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Rhode Island Energy™
a PPL company

December 21, 2023

VIA ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 23-37-EL – The Narragansett Electric Company d/b/a Rhode Island Energy's Petition for Acceleration of a System Modification Due to Distributed Generation Project
Tiverton Project
Responses to Division Data Requests – Set 1

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed, please find the Company's responses to the Division of Public Utilities and Carriers' ("Division's") First Set of Data Requests in the above-referenced docket.

Thank you for your attention to this filing. If you have any questions, please contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket 23-37-EL Service List

Division 1-1

Request:

Provide a copy of the most recent Area Study which incorporated the Tiverton Substation project.

Response:

Please see Exhibit EJRS-3 attached to the Pre-Filed Joint Testimony of Erica Russell Salk and Stephanie A. Briggs,[1] which is a copy of the latest Tiverton Area Study dated September 2022.

Please note that copies of redacted (in this case, Tiverton does not contain any confidential information, so there are no redactions) area studies are located on the Rhode Island System Data Portal at the following link:

https://systemdataportal.nationalgrid.com/RI/

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[1] See https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-10/2337-RIE-DGPetition-Tiverton-10-17-23-bates.pdf, begins at Bates 153 (PDF Page 161 out of 203)

Division 1-2

Request:

Provide a copy of the most recent CYME model which supported the decision for the Tiverton Substation project work incorporated in the latest Area Study.

Response:

Please find attached two separate CYME files for the Tiverton Area Study work. One is a case prior to the area study recommendations (base case) and the second is with the area study recommendations.

Prepared by or under the supervision of: Ryan Constable

Attachments DIV 1-2

The Company provided its CYME files in zip folders in response to this request.

Prepared by or under the supervision of: Ryan Constable

Division 1-3

Request:

Provide a copy of the load forecast for the Tiverton Substation which was used in the latest Area Study incorporating Tiverton Substation and the associated CYME engineering model for this project.

Response:

Please find attached the 2020 Electric Peak (MW) Forecast, dated November 2019 which was used in the Tiverton area study.

All forecasts are located on the Rhode Island System Data Portal at the following link:

https://systemdataportal.nationalgrid.com/RI/

NARRAGANSETT ELECTRIC COMPANY

2020 Electric Peak (MW) Forecast

15-Year Long-Term

2020 to 2034

November 2019

Original, 11/01/2019

Economics and Load Forecasting
Advanced Data & Analytics

nationalgrid

REVISION HISTORY & GENERAL NOTES

Revision History

Version	Date	Changes
Original	11/01/2019	- ORIGINAL

General Notes:

- Hourly load data through August 2019; projections from 2020 forward;
- Economic data is from Moody's vintage August 2019.
- Energy Efficiency data is internal data vintage August 2019.
- Distributed Generation data is internal data vintage August 2019.
- Electric Vehicle data is POLK data vintage August 2019.
- Peak MW and Energy GWH source is ISO-NE/MDS meter-reconciled data (1/2003 to 6/2019), internal unreconciled **preliminary** data (Jul 2019 to Aug. 2019).
- Peak load data is metered zonal load; but without ISO bulk system losses.
- The term "Weather-Normal" is based on a twenty-year average.
- PV impacts are based on non-supply (ISO) installations
- High and low DER scenarios are added this year in addition to the standard base case
- Demand Response added this year
- The impacts of changing peak hours over time due to DERs is considered

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CONTENTS

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.

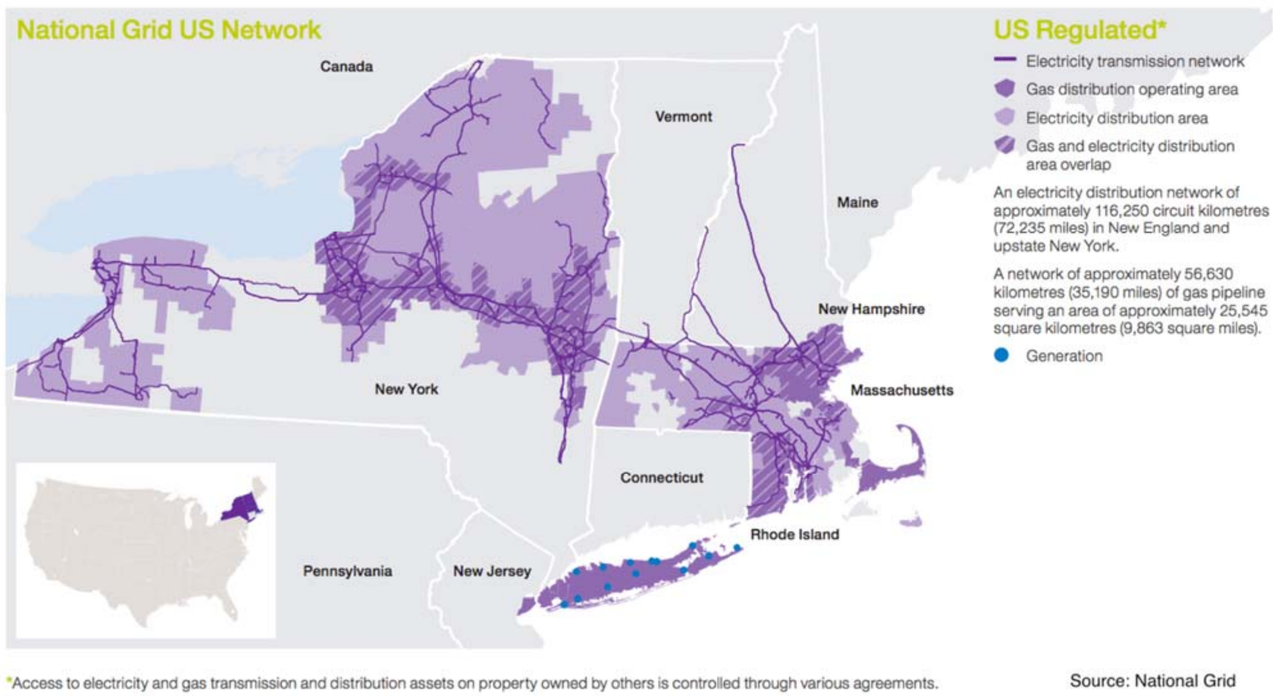


Figure 1: National Grid U.S. Service Territory

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 2019 was 1,750 MW on Sunday, July 21st at hour-ending 18. This 2019 peak was 12% 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 82 percentile of peak weather over the last 20 years. This means that only 18%

[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 summers are expected to be warmer[3]. This year's peak is considered 3 MW below the peak the company would have experienced under normal weather and 'day of the week' conditions (Sunday peaks are very unusual). Thus, on an adjusted "normal" basis this year's peak was estimated to be 1,753 MW, a decrease of 1.8% compared to last year's adjusted peak.

The forecast indicates that the service territory will experience a peak decline of about 0.6% annually over the next fifteen years, primarily due to the impacts of distributed energy resources (DERs) offsetting any underlying economic growth.

Figure 2 shows this forecast graphically.

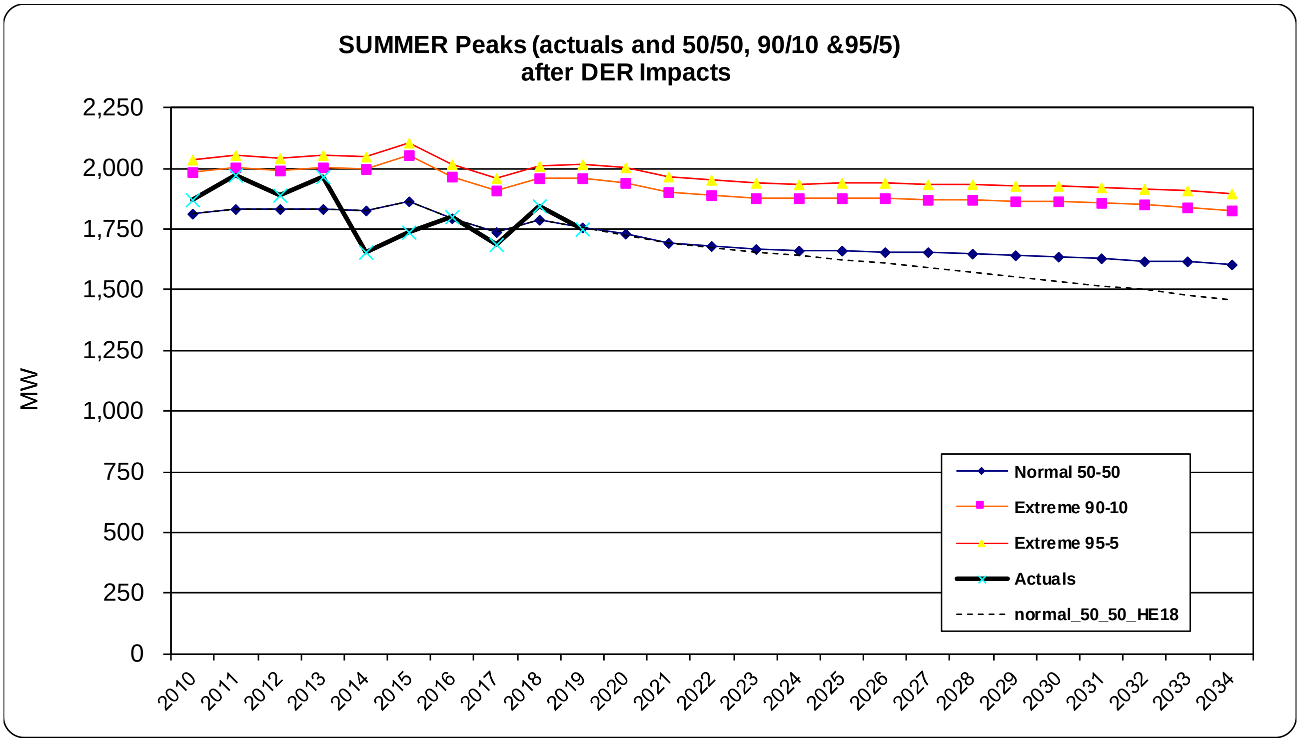


Figure 2: Historical (actual & weather-adjusted) and Projected Summer Peaks

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 late afternoon/early evening time to later in the evening and early night time by the end of the fifteen-year planning horizon. As this occurs, the impact of PV is less pronounced on the new peak hour. For comparison, the dotted 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. 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. For distribution planning, the degree of diversity is reduced and the variability of load is greater, so a 95/5 forecast is used. 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.

[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-values" and standard deviations to calculate the extreme weather scenarios. As a result, the more spread out the numbers on peak days over the historical period, the more the 90/10 and 95/5 values will be above the mean (or the normal).

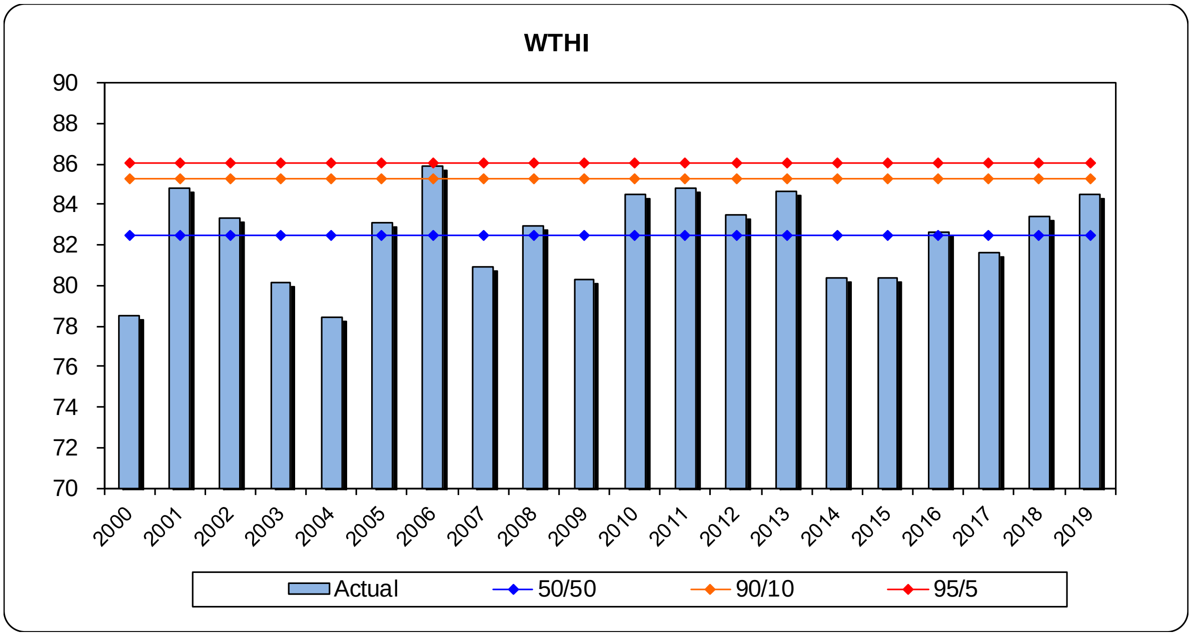


Figure 3: Actual, weather-normal and extreme WTHI

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, solar-PV, electric vehicles and demand response. 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. In general, DERs are expected to decrease future growth from 0.4% per year over the next fifteen years to <u>negative</u> 0.6% per year.

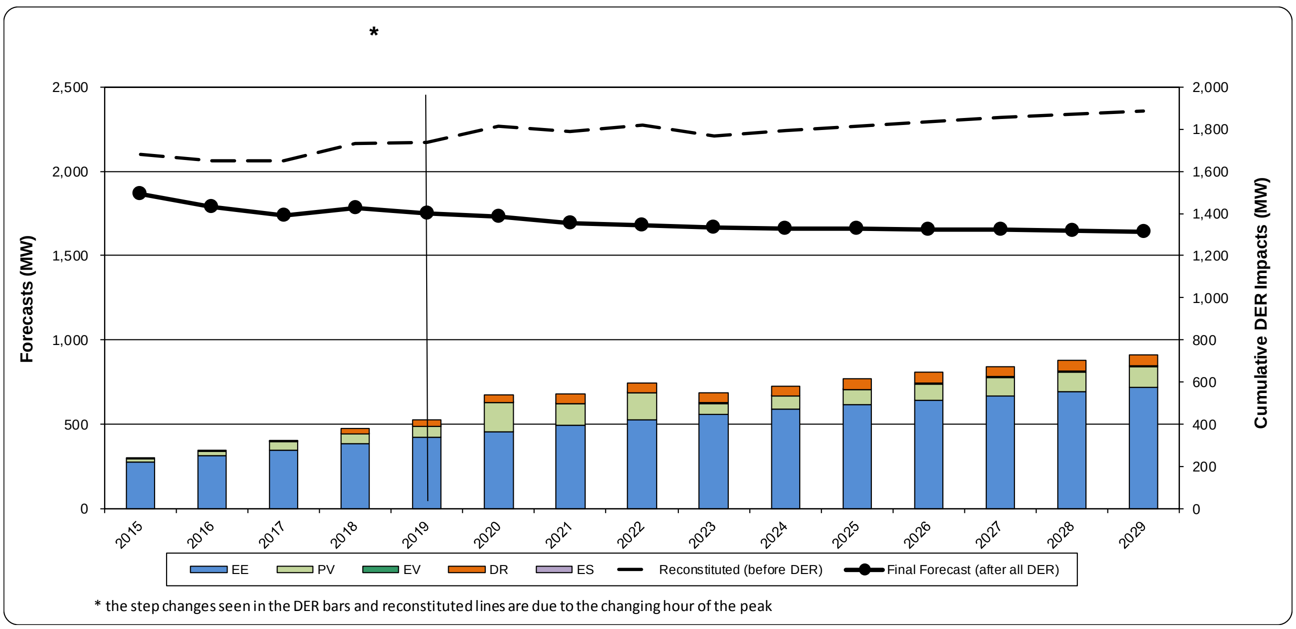


Figure 4: Annual impact of DERs

In addition to impacting the magnitude of the peak, the DERs change the peak-day load shape which shifts the peak hour over time. Over time, the peak hours shifts to later in the day. 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 5-6 PM to 7-8-9 PM over the fifteen-year planning horizon. As this occurs, the impact of PV is less pronounced on the peak hour. The visible decrease in DERs shown in Figure 4 in 2023 is due to this shift.

Each of the DERs is discussed next.

[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.

Energy Efficiency (EE)

National Grid has run energy efficiency programs in its Rhode Island jurisdiction for many years and will continue to do so for the foreseeable future. In the short-term, energy efficiency 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 new EE each year to account for long-term saturation, higher marginal costs, and a lower load base to capture savings from as long-term EE lowers overall load over time. (This practice of declining EE over time is similar to what each regional ISO does).

Figure 4 above shows the expected load and energy efficiency program impacts to peaks by year for the base case. As of 2019, it is estimated that these EE programs have reduced load by 338 MW, or 15.6% compared to the counterfactual with no EE programs. By 2034, it is expected that this reduction will grow to 654 MW or 28.4% 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 0.4% to negative 0.1% per year.

Solar - PV[8]

There has been a rapid increase in the adoption of solar PV throughout the state. Actual installed PV is tracked by the Company and used for the historical values in Figure 5. 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 5 shows the historical and projected connected PV installations. As of 2019, it is estimated about 224 MWs will have been connected, growing to 1,506 MW by the end of the planning period.

[8] This discussion is limited to PV which expected to reduce loads and would not include those PV installations considered as ‘supply’ by the ISO. This can include both ‘behind-the-meter” and in “front-of-the-meter” for those installations like community solar which is allocated back to customers.

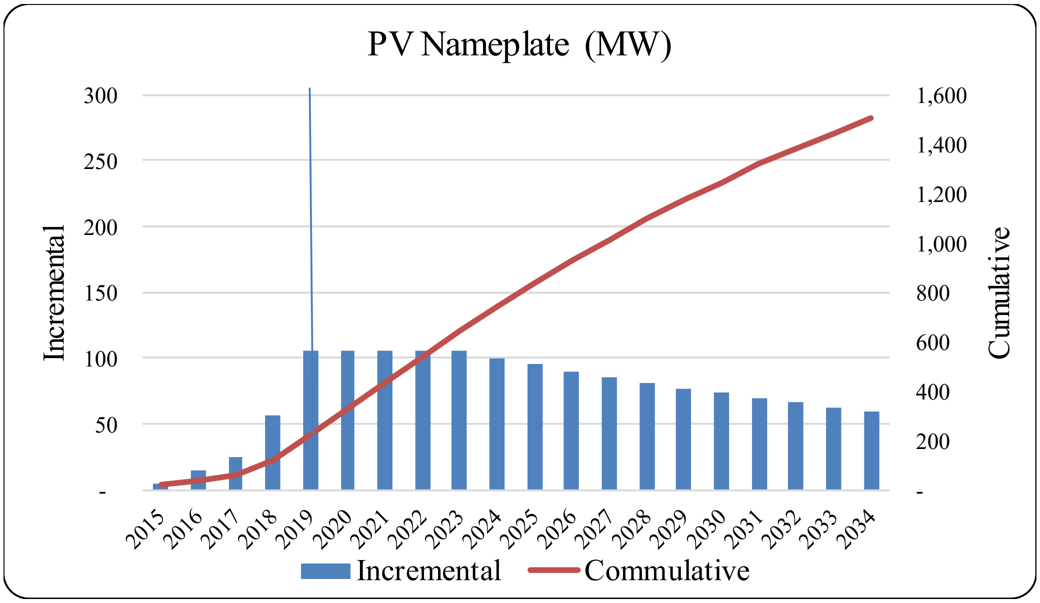


Figure 5: Solar-PV connected nameplate (AC) MW by year

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)

Electric vehicles 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 been increasing. 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 6 shows the historical and estimated number of EVs in the Company's upstate New York service territory. As of the end of 2019, it is estimated that almost 2,000 EVs will be on the roads in the service territory, growing to almost 34,000 by the end of the fifteen-year planning horizon.

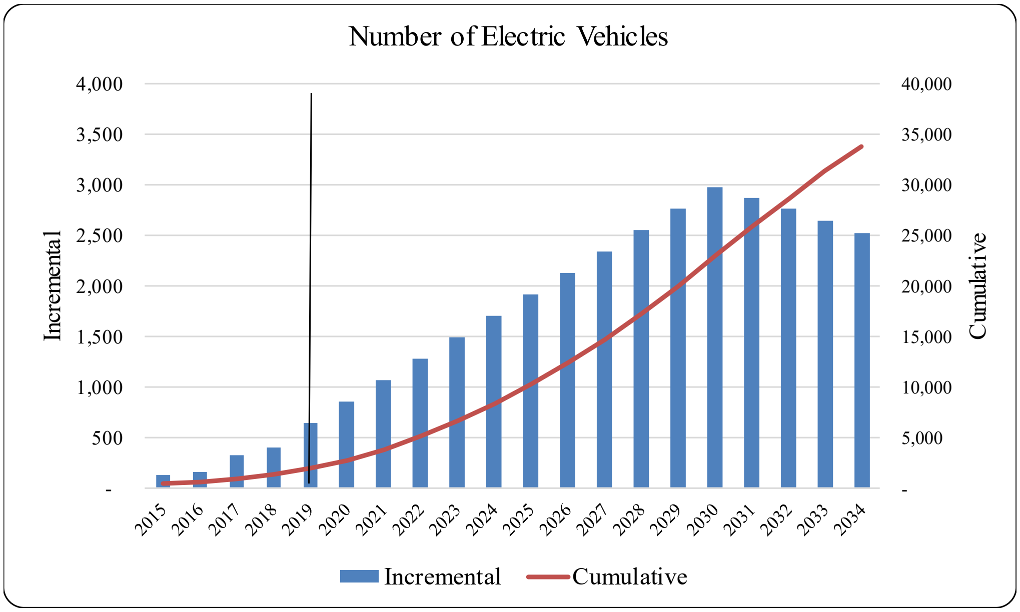


Figure 6: Number of Incremental and Cumulative EVs

It is estimated that these vehicles may have increased cumulative summer peak loads by about 0.4 MW as of 2019, increasing to about 13 MW of cumulative peak load increase in year 2034. While EVs do add to both peak and energy loads over time, they are considered 'beneficial'[9] electrification.

Demand Response (DR)

Demand Response (or "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 operating areas, such as 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.

[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.

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.

In 2019, estimated impact of the retail DR program was about 27 MW and is expected to grow to about 54 MW, or 2.3% of summer peak load by year 2034. The Company DR program was not called on this year's Sunday, July 21st peak. The hours of dispatch for DR would be assumed to move over time to capture the hours of the peak, however, as the hours of the peak move outside of normal commercial sector activity it is expected that additional DR impacts would be harder to achieve.

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 important. 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 solar PV is placed on the system, the concept is that the summer peak hour will shift away from afternoon hours where solar irradiation is highest to evening hours as the solar reductions taper off. And as more electric vehicles chargers are installed, evening and nighttime loads can go up.

Figure 7 shows the impact of the "24 hour" peak summer day for selected years over the planning horizon for the base case DERs.

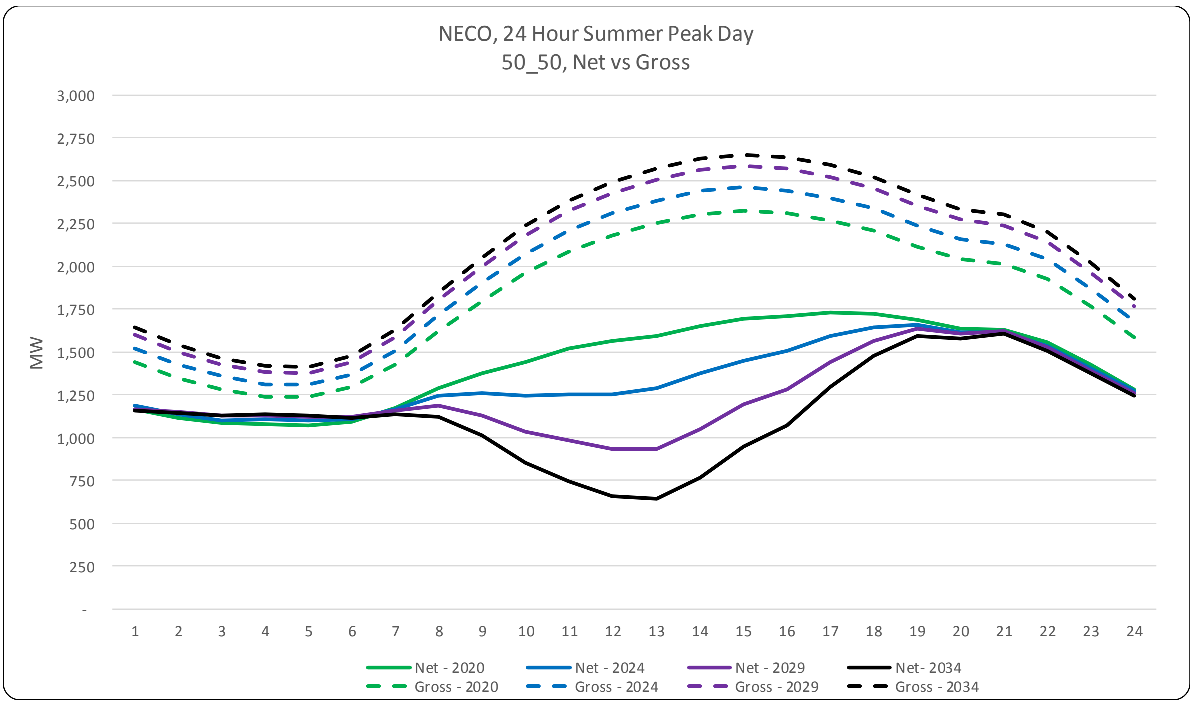


Figure 7: Peak Summer day hourly load, pre and post DERs

Figure 7 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 2020, 2024, 2029 and 2034.

Figure 8 shows the impact of the "24 hour" peak winter day for selected years over the planning horizon with the base case DERs.

