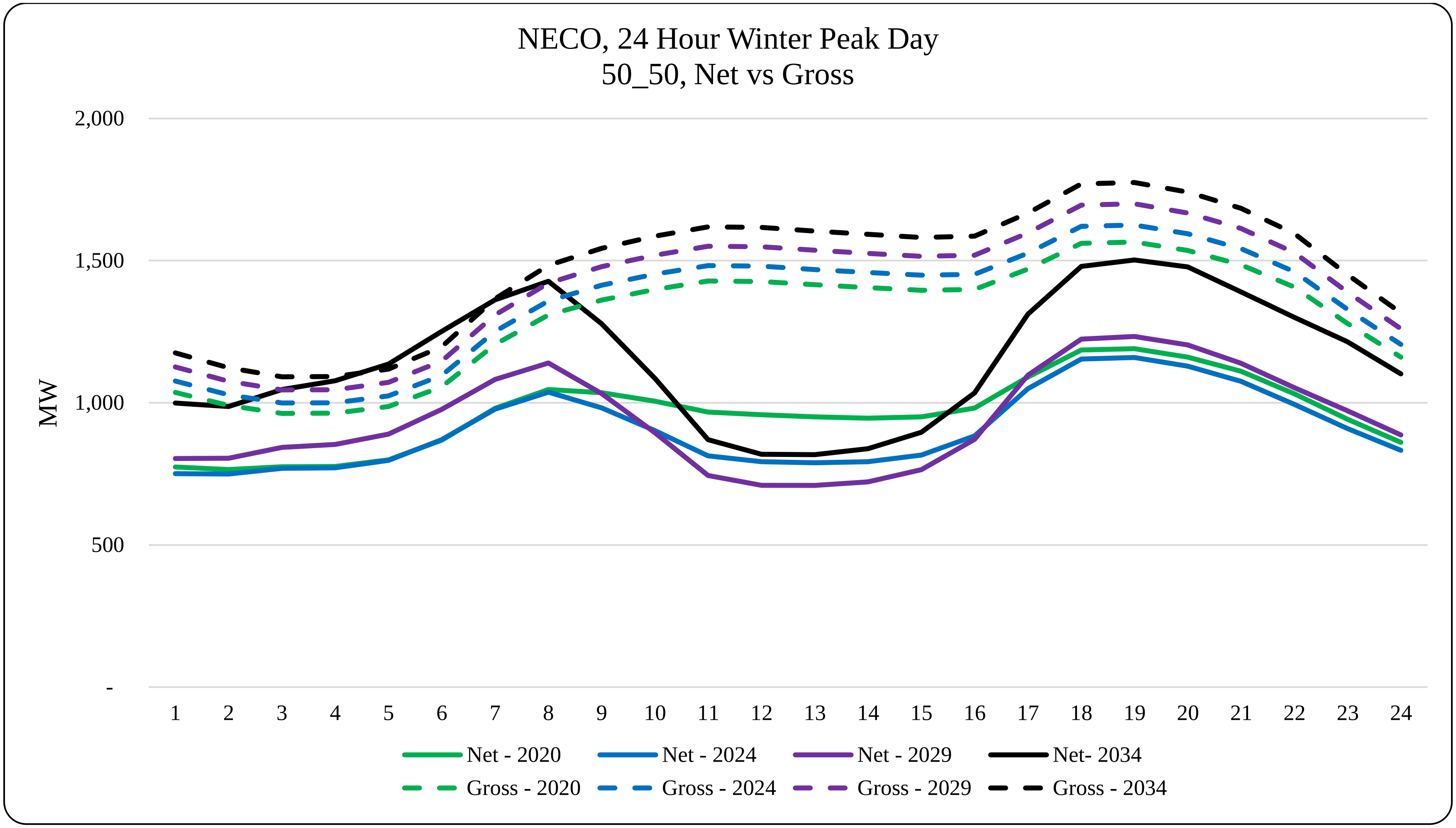
year	date	hour
2003	1/15/2004	19
2004	12/20/2004	19
2005	12/14/2005	18
2006	2/5/2007	19
2007	1/3/2008	19
2008	12/8/2008	18
2009	12/29/2009	19
2010	1/24/2011	19
2011	1/4/2012	18
2012	1/24/2013	19
2013	12/17/2013	18
2014	1/8/2015	18
2015	2/15/2016	19
2016	12/15/2016	18
2017	1/2/2018	19
2018	1/21/2019	18
2019	12/19/2019	19

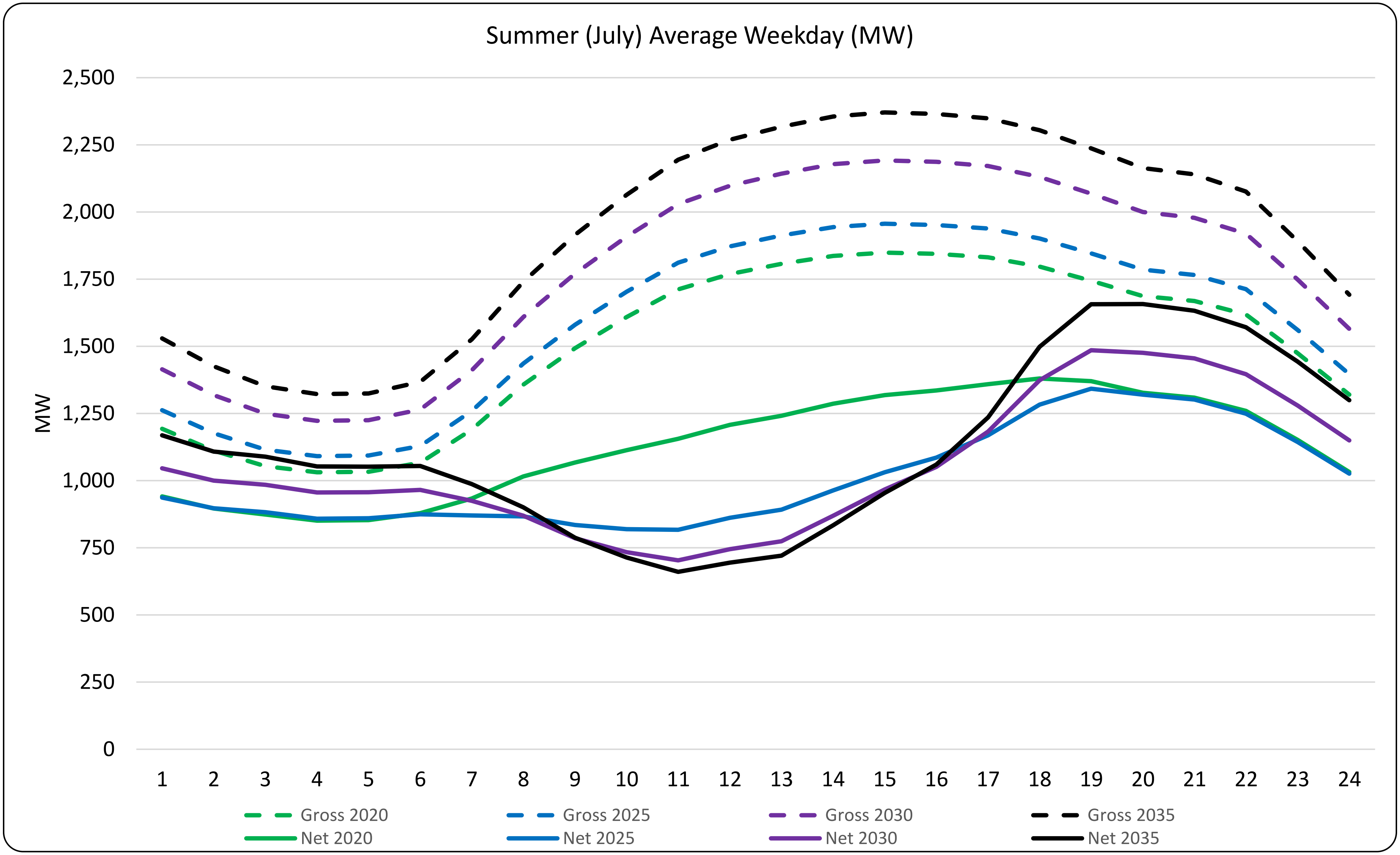
Appendix C: Load Shapes for Typical Day Types

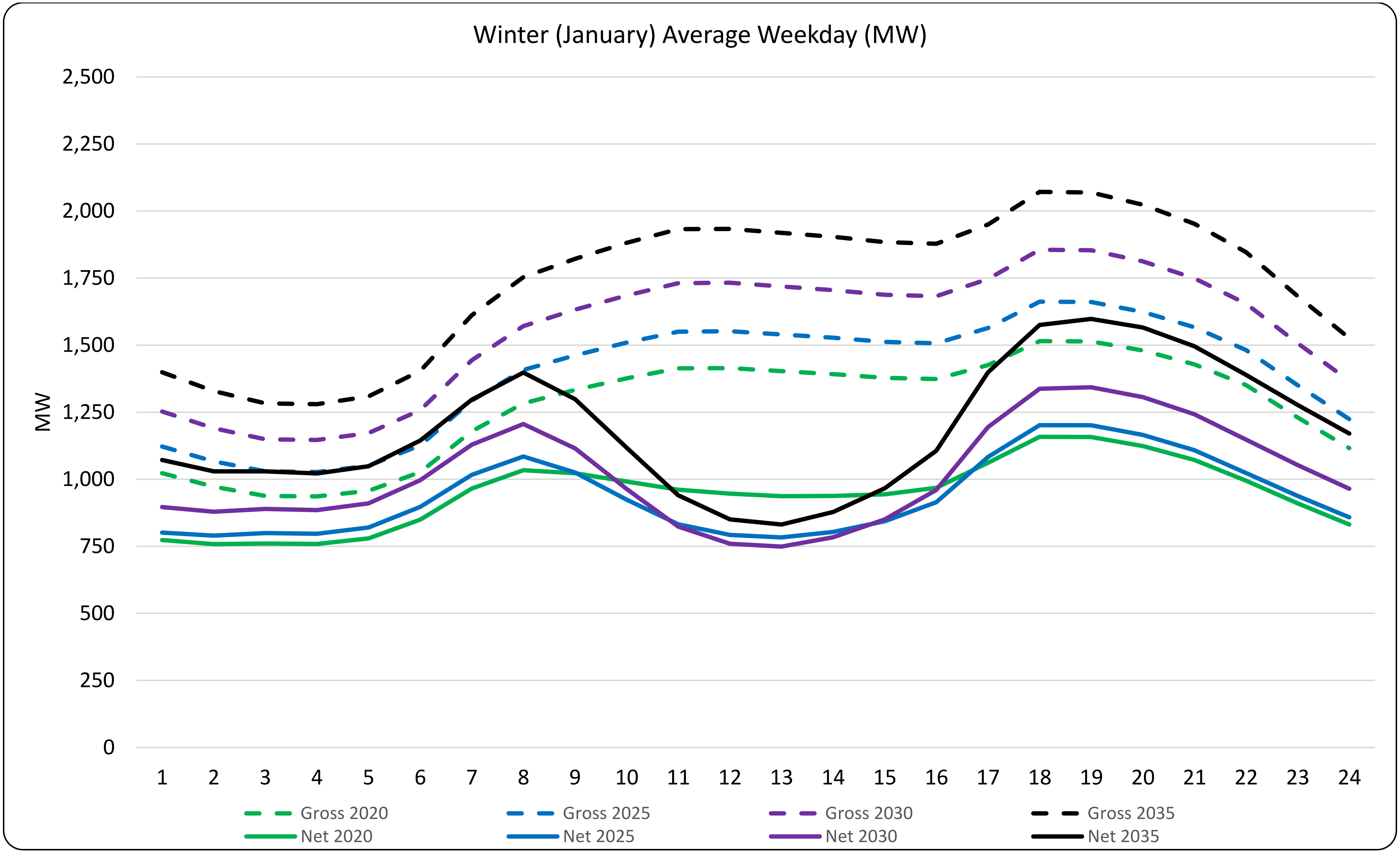
(for Base Case)