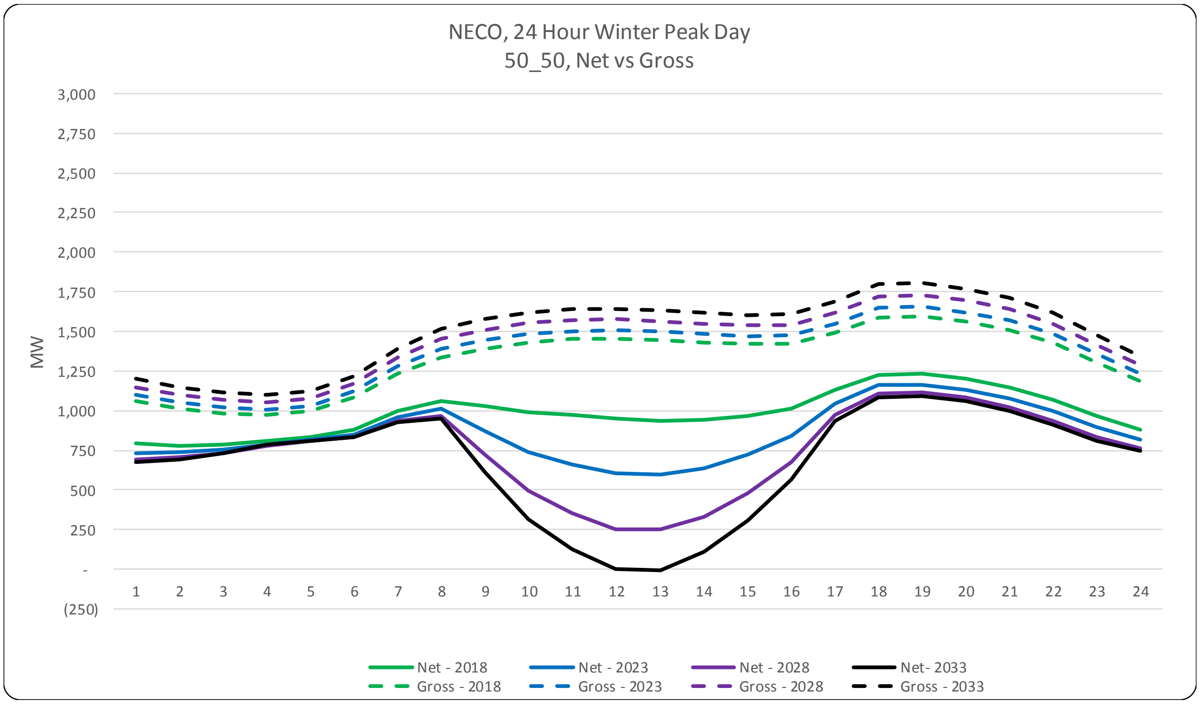


Figure 8: Peak Winter day hourly load, pre and post DERs

This figure 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 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

The body of this report thus far 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 and DR) also has a higher case and a lower case scenario, as 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].

Figure 9 shows what the range of annual summer peaks could look like for all of the various combinations of DER scenarios for each of the next fifteen years.

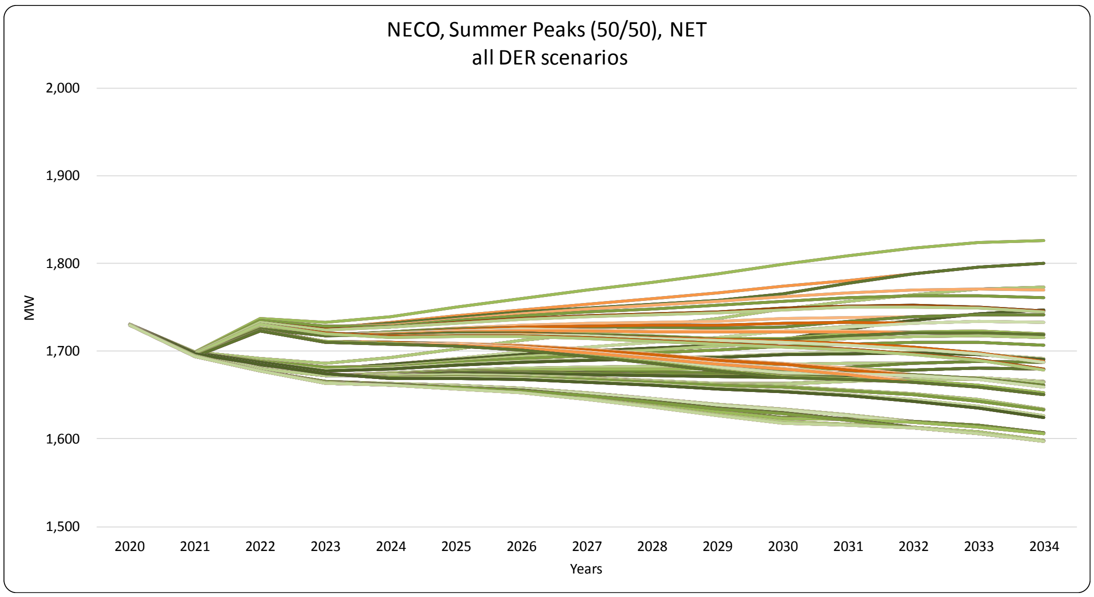


Figure 9: Summer Peaks (50/50), NET, all DER scenarios

[10] In this forecast, four DERs, each with three scenarios – base, higher and lower, creates 81 cases (3^4) for each weather scenario. With three weather scenarios 243 cases are generated for the Company.

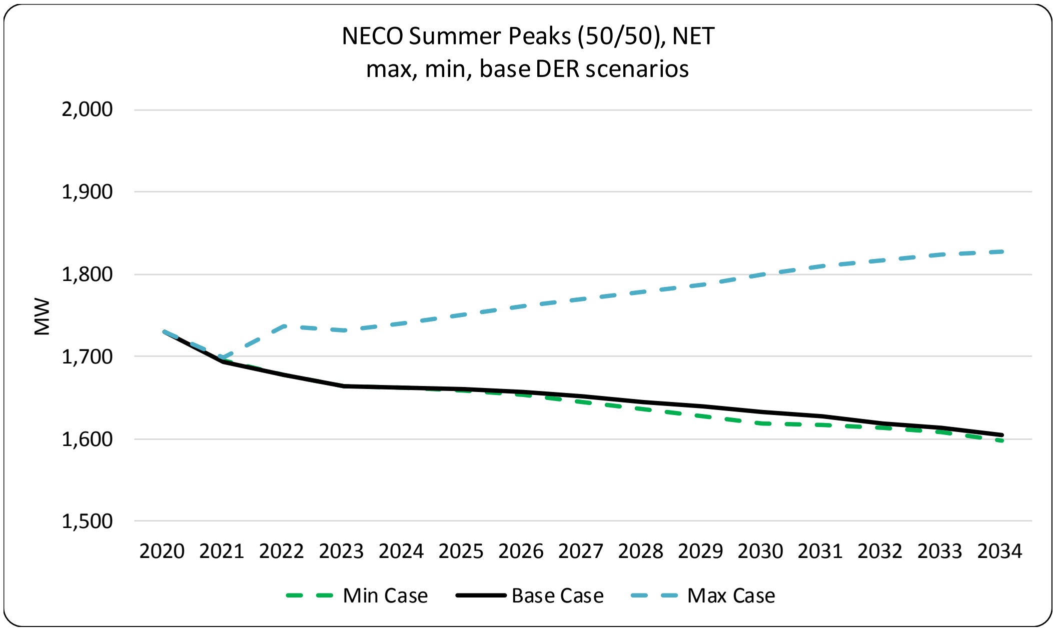


Figure 10: Annual Summer Peaks for Base Case, Maximum and Minimum Cases

Figure 10 is similar to the Figure 9, however with only the maximum, minimum and base cases shown. It should be noted that no attempt to put probabilities on these cases are made in this forecast and the likelihood of either the maximum or minimum may be low or high. Figure 10 shows that the range five years from now in year 2024 ranges from about 1,660 MW to 1,740 MW - an 80 MW spread, with the base case at 1,662 MW. The uncertainty increases over time, so that fifteen years from now in year 2034, the range expands from about 1,600 MW to about 1,825 MW, or about a 225 MW spread, with the base case at 1,606 MW. It is noted that the base case is very close to the minimum case, meaning that most of the risk is in the higher load direction. This is expected based on the DER scenarios. Specifically,

- there is no high EE case (i.e. lower loads) in Rhode Island
- there is no high DR case
- there are no energy storage scenarios
- the base and high PV case is the same in the early years. In the mid to later years, the hour of the peak moves to late evening and early night hours where PV does not have significant impact

While the figures above show what the longer term annual single summer peaks look like, Figures 11 and 12 show what the 24-hour peak day profiles might be for selected years.

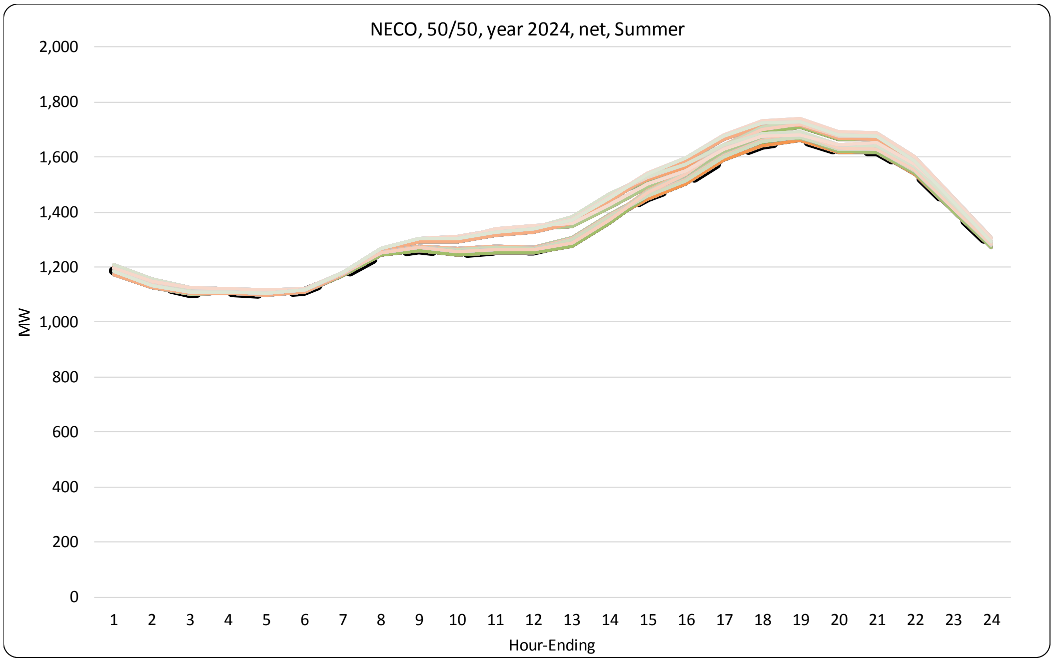


Figure 11: 50/50 case, net summer peak, w/range of DER scenarios, year 2024

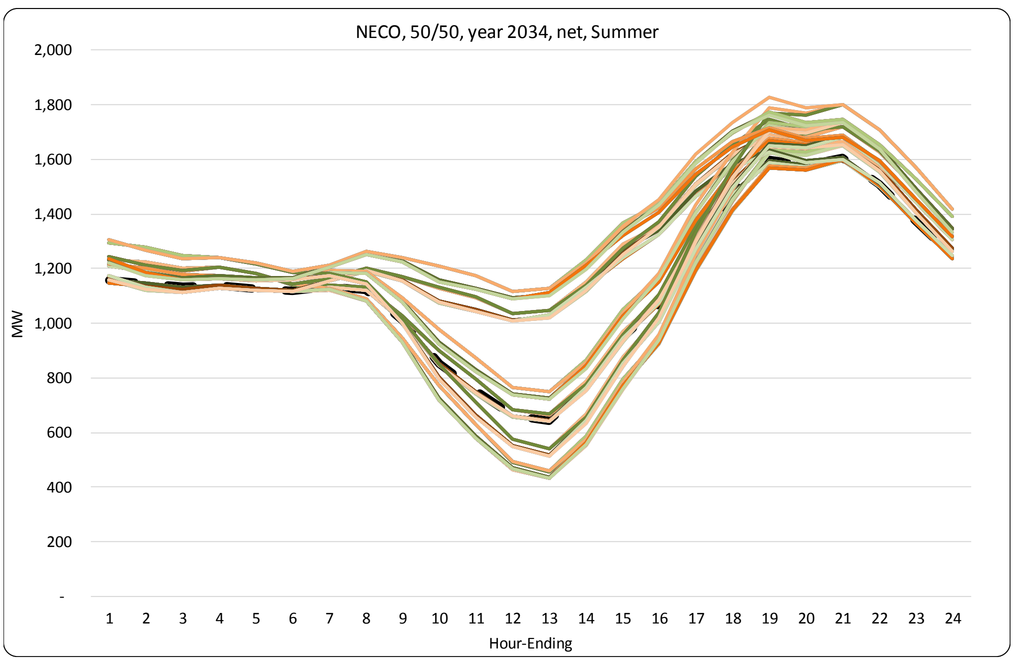


Figure 12: 50/50 case, net summer peak, w/range of DER scenarios, year 2034

What becomes apparent is that the range of possible outcomes in the early years, quickly widens fifteen years out. Note that the mid-day hours have a wider range of possible loads than other times of the day.

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 sector and electrification of the heating sector. The Company is actively monitoring these processes and will incorporate, as appropriate, new policies and scenarios as they become more likely. In addition, no attempt to put probabilities on any of the base, higher or lower scenarios are made in this forecast. The Company is investigating adding probabilities for future iterations of this report. 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.

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
2003	1,670		1,815		1,965		2,008		80.1
2004	1,628	-2.5%	1,851	2.0%	2,009	2.2%	2,054	2.3%	78.5
2005	1,805	10.8%	1,784	-3.6%	1,941	-3.4%	1,986	-3.3%	83.1
2006	1,985	10.0%	1,814	1.7%	1,956	0.7%	1,994	0.4%	85.9
2007	1,777	-10.5%	1,864	2.7%	2,023	3.4%	2,068	3.7%	80.9
2008	1,824	2.6%	1,828	-1.9%	1,980	-2.1%	2,023	-2.2%	82.9
2009	1,713	-6.1%	1,829	0.1%	2,004	1.2%	2,054	1.5%	80.3
2010	1,872	9.3%	1,812	-1.0%	1,986	-0.9%	2,035	-0.9%	84.5
2011	1,974	5.5%	1,831	1.0%	2,003	0.9%	2,052	0.8%	84.8
2012	1,892	-4.2%	1,835	0.2%	1,993	-0.5%	2,038	-0.7%	83.5
2013	1,965	3.9%	1,831	-0.2%	2,003	0.5%	2,052	0.7%	84.7
2014	1,653	-15.9%	1,824	-0.4%	1,998	-0.2%	2,048	-0.2%	80.4
2015	1,738	5.1%	1,865	2.2%	2,053	2.8%	2,107	2.9%	80.4
2016	1,803	3.8%	1,791	-3.9%	1,964	-4.3%	2,013	-4.4%	82.6
2017	1,688	-6.4%	1,737	-3.0%	1,910	-2.7%	1,960	-2.7%	81.7
2018	1,847	9.4%	1,785	2.8%	1,961	2.6%	2,010	2.6%	83.4
2019	1,750	-5.3%	1,753	-1.8%	1,957	-0.2%	2,015	0.2%	84.5
2020	-	-	1,730	-1.3%	1,943	-0.7%	2,003	-0.6%	-
2021	-	-	1,694	-2.1%	1,905	-2.0%	1,965	-1.9%	-
2022	-	-	1,678	-1.0%	1,892	-0.7%	1,953	-0.6%	-
2023	-	-	1,665	-0.8%	1,878	-0.7%	1,940	-0.7%	-
2024	-	-	1,662	-0.1%	1,875	-0.2%	1,935	-0.3%	-
2025	-	-	1,660	-0.1%	1,876	0.1%	1,937	0.1%	-
2026	-	-	1,657	-0.2%	1,876	0.0%	1,938	0.0%	-
2027	-	-	1,652	-0.3%	1,873	-0.2%	1,936	-0.1%	-
2028	-	-	1,645	-0.4%	1,869	-0.2%	1,932	-0.2%	-
2029	-	-	1,639	-0.4%	1,864	-0.2%	1,928	-0.2%	-
2030	-	-	1,633	-0.3%	1,861	-0.2%	1,926	-0.2%	-
2031	-	-	1,627	-0.4%	1,856	-0.3%	1,921	-0.2%	-
2032	-	-	1,619	-0.5%	1,849	-0.3%	1,915	-0.3%	-
2033	-	-	1,614	-0.3%	1,841	-0.5%	1,907	-0.4%	-
2034	-	-	1,605	-0.5%	1,828	-0.7%	1,894	-0.6%	-

	50/50	90/10	
Avg, last 15 yrs	-0.4%	-0.2%	-0.1%
Avg. last 10 yrs	-0.4%	-0.2%	-0.2%
Avg. last 5 yrs	-0.8%	-0.4%	-0.3%
BASE 2019			
Avg. next 5 yrs	-1.1%	-0.9%	-0.8%
Avg. next 10 yrs	-0.7%	-0.5%	-0.4%
Avg. next 15 yrs	-0.6%	-0.5%	-0.4%

WTHI

NORMAL	82.4
EXTREME 90/10	85.3
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)

Calendar Year	SYSTEM PEAK Reconstituted (before DER)	Forecast w/ EE only	Forecast w/ PV only	Forecast w/ EV only	Forecast w/ DR only	Forecast w/ ES only	Final Forecast (after all DER)	DER IMPACTS EE	PV	EV	DR	ES	DER	% of reconstituted peaks EE	PV	EV	DR	ES	DER
2003	1,824	1,815	1,824	1,824	1,824	1,824	**1,815**	9	0	0.0	0.0	0.0	9	0.5%	0.0%	0.0%	0.0%	0.0%	0.5%
2004	1,872	1,851	1,872	1,872	1,872	1,872	**1,851**	21	0	0.0	0.0	0.0	21	1.1%	0.0%	0.0%	0.0%	0.0%	1.1%
2005	1,814	1,784	1,814	1,814	1,814	1,814	**1,784**	30	0	0.0	0.0	0.0	30	1.7%	0.0%	0.0%	0.0%	0.0%	1.7%
2006	1,856	1,815	1,855	1,856	1,856	1,856	**1,814**	41	0	0.0	0.0	0.0	41	2.2%	0.0%	0.0%	0.0%	0.0%	2.2%
2007	1,915	1,864	1,915	1,915	1,915	1,915	**1,864**	51	0	0.0	0.0	0.0	51	2.7%	0.0%	0.0%	0.0%	0.0%	2.7%
2008	1,890	1,829	1,890	1,890	1,890	1,890	**1,828**	61	0	0.0	0.0	0.0	62	3.2%	0.0%	0.0%	0.0%	0.0%	3.3%
2009	1,907	1,830	1,906	1,907	1,907	1,907	**1,829**	77	1	0.0	0.0	0.0	77	4.0%	0.0%	0.0%	0.0%	0.0%	4.0%
2010	1,901	1,812	1,901	1,901	1,901	1,901	**1,812**	89	1	0.0	0.0	0.0	90	4.7%	0.0%	0.0%	0.0%	0.0%	4.7%
2011	1,933	1,832	1,932	1,933	1,933	1,933	**1,831**	102	1	0.0	0.0	0.0	103	5.3%	0.1%	0.0%	0.0%	0.0%	5.3%
2012	1,957	1,836	1,955	1,957	1,957	1,957	**1,835**	121	2	0.0	0.0	0.0	123	6.2%	0.1%	0.0%	0.0%	0.0%	6.3%
2013	1,988	1,840	1,979	1,988	1,988	1,988	**1,831**	148	9	0.0	0.0	0.0	157	7.4%	0.4%	0.0%	0.0%	0.0%	7.9%
2014	2,021	1,835	2,011	2,021	2,021	2,021	**1,824**	187	11	0.0	0.0	0.0	197	9.2%	0.5%	0.0%	0.0%	0.0%	9.8%
2015	2,100	1,880	2,085	2,100	2,100	2,100	**1,865**	220	16	0.1	0.0	0.0	236	10.5%	0.7%	0.0%	0.0%	0.0%	11.2%
2016	2,064	1,813	2,042	2,064	2,064	2,064	**1,791**	250	22	0.1	0.0	0.0	272	12.1%	1.1%	0.0%	0.0%	0.0%	13.2%
2017	2,062	1,782	2,025	2,062	2,053	2,062	**1,737**	280	37	0.1	8.3	0.0	325	13.6%	1.8%	0.0%	0.4%	0.0%	15.8%
2018	2,165	1,857	2,116	2,165	2,142	2,165	**1,785**	308	49	0.2	22.8	0.0	379	14.2%	2.3%	0.0%	1.1%	0.0%	17.5%
2019	2,172	1,834	2,118	2,172	2,145	2,172	**1,753**	338	54	0.4	27.3	0.0	418	15.6%	2.5%	0.0%	1.3%	0.0%	19.3%
2020	2,269	1,903	2,134	2,270	2,232	2,269	**1,730**	367	136	0.5	37.7	0.0	540	16.2%	6.0%	0.0%	1.7%	0.0%	23.8%
2021	2,238	1,842	2,134	2,239	2,193	2,238	**1,694**	395	104	0.8	45.0	0.0	544	17.7%	4.6%	0.0%	2.0%	0.0%	24.3%
2022	2,273	1,851	2,144	2,274	2,228	2,273	**1,678**	422	129	1.0	45.7	0.0	596	18.6%	5.7%	0.0%	2.0%	0.0%	26.2%
2023	2,209	1,762	2,156	2,212	2,163	2,209	**1,665**	447	54	2.4	46.5	0.0	545	20.2%	2.4%	0.1%	2.1%	0.0%	24.7%
2024	2,239	1,768	2,177	2,242	2,192	2,239	**1,662**	471	62	3.1	47.2	0.0	577	21.0%	2.8%	0.1%	2.1%	0.0%	25.8%
2025	2,268	1,774	2,198	2,272	2,220	2,268	**1,660**	494	70	3.8	47.9	0.0	608	21.8%	3.1%	0.2%	2.1%	0.0%	26.8%
2026	2,294	1,778	2,217	2,298	2,245	2,294	**1,657**	515	77	4.6	48.6	0.0	637	22.5%	3.4%	0.2%	2.1%	0.0%	27.8%
2027	2,316	1,780	2,232	2,322	2,267	2,316	**1,652**	536	84	5.4	49.4	0.0	664	23.1%	3.6%	0.2%	2.1%	0.0%	28.7%
2028	2,336	1,780	2,245	2,342	2,286	2,336	**1,645**	556	91	6.4	50.1	0.0	691	23.8%	3.9%	0.3%	2.1%	0.0%	29.6%
2029	2,354	1,780	2,256	2,361	2,303	2,354	**1,639**	574	98	7.4	50.8	0.0	715	24.4%	4.1%	0.3%	2.2%	0.0%	30.4%
2030	2,372	1,780	2,268	2,380	2,320	2,372	**1,633**	592	104	8.5	51.5	0.0	739	24.9%	4.4%	0.4%	2.2%	0.0%	31.1%
2031	2,387	1,779	2,278	2,397	2,335	2,387	**1,627**	608	110	9.6	52.2	0.0	761	25.5%	4.6%	0.4%	2.2%	0.0%	31.9%
2032	2,285	1,661	2,285	2,296	2,233	2,285	**1,619**	624	0	10.9	52.8	0.0	666	27.3%	0.0%	0.5%	2.3%	0.0%	29.2%
2033	2,295	1,655	2,295	2,307	2,242	2,295	**1,614**	640	0	11.9	53.4	0.0	681	27.9%	0.0%	0.5%	2.3%	0.0%	29.7%
2034	2,300	1,647	2,300	2,313	2,247	2,300	**1,605**	654	0	12.8	54.0	0.0	695	28.4%	0.0%	0.6%	2.3%	0.0%	30.2%

Avg, last 15 yrs	1.0%	-0.1%	0.8%	1.0%	0.9%	1.0%	**-0.4%**
Avg. last 10 yrs	1.3%	0.0%	1.1%	1.3%	1.2%	1.3%	**-0.4%**
Avg. last 5 yrs	1.4%	0.0%	1.0%	1.4%	1.2%	1.4%	**-0.8%**
BASE 2019							
Avg. next 5 yrs	0.6%	-0.7%	0.6%	0.6%	0.4%	0.6%	**-1.1%**
Avg. next 10 yrs	0.8%	-0.3%	0.6%	0.8%	0.7%	0.8%	**-0.7%**
Avg. next 15 yrs	0.4%	-0.7%	0.6%	0.4%	0.3%	0.4%	**-0.6%**

EE: Energy Efficiency
PV: Solar - Photovoltaics
EV: Electric Vehicles
DR: Demand Response (Company only)
ES: Energy Storage

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
2003	1,389		1,389		1,389		1,389		55.7
2004	1,394	0.4%	1,428	2.8%	1,484	6.8%	1,500	7.9%	36.7
2005	1,329	-4.6%	1,324	-7.3%	1,375	-7.3%	1,390	-7.3%	45.0
2006	1,329	0.0%	1,317	-0.5%	1,369	-0.5%	1,384	-0.4%	45.5
2007	1,352	1.7%	1,327	0.8%	1,378	0.6%	1,392	0.6%	44.8
2008	1,305	-3.5%	1,317	-0.8%	1,371	-0.5%	1,387	-0.4%	40.0
2009	1,294	-0.8%	1,328	0.9%	1,386	1.1%	1,402	1.1%	35.0
2010	1,315	1.6%	1,265	-4.8%	1,324	-4.5%	1,340	-4.4%	53.1
2011	1,243	-5.5%	1,251	-1.1%	1,309	-1.1%	1,325	-1.1%	41.6
2012	1,320	6.2%	1,290	3.1%	1,347	3.0%	1,364	2.9%	51.9
2013	1,328	0.7%	1,324	2.6%	1,382	2.6%	1,399	2.6%	43.9
2014	1,275	-4.0%	1,229	-7.1%	1,288	-6.8%	1,305	-6.7%	52.2
2015	1,223	-4.1%	1,201	-2.3%	1,255	-2.6%	1,270	-2.7%	55.0
2016	1,239	1.3%	1,278	6.4%	1,344	7.1%	1,362	7.3%	35.9
2017	1,277	3.1%	1,206	-5.6%	1,283	-4.5%	1,305	-4.2%	53.8
2018	1,301	1.9%	1,250	3.7%	1,320	2.9%	1,340	2.6%	51.0
2019	-	-	1,234	-1.3%	1,305	-1.2%	1,325	-1.1%	-
2020	-	-	1,214	-1.6%	1,287	-1.4%	1,307	-1.4%	-
2021	-	-	1,196	-1.5%	1,270	-1.3%	1,291	-1.2%	-
2022	-	-	1,180	-1.4%	1,255	-1.2%	1,277	-1.1%	-
2023	-	-	1,165	-1.2%	1,242	-1.0%	1,264	-1.0%	-
2024	-	-	1,152	-1.1%	1,231	-0.9%	1,253	-0.9%	-
2025	-	-	1,141	-1.0%	1,221	-0.8%	1,243	-0.8%	-
2026	-	-	1,130	-0.9%	1,212	-0.7%	1,235	-0.7%	-
2027	-	-	1,122	-0.8%	1,205	-0.6%	1,229	-0.6%	-
2028	-	-	1,114	-0.7%	1,199	-0.5%	1,223	-0.4%	-
2029	-	-	1,108	-0.6%	1,194	-0.4%	1,219	-0.3%	-
2030	-	-	1,103	-0.4%	1,191	-0.3%	1,216	-0.3%	-
2031	-	-	1,099	-0.4%	1,188	-0.2%	1,214	-0.2%	-
2032	-	-	1,096	-0.3%	1,187	-0.1%	1,212	-0.1%	-
2033	-	-	1,094	-0.2%	1,186	-0.1%	1,212	0.0%	-