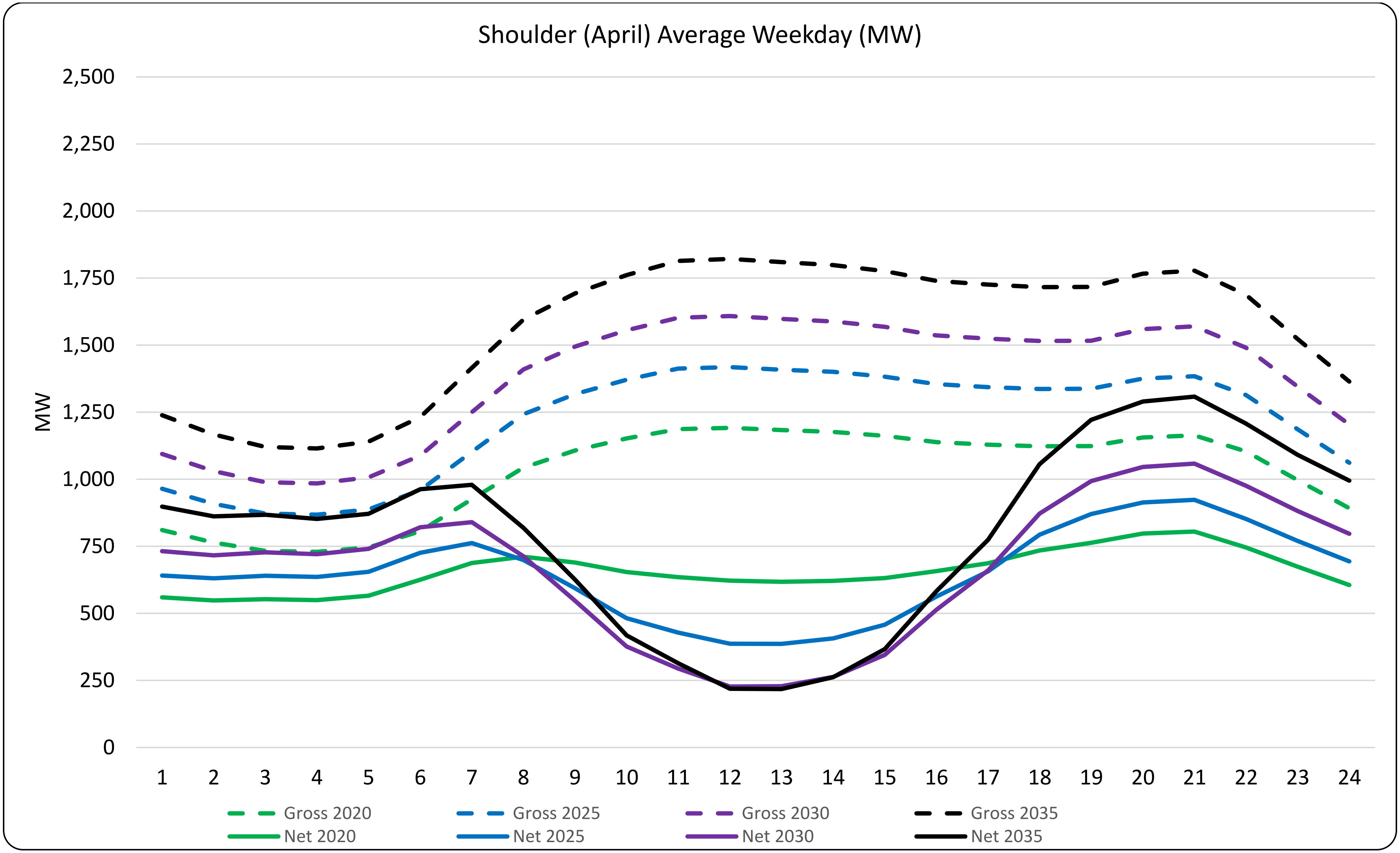


NECO, 24 Hour Summer Peak Day
50_50, Net vs Gross
MW
3,000
2,500
2,000
1,500
1,000
500
-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Net - 2021
Net - 2025
Net - 2030
Net- 2035
Gross - 2021
Gross - 2025
Gross - 2030
Gross - 2035

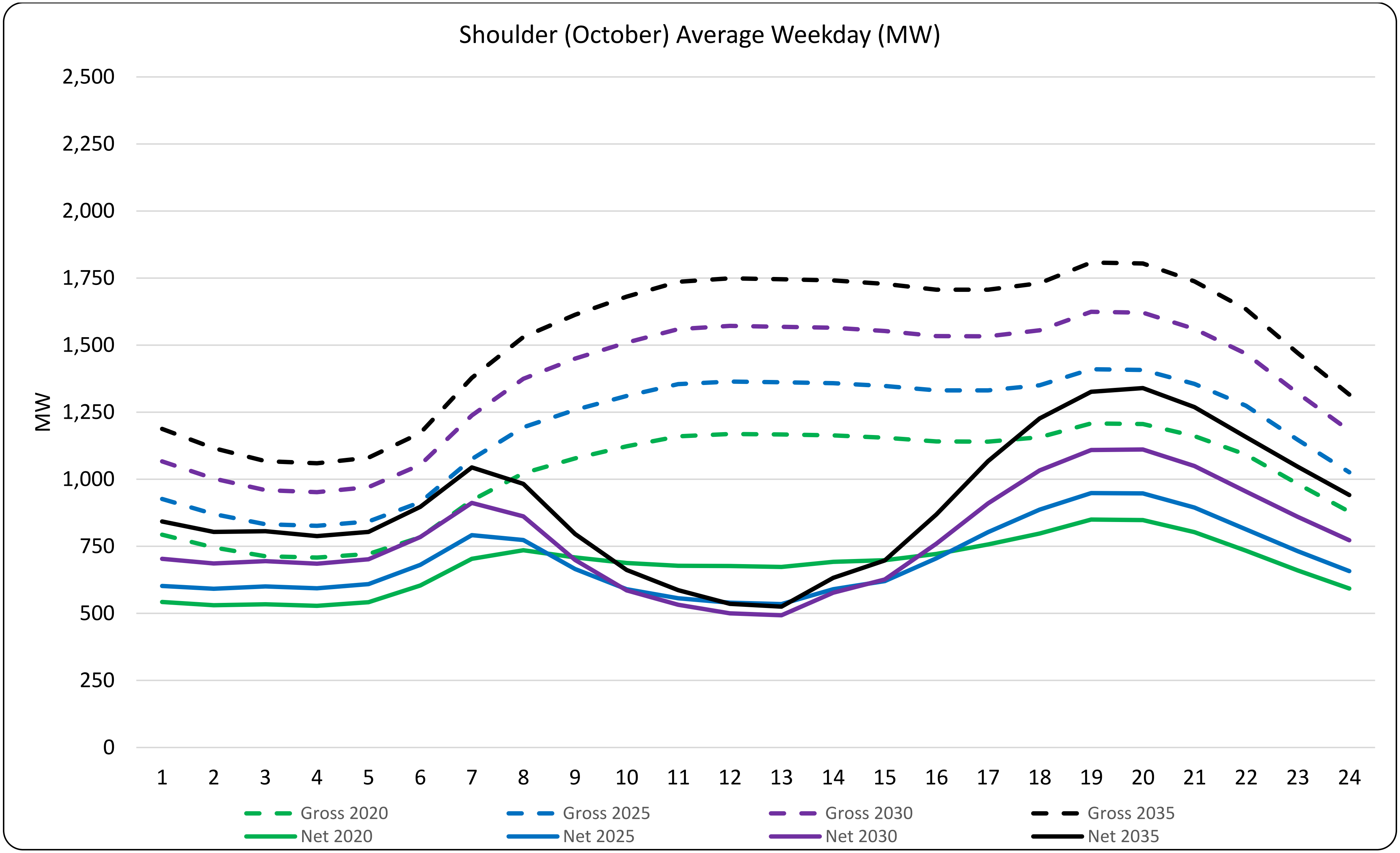

NECO, 24 Hour Winter Peak Day
50_50, Net vs Gross
MW
2,000
1,500
1,000
500
-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Net - 2020
Net - 2024
Net - 2029
Net- 2034
Gross - 2020
Gross - 2024
Gross - 2029
Gross - 2034


Summer (July) Average Weekday (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2020
Gross 2025
Gross 2030
Gross 2035
Net 2020
Net 2025
Net 2030
Net 2035

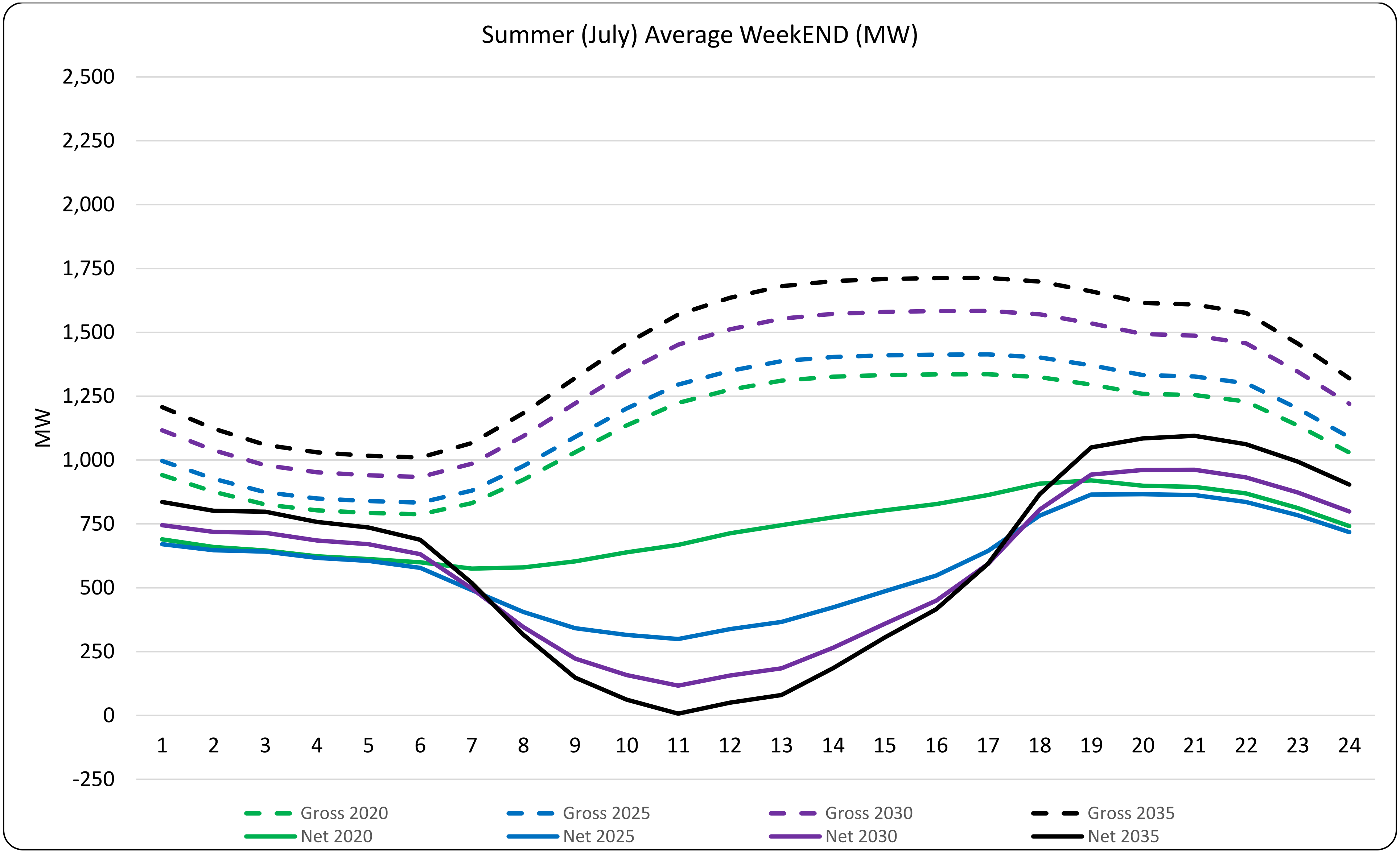

Winter (January) Average Weekday (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2020
Gross 2025
Gross 2030
Gross 2035
Net 2020
Net 2025
Net 2030
Net 2035

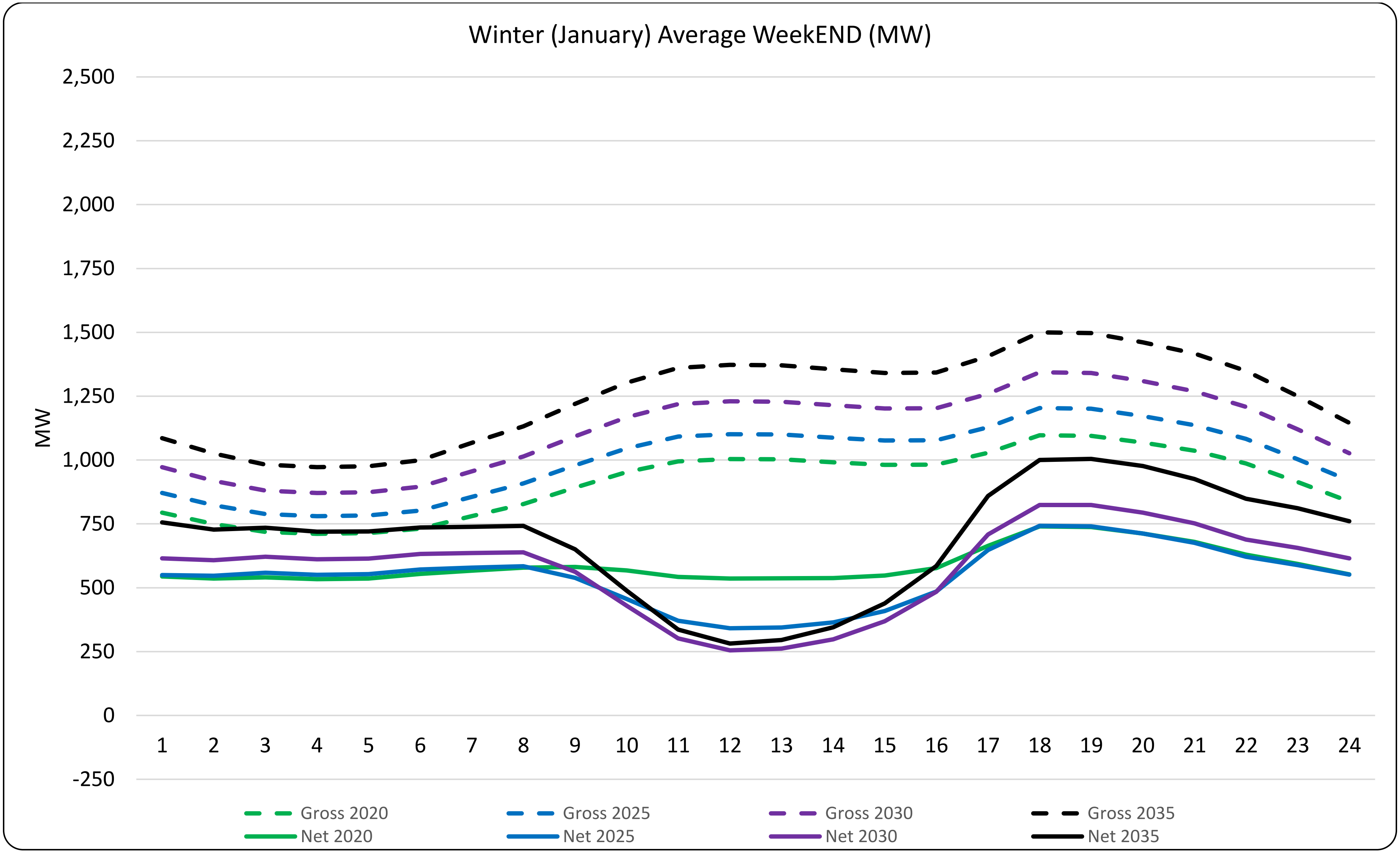


Shoulder (April) Average Weekday (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2020
Gross 2025
Gross 2030
Gross 2035
Net 2020
Net 2025
Net 2030
Net 2035