	Normal 50-50	Extreme 10-90	Extreme 05-95
Avg, last 15 yrs	-0.7%	-0.3%	-0.2%
Avg. last 10 yrs	-0.5%	-0.4%	-0.3%
Avg. last 5 yrs	-1.1%	-0.9%	-0.9%
BASE 2018			
Avg. next 5 yrs	-1.4%	-1.2%	-1.2%
Avg. next 10 yrs	-1.1%	-1.0%	-0.9%
Avg. next 14 yrs	-0.9%	-0.8%	-0.7%

HDD_wtd

NORMAL	43.8
EXTREME 90/10	54.7
EXTREME 95/5	57.8

**** 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)***

Appendix B: Historical Peaks Days and Hours

Summer Peaks

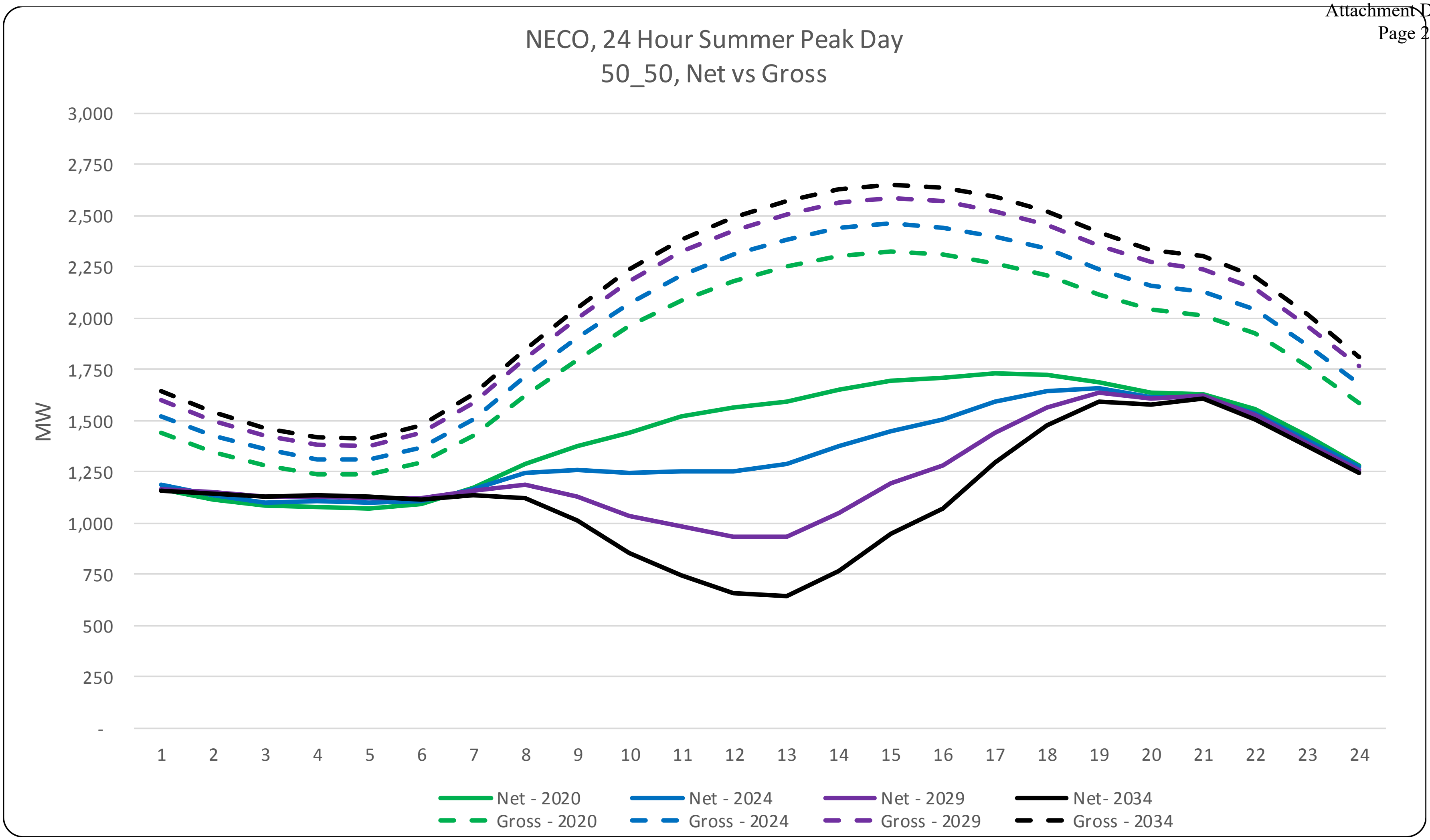
Year	Date	Hour-Ending
2003	8/22/2003	15
2004	8/30/2004	15
2005	8/5/2005	15
2006	8/2/2006	15
2007	8/3/2007	15
2008	6/10/2008	15
2009	8/18/2009	15
2010	7/6/2010	15
2011	7/22/2011	16
2012	7/18/2012	15
2013	7/19/2013	15
2014	9/2/2014	16
2015	7/20/2015	15
2016	8/12/2016	16
2017	7/20/2017	16
2018	8/29/2018	17
2019	7/21/2019	18

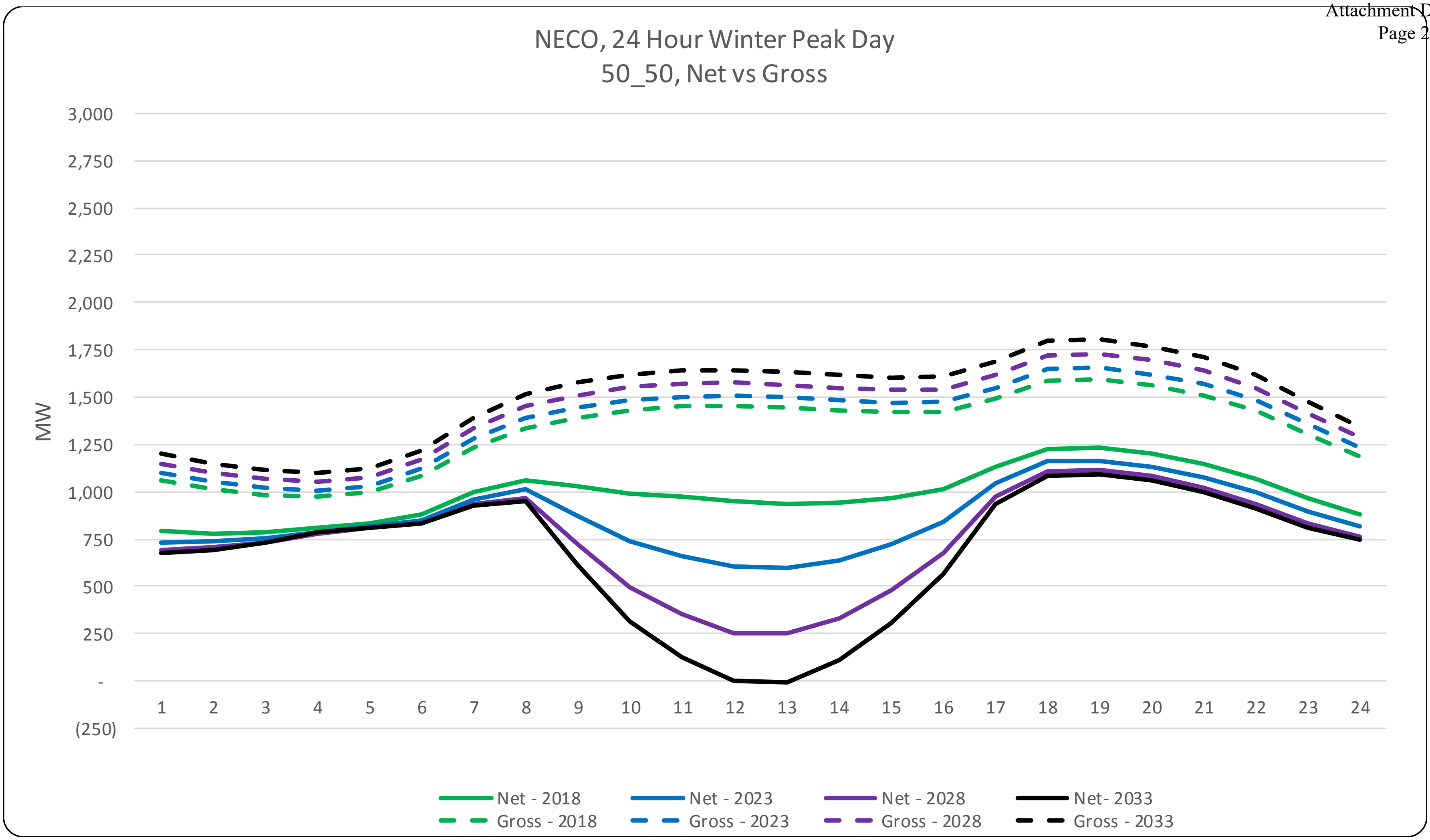
Winter Peaks

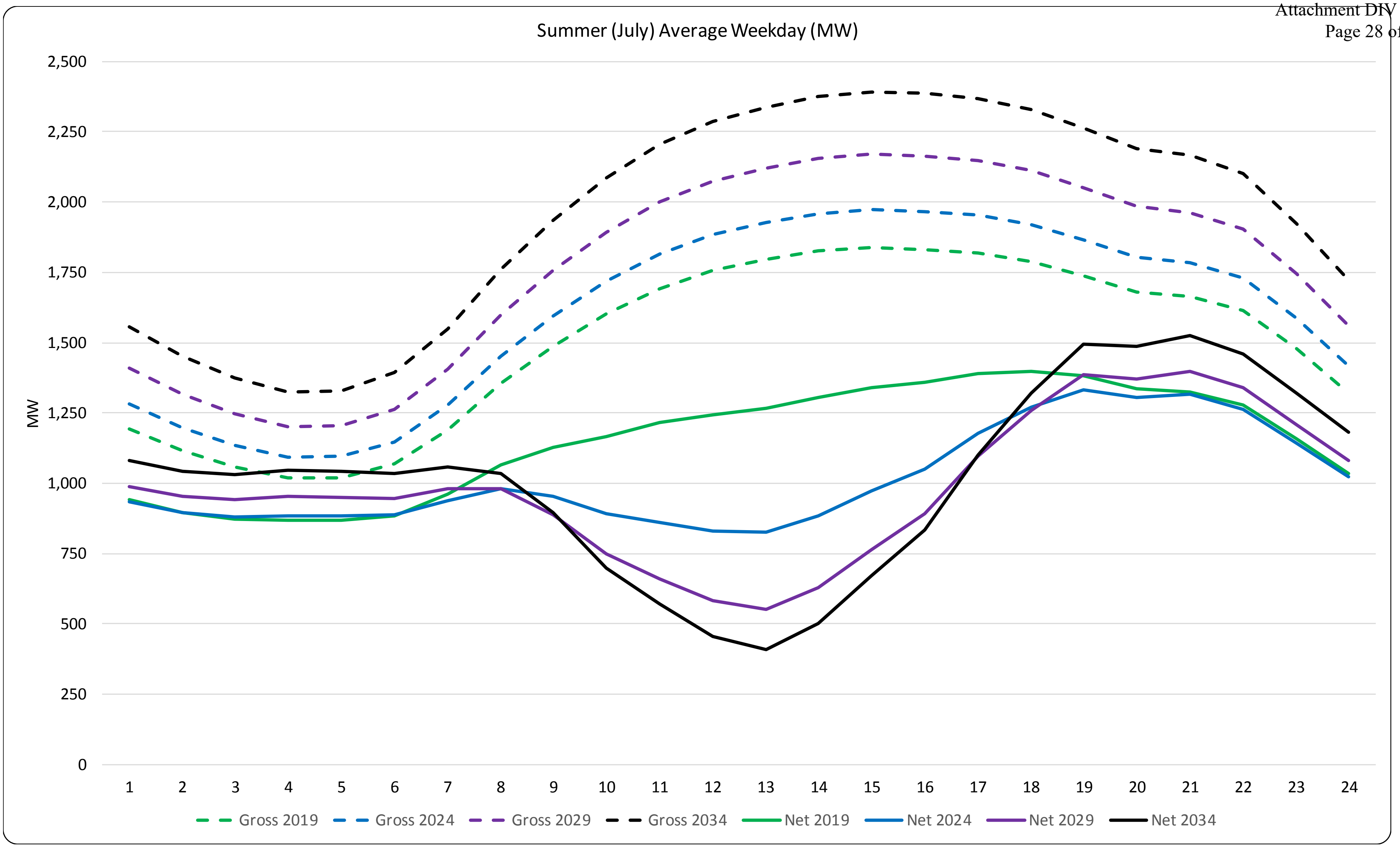
Year	Date	Hour-Ending
2003-04	1/15/2004	19
2004-05	12/20/2004	19
2005-06	12/14/2005	18
2006-07	2/5/2007	19
2007-08	1/3/2008	19
2008-09	12/8/2008	18
2009-10	12/29/2009	19
2010-11	1/24/2011	19
2011-12	1/4/2012	18
2012-13	1/24/2013	19
2013-14	12/17/2013	18
2014-15	1/8/2015	18
2015-16	2/15/2016	19
2016-17	12/15/2016	18
2017-18	1/2/2018	19
2018-19	1/21/2019	18

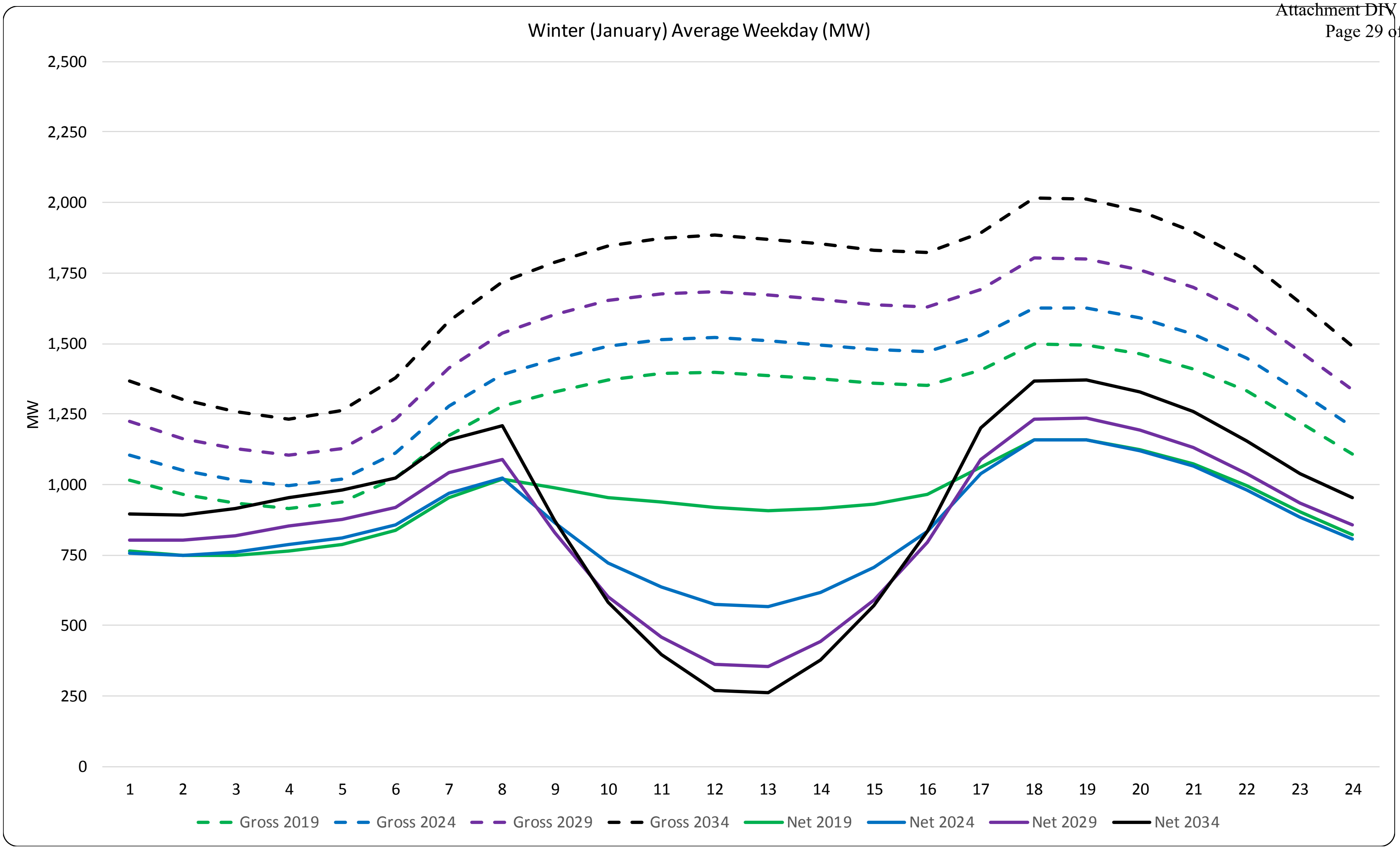
Appendix C: Load Shapes for Typical Day Types

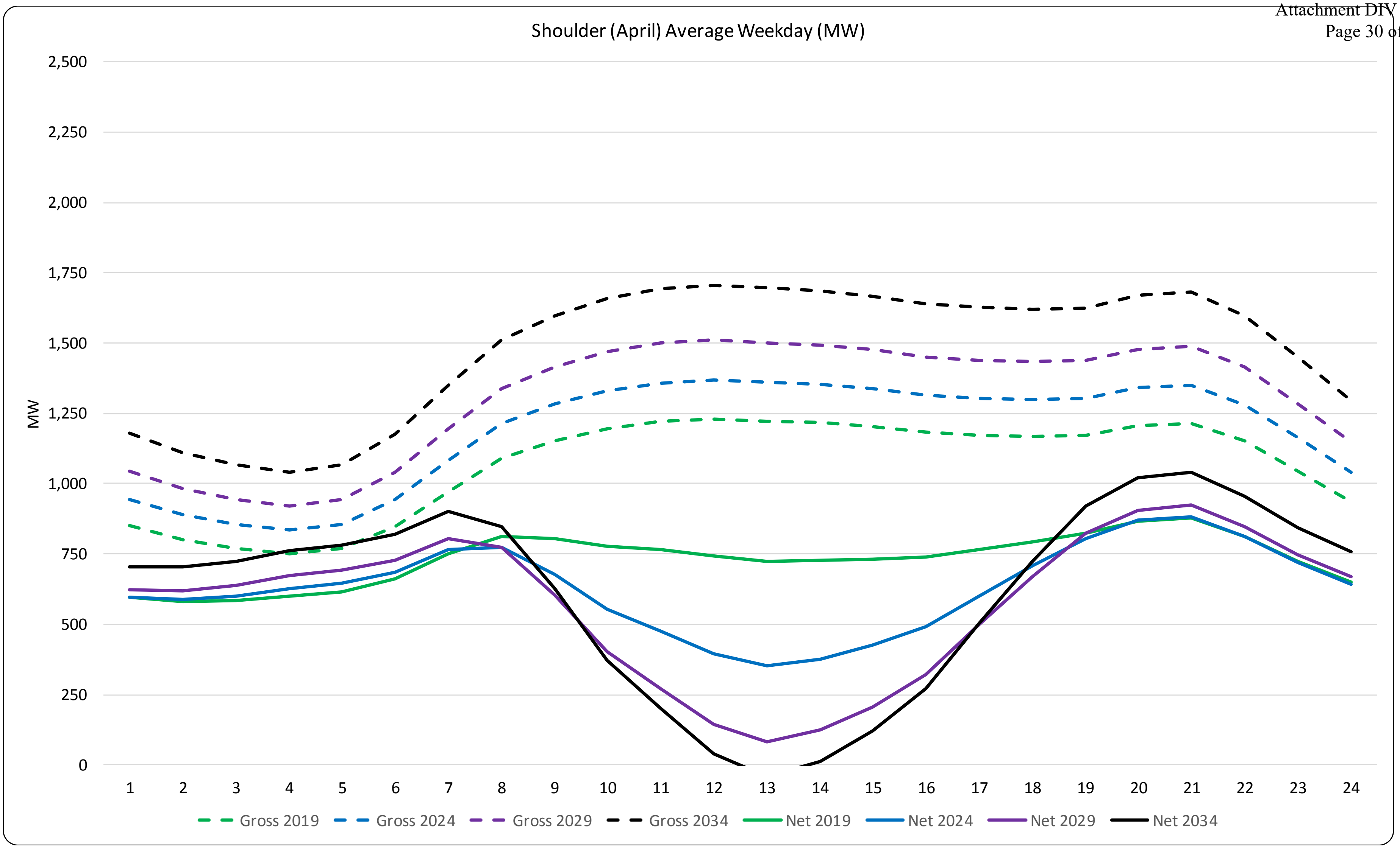
(for Base Case)

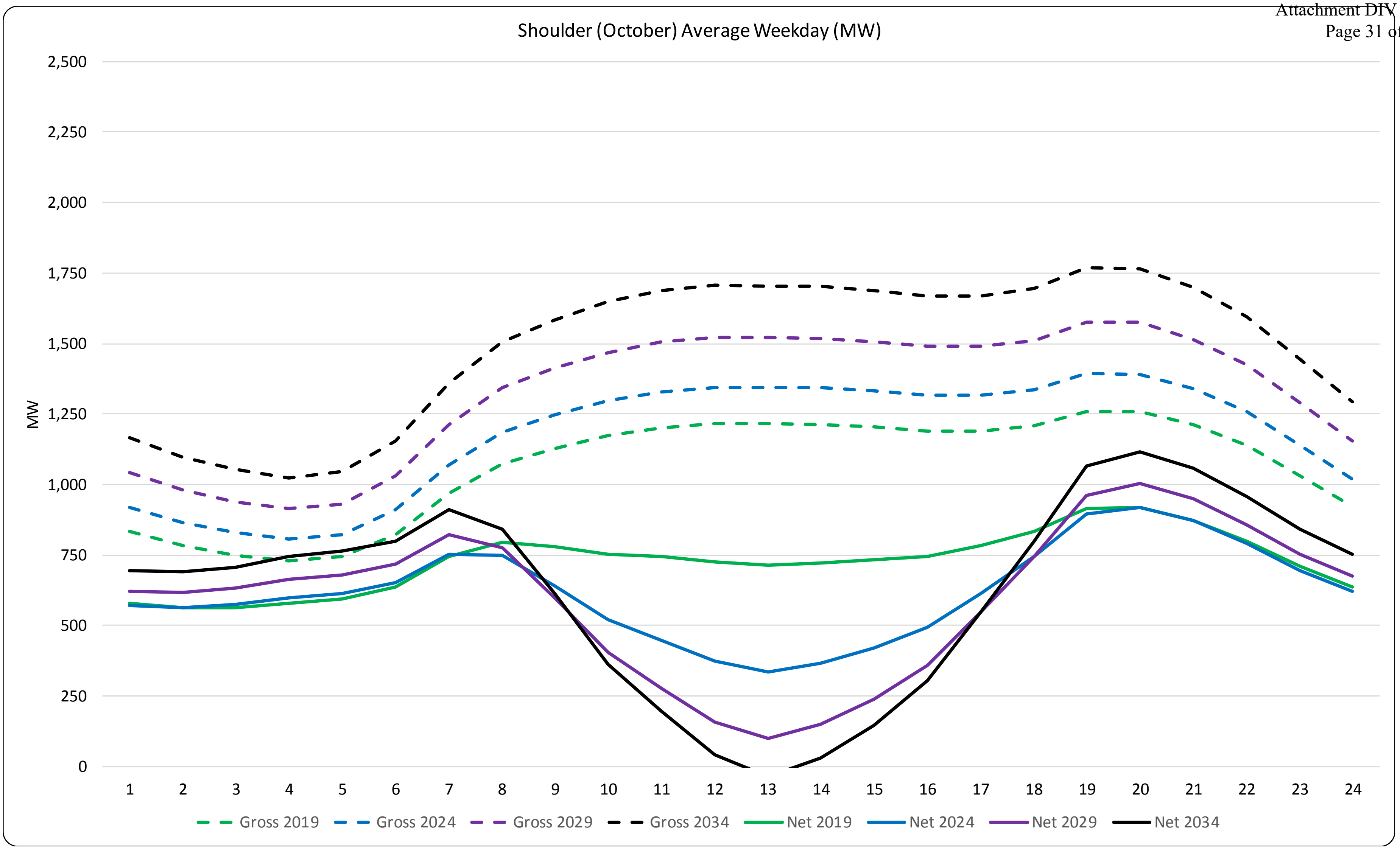

NECO, 24 Hour Summer Peak Day
50_50, Net vs Gross
MW
3,000
2,750
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Net - 2020
Net - 2024
Net - 2029
Net- 2034
Gross - 2020
Gross - 2024
Gross - 2029
Gross - 2034