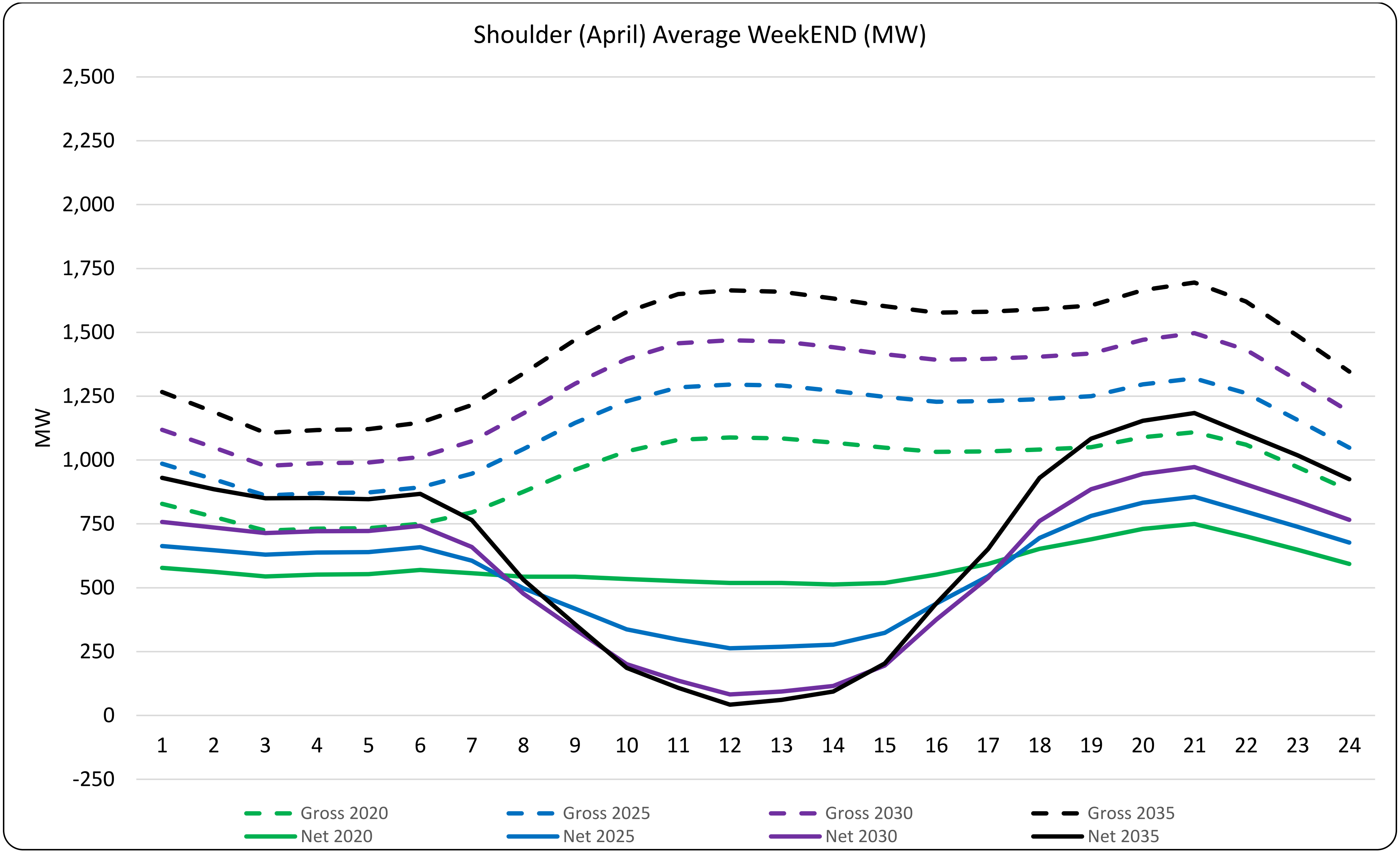


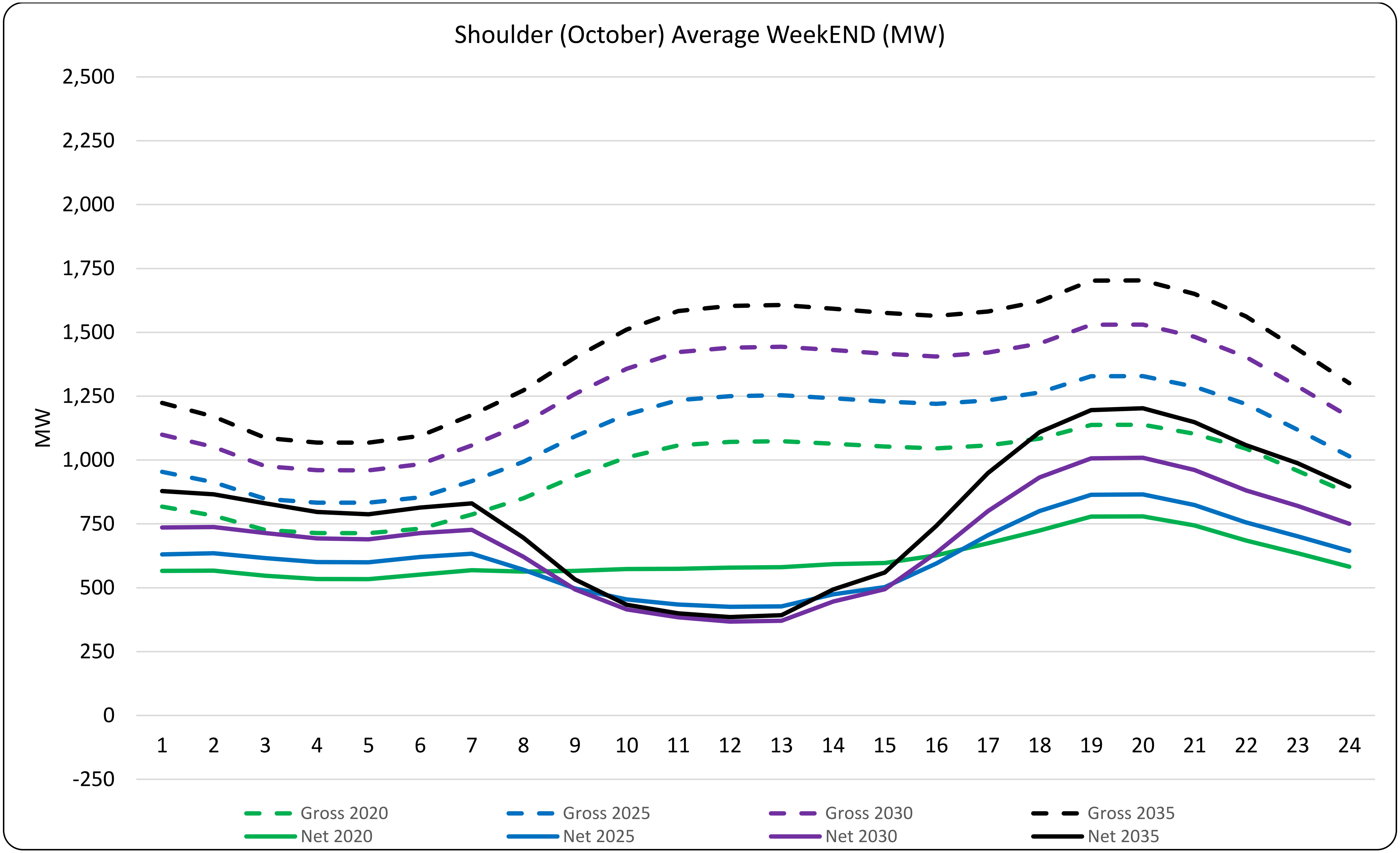
Shoulder (October) Average Weekday (MW)
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Gross 2020
Gross 2025
Gross 2030
Gross 2035
Net 2020
Net 2025
Net 2030
Net 2035


Summer (July) Average WeekEND (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
-250
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2020
Gross 2025
Gross 2030
Gross 2035
Net 2020
Net 2025
Net 2030
Net 2035



Winter (January) Average WeekEND (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
-250
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2020
Gross 2025
Gross 2030
Gross 2035
Net 2020
Net 2025
Net 2030
Net 2035


Shoulder (April) Average WeekEND (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
-250
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Gross 2020
Gross 2025
Gross 2030
Gross 2035
Net 2020
Net 2025
Net 2030
Net 2035

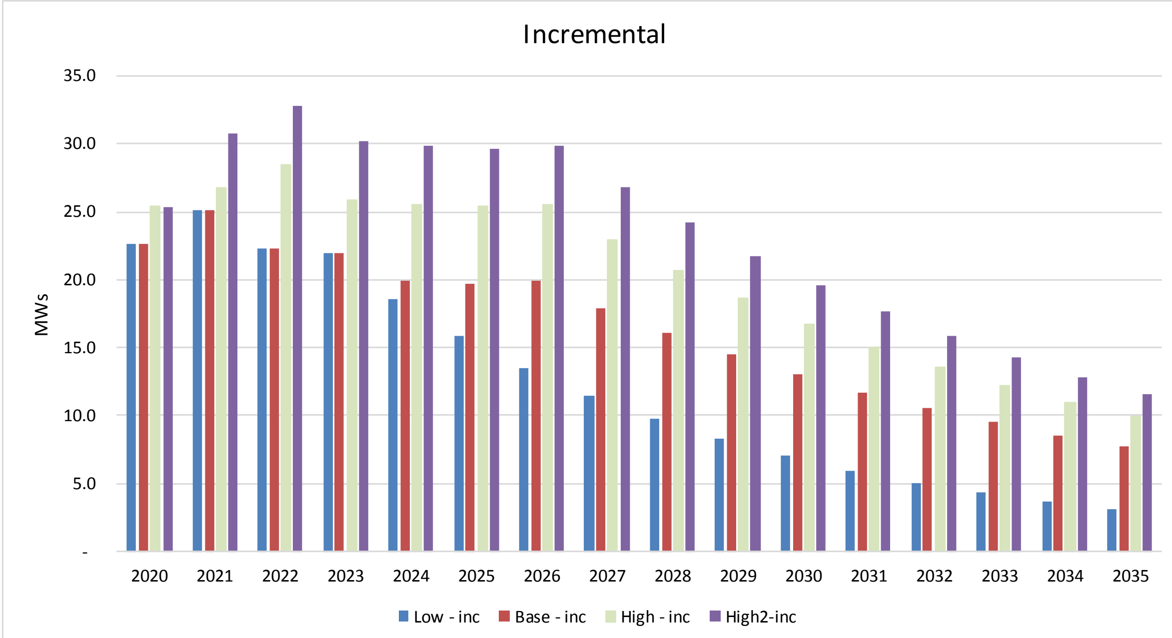


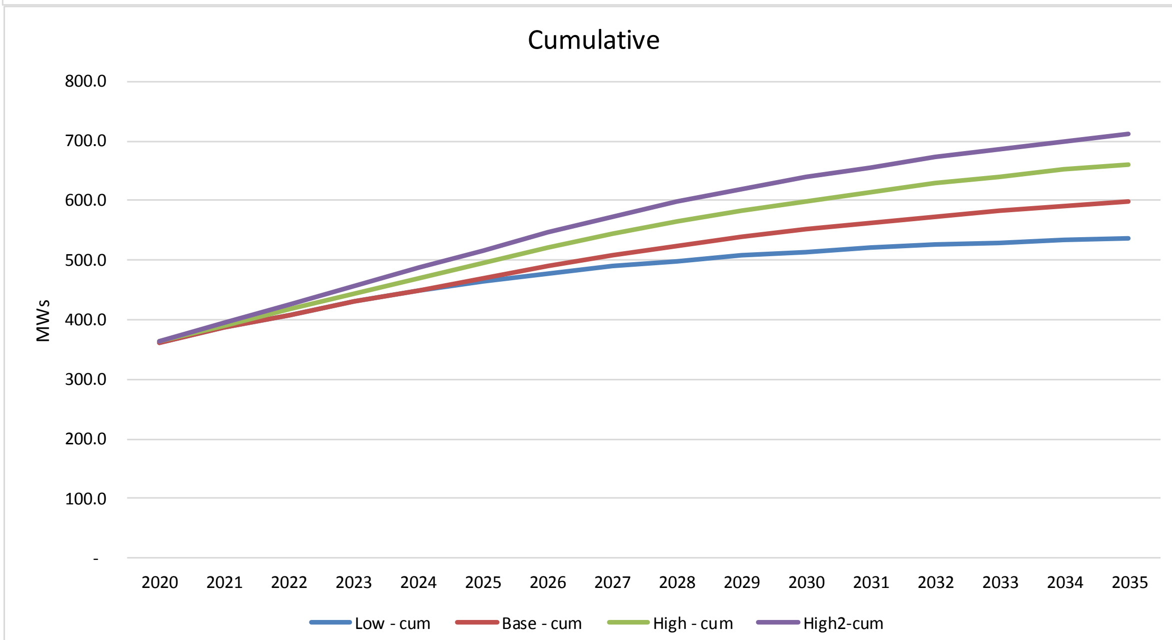
Shoulder (October) Average WeekEND (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
-250
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2020
Gross 2025
Gross 2030
Gross 2035
Net 2020
Net 2025
Net 2030
Net 2035

Appendix D: DER Scenarios Inputs

Energy Efficiency (NECO)

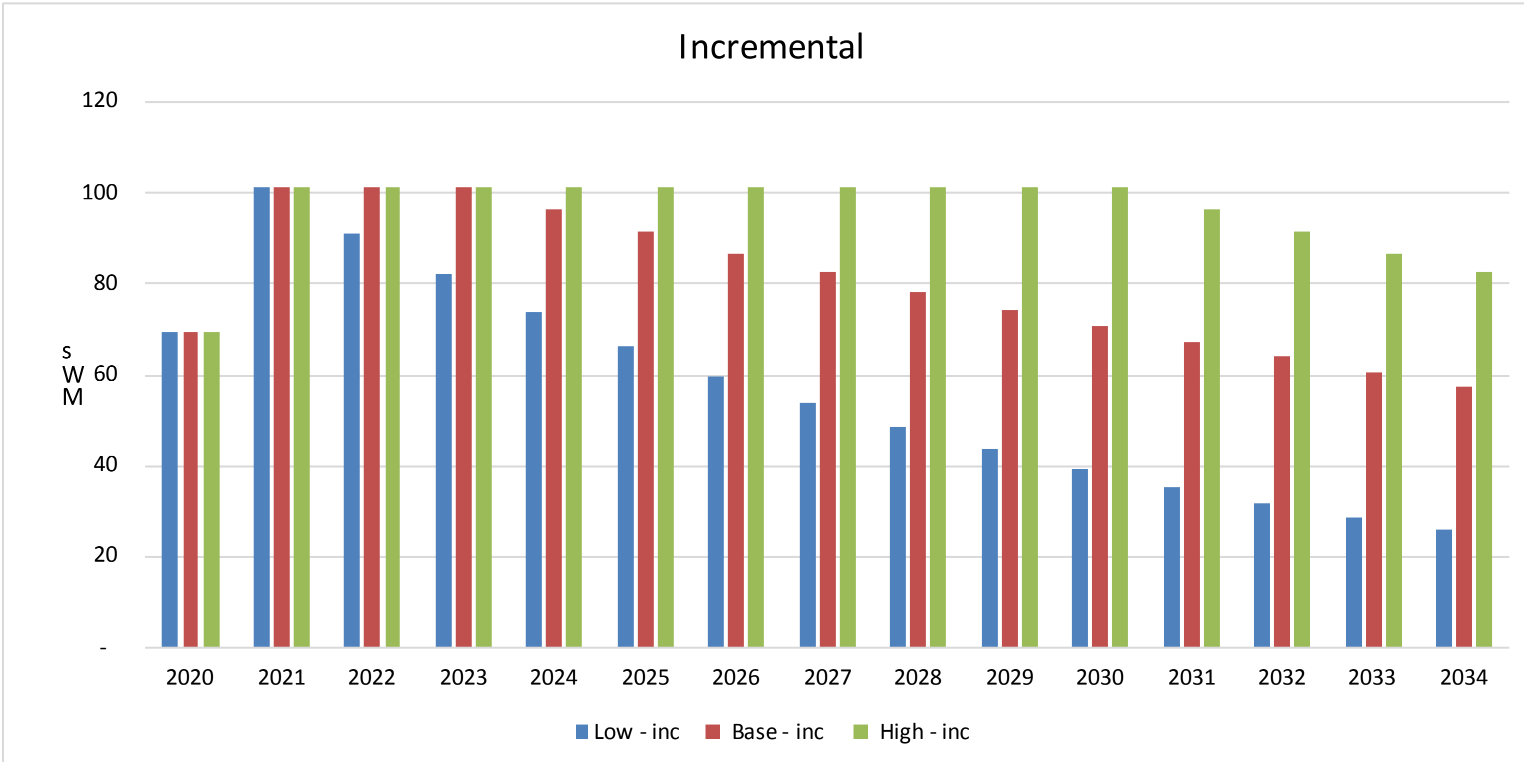
Summer Peak MWs								
Year	**Low - inc**	**Low - cum**	**Base - inc**	**Base - cum**	**High - inc**	**High - cum**	**High2-inc**	**High2-cum**
2020	22.7	360.9	22.7	360.9	25.4	363.5	25.4	363.5
2021	25.1	385.9	25.1	385.9	26.7	390.2	30.8	394.3
2022	22.3	408.2	22.3	408.2	28.4	418.7	32.8	427.1
2023	21.9	430.1	21.9	430.1	25.9	444.5	30.2	457.3
2024	18.6	448.8	19.9	450.0	25.5	470.1	29.8	487.1
2025	15.8	464.6	19.7	469.7	25.4	495.4	29.7	516.8
2026	13.5	478.0	19.9	489.6	25.5	520.9	29.8	546.6
2027	11.4	489.5	17.9	507.5	23.0	543.9	26.9	573.5
2028	9.7	499.2	16.1	523.7	20.7	564.6	24.2	597.6
2029	8.3	507.5	14.5	538.2	18.6	583.2	21.8	619.4
2030	7.0	514.5	13.0	551.2	16.7	600.0	19.6	638.9
2031	6.0	520.5	11.7	562.9	15.1	615.0	17.6	656.6
2032	5.1	525.5	10.6	573.5	13.6	628.6	15.9	672.4
2033	4.3	529.9	9.5	583.0	12.2	640.8	14.3	686.7
2034	3.7	533.5	8.6	591.6	11.0	651.8	12.8	699.5
2035	3.1	536.6	7.7	599.3	9.9	661.7	11.6	711.1

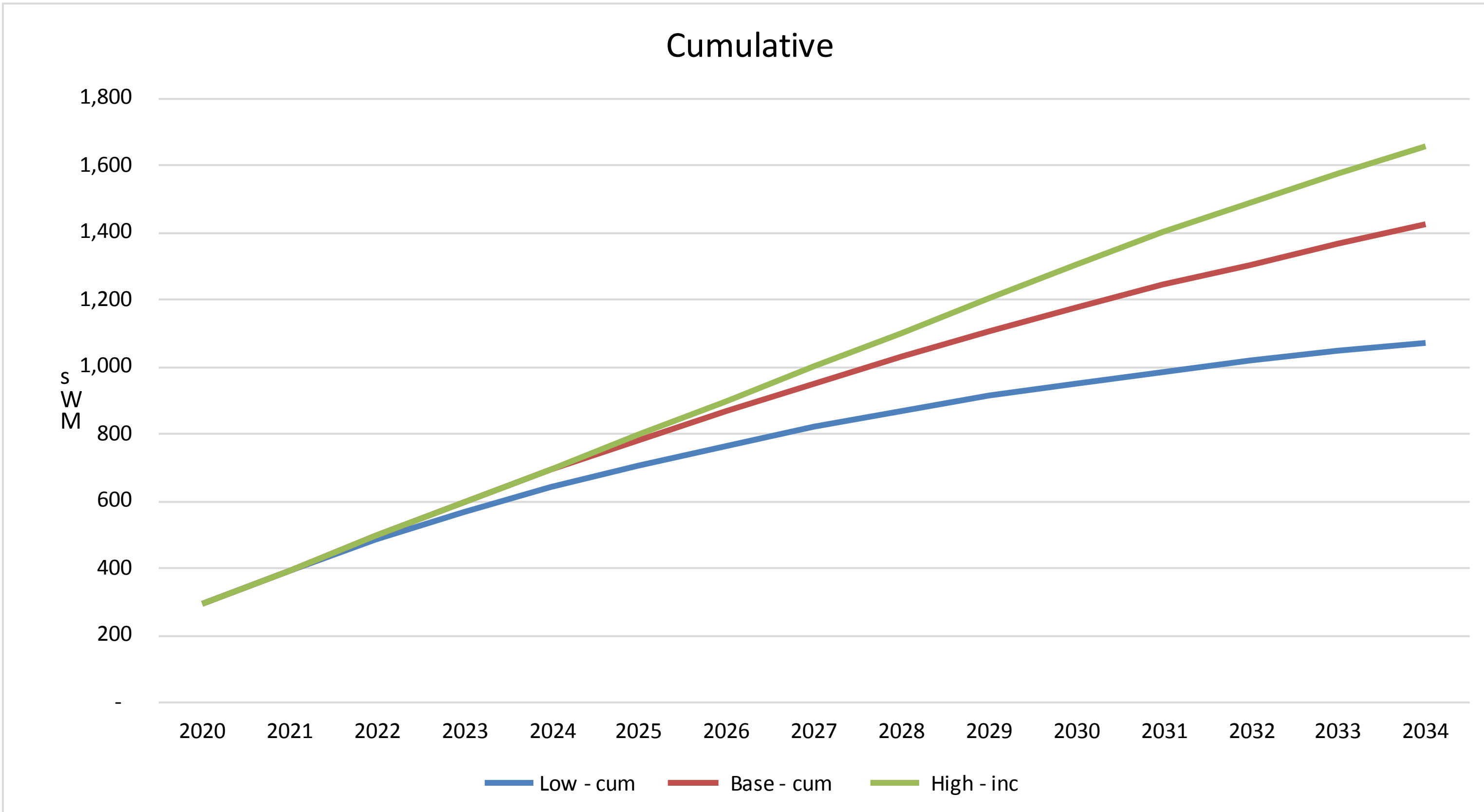

Incremental
35.0
30.0
25.0
20.0
15.0
10.0
5.0
-
MWs
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Low - inc
Base - inc
High - inc
High2-inc


Cumulative
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
-
MWs
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Low - cum
Base - cum
High - cum
High2-cum

Solar – PV (NECO)
Installed Nameplate MWs

Year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum
2020	69	289	69	289	69	289
2021	101	390	101	390	101	390
2022	91	481	101	491	101	491
2023	82	563	101	593	101	593
2024	74	637	96	689	101	694
2025	66	703	91	780	101	795
2026	60	763	87	867	101	896
2027	54	817	82	949	101	997
2028	48	865	78	1,028	101	1,099
2029	44	909	74	1,102	101	1,200
2030	39	948	71	1,173	101	1,301
2031	35	983	67	1,240	96	1,397
2032	32	1,015	64	1,303	91	1,488
2033	29	1,044	61	1,364	87	1,575
2034	26	1,069	58	1,422	82	1,657
2035	23	1,093	55	1,476	78	1,736