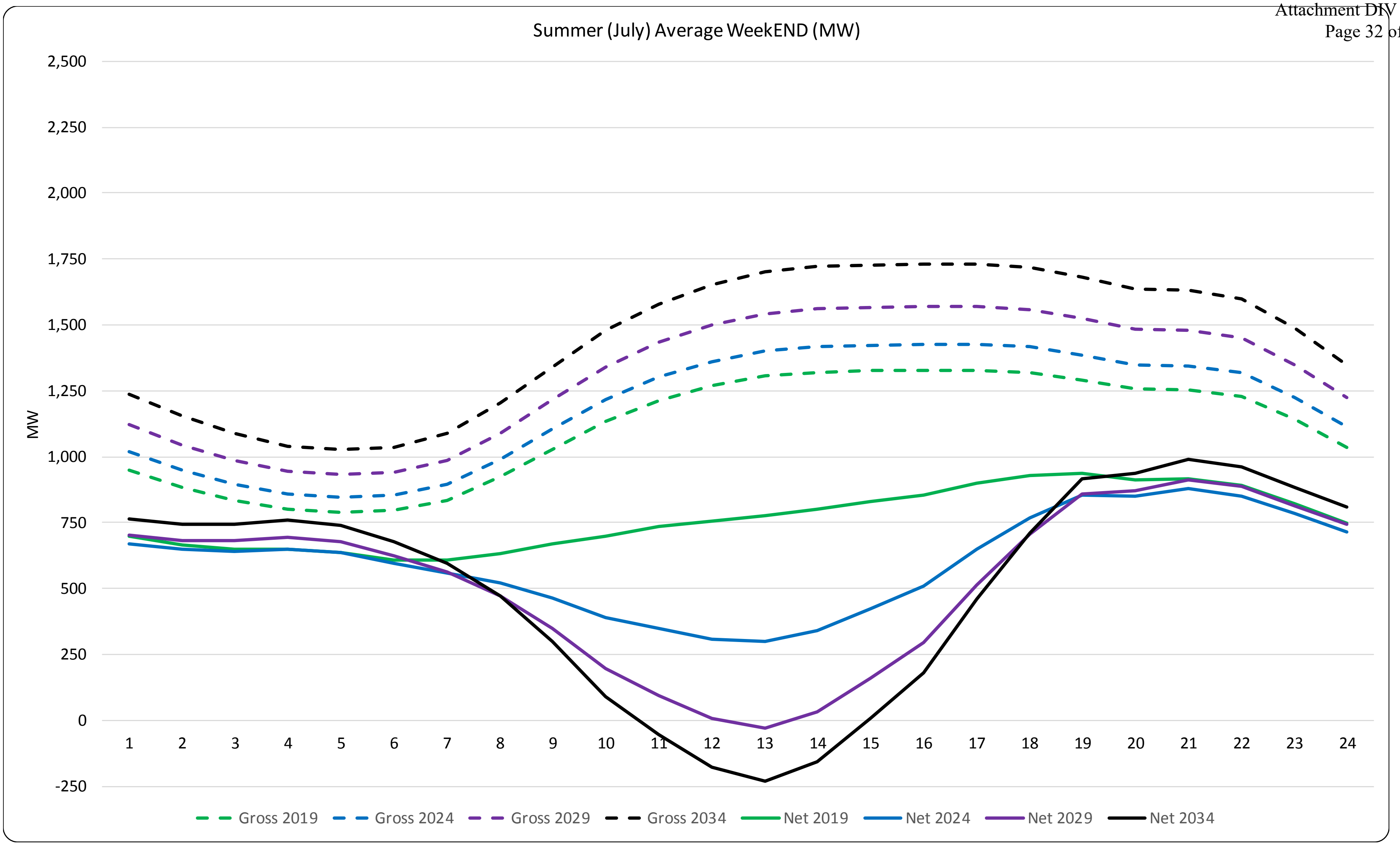

NECO, 24 Hour Winter Peak Day
50_50, Net vs Gross
MW
3,000
2,750
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
-
(250)
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Net - 2018
Net - 2023
Net - 2028
Net- 2033
Gross - 2018
Gross - 2023
Gross - 2028
Gross - 2033

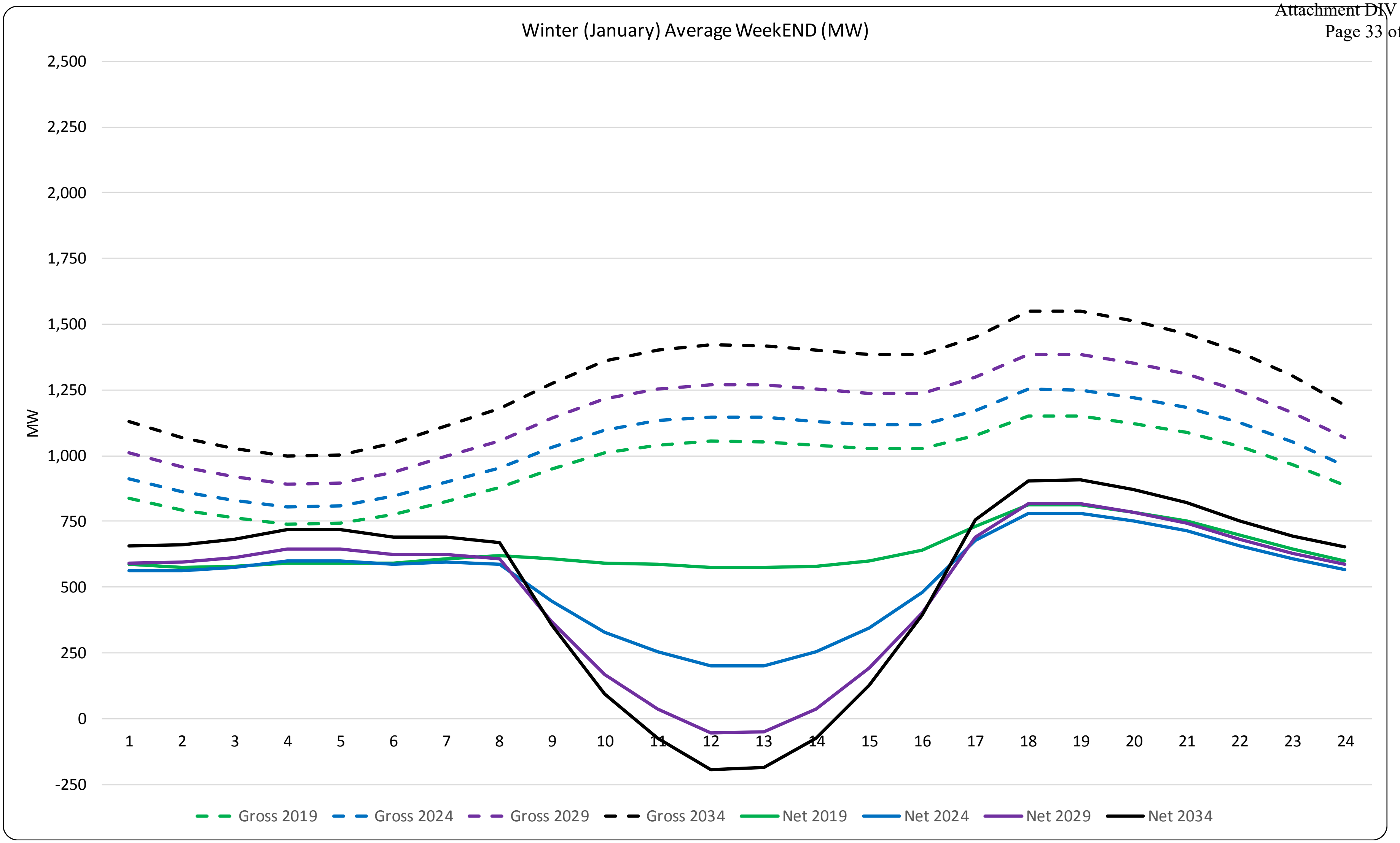

Summer (July) Average Weekday (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2019
Gross 2024
Gross 2029
Gross 2034
Net 2019
Net 2024
Net 2029
Net 2034

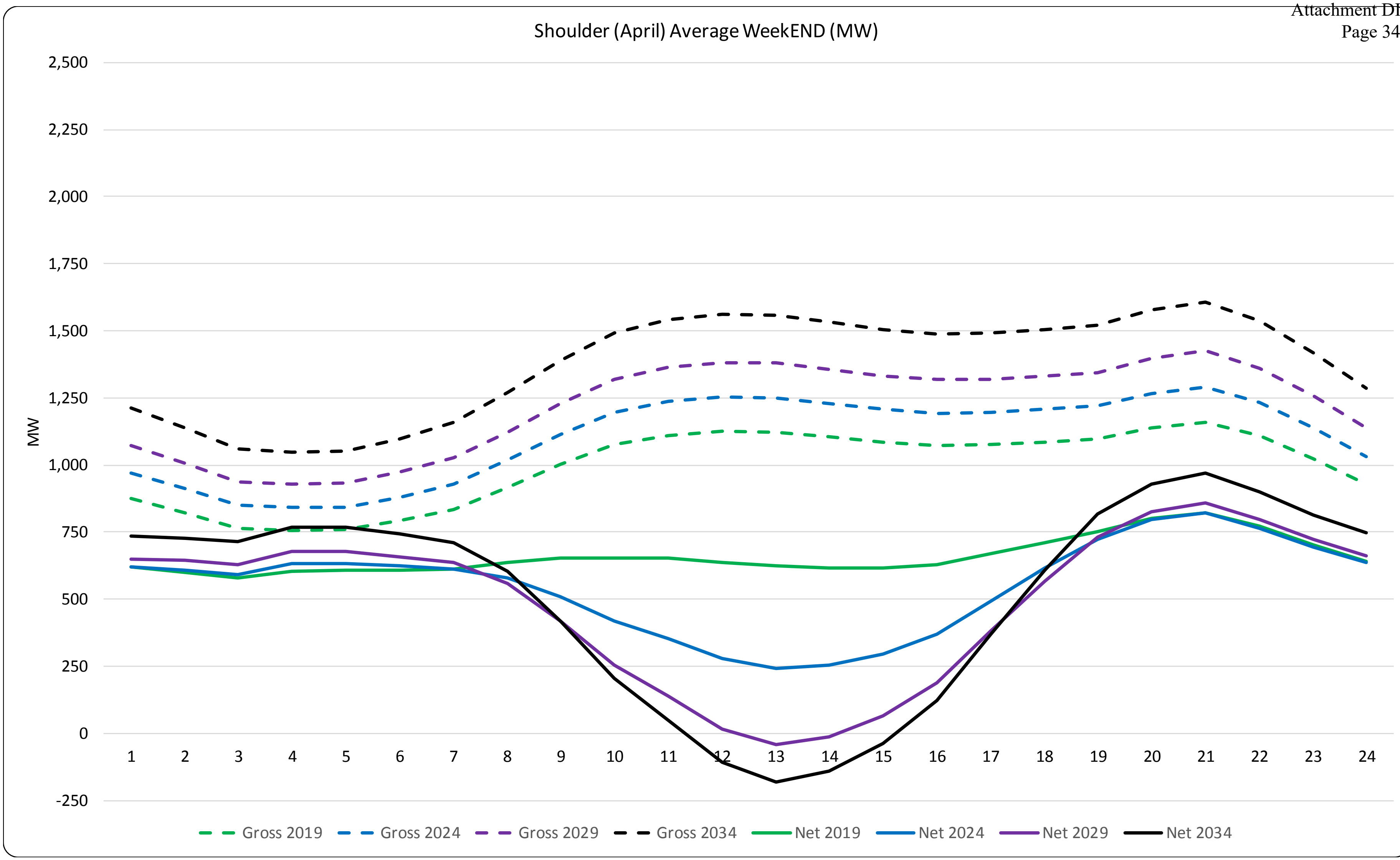

Winter (January) Average Weekday (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2019
Gross 2024
Gross 2029
Gross 2034
Net 2019
Net 2024
Net 2029
Net 2034

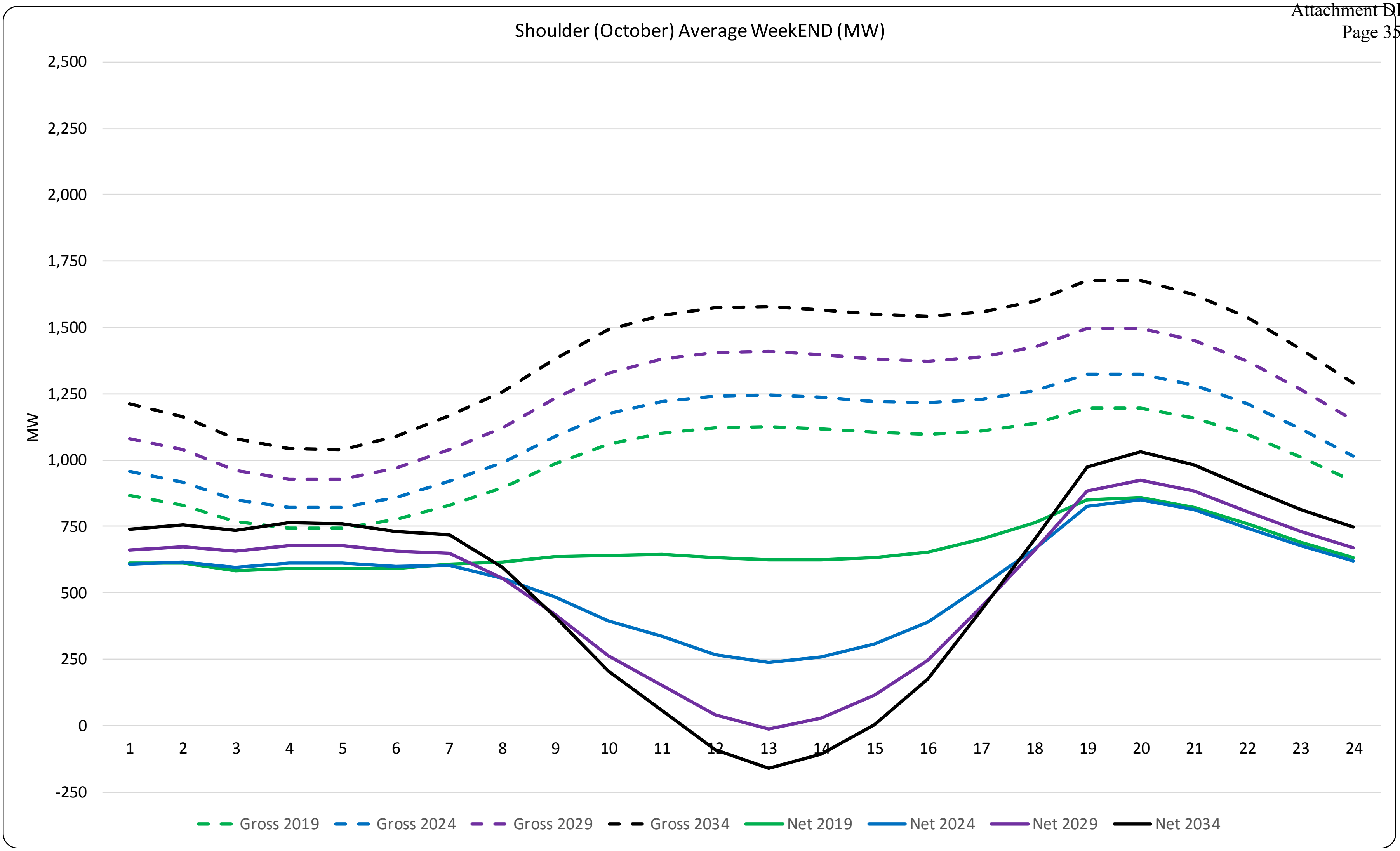

Shoulder (April) Average Weekday (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2019
Gross 2024
Gross 2029
Gross 2034
Net 2019
Net 2024
Net 2029
Net 2034


Shoulder (October) 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 2019
Gross 2024
Gross 2029
Gross 2034
Net 2019
Net 2024
Net 2029
Net 2034


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 2019
Gross 2024
Gross 2029
Gross 2034
Net 2019
Net 2024
Net 2029
Net 2034


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 2019
Gross 2024
Gross 2029
Gross 2034
Net 2019
Net 2024
Net 2029
Net 2034

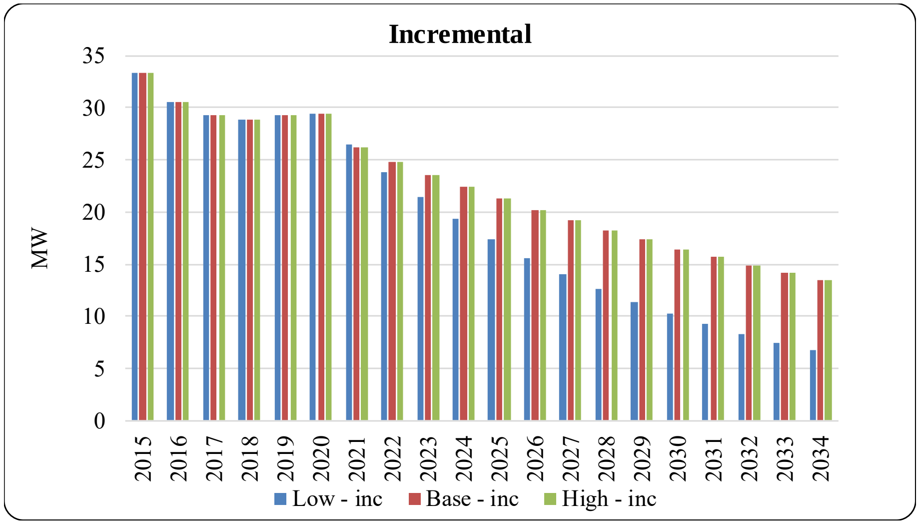

Shoulder (April) Average WeekEND (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
-250
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2019
Gross 2024
Gross 2029
Gross 2034
Net 2019
Net 2024
Net 2029
Net 2034

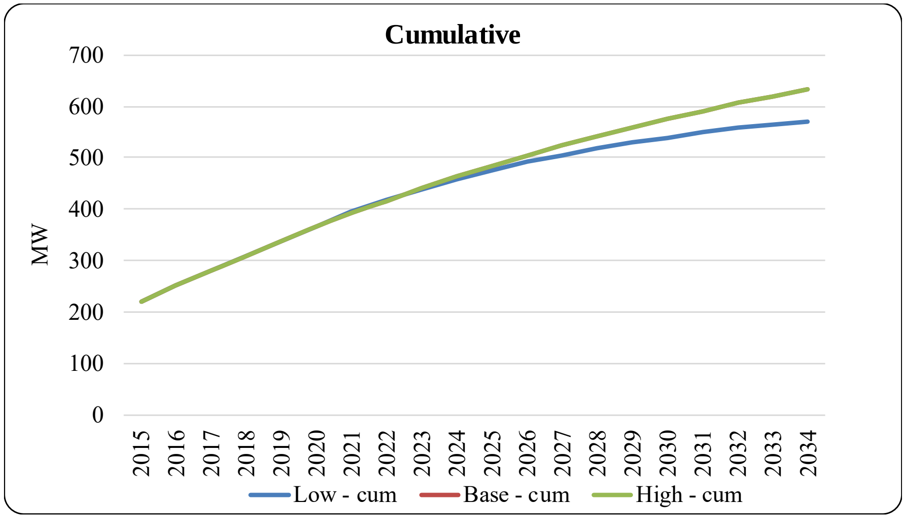

Shoulder (October) Average WeekEND (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
-250
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2019
Gross 2024
Gross 2029
Gross 2034
Net 2019
Net 2024
Net 2029
Net 2034

Appendix D: DER Scenarios Inputs

Energy Efficiency (NECO)

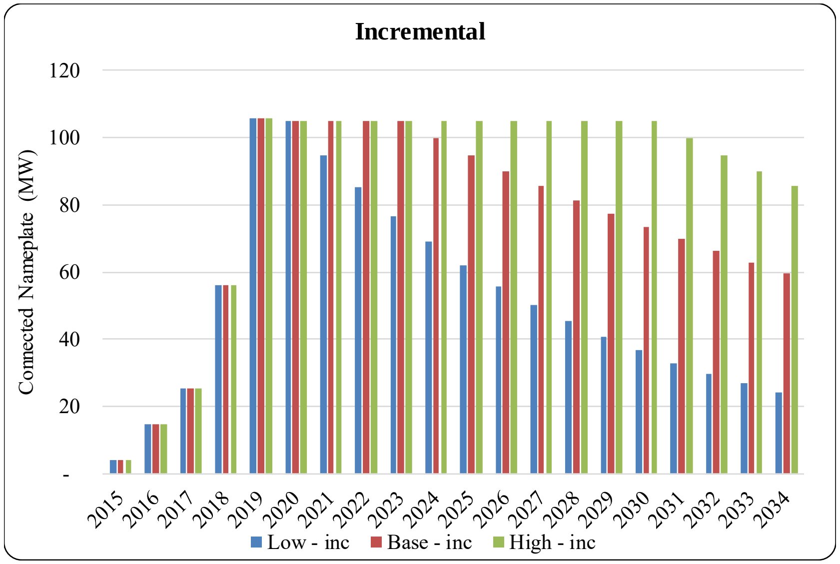
Summer Peak MWs						
Year	**Low - inc**	**Low - cum**	**Base - inc**	**Base - cum**	**High - inc**	**High - cum**
2015	33.3	219.9	33.3	219.9	33.3	219.9
2016	30.5	250.4	30.5	250.4	30.5	250.4
2017	29.4	279.8	29.4	279.8	29.4	279.8
2018	28.8	308.6	28.8	307.7	28.8	307.7
2019	29.3	337.9	29.3	336.7	29.3	336.7
2020	29.4	367.3	29.4	365.7	29.4	365.7
2021	26.5	393.8	26.2	391.8	26.2	391.8
2022	23.8	417.7	24.9	416.7	24.9	416.7
2023	21.5	439.1	23.6	440.3	23.6	440.3
2024	19.3	458.4	22.4	462.8	22.4	462.8
2025	17.4	475.8	21.3	484.1	21.3	484.1
2026	15.6	491.5	20.3	504.3	20.3	504.3
2027	14.1	505.5	19.2	523.6	19.2	523.6
2028	12.7	518.2	18.3	541.8	18.3	541.8
2029	11.4	529.6	17.4	559.2	17.4	559.2
2030	10.3	539.9	16.5	575.7	16.5	575.7
2031	9.2	549.1	15.7	591.4	15.7	591.4
2032	8.3	557.4	14.9	606.3	14.9	606.3
2033	7.5	564.9	14.1	620.4	14.1	620.4
2034	6.7	571.6	13.4	633.8	13.4	633.8

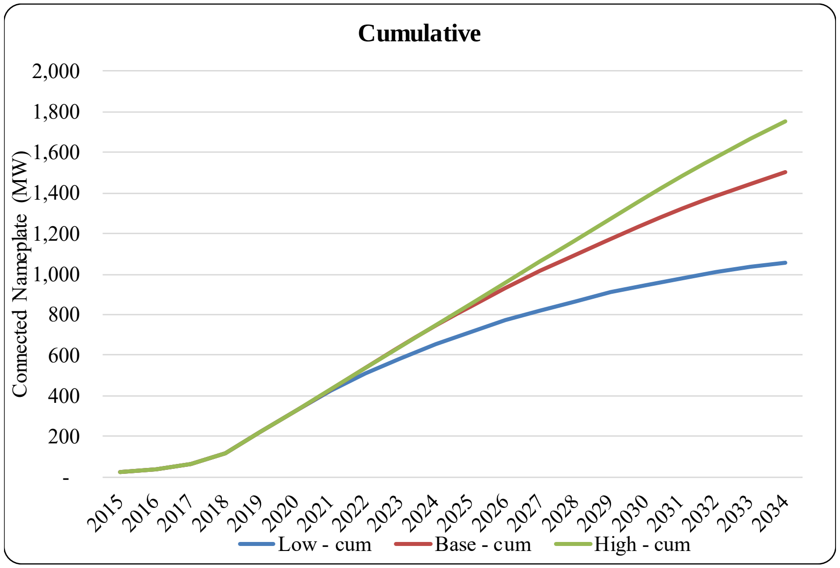




Solar – PV (NECO)

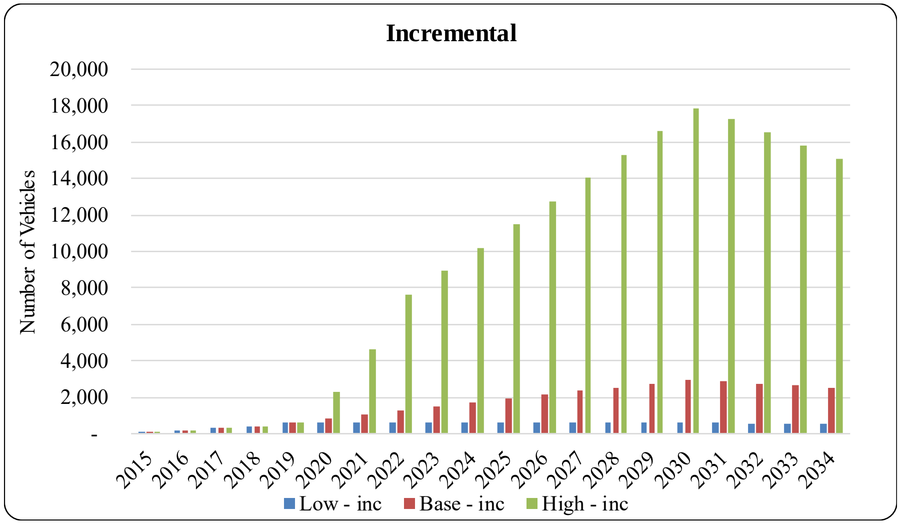
Connected Nameplate (MW)						
Year	**Low - inc**	**Low - cum**	**Base - inc**	**Base - cum**	**High - inc**	**High - cum**
2015	4	22	4	22	4	22
2016	15	37	15	37	15	37
2017	25	62	25	62	25	62
2018	56	118	56	118	56	118
2019	106	224	106	224	106	224
2020	105	329	105	329	105	329
2021	95	424	105	434	105	434
2022	85	509	105	539	105	539
2023	77	585	105	644	105	644
2024	69	654	100	744	105	749
2025	62	716	95	839	105	855
2026	56	772	90	929	105	960
2027	50	822	86	1,015	105	1,065
2028	45	868	81	1,096	105	1,170
2029	41	908	77	1,173	105	1,275
2030	37	945	73	1,247	105	1,380
2031	33	978	70	1,317	100	1,480
2032	30	1,008	66	1,383	95	1,575
2033	27	1,035	63	1,446	90	1,665
2034	24	1,059	60	1,506	86	1,751

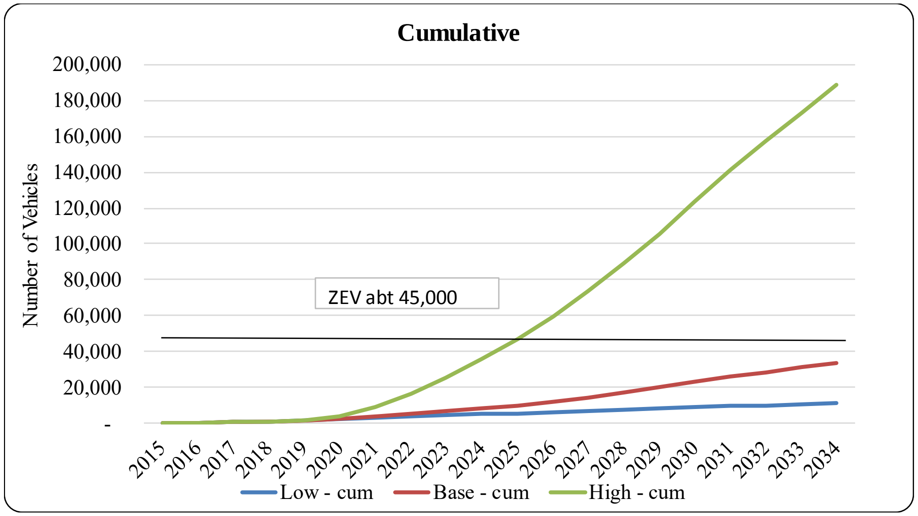




Electric Vehicles (NECO)

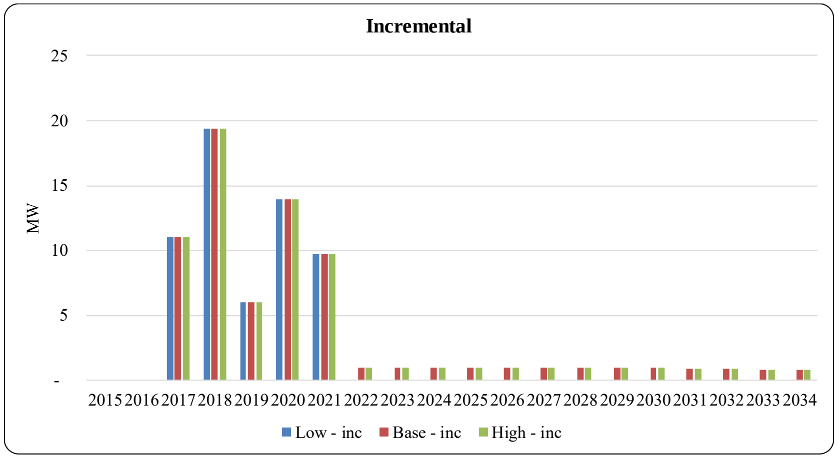
Number of Vehicles						
year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum
2015	120	404	120	404	120	404
2016	155	559	155	559	155	559
2017	318	877	318	877	318	877
2018	397	1,274	397	1,274	397	1,274
2019	639	1,913	639	1,913	639	1,913
2020	637	2,550	850	2,763	2,268	4,181
2021	637	3,186	1,063	3,827	4,607	8,788
2022	637	3,823	1,276	5,103	7,657	16,445
2023	637	4,459	1,489	6,592	8,934	25,379
2024	637	5,096	1,702	8,294	10,211	35,590
2025	637	5,732	1,915	10,208	11,489	47,079
2026	637	6,369	2,128	12,336	12,766	59,845
2027	637	7,006	2,341	14,677	14,043	73,888
2028	637	7,642	2,553	17,230	15,321	89,209
2029	637	8,279	2,766	19,996	16,598	105,807
2030	637	8,915	2,979	22,976	17,875	123,682
2031	605	9,520	2,873	25,848	17,237	140,919
2032	575	10,095	2,758	28,606	16,548	157,467
2033	546	10,640	2,637	31,244	15,824	173,291
2034	518	11,159	2,513	33,757	15,080	188,371

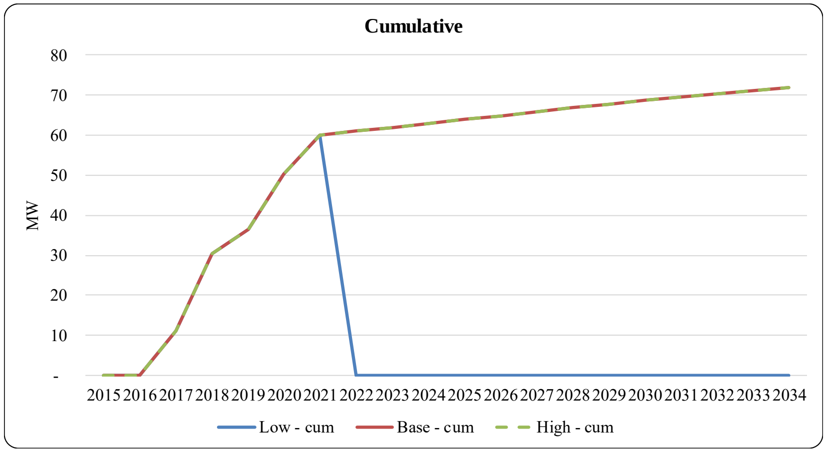




Demand Response (NECO)

Year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum
2015	-	-	-	-	-	-
2016	-	-	-	-	-	-
2017	11	11	11.0	11.0	11.0	11.0
2018	19	30	19.4	30.4	19.4	30.4
2019	6	36	6.0	36.4	6.0	36.4
2020	14	50	13.9	50.3	13.9	50.3
2021	10	60	9.7	60.0	9.7	60.0
2022	-	-	1.0	61.0	1.0	61.0
2023	-	-	1.0	61.9	1.0	61.9
2024	-	-	1.0	62.9	1.0	62.9
2025	-	-	1.0	63.9	1.0	63.9
2026	-	-	1.0	64.9	1.0	64.9
2027	-	-	1.0	65.8	1.0	65.8
2028	-	-	1.0	66.8	1.0	66.8
2029	-	-	1.0	67.8	1.0	67.8
2030	-	-	0.9	68.7	0.9	68.7
2031	-	-	0.9	69.6	0.9	69.6
2032	-	-	0.8	70.4	0.8	70.4
2033	-	-	0.8	71.2	0.8	71.2
2034	-	-	0.8	71.9	0.8	71.9





Appendix E: DER Scenarios Development

Base Case:

EE:

- The approved Company goals from the Subject Matter Experts (SMEs) are used for the short-term (i.e. through 2020).
- Post-2020, 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 5% less each year.

PV:

- The near-term (i.e. 2019 and 2020) predictions are based on SME expectations for new installations estimated from those in the queue. The projections are compared with the state policy goal of about 40 MW/year (renewable energy growth (REG)). The base case is already doing more than the state target as of now.
- From 2021 to 2023, the same level of incremental growth as 2020 is assumed. This is based on the current queue which has enough to continue at the 2019 assumed rate for several years.
- For the longer term, similar, to other technologies, new installations are assumed to taper off over time due to saturation and increasing costs for the same reductions (at 5% less as in EE above).

EV:

- The near-term trend in annual installations is used to project future installations. This trend is considered to continue through 2030 which coincides with the major milestone year for the 80 * 50 target, a year where many policy targets in the Northeast are established.
- Post-2030 to the end of the forecast horizon, the incremental growth is assumed to taper off. The annual decrease is about 4-5% fewer new vehicles per year than the prior year.

DR (retail):

- For the short term (i.e. until 2021), the approved Company targets from the SMEs in the DR Dept. are used as the projection.
- For the longer term, because the 2021 target level is already at an 'aggressive' level as defined by the consultant report on market potential study (in MA), the projections are only allowed to grow at a minimum rate (i.e. about 10% of the 2021 level).

ES:

- There is currently no energy storage state policy target in RI, thus no assumption for energy storage is made for this planning cycle there. The Company will monitor this and update future forecasts as appropriate. It is noted that there is a small amount of storage being captured in the Company's Demand Response program in RI.

High Case:

EE:

There is no high case at this time because a recent market potential study in MA shows the base is already established at the potential level and a similar study is underway in RI.

PV:

There is no specific new expanded target yet approved in RI, however, there is much discussion in all three states (NY, MA, and RI) on increased renewables by milestone year 2030. Thus, the high case is assumed to be a continuation of the base case levels until milestone year 2030 before saturation and declining growth is assumed. However, a continuation of the base case levels in the 2020's years (vs. an increase in those levels) easily make more than double current state policy target by 2030.

EV:

The base case does not meet the ZEV target by 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. Annual installations are rapidly increased to make the targets. 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 5% 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.

DR:

No high case is developed because the base case is already at an aggressive level.

Low Case:

EE:

The low case begins the same as in the base cases, however, the tapering off is set at 10% less each year instead of 5%.

PV:

The low case for PV is a tapering off of the current base case in year 2021, the year after the current SME short term projections end, instead of in the year 2023. It also assumes a faster tapering off at 10% less each year.

EV:

The low case is a continuation of the 2019 annual adoption levels. This case assumes continued annual growth, but at a flat level instead of increasing annual levels. In this scenario, the adoption of EVs comes nowhere close to the ZEV targets over the entire 15-year planning horizon.

DR:

The low case for DR is assumed to be a discontinuation of the DR program in the year 2022. 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.

Other:

- DERs profiles are applied to allocate the annual projections to peak hours and daily load profiles. Typical Northeastern profiles are applied to all companies and zones.
- It is noted that no attempt to assign probabilities to each of the base, high and low scenarios are made at this time. The base case will be used to establish the forecast base. The highs and lows are provided to inform possible higher and lower cases than the base. Future cycles of the ELF will consider probabilistic approaches.

Appendix F: Power Supply Areas (PSAs)

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

			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	2020	2021	2022	2023	2024	'20 to '24	'25 to '29	'30 to '34
RI	Blackstone Valley	RI	100.2%	111.8%	115.1%	(4.2)	(1.1)	(0.2)	(0.2)	(0.2)	(1.2)	(0.3)	(0.5)
RI	Newport	RI	100.2%	111.8%	115.1%	(3.7)	(0.7)	0.1	0.1	0.1	(0.8)	(0.1)	(0.4)
RI	Providence	RI	100.2%	111.8%	115.1%	(4.1)	(1.0)	(0.2)	(0.2)	(0.2)	(1.1)	(0.3)	(0.5)
RI	Western Narraganset	RI	100.2%	111.8%	115.1%	(3.2)	(0.2)	0.6	0.5	0.4	(0.4)	0.2	(0.2)

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

			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	2020	2021	2022	2023	2024	'20 to '24	'25 to '29	'30 to '34
RI	Blackstone Valley	RI	100.2%	111.8%	115.1%	(5.3)	(0.6)	0.2	0.2	0.2	(1.1)	0.1	(0.2)
RI	Newport	RI	100.2%	111.8%	115.1%	(4.9)	(0.2)	0.6	0.5	0.5	(0.7)	0.3	(0.1)
RI	Providence	RI	100.2%	111.8%	115.1%	(5.2)	(0.6)	0.3	0.2	0.2	(1.0)	0.1	(0.2)
RI	Western Narraganset	RI	100.2%	111.8%	115.1%	(4.4)	0.2	1.0	0.9	0.8	(0.3)	0.5	0.1

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

			2018/19 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	2019	2020	2021	2022	2023	'19 to '23	'24 to '28	'29 to '33
RI	Blackstone Valley	RI	96.1%	101.5%	103.0%	(1.6)	(1.8)	(1.7)	(1.5)	(1.3)	(2.2)	(1.0)	(0.4)
RI	Newport	RI	96.1%	101.5%	103.0%	(1.1)	(1.4)	(1.2)	(1.1)	(1.0)	(0.2)	(0.8)	(0.3)
RI	Providence	RI	96.1%	101.5%	103.0%	(1.5)	(1.7)	(1.6)	(1.4)	(1.3)	(0.4)	(1.0)	(0.4)
RI	Western Narraganset	RI	96.1%	101.5%	103.0%	(0.7)	(0.9)	(0.8)	(0.7)	(0.7)	0.3	(0.5)	(0.1)

(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.

Division 1-4

Request:

Provide a copy of the most recent load forecast for the Tiverton Substation.

Response:

Please find attached the latest 2022 Electric Peak (MW) Forecast, dated November 2022.

All forecasts are located on the Rhode Island System Data Portal at the following link:

https://systemdataportal.nationalgrid.com/RI/

RHODE ISLAND ENERGY

2022 Electric Peak (MW) Forecast

15-Year Long-Term

2023 to 2037

November 2022

Original, Nov/01/2022

Load & Settlement
Finance and Regulatory Affairs

REVISION HISTORY & GENERAL NOTES

Revision History

Version	Date	Changes
Original	11/01/2022	- ORIGINAL

General Notes:

- Hourly load data through August 2022; projections from 2022 winter forward.
- Economic data is from Moody's vintage August 2022.
- Energy Efficiency, electric heating, solar, energy storage and demand response is internal data vintage August 2022.
- Electric Vehicle data is POLK data vintage May 2022. Medium- and heavy- duty electric vehicles and E-buses have been added this year.
- Peak MW and Energy GWH source is ISO-NE/MDS meter-reconciled data (Jan. 2003 to Jun. 2022), internal unreconciled **preliminary** data (Jul. 2021 to Aug. 2022).
- Peak load data is metered zonal load; but without ISO bulk system losses.

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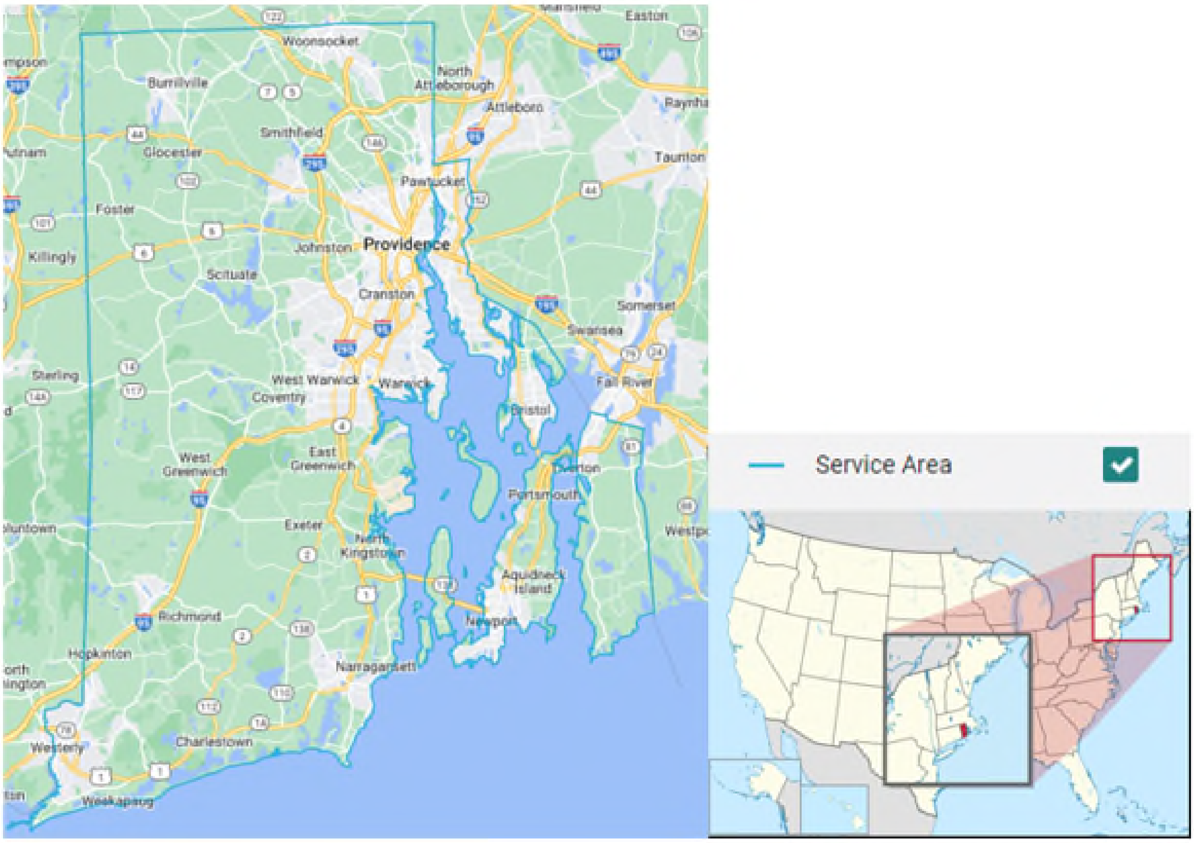
CONTENTS

Summary

Rhode Island Energy

Rhode Island Energy (RIE), formerly known as Narragansett Electric Company, makes up 27% of New England deliveries and serves 0.5 million customers in Rhode Island. Figure 1 shows the Company's service territory in the U.S.



<u>Figure 1: Rhode Island Energy U.S. Service Territory</u>

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[1] peak demand in 2022 was 1,858 MW on Tuesday, August 9 at hour-ending 15. This 2022 peak was 6% 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 85 percentile of peak weather over the last 20 years. This means that only 15%

[1] Company refers to Rhode Island Energy for the remainder of this report.

of summer peaks are expected to be warmer. This year's peak is considered 126 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 1,732 MW, a decrease of 0.1% compared to last year's adjusted peak.

NECO expects slightly growing peak load in the next five years, and bigger growth is expected in late years of the forecast horizon driven by growing demand and load adding from increasing penetration of transportation electrification. Summer peak remains to be the annual peak for the Company throughout the forecast horizon. Figure 2 shows this forecast graphically.

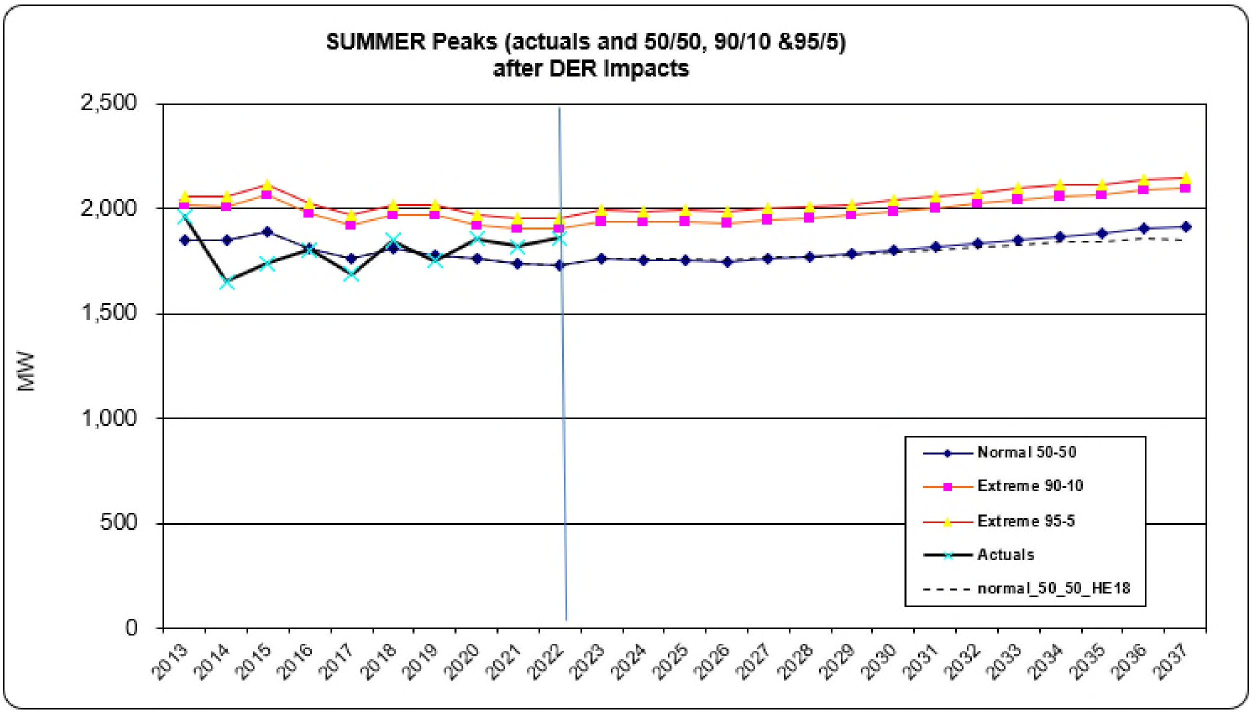


Figure 2: Historical (actual & weather-adjusted) and Projected Summer Peaks

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 evening time. As this occurs, the impact of PV is less pronounced on the new peak hour. For comparison, the dashed line in Figure 2 shows how the load at the 5-6 PM hour or hour-ending 18, where PV has more impact continues to decline over the planning horizon.

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)[2] 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)[3] 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)[4].

- 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.

[2] 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.
[3] WTHI is weighted 70% day of peak, 20% one day prior and 10% two days prior.
[4] 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.

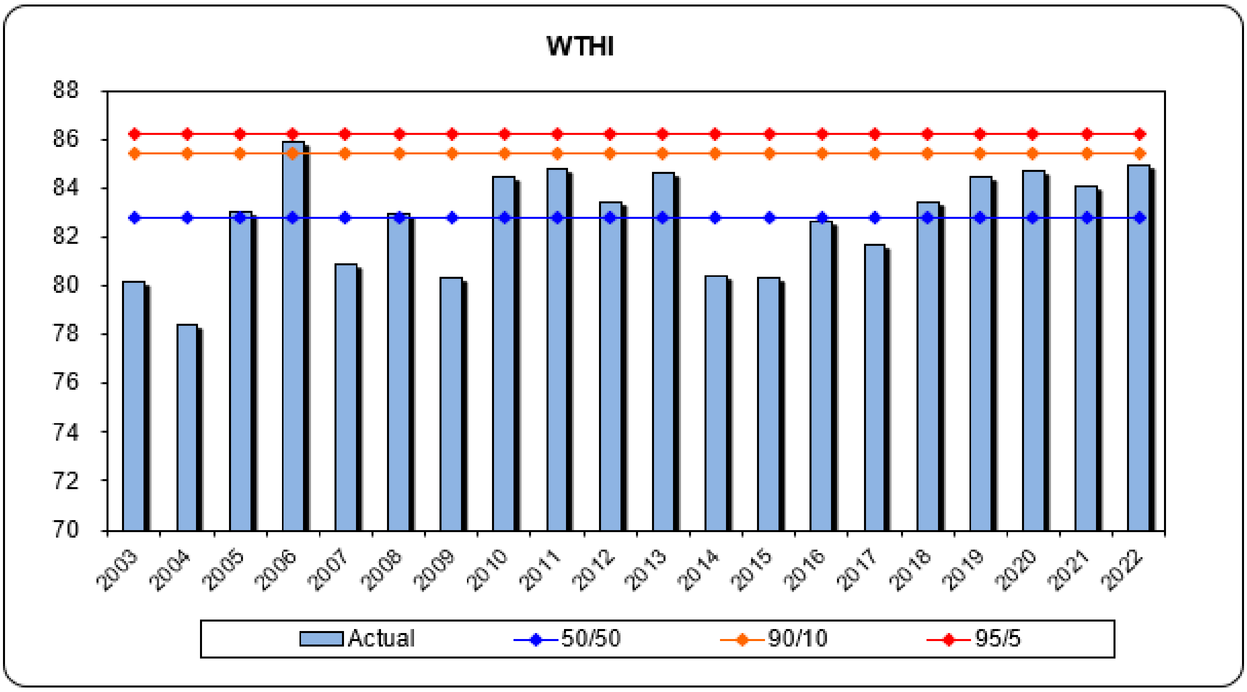


Figure 3: Actual, weather-normal and extreme WTHI

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), electric storage (ES), 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 cases 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 load before and after DERs impacts and Figure 5 shows the impacts for the DERs each year. On average, pre-DERs load is projected to decrease future growth by 1.4% per year over the next five years. This decline is driven by a projected shift in the peak hour from the afternoon, hours 15 and 16, to the evening – hour 18 as the evening pre-DER load is typically lower than that in the afternoon. The post-DER, or net load, is projected to grow 0.3 % per year over the next five years. In the longer term – next fifteen years, the pre-DER growth rate is expected to decrease by -0.4% per year. With the increasing penetration of beneficial electrification and the shift of expected peak hour to later of the day, the net savings from DERs is expected to become smaller and the post-DER growth rate is expected to be 0.7% per year.

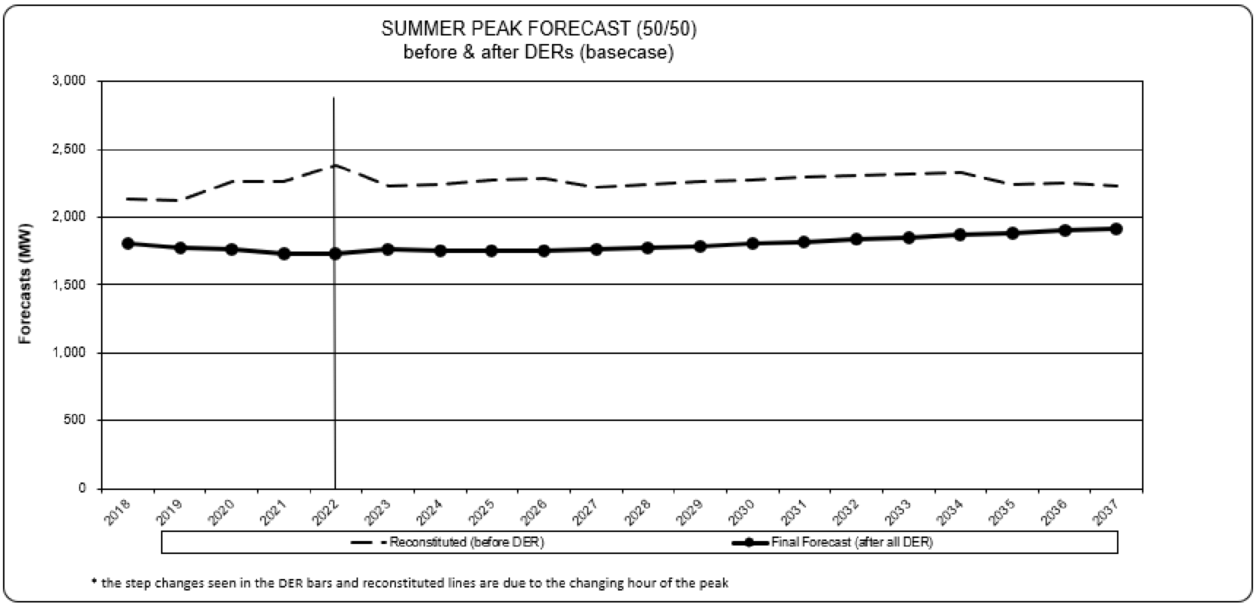


Figure 4: Annual loads before and after the impacts of DERs

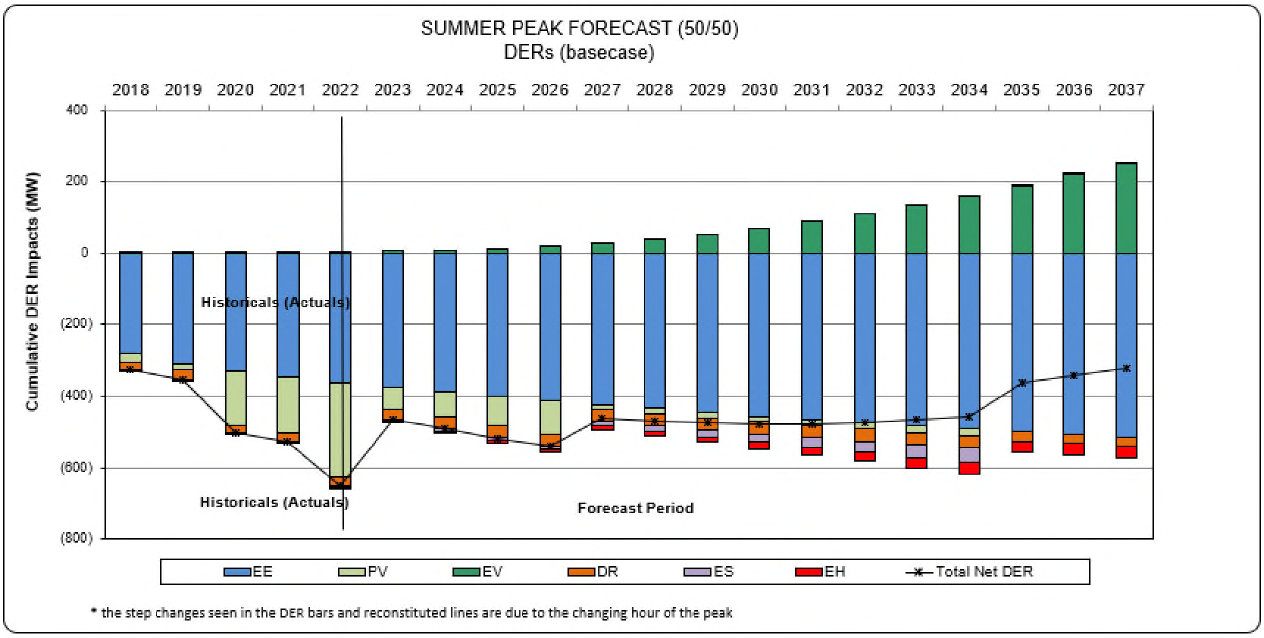


Figure 5: Annual impact of DERs

Each of the DERs is discussed next.