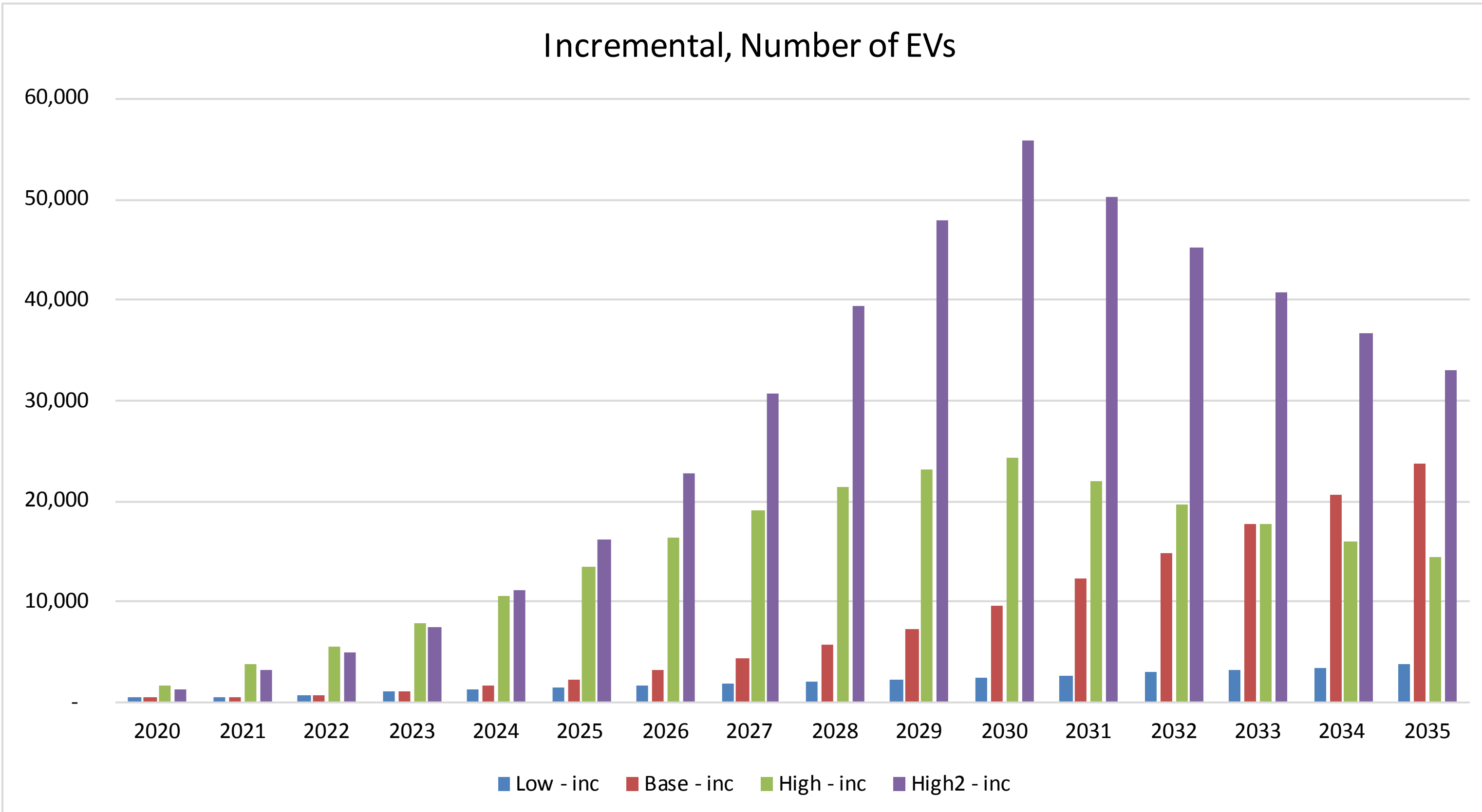

Incremental
120
100
80
60
40
20
-
MWs
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
Low - inc
Base - inc
High - inc



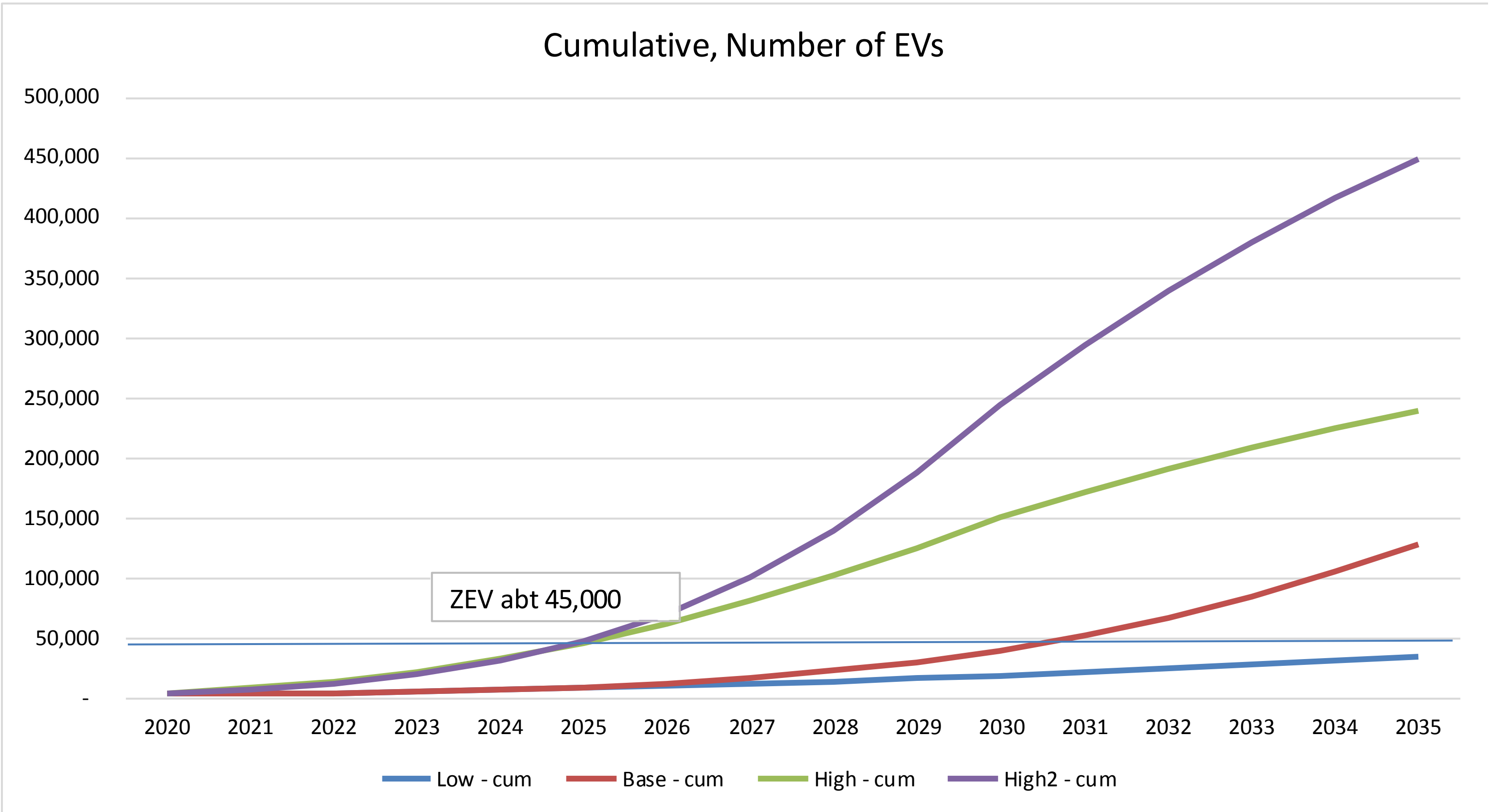
Cumulative
1,800
1,600
1,400
1,200
1,000
800
600
400
200
-
MWs
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
Low - cum
Base - cum
High - inc

Electric Vehicles (NECO)

Year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum	High2 - inc	High2 - cum
2020	416	2,654	416	2,654	1,736	3,974	1,302	3,540
2021	484	3,138	484	3,138	3,813	7,787	3,229	6,769
2022	717	3,855	717	3,855	5,534	13,322	4,949	11,718
2023	1,099	4,954	1,099	4,954	7,770	21,092	7,493	19,211
2024	1,310	6,264	1,564	6,518	10,467	31,559	11,147	30,359
2025	1,493	7,757	2,177	8,695	13,441	45,000	16,178	46,537
2026	1,700	9,457	3,178	11,873	16,415	61,415	22,715	69,252
2027	1,874	11,331	4,350	16,223	19,112	80,527	30,598	99,850
2028	2,042	13,372	5,783	22,006	21,348	101,875	39,293	139,143
2029	2,225	15,598	7,356	29,363	23,069	124,944	47,987	187,130
2030	2,449	18,047	9,591	38,954	24,319	149,264	55,870	243,000
2031	2,693	20,740	12,282	51,236	21,887	171,151	50,283	293,283
2032	2,939	23,679	14,881	66,116	19,698	190,849	45,255	338,538
2033	3,193	26,872	17,643	83,760	17,729	208,578	40,729	379,267
2034	3,457	30,330	20,647	104,407	15,956	224,534	36,656	415,924
2035	3,733	34,062	23,709	128,117	14,360	238,894	32,991	448,915

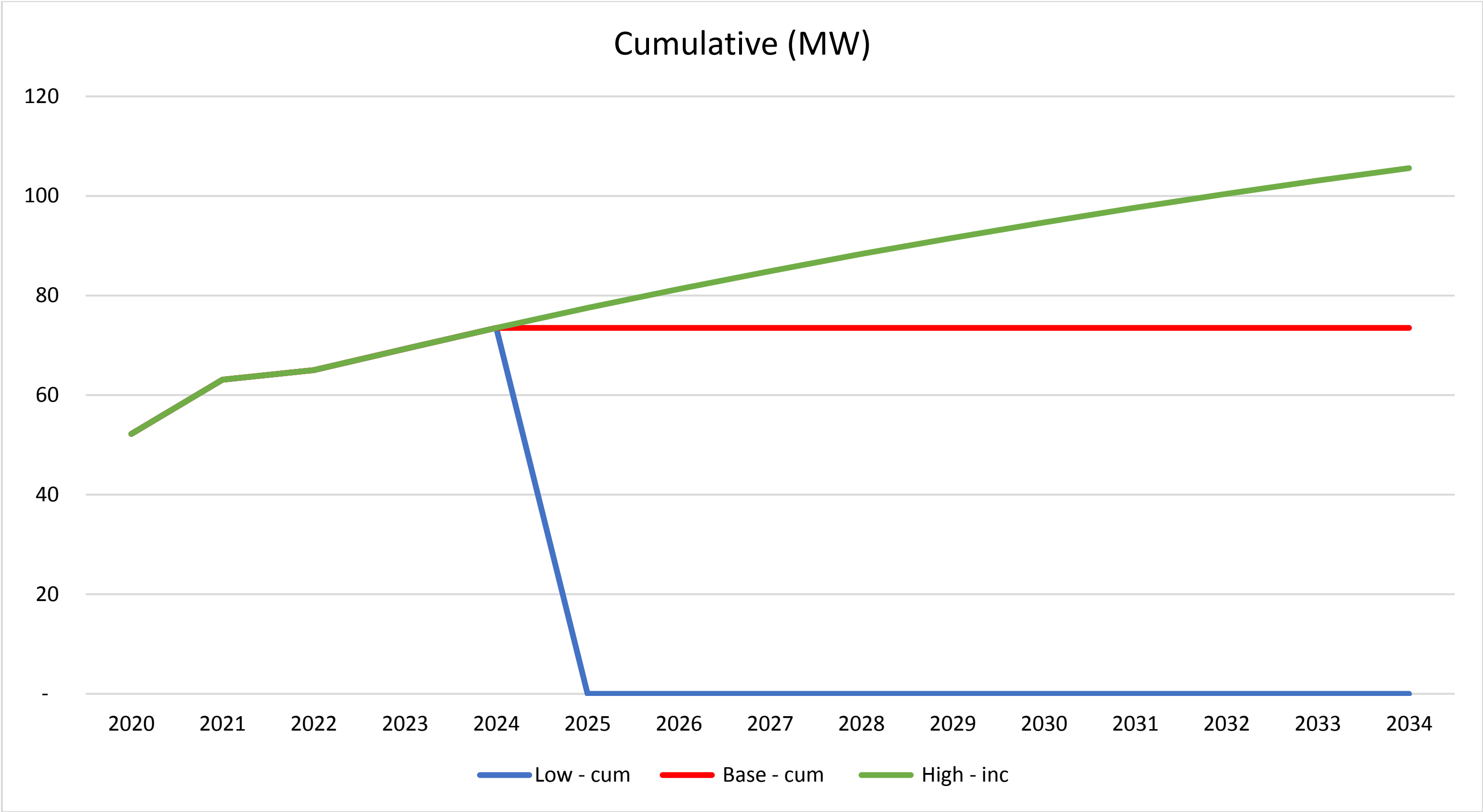


Incremental, Number of EVs
60,000
50,000
40,000
30,000
20,000
10,000
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Low - inc
Base - inc
High - inc
High2 - inc


Cumulative, Number of EVs
500,000
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
ZEV abt 45,000
Low - cum
Base - cum
High - cum
High2 - cum

Demand Response (NECO)

Year	Low - cum	Base - cum	High - cum
2020	52	52	52
2021	63	63	63
2022	65	65	65
2023	69	69	69
2024	74	74	74
2025	-	74	77
2026	-	74	81
2027	-	74	85
2028	-	74	88
2029	-	74	92
2030	-	74	95
2031	-	74	98
2032	-	74	100
2033	-	74	103
2034	-	74	106
2035	-	74	108

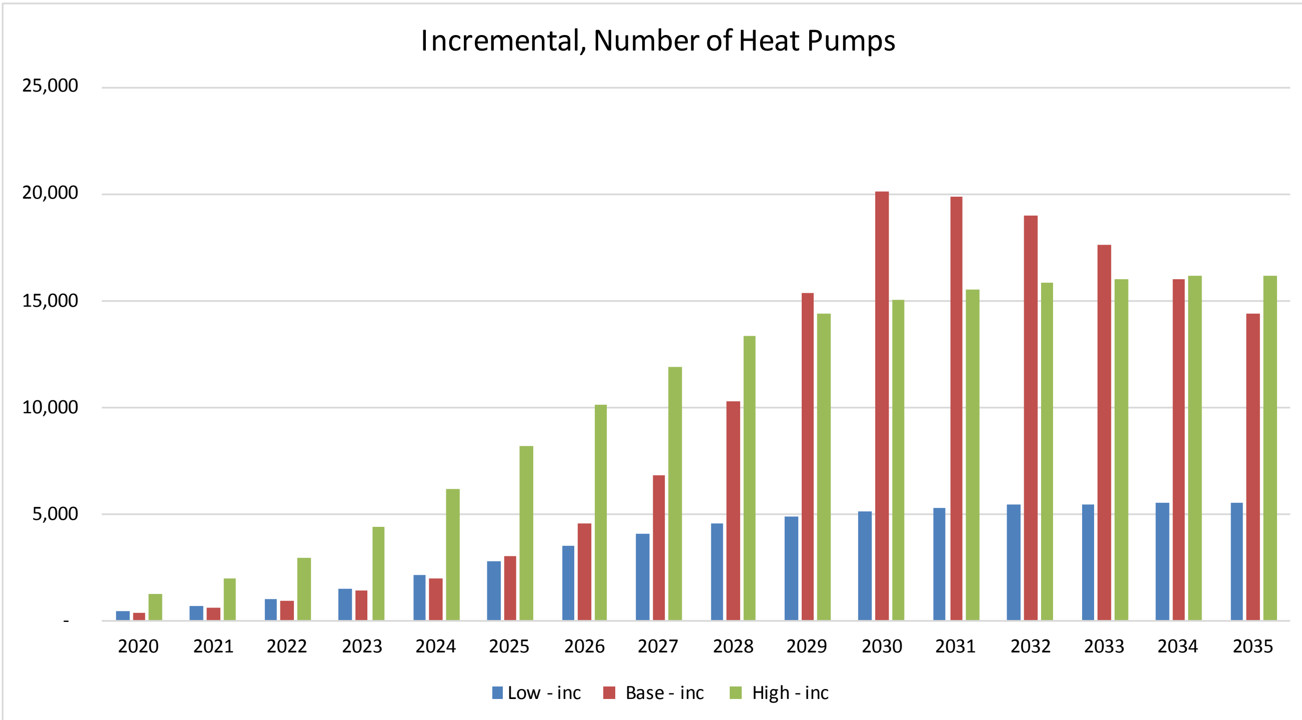


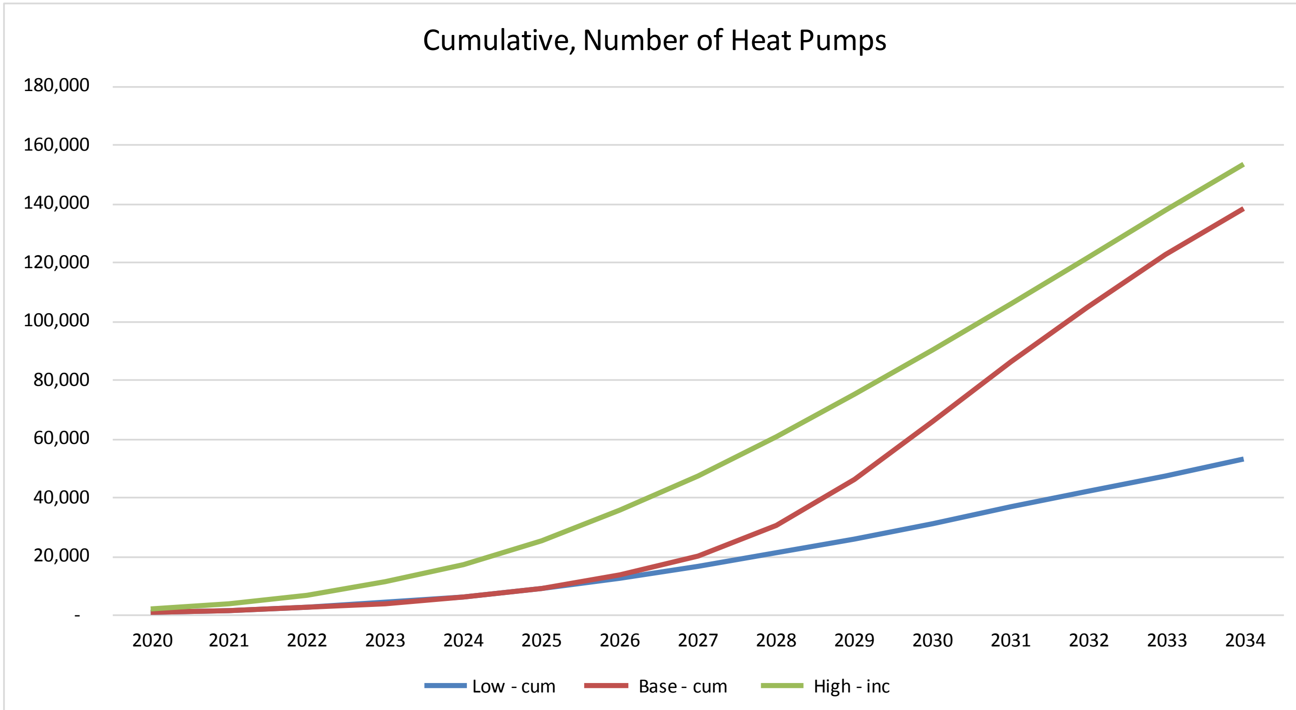
Cumulative (MW)
120
100
80
60
40
20
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
Low - cum
Base - cum
High - inc

Electric Heat Pumps (NECO)

Number of Electric Heat Pumps

Year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum
2020	423	723	400	700	1,237	1,537
2021	665	1,389	600	1,300	1,944	3,481
2022	1,018	2,407	900	2,200	2,975	6,457
2023	1,501	3,908	1,400	3,600	4,386	10,843
2024	2,107	6,016	2,000	5,600	6,157	17,000
2025	2,791	8,807	3,000	8,600	8,155	25,155
2026	3,475	12,281	4,600	13,200	10,152	35,306
2027	4,081	16,362	6,800	20,000	11,923	47,229
2028	4,564	20,925	10,300	30,300	13,334	60,563
2029	4,916	25,842	15,400	45,700	14,365	74,928
2030	5,158	31,000	20,138	65,838	15,072	90,000
2031	5,317	36,317	19,916	85,755	15,536	105,536
2032	5,418	41,735	18,978	104,732	15,831	121,367
2033	5,481	47,217	17,618	122,350	16,016	137,382
2034	5,521	52,737	16,043	138,392	16,130	153,512
2035	5,545	58,282	14,393	152,785	16,200	169,712


Incremental, Number of Heat Pumps
25,000
20,000
15,000
10,000
5,000
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Low - inc
Base - inc
High - inc



Cumulative, Number of Heat Pumps
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
-
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
Low - cum
Base - cum
High - inc

Appendix E: DER Scenarios Development

Energy Efficiency

Base

- The 2020 approved Company goal and 2021-2023 three-year plan from the Subject Matter Experts (SMEs) are used for 2020-2023.
- Between 2024 and 2026, the outlook from the **Business-as-Usual / Low Scenario** of the RI Market Potential study[1] performed by the Dunsky Energy Consulting are applied.
- Post-2026, a declining annual incremental new EE assumption is applied, which is similar to ISO-NE's assumption to reflect the concept of declining returns over time as the market becomes saturated. As a result, the cumulative annual value is still expected to continue to grow, but at a slower rate each year. This value is set at 10% less each year.