Energy Efficiency (EE)

Rhode Island Energy has run EE programs in its service area for many years and will continue to do so for the foreseeable future. In the short-term and through 2023, EE targets are based on the Company three-year plan. Post-2024 until 2027, the incremental value of persistent EE savings is held constant at 2023 levels assuming the programs remain steady with no growth and then there is a slow decline from 2028 to 2037

Figure 5 above shows the expected load and energy efficiency program impacts to peaks by year for the base case. As of 2022, it is estimated that these EE programs have reduced load by 362 MW, or 15.2% compared to the counterfactual with no EE programs. By 2037, it is expected that this reduction will grow to 515 MW or 23% 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 0.4% to negative 1.1% per year. Figure 6 presents the annual incremental (left) and cumulative (right) estimated EE summer MW savings.

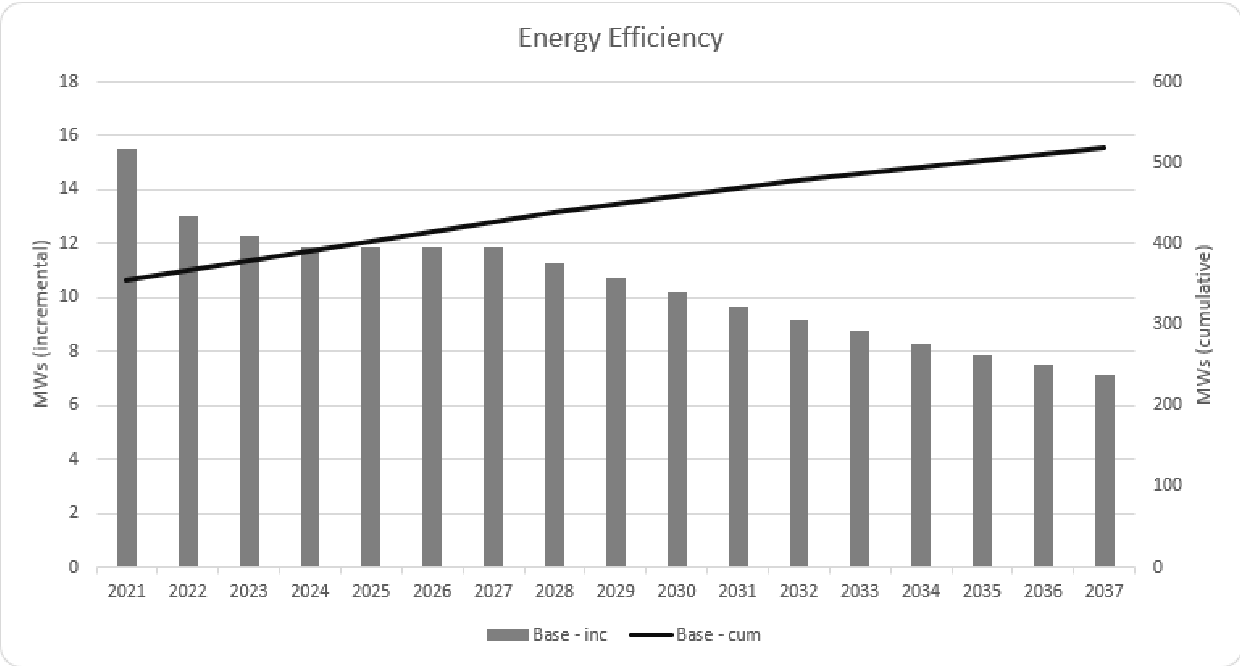


Figure 6: Energy efficiency summer MWs by year

Solar Photovoltaic (PV)[5]

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 current year, then a continuation of those levels until year 2025, and then a slowly declining number of new annual installations to account for saturation, increasing marginal costs, and/or the uncertainties on the continuation of existing public policies.

Figure 7 shows the projected connected PV installations. As of 2022, it is estimated about 490 MWs will have been connected, growing to 1,465 MW by the end of the planning period.

[5] 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).

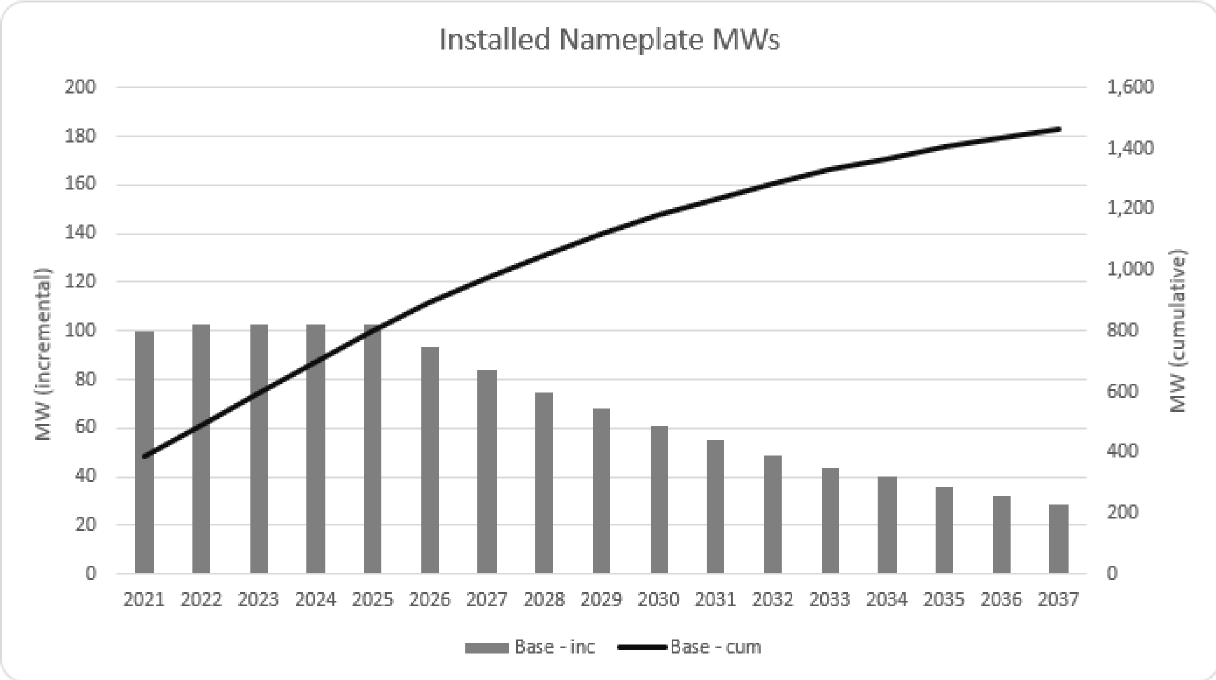


Figure 7: Solar-PV connected nameplate (AC) MW by year

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. EVs 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 have impacts on the electric network. In addition to light-duty EVs that the Company has been tracking and considering in its electric load forecasts, this year, the Company expand the scope from light-duty EVs only to include light-duty, medium-duty, heavy-duty EVs and electric buses, and consider the EV adoptions of BEVs and PHEVs in these four different vehicle types.

The light-duty EV base case is developed from Bloomberg's 20221 Long-term Electric Vehicle Outlook (BNEF-2022). The EV sales share of light-duty vehicles sales is assumed to follow BNEF-2022 estimates and vehicle scrap is also assumed based on BNEF-2022's estimates to develop the net EV in-operation numbers. In this case, the EV sales share of LDV sales is assumed to achieve 31%s by 2030 and 59% by 2035. The adoptions of medium-duty EV (MDEV) and heavy- duty EV (HDEV) and E-buses are based on BNEF-2021 estimates and MOU policy targets. The base case is more of a market-driven case of adopting MDEV, HDEV, and E-buses. In this case, the MDEV, HDEV, and E-buses are estimated to be about 16%, 17%, and 26% of MDV, HDV, and buses respectively by the year 2036.

Figure 8 shows the future estimated number of EVs in the Company's Rhode Island service territory. As of the end of 2022, it is estimated that about 7,106EVs, including light-duty, medium-duty, heavy-duty and buses, will be on the roads in the service territory, growing to almost 282,000 by the end of the fifteen-year planning horizon.

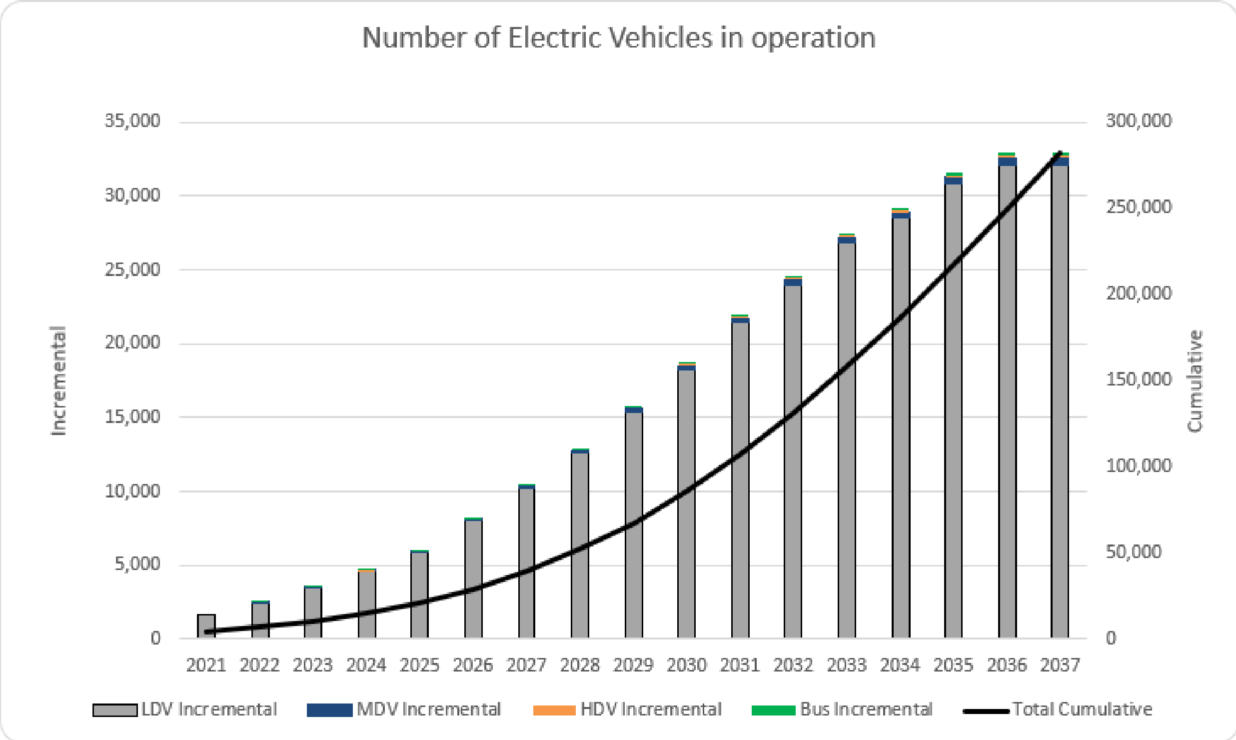


Figure 8: Number of Incremental and Cumulative EVs

It is estimated that these vehicles may have increased cumulative summer peak loads by about 2.7 MW as of 2022, increasing to 2528 MW of cumulative peak load increase in 2037. While EVs do add to both peak and energy loads over time, they are considered 'beneficial'[6] 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

[6] 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.

(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.

In 2022, estimated impact of the retail DR program was about 23 MW and is expected to grow to about 34 MW, or 1.5% of summer peak load by year 2027. No additional incremental DR MW is expected beyond that point because it is assumed that the program's market potential is at its maximum by then but the cumulated MW is expected to be carried through the rest of the forecast horizon.

Energy Storage (ES):

There is currently no explicit state energy storage policy targets in Rhode Island, nor any Company run programs to promote this DER. In year 2021 about 1.4 MW of storage was installed. By 2037, it is estimated that storage may help shave the summer peak load by about 7.6 MW, which is about 0.4% of what load would have been had these programs not been implemented. It is also noted that there is a small amount of storage being captured in the Company's Demand Response program in Rhode Island.

Electric Heat Pumps (EH):

The base case for years 2022 to 2030 are based on the Company's pro rata share of the ISO-NE heat electrification forecast, which is a projection for residential heat pumps installations in the state. Commercial heat pumps are not currently incentivized. Subsequent to this and through the end of the planning cycle in year 2037, 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.

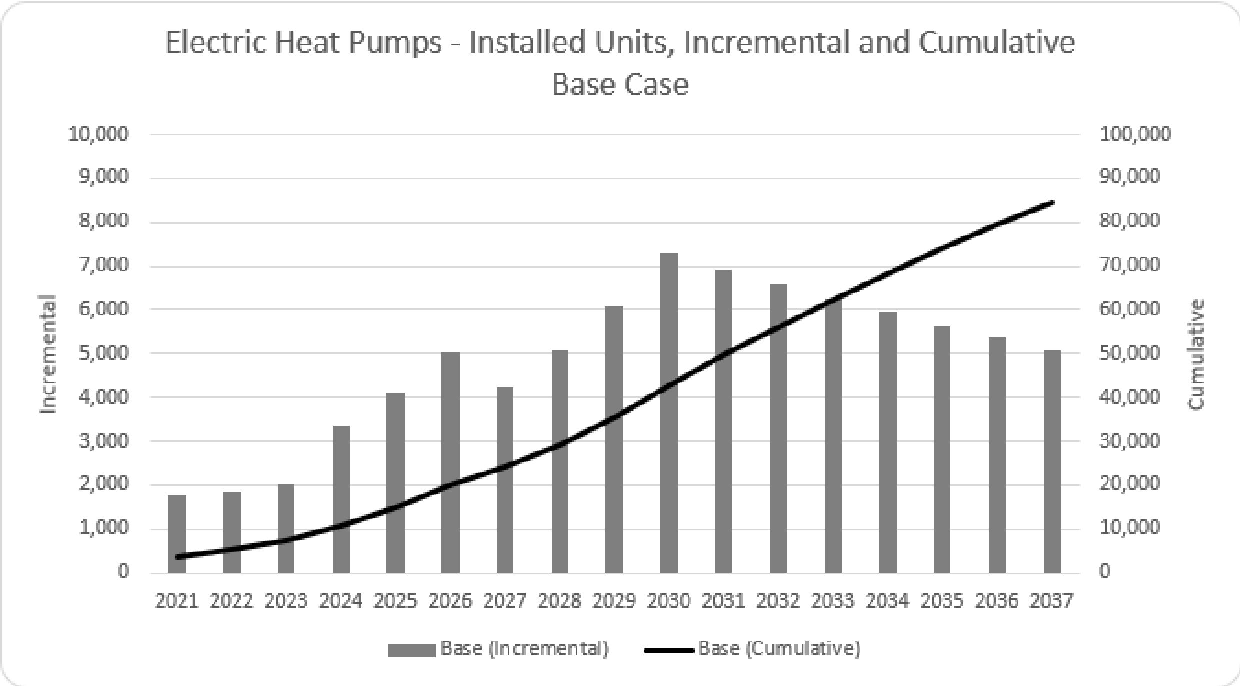


Figure 9: Number of electric heat pumps

All prior discussion on load & DERs above is limited to the <u>base</u> 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 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 <u>summer</u> day for selected years over the planning horizon for the <u>base case</u> DERs.

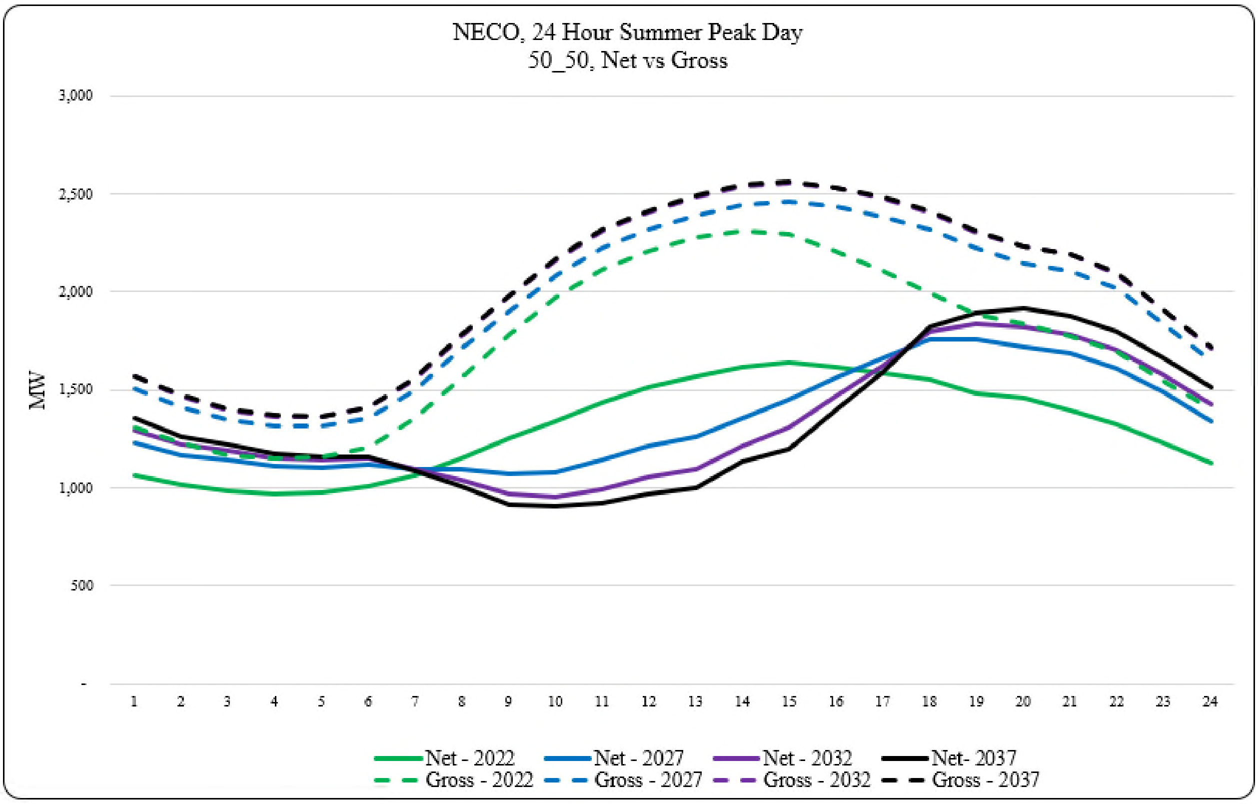


Figure 10: Peak Summer day hourly load, pre and post DERs

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 2022, 2027, 2032 and 2037.

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

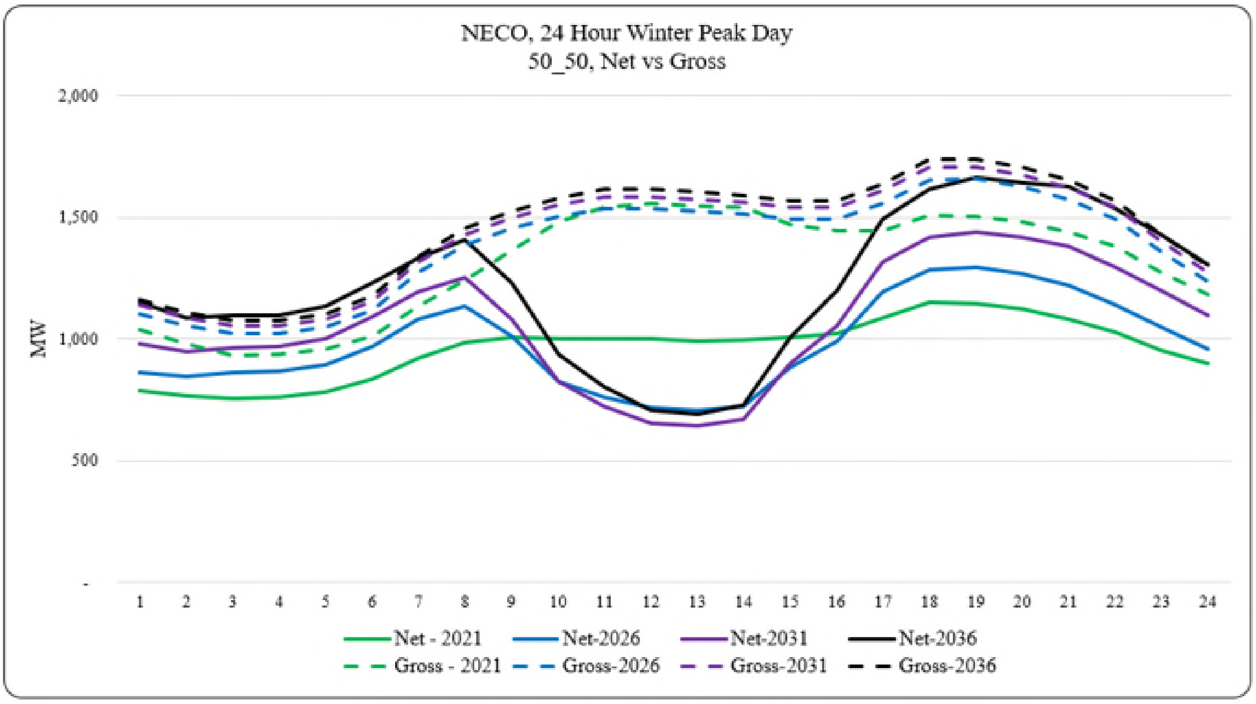


Figure 11: Peak Winter day hourly load, pre and post DERs

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 and electric vehicles 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.

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[7].

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, 15% for the low case, and 5% for the high 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

RI	Low	Base	High
Energy Efficiency	15%	80%	5%
Solar - PV	5%	60%	35%
Electric Vehicles	20%	70%	10%
Demand Response	5%	85%	10%
Energy Storage	n/a	100%	n/a
Electric Heat Pumps	20%	75%	5%

Figure 12 shows the basecase (which is the most likely) in blue solid line and the maximum and minimum cases in red solid lines which provide the highest and lowest bounds for planning purposes. The base is the scenario with base cases from all DER technologies. The maximum load scenario / minimum DER saving scenario is the scenario with high cases for energy efficiency, solar PV, demand response, and energy storage; and low cases for electric vehicles and electric heat pumps. The minimum load scenario / maximum DER saving scenario is the scenario with low cases for energy efficiency, solar PV, demand response, and energy storage; and high cases for electric vehicles and electric heat pumps. It also shows the other more likely cases besides the basecase, and they are shown as black dashed lines.

The peak load five years from now or in year 2027, ranges from about 1,705 MW to 1,832 MW - a 127 MW spread, with the base case at 1,758 MW. The uncertainty increases over time, so that fifteen years from now or in year 2037, the range expands to from about 1,817 MW to 2,156 MW, or a 339 MW spread, with the base case at 1,914 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.

[7] In this forecast, six DERs, each with three cases (ES only has base case) – base, high and low, creates 244 (3^5+1) cases for each weather scenario. With three weather scenarios 732 scenarios are generated for the Company.

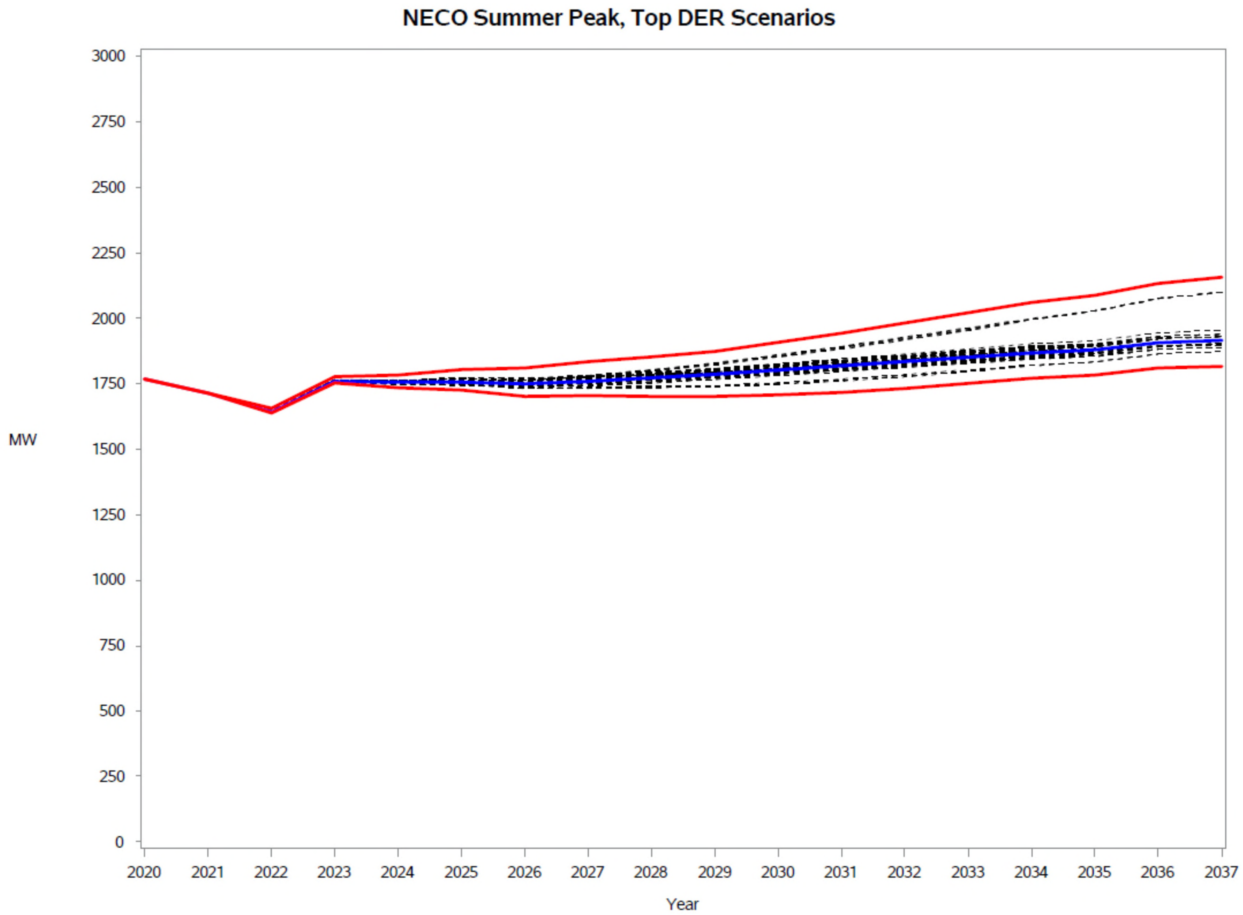
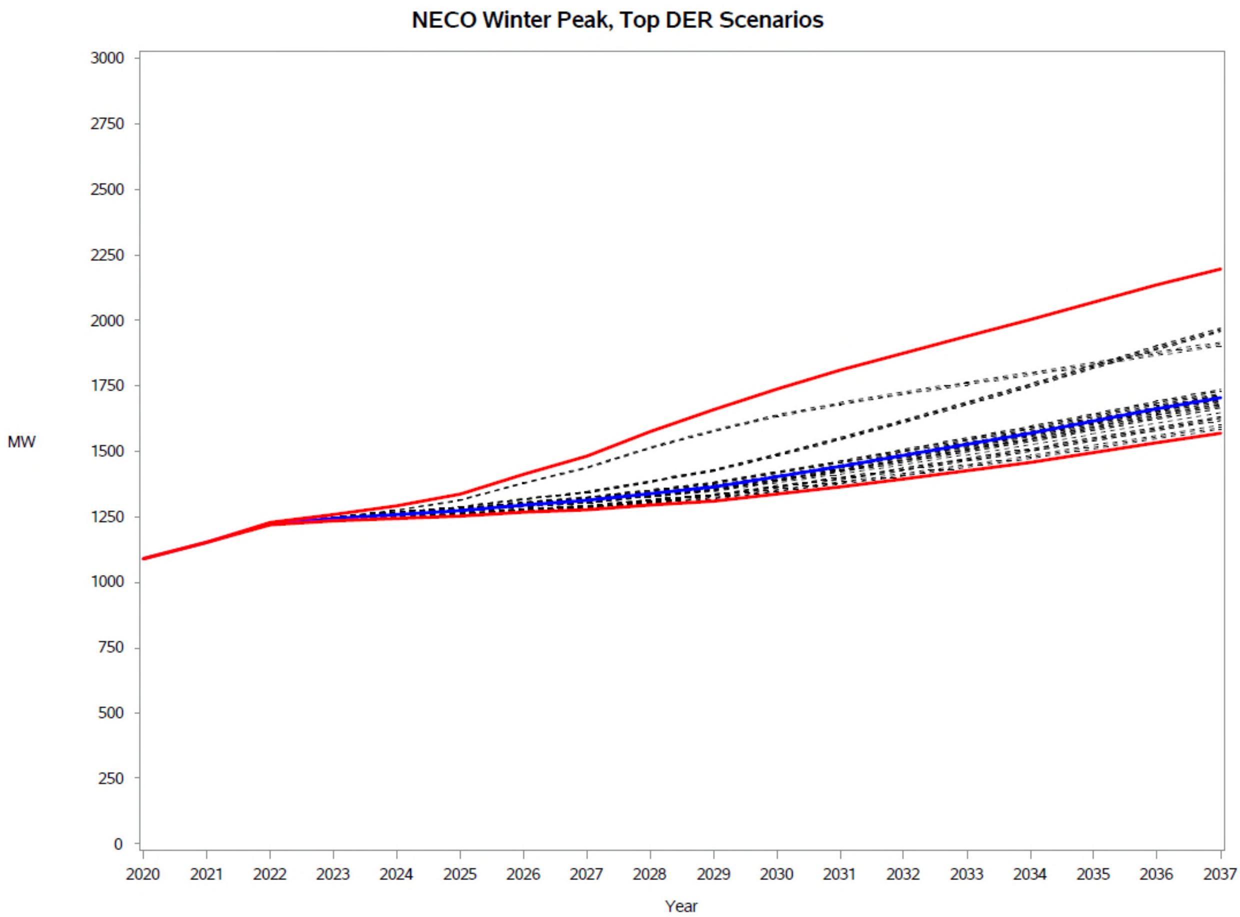


Figure 12: Summer Peaks (50/50), NET, selected DER scenarios

Although summer peaks remain to be the annual peak throughout the forecast horizon, winter peaks attract increasing interests with the increasing penetration in the heating electrification sector. Figure 13 shows the winter peak load of selected DER scenarios through the end of the forecast horizon in the same format as Figure 12. Please note, because the winter peak hour is expected to be hour-ending 19 or later, solar irradiance is not expected to be available for these projected peak hour thus there is no PV saving expected for the net peak hour in winter. There are two dash lines being closer to the maximum load scenario on the top, they represent the high electric heat pump case with base cases for other DER technologies and high electric vehicle case with base cases for other DER technologies.



While Figure 12 & 13 above show what the longer term annual single summer peaks and winter peaks look like, Figures 14 and 15 show what the 24-hour peak day profiles might be for selected years.

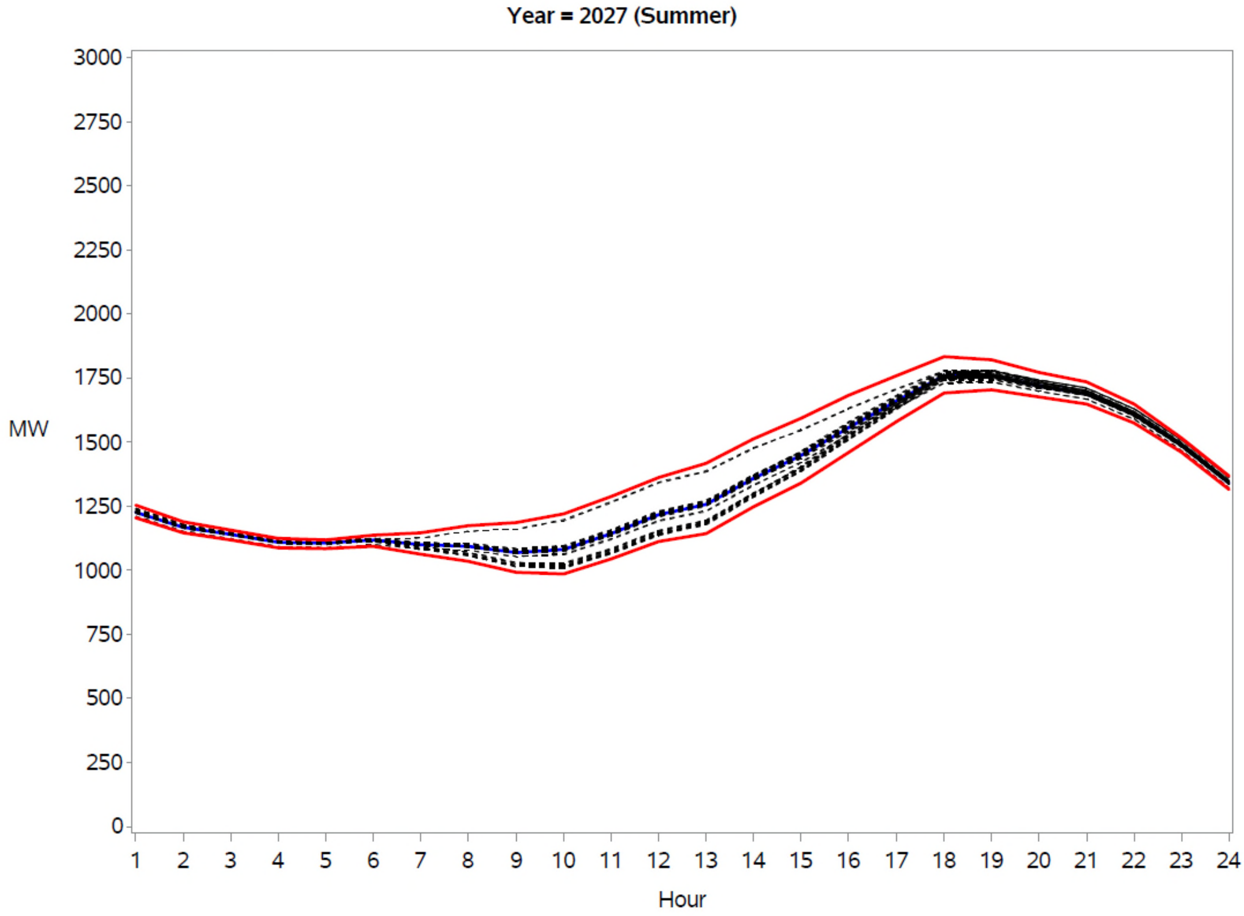


Figure 14: 50/50 case, net summer peak, w/range of DER scenarios, year 2027

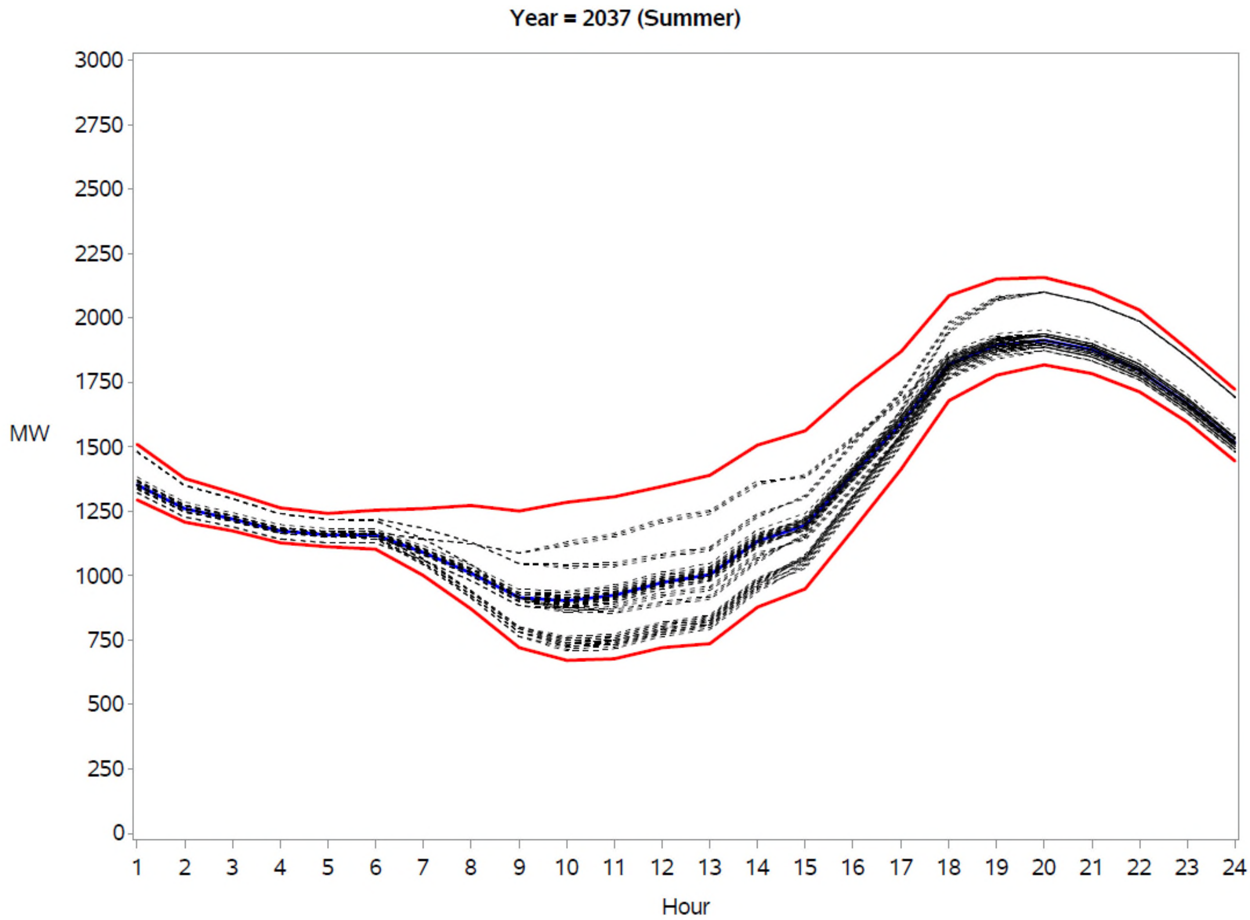


Figure 15: 50/50 case, net summer peak, w/range of DER scenarios, year 2037

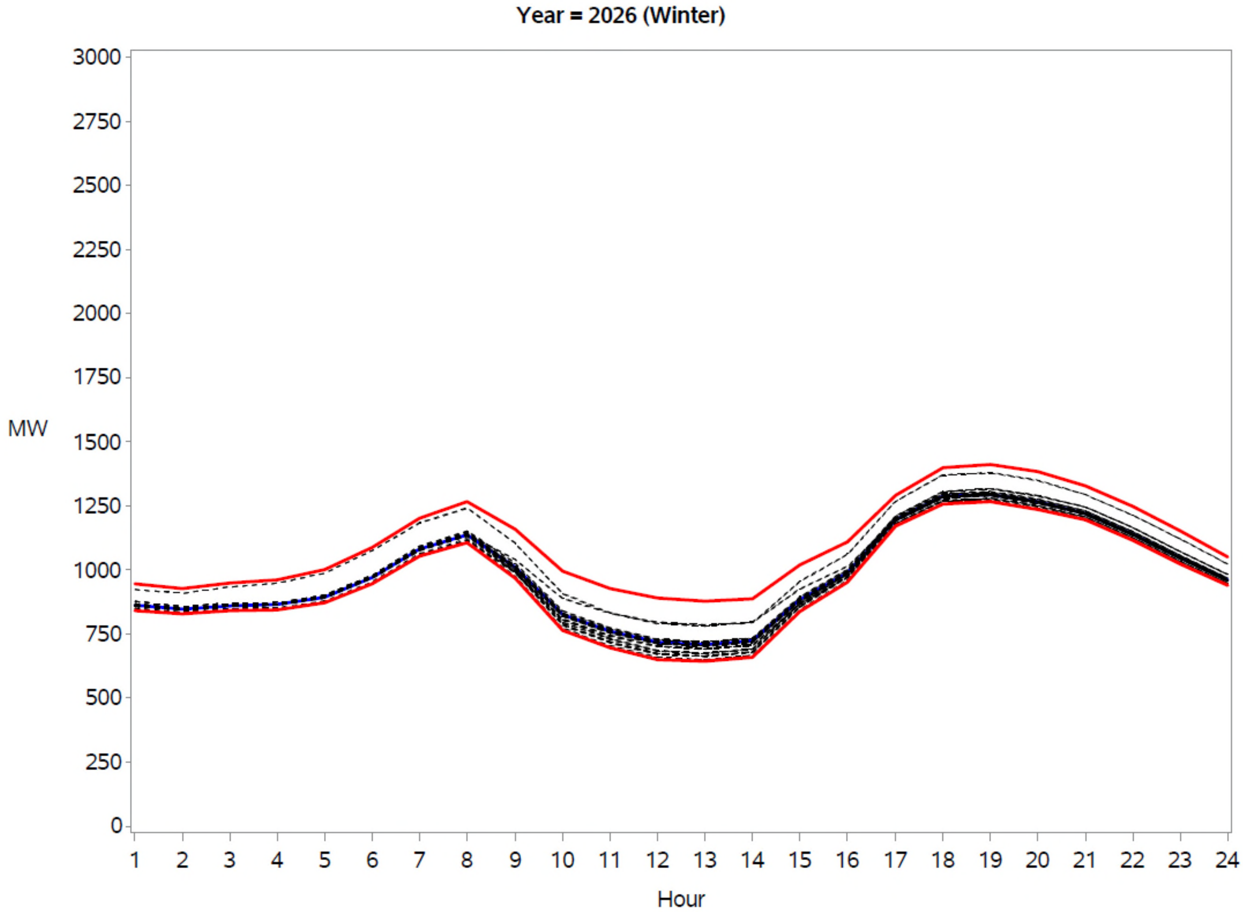


Figure 16: 50/50 case, net winter peak, w/range of DER scenarios, year 2026

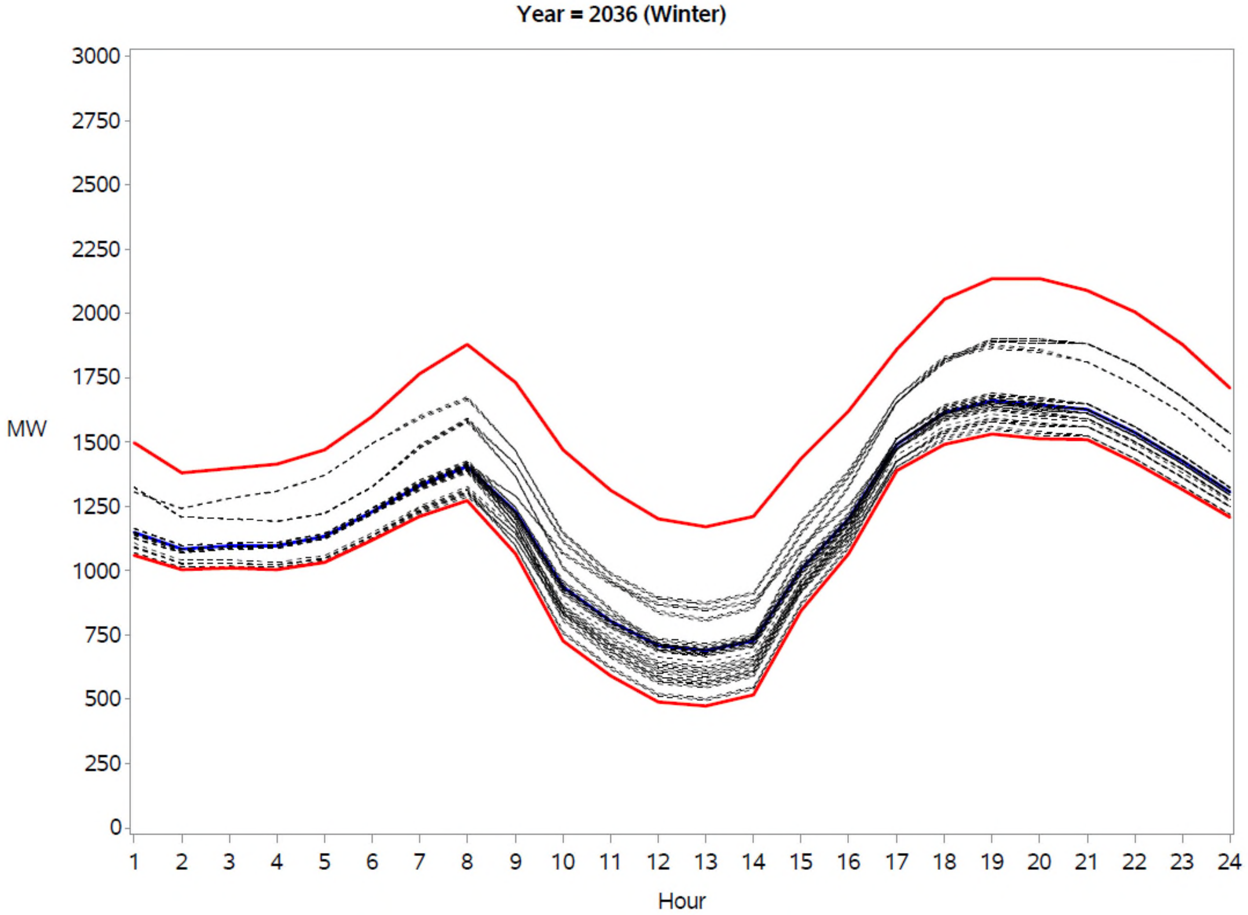


Figure 17: 50/50 case, net winter peak, w/range of DER scenarios, year 2036

What becomes apparent is that the range of possible outcomes in the early years (Figure 14 &16), quickly increases fifteen years out (Figure 15 & 17). Note that the mid-day hours have a wider range of possible loads than other times of the day.

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, and managed EV charging. The Company is actively monitoring these processes and will incorporate, as appropriate, new policies and scenarios as they become more likely.

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 18 compares the basecase, 50/50 summer peak forecast vs. alternative loads with higher average weather values.

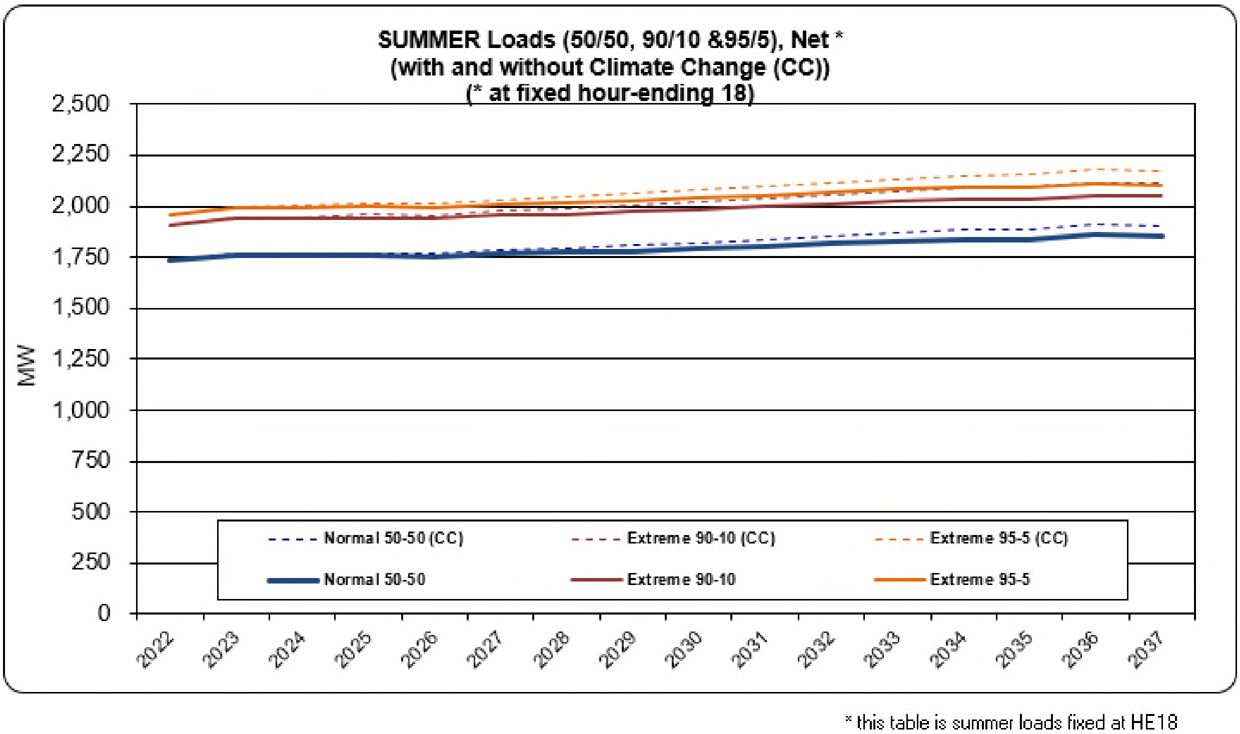


Figure 18 Summer loads basecase and with climate change

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.[8] 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 2 shows the differences between the loads in the basecase and the potential higher loads with the climate change assumptions for the three weather scenarios.

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

	50-50		90-10		95-5	
	Base	w/CC	Base	w/CC	Base	w/CC
Year 2037 (MWs)	1,853	1,908	2,049	2,117	2,105	2,177
Delta (MWs)		55		68		72
Delta (%)		3.0%		3.3%		3.4%

Table 2 Comparison of loads between Basecase and Climate Change scenario for year 2037[9]

[9] 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 2022 Forecast to 2021 Forecast

Figure 19 provides a comparison of this year's summer peak (which is also the annual peak) forecast to last year's. Generally speaking, there is very little difference in the "Gross" forecasts (the forecast with the DERs reconstituted) and the "Net" forecasts compare to the forecasts released in 2021.

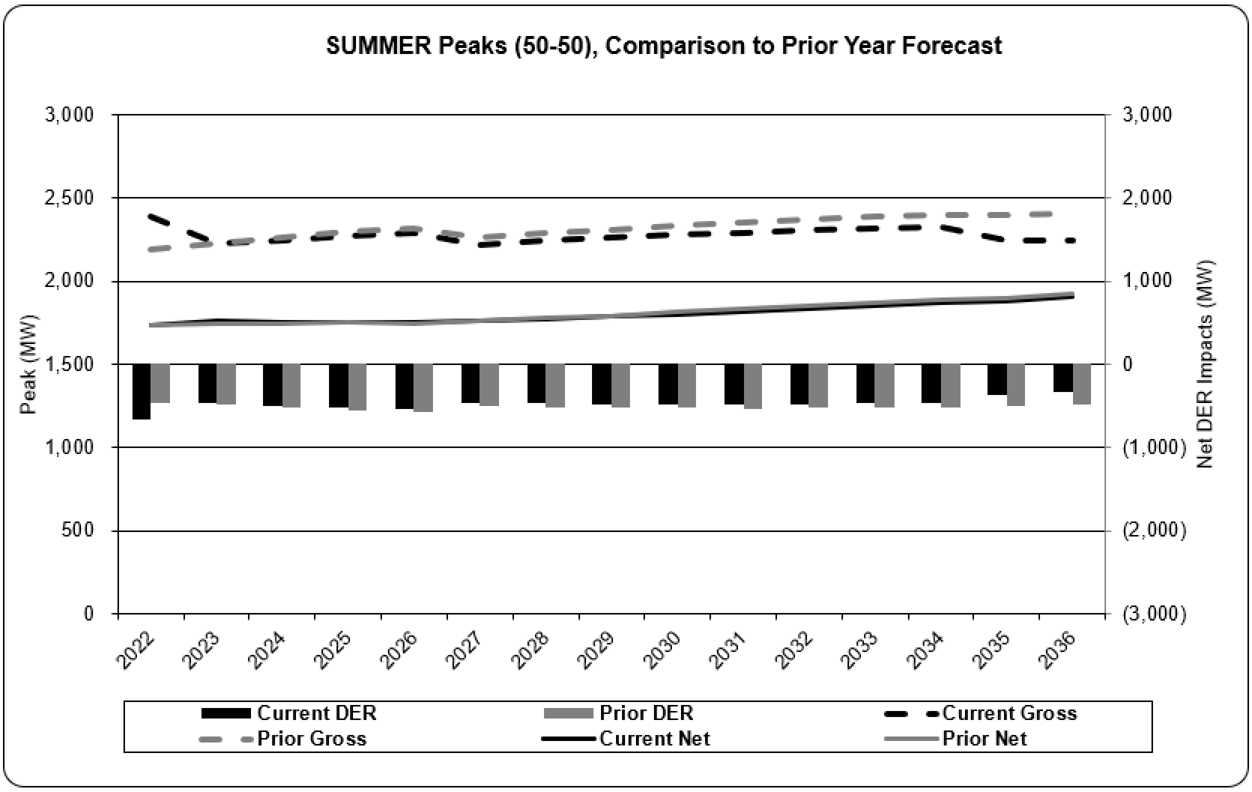


Figure 19 Comparison of current forecast to prior forecast, Gross and Net, Summer 50-50

Figure 20 provides a comparison of this year's winter peak forecast to last year's. The "Gross" forecasts (the forecast with the DERs reconstituted) are pretty close as last year's release. The "Net" forecasts are higher mainly driven by the lower net DER impacts.