High

- Between 2020 and 2026, the expectations from the **Mid Scenario** of the RI Market Potential study performed by the Dunsky Energy Consulting are applied. It expects increasing incentives and enabling activities above and beyond the company's current plan. In the short-run, it anticipates the persistence of claimable savings from existing standard lighting programs as well as the ramp-up of emerging technologies. This will help maintain the same level of annual incremental EE savings as 2019.
- Post-2026, a declining annual incremental new EE assumption is applied, which is similar to ISO-NE's assumption to reflect the concept of declining returns over time as the market becomes saturated. As a result, the cumulative annual value is still expected to continue to grow, but at a slower rate each year. This value is set at 10% less each year.

High2

- Between 2020 and 2026, the expectations from the **Max Scenario** of the RI Market Potential study performed by the Dunsky Energy Consulting are applied. It represents the view on the company's maximum achievable potential. In the short-run, it expects the persistence of claimable savings from existing standard lighting programs as well as the fast ramp-up of emerging technologies. The savings from such lighting programs are expected to phase out by the 2022 program year. Overall, new saving programs are expected to offer greater saving opportunities throughout the whole evaluation period.
- Post-2026, a declining annual incremental new EE assumption is applied, which is similar to ISO-NE's assumption to reflect the concept of declining returns over time as the market becomes saturated. As a result, the cumulative annual value is still expected to continue to grow, but at a slower rate each year. This value is set at 10% less each year.

Low

- The 2020 approved Company goal and 2021-2023 three-year plan from the Subject Matter Experts (SMEs) are used for 2020-2023.
- Beyond 2023, a declining annual incremental new EE assumption is applied, which is similar to ISO-NE's assumption to reflect the concept of declining returns over time as the market becomes saturated. As a result, the cumulative annual value is still expected to continue to grow, but at a slower rate each year. This value is set at 15% less each year.

[1] Rhode Island Market Potential Study (2021-2026) https://rieermc.ri.gov/rhode-island-market-potential-study-2021-2026/

Solar-PV

Base

- Short-term (2020 – 2021) predictions are mainly based on the 2020 Year-to-Date connected projects, the SME expectations from projects in the queue, and the status/stages of the projects in the queue. The same level of new installations is assumed for two more years.
- For the longer term, similar to other technologies, new installations are assumed to taper off over time due to saturation and increasing costs.

High

- Predictions for 2020 – 2021 are mainly based on the 2020 Year-to-Date connected projects, the SME expectations from projects in the queue, and the status/stages of the projects in the queue.
- Between 2022 and 2030, the same level of incremental growth as 2021 is assumed to continue. The cumulative incremental installations between 2020 and 2030 generally align with the high DER scenario of the RI Grid Modernization Plan.
- For the longer term, similar to other technologies, new installations are assumed to taper off over time due to saturation and increasing costs.

Low

- The low case for PV is assumed to start tapering off in year 2022, the year immediately after the current SME short term projections end. It also assumes a faster tapering off at 10% less each year.

Electric Vehicles

Base

- The base case is developed from Bloomberg's 2020 Long-term Electric Vehicle Outlook (BNEF-2020). Both Battery Electric Vehicle (BEV) and Plug-in Hybrid Electric Vehicle (PHEV) are expected to take an increasing share of the LDV over the forecast horizon, with BEV becoming the major EV types in later years. Instead of directly taking the BNEF-2020 expected BEV and PHEV shares in LDV that are provided at the national level, we allow the Company's BEV and PHEV shares in LDV to gradually trend from their current level to the national level over a reasonable period. The Company's EV is about 0.3% of LDV as of 2019, and its share is expected to be about 1% by 2025, 4.6% by 2030, and 15% by 2035. The BEV is about 41% of EV as of 2019 and its share is expected to be 64% by 2025, 72% by 2030, and 79% by 2035.

High

- The base case does not meet the ZEV target by the year 2025, which is about 45,000. Thus, the high EV case is a significant increase in annual growth to achieve the ZEV target by 2025. An S-curve type ramp-up is assumed. No attempt is made to determine the feasibility of such rapid increases. This trend is continued until the milestone year 2030 where in subsequent years, saturation is assumed, and an annual decline in new vehicles is assumed. This level is set at about 10% less per year as in the other technologies. It is assumed that significant incentives on the state and federal levels, as well as a transformational change in the industry would be required to enable this scenario.

High2

- Another high case is developed from the High DER scenario of RI Grid Modernization Plan to reach 243,000 EV by 2030. An S-curve type ramp-up is assumed to reach this level. Beyond 2030, the incremental EV is assumed to decrease at 10% per year.

Low

- The low case is developed from EIA's 2020 Annual Energy Outlook in a similar way as the base case. This case results in EV to be 4% of LDV with 85% as BEV and 15% as PHEV by the year 2035.

Demand Response

Base Case
For the short term (i.e. until 2024), the approved Company targets from the SMEs in the DR Dept. are used as the projection. For the longer term, because the 2024 target level is based on market potential, the projections are held constant through 2035.

High Case
The high case is a continued incremental growth following the approved program years. Beginning in year 2025, the prior years annual incremental level is continued, however, at a smaller amount each year forward to reflect a level of saturation. This value is set at 5% less incremental new participation each year versus the prior year.

High Case 2
No higher case is warranted at this time.

Low Case
The low case for DR is assumed to be a discontinuation of the DR program in the year 2025. Since DR needs to be implemented, dispatched, and paid for continuously unlike other DER programs which once installed persist for many years and still garner savings, the low case is assumed to be an end to the DR due to budget or other circumstances.

Electric Heat Pumps

Base Case:

The target is set at 45,000 by year 2029. This is based on the ISO-NE which provides an estimate for heat pumps in the state (which is estimated to be about 10% of all homes). Subsequent to this and through the end of the planning cycle in year 2035, incremental heat pumps continue to grow but at a smaller amount each year to reflect a level of saturation. This saturation value is about 5% less new incremental amounts from the prior year. This approach provides for about a 14% penetration of all homes by year 2030; and about 30% by year 2035.

High Case:

The high case is based on achieving about a 20% by year 2030 and 40% by year 2035 penetration of heat pumps. An "S-Curve function is used to reach this target by year 2030 and then continues post 2030. This approach provides for about a 20% penetration of all homes by year 2030; and about 40% by year 2035.This is somewhat higher than the RI reference case for its Grid Modernization target and is instead based on the MA Grid modernization penetration levels. This is because the RI base case already achieves the RI Grid Modernization target of about the 70,000 heat pumps by year 2030.

High Case 2:

No higher case is warranted at this time. The high case itself is based on the Grid Modernization goals which include higher penetrations of renewables and electrification already. It is also higher than the US Strategy high case as well. Thus, the existing cases encompass current projections for high levels of heat pumps.

Low Case:

The low case is set at half of the year 2030 base case level. An S-curve function is used to determine the year-by-year values. This approach provides for about a 7% penetration of all homes by year 2030; and about 13% by year 2035.

Appendix F: Power Supply Areas (PSAs)

Year One Weather-Adjustment and Multi-Year Annual Growth Percentages (Summer) — **after EE, PV, EV, DR, and EH impacts**

			2020 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg
State	**PSA**	**Zone (1)**	**for 50/50**	**for 90/10**	**for 95/5**	**2021**	**2022**	**2023**	**2024**	**2025**	**'21 to '25**	**'26 to '30**	**'31 to '35**
RI	Blackstone Valley	RI	94.3%	103.0%	105.5%	(1.7)	(1.5)	(0.8)	(0.1)	0.1	(0.8)	(0.1)	(0.1)
RI	Newport	RI	94.3%	103.0%	105.5%	(1.0)	(0.9)	(0.3)	0.3	0.5	(0.3)	0.2	0.1
RI	Providence	RI	94.3%	103.0%	105.5%	(1.0)	(0.9)	(0.3)	0.3	0.5	(0.3)	0.2	0.1
RI	Western Narraganset	RI	94.3%	103.0%	105.5%	(0.8)	(0.7)	(0.1)	0.5	0.7	(0.1)	0.4	0.2

Year One Weather-Adjustment & Multi-Year Annual Growth (Summer) — **after EE, EV, DR, and EH impacts, but before PV reduction**

			2019 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg
State	**PSA**	**Zone (1)**	**for 50/50**	**for 90/10**	**for 95/5**	**2021**	**2022**	**2023**	**2024**	**2025**	**'21 to '25**	**'26 to '30**	**'31 to '35**
RI	Blackstone Valley	RI	94.3%	103.0%	105.5%	(0.9)	(0.7)	(0.0)	0.6	0.8	(0.0)	0.5	0.3
RI	Newport	RI	94.3%	103.0%	105.5%	(0.2)	(0.1)	0.5	1.1	1.2	0.5	0.8	0.5
RI	Providence	RI	94.3%	103.0%	105.5%	(0.2)	(0.1)	0.5	1.1	1.2	0.5	0.8	0.5
RI	Western Narraganset	RI	94.3%	103.0%	105.5%	0.0	0.1	0.7	1.3	1.4	0.7	0.9	0.6

Year One Weather-Adjustment and Multi-Year Annual Growth Percentages (WINTER) — **after EE, PV, EV, and EH impacts**

			2019/20 Weather-Adjustments (2)			Annual Growth Rates (percents) (3)					5-yr avg	5-yr avg	5-yr avg
State	**PSA**	**Zone (1)**	**for 50/50**	**for 10/90**	**for 05/95**	**2020**	**2021**	**2022**	**2023**	**2024**	**'20 to '24**	**'25 to '29**	**'30 to '34**
RI	Blackstone Valley	RI	101.1%	106.6%	108.1%	(0.9)	(1.5)	(1.1)	(0.9)	(0.5)	(1.0)	1.0	3.7
RI	Newport	RI	101.1%	106.6%	108.1%	(0.2)	(0.8)	(0.5)	(0.4)	(0.1)	(0.4)	1.3	3.8
RI	Providence	RI	101.1%	106.6%	108.1%	(0.2)	(0.9)	(0.5)	(0.4)	(0.1)	(0.4)	1.3	3.9
RI	Western Narraganset	RI	101.1%	106.6%	108.1%	0.0	(0.6)	(0.3)	(0.2)	0.1	(0.2)	1.4	4.0

(1) Zones refer to ISO-NE designations

(2) These first year weather-adjustment values can be applied to actual MW readings for current winter peaks to determine what the weather-adjusted value is for any of the three weather scenarios.

(3) These annual growth percents can be applied to the current winter peaks to determine what the growth for each area is.