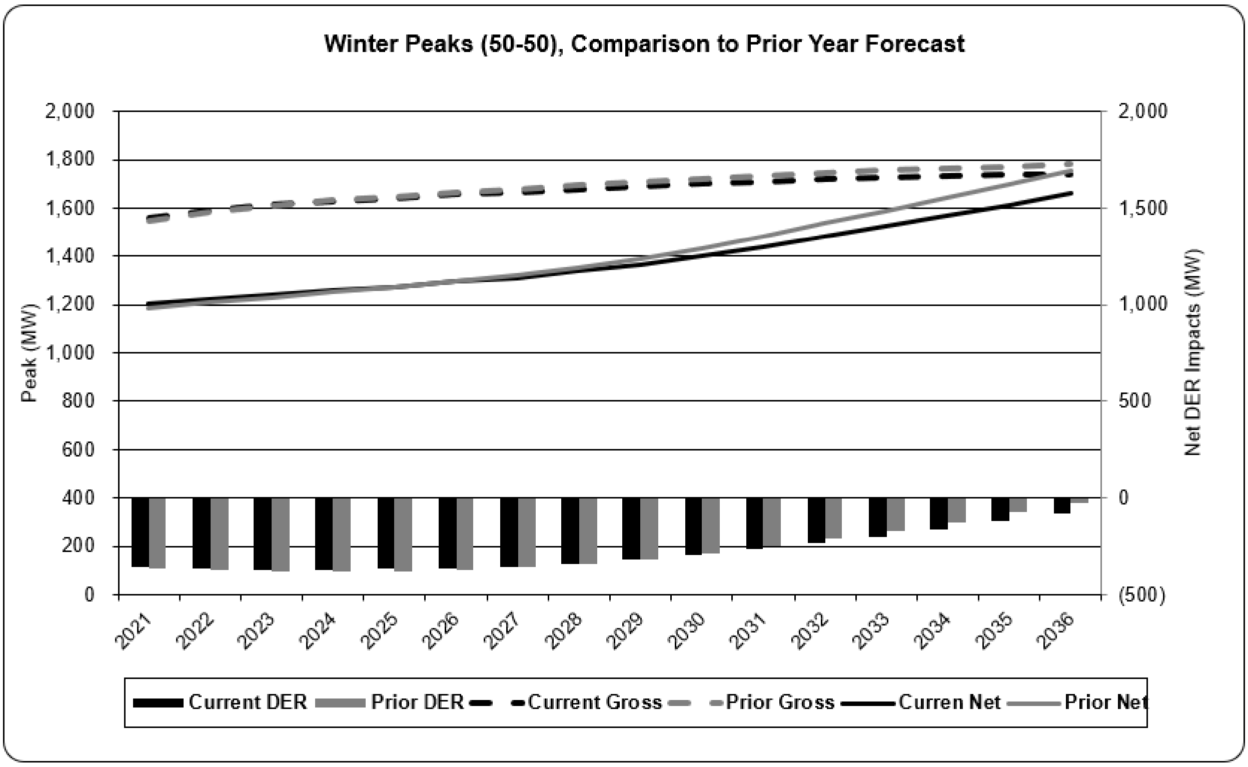


Figure 20 Comparison of current forecast to prior forecast, Gross and Net, Winter 50-50

Appendix A: Forecast Details

NECO
SUMMER Peaks

AFTER DER Impacts *

YEAR	Actuals		Normal 50-50		Extreme 90-10		Extreme 95-5		WTHI
	(MW)	(% Grwth)	(MW)	(% Grwth)	(MW)	(% Grwth)	(MW)	(% Grwth)	ACTUAL
2006	1,985		1,833		1,965		2,002		85.9
2007	1,777	-10.5%	1,884	2.8%	2,034	3.5%	2,077	3.8%	80.9
2008	1,824	2.6%	1,847	-1.9%	1,991	-2.1%	2,032	-2.2%	82.9
2009	1,713	-6.1%	1,849	0.1%	2,014	1.2%	2,061	1.4%	80.3
2010	1,872	9.3%	1,834	-0.8%	1,998	-0.8%	2,045	-0.8%	84.5
2011	1,974	5.5%	1,852	1.0%	2,015	0.9%	2,061	0.8%	84.8
2012	1,892	-4.2%	1,855	0.1%	2,005	-0.5%	2,047	-0.7%	83.5
2013	1,965	3.9%	1,852	-0.1%	2,015	0.5%	2,061	0.7%	84.7
2014	1,653	-15.9%	1,846	-0.4%	2,011	-0.2%	2,057	-0.2%	80.4
2015	1,738	5.1%	1,887	2.2%	2,065	2.7%	2,115	2.8%	80.4
2016	1,803	3.8%	1,813	-3.9%	1,977	-4.3%	2,023	-4.4%	82.6
2017	1,688	-6.4%	1,759	-3.0%	1,923	-2.7%	1,969	-2.7%	81.7
2018	1,847	9.4%	1,807	2.8%	1,973	2.6%	2,020	2.6%	83.4
2019	1,750	-5.3%	1,774	-1.8%	1,966	-0.3%	2,021	0.0%	84.5
2020	1,855	6.0%	1,762	-0.7%	1,925	-2.1%	1,972	-2.4%	84.7
2021	1,819	-2.0%	1,734	-1.6%	1,906	-1.0%	1,955	-0.8%	84.1
2022	1,859	2.2%	1,732	-0.1%	1,907	0.0%	1,956	0.1%	85.0
2023	-	-	1,760	1.6%	1,939	1.7%	1,990	1.7%	-
2024	-	-	1,755	-0.3%	1,936	-0.2%	1,988	-0.1%	-
2025	-	-	1,756	0.1%	1,940	0.2%	1,992	0.2%	-
2026	-	-	1,749	-0.4%	1,934	-0.3%	1,986	-0.3%	-
2027	-	-	1,759	0.6%	1,946	0.6%	1,999	0.7%	-
2028	-	-	1,772	0.7%	1,953	0.4%	2,006	0.4%	-
2029	-	-	1,785	0.8%	1,969	0.8%	2,021	0.7%	-
2030	-	-	1,802	0.9%	1,987	0.9%	2,040	0.9%	-
2031	-	-	1,817	0.9%	2,004	0.8%	2,057	0.8%	-
2032	-	-	1,834	0.9%	2,022	0.9%	2,075	0.9%	-
2033	-	-	1,852	1.0%	2,041	0.9%	2,094	0.9%	-
2034	-	-	1,867	0.8%	2,057	0.8%	2,110	0.8%	-
2035	-	-	1,878	0.6%	2,063	0.3%	2,117	0.3%	-
2036	-	-	1,906	1.5%	2,089	1.3%	2,142	1.2%	-
2037	-	-	1,914	0.4%	2,096	0.3%	2,148	0.3%	-

	Normal 50-50	Extreme 90-10	Extreme 95-5
Avg. last 15 yrs	-0.6%	-0.4%	-0.4%
Avg. last 10 yrs	-0.7%	-0.5%	-0.5%
Avg. last 5 yrs	-0.3%	-0.2%	-0.1%
BASE 2022			
Avg. next 5 yrs	0.3%	0.4%	0.4%
Avg. next 10 yrs	0.6%	0.6%	0.6%
Avg. next 15 yrs	0.7%	0.6%	0.6%

WTHI

NORMAL	82.8
EXTREME 90/10	85.5
EXTREME 95/5	86.2

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

NECO	SUMMER 50/50 Peaks (MW) (before & after DERs)																					
	SYSTEM PEAK								DER IMPACTS							% of reconstituted peaks						
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	EE	PV	EV	DR	ES	EH	DER
2006	1,869	1,833	1,869	1,869	1,869	1,869	1,869	**1,833**	(37)	(0)	0.0	0.0	0.0	0.0	(37)	-2.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-2.0%
2007	1,931	1,884	1,931	1,931	1,931	1,931	1,931	**1,884**	(47)	(0)	0.0	0.0	0.0	0.0	(47)	-2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	-2.4%
2008	1,905	1,848	1,904	1,905	1,905	1,905	1,905	**1,847**	(57)	(0)	0.0	0.0	0.0	0.0	(57)	-3.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-3.0%
2009	1,920	1,850	1,919	1,920	1,920	1,920	1,920	**1,849**	(70)	(0)	0.0	0.0	0.0	0.0	(71)	-3.7%	0.0%	0.0%	0.0%	0.0%	0.0%	-3.7%
2010	1,918	1,834	1,918	1,918	1,918	1,918	1,918	**1,834**	(84)	(1)	0.0	0.0	0.0	0.0	(84)	-4.4%	0.0%	0.0%	0.0%	0.0%	0.0%	-4.4%
2011	1,949	1,853	1,949	1,949	1,949	1,949	1,949	**1,852**	(96)	(1)	0.0	0.0	0.0	0.0	(97)	-4.9%	0.0%	0.0%	0.0%	0.0%	0.0%	-5.0%
2012	1,969	1,856	1,967	1,969	1,969	1,969	1,969	**1,855**	(113)	(1)	0.0	0.0	0.0	0.0	(114)	-5.7%	-0.1%	0.0%	0.0%	0.0%	0.0%	-5.8%
2013	1,994	1,857	1,989	1,994	1,994	1,994	1,994	**1,852**	(137)	(5)	0.1	0.0	0.0	0.0	(141)	-6.9%	-0.2%	0.0%	0.0%	0.0%	0.0%	-7.1%
2014	2,022	1,853	2,016	2,022	2,022	2,022	2,022	**1,846**	(170)	(7)	0.1	0.0	0.0	0.0	(176)	-8.4%	-0.3%	0.0%	0.0%	0.0%	0.0%	-8.7%
2015	2,100	1,898	2,089	2,101	2,100	2,100	2,100	**1,887**	(202)	(12)	0.2	0.0	0.0	0.0	(214)	-9.6%	-0.6%	0.0%	0.0%	0.0%	0.0%	-10.2%
2016	2,056	1,826	2,043	2,056	2,056	2,056	2,056	**1,813**	(230)	(13)	0.3	(0.0)	0.0	0.0	(243)	-11.2%	-0.6%	0.0%	0.0%	0.0%	0.0%	-11.8%
2017	2,041	1,786	2,019	2,042	2,036	2,041	2,041	**1,759**	(256)	(22)	0.4	(5.0)	0.0	0.0	(283)	-12.5%	-1.1%	0.0%	-0.2%	0.0%	0.0%	-13.9%
2018	2,132	1,850	2,106	2,132	2,114	2,131	2,132	**1,807**	(281)	(26)	0.7	(17.6)	(0.0)	0.0	(324)	-13.2%	-1.2%	0.0%	-0.8%	0.0%	0.0%	-15.2%
2019	2,127	1,820	2,108	2,128	2,100	2,127	2,127	**1,774**	(307)	(19)	1.3	(27.2)	(0.2)	(0.3)	(353)	-14.4%	-0.9%	0.1%	-1.3%	0.0%	0.0%	-16.6%
2020	2,265	1,934	2,111	2,266	2,245	2,264	2,264	**1,762**	(330)	(153)	1.1	(19.2)	(0.6)	(0.8)	(503)	-14.6%	-6.8%	0.1%	-0.8%	0.0%	0.0%	-22.2%
2021	2,260	1,913	2,107	2,262	2,236	2,259	2,259	**1,734**	(348)	(153)	1.6	(24.3)	(1.4)	(1.4)	(527)	-15.4%	-6.8%	0.1%	-1.1%	-0.1%	-0.1%	-23.3%
2022	2,385	2,023	2,119	2,388	2,363	2,383	2,383	**1,732**	(362)	(266)	2.7	(22.7)	(2.6)	(2.3)	(653)	-15.2%	-11.1%	0.1%	-1.0%	-0.1%	-0.1%	-27.4%
2023	2,227	1,852	2,166	2,233	2,197	2,222	2,223	**1,760**	(375)	(61)	6.1	(29.9)	(4.1)	(3.3)	(467)	-16.8%	-2.7%	0.3%	-1.3%	-0.2%	-0.1%	-21.0%
2024	2,247	1,861	2,175	2,256	2,215	2,241	2,242	**1,755**	(387)	(72)	9.2	(32.1)	(5.8)	(4.7)	(492)	-17.2%	-3.2%	0.4%	-1.4%	-0.3%	-0.2%	-21.9%
2025	2,274	1,875	2,190	2,287	2,240	2,266	2,267	**1,756**	(399)	(84)	13.3	(33.9)	(7.8)	(6.6)	(517)	-17.5%	-3.7%	0.6%	-1.5%	-0.4%	-0.3%	-22.7%
2026	2,287	1,877	2,193	2,306	2,253	2,277	2,278	**1,749**	(410)	(94)	18.8	(33.9)	(10.1)	(8.9)	(539)	-17.9%	-4.1%	0.8%	-1.5%	-0.5%	-0.4%	-23.6%
2027	2,221	1,799	2,209	2,252	2,187	2,208	2,211	**1,759**	(422)	(13)	30.2	(33.9)	(13.6)	(10.1)	(463)	-19.0%	-0.6%	1.4%	-1.5%	-0.8%	-0.5%	-20.8%
2028	2,241	1,808	2,228	2,282	2,207	2,225	2,229	**1,772**	(434)	(14)	40.7	(33.9)	(16.7)	(12.2)	(470)	-19.4%	-0.6%	1.8%	-1.5%	-0.9%	-0.5%	-21.0%
2029	2,260	1,815	2,245	2,314	2,226	2,240	2,245	**1,785**	(445)	(15)	53.8	(33.9)	(20.2)	(14.8)	(475)	-19.7%	-0.7%	2.4%	-1.5%	-1.1%	-0.7%	-21.0%
2030	2,279	1,823	2,263	2,348	2,245	2,255	2,261	**1,802**	(455)	(16)	69.6	(33.9)	(24.0)	(17.8)	(477)	-20.0%	-0.7%	3.1%	-1.5%	-1.3%	-0.8%	-20.9%
2031	2,293	1,828	2,277	2,382	2,260	2,265	2,272	**1,817**	(465)	(16)	88.2	(33.9)	(28.1)	(21.0)	(476)	-20.3%	-0.7%	3.8%	-1.5%	-1.5%	-0.9%	-20.8%
2032	2,307	1,832	2,290	2,416	2,273	2,274	2,283	**1,834**	(475)	(17)	109.6	(33.9)	(32.5)	(24.0)	(473)	-20.6%	-0.7%	4.7%	-1.5%	-1.8%	-1.0%	-20.5%
2033	2,318	1,834	2,300	2,451	2,284	2,280	2,291	**1,852**	(483)	(18)	133.5	(33.9)	(37.3)	(26.9)	(466)	-20.9%	-0.8%	5.8%	-1.5%	-2.0%	-1.2%	-20.1%
2034	2,324	1,832	2,306	2,483	2,290	2,281	2,294	**1,867**	(492)	(18)	159.5	(33.9)	(42.4)	(29.6)	(457)	-21.2%	-0.8%	6.9%	-1.5%	-2.3%	-1.3%	-19.7%
2035	2,241	1,741	2,241	2,432	2,215	2,241	2,212	**1,878**	(500)	0	190.8	(25.5)	0.4	(28.6)	(363)	-22.3%	0.0%	8.5%	-1.1%	0.0%	-1.3%	-16.2%
2036	2,249	1,741	2,249	2,470	2,223	2,249	2,218	**1,906**	(508)	0	221.0	(25.5)	0.5	(30.8)	(343)	-22.6%	0.0%	9.8%	-1.1%	0.0%	-1.4%	-15.2%
2037	2,235	1,720	2,235	2,487	2,210	2,235	2,202	**1,914**	(515)	0	252.1	(25.5)	0.5	(32.9)	(321)	-23.0%	0.0%	11.3%	-1.1%	0.0%	-1.5%	-14.4%
Avg. last 15 yrs	1.4%	0.5%	0.6%	1.4%	1.4%	1.4%	1.4%	**-0.6%**									-1.6%					
Avg. last 10 yrs	1.9%	0.9%	0.7%	2.0%	1.8%	1.9%	1.9%	**-0.7%**									-0.1%					
Avg. last 5 yrs	3.2%	2.5%	1.0%	3.2%	3.0%	3.1%	3.1%	**-0.3%**														
BASE 2021																						
Avg. next 5 yrs	-1.4%	-2.3%	0.8%	-1.2%	-1.5%	-1.5%	-1.5%	**0.3%**														
Avg. next 10 yrs	-0.3%	-1.0%	0.8%	0.1%	-0.4%	-0.5%	-0.4%	**0.6%**														
Avg. next 15 yrs	-0.4%	-1.1%	0.4%	0.3%	-0.4%	-0.4%	-0.5%	**0.7%**														

EE: Energy Efficiency (reduces load)
PV: Solar - Photovoltaics (reduces load)
EV: Electric Vehicles (ADDs to load)
DR: Demand Response (Company only) (reduces load)
ES: Energy Storage (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
2006	1,329		1,328		1,366		1,376		45.5
2007	1,352	1.7%	1,338	0.7%	1,375	0.7%	1,385	0.6%	44.8
2008	1,305	-3.5%	1,329	-0.7%	1,368	-0.5%	1,379	-0.4%	40.0
2009	1,294	-0.8%	1,341	0.9%	1,383	1.1%	1,394	1.1%	35.0
2010	1,315	1.6%	1,275	-4.9%	1,321	-4.4%	1,335	-4.3%	53.1
2011	1,243	-5.5%	1,263	-0.9%	1,305	-1.2%	1,317	-1.3%	41.6
2012	1,320	6.2%	1,302	3.1%	1,344	3.0%	1,356	3.0%	51.9
2013	1,328	0.7%	1,336	2.6%	1,379	2.6%	1,391	2.6%	43.9
2014	1,275	-4.0%	1,239	-7.3%	1,286	-6.7%	1,299	-6.6%	52.2
2015	1,223	-4.1%	1,212	-2.1%	1,251	-2.7%	1,262	-2.8%	55.0
2016	1,239	1.3%	1,292	6.6%	1,340	7.0%	1,353	7.2%	35.9
2017	1,277	3.1%	1,218	-5.7%	1,281	-4.4%	1,298	-4.0%	53.8
2018	1,301	1.9%	1,263	3.6%	1,314	2.6%	1,329	2.4%	51.0
2019	1,183	-9.1%	1,203	-4.7%	1,259	-4.2%	1,274	-4.1%	42.4
2020	1,181	-0.1%	1,171	-2.6%	1,220	-3.1%	1,234	-3.2%	44.6
2021	1,208	2.3%	1,203	2.7%	1,250	2.5%	1,263	2.4%	43.8
2022	-	-	1,224	1.8%	1,274	1.9%	1,288	1.9%	-
2023	-	-	1,243	1.5%	1,295	1.6%	1,309	1.7%	-
2024	-	-	1,258	1.2%	1,312	1.3%	1,327	1.3%	-
2025	-	-	1,273	1.2%	1,327	1.2%	1,343	1.2%	-
2026	-	-	1,295	1.7%	1,351	1.8%	1,366	1.8%	-
2027	-	-	1,312	1.3%	1,368	1.3%	1,384	1.3%	-
2028	-	-	1,339	2.1%	1,396	2.1%	1,412	2.1%	-
2029	-	-	1,364	1.9%	1,422	1.9%	1,439	1.9%	-
2030	-	-	1,403	2.8%	1,461	2.8%	1,478	2.7%	-
2031	-	-	1,442	2.8%	1,502	2.8%	1,519	2.7%	-
2032	-	-	1,483	2.9%	1,544	2.8%	1,561	2.8%	-
2033	-	-	1,526	2.9%	1,588	2.8%	1,605	2.8%	-
2034	-	-	1,569	2.8%	1,630	2.7%	1,648	2.7%	-
2035	-	-	1,615	2.9%	1,677	2.8%	1,694	2.8%	-
2036	-	-	1,662	2.9%	1,724	2.8%	1,742	2.8%	-
2037	-	-	1,706	2.6%	1,768	2.6%	1,786	2.5%	-

	Normal 50-50 (% Grwth)	Extreme 10-90 (% Grwth)	Extreme 05-95 (% Grwth)
Avg. last 15 yrs	-0.7%	-0.6%	-0.6%
Avg. last 10 yrs	-0.5%	-0.4%	-0.4%
Avg. last 5 yrs	-1.4%	-1.4%	-1.4%
BASE 2020			
Avg. next 5 yrs	1.5%	1.6%	1.6%
Avg. next 10 yrs	1.8%	1.9%	1.9%
Avg. next 14 yrs	2.3%	2.3%	2.3%

HDD_wtd

NORMAL	45.5
EXTREME 90/10	54.3
EXTREME 95/5	56.8

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

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

Calendar Year	SYSTEM PEAK: 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)	DER IMPACTS: EE	PV	EV	DR	ES	EH	DER	% of reconstituted peaks: EE	PV	EV	DR	ES	EH	DER
2006	1,374	1,328	1,374	1,374	1,374	1,374	1,374	**1,328**	(46)	0	0.0	0.0	0.0	0.0	(46)	-3.3%	0.0%	0.0%	0.0%	0.0%	0.0%	-3.3%
2007	1,395	1,338	1,395	1,395	1,395	1,395	1,395	**1,338**	(56)	0	0.0	0.0	0.0	0.0	(56)	-4.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-4.0%
2008	1,394	1,329	1,394	1,394	1,394	1,394	1,394	**1,329**	(66)	0	0.0	0.0	0.0	0.0	(65)	-4.7%	0.0%	0.0%	0.0%	0.0%	0.0%	-4.7%
2009	1,420	1,341	1,420	1,420	1,420	1,420	1,420	**1,341**	(79)	0	0.0	0.0	0.0	0.0	(79)	-5.6%	0.0%	0.0%	0.0%	0.0%	0.0%	-5.6%
2010	1,365	1,275	1,365	1,365	1,365	1,365	1,365	**1,275**	(91)	0	0.0	0.0	0.0	0.0	(91)	-6.6%	0.0%	0.0%	0.0%	0.0%	0.0%	-6.6%
2011	1,368	1,263	1,368	1,368	1,368	1,368	1,368	**1,263**	(104)	0	0.0	0.0	0.0	0.0	(104)	-7.6%	0.0%	0.0%	0.0%	0.0%	0.0%	-7.6%
2012	1,426	1,302	1,426	1,426	1,426	1,426	1,426	**1,302**	(124)	0	0.1	0.0	0.0	0.0	(123)	-8.7%	0.0%	0.0%	0.0%	0.0%	0.0%	-8.7%
2013	1,489	1,336	1,489	1,489	1,489	1,489	1,489	**1,336**	(153)	0	0.1	0.0	0.0	0.0	(153)	-10.3%	0.0%	0.0%	0.0%	0.0%	0.0%	-10.2%
2014	1,436	1,238	1,436	1,436	1,436	1,436	1,436	**1,239**	(197)	0	0.3	0.0	0.0	0.0	(197)	-13.7%	0.0%	0.0%	0.0%	0.0%	0.0%	-13.7%
2015	1,438	1,212	1,438	1,438	1,438	1,438	1,438	**1,212**	(226)	0	0.5	0.0	0.0	0.0	(225)	-15.7%	0.0%	0.0%	0.0%	0.0%	0.0%	-15.7%
2016	1,544	1,292	1,544	1,544	1,544	1,544	1,544	**1,292**	(252)	0	0.6	0.0	0.0	0.0	(252)	-16.3%	0.0%	0.0%	0.0%	0.0%	0.0%	-16.3%
2017	1,498	1,217	1,498	1,499	1,498	1,498	1,498	**1,218**	(281)	0	1.1	0.0	0.0	0.0	(279)	-18.7%	0.0%	0.1%	0.0%	0.0%	0.0%	-18.7%
2018	1,568	1,261	1,568	1,569	1,568	1,567	1,568	**1,263**	(306)	0	1.4	0.0	(0.1)	0.0	(305)	-19.5%	0.0%	0.1%	0.0%	0.0%	0.0%	-19.5%
2019	1,529	1,199	1,529	1,531	1,529	1,529	1,531	**1,203**	(330)	0	2.1	0.0	(0.4)	2.2	(326)	-21.6%	0.0%	0.1%	0.0%	0.0%	0.1%	-21.3%
2020	1,516	1,165	1,516	1,519	1,516	1,516	1,520	**1,171**	(351)	0	2.8	0.0	(0.8)	3.7	(346)	-23.2%	0.0%	0.2%	0.0%	-0.1%	0.2%	-22.8%
2021	1,562	1,194	1,562	1,566	1,562	1,560	1,569	**1,203**	(368)	0	3.6	0.0	(2.0)	7.2	(359)	-23.6%	0.0%	0.2%	0.0%	-0.1%	0.5%	-23.0%
2022	1,590	1,209	1,590	1,597	1,590	1,587	1,601	**1,224**	(381)	0	7.1	0.0	(3.4)	10.9	(366)	-23.9%	0.0%	0.4%	0.0%	-0.2%	0.7%	-23.0%
2023	1,614	1,222	1,614	1,625	1,614	1,609	1,629	**1,243**	(392)	0	11.1	0.0	(5.1)	15.0	(371)	-24.3%	0.0%	0.7%	0.0%	-0.3%	0.9%	-23.0%
2024	1,630	1,227	1,630	1,646	1,630	1,623	1,651	**1,258**	(403)	0	16.5	0.0	(7.0)	21.7	(371)	-24.7%	0.0%	1.0%	0.0%	-0.4%	1.3%	-22.8%
2025	1,642	1,229	1,642	1,666	1,642	1,633	1,672	**1,273**	(413)	0	23.8	0.0	(9.3)	29.9	(369)	-25.2%	0.0%	1.5%	0.0%	-0.6%	1.8%	-22.5%
2026	1,657	1,233	1,657	1,691	1,657	1,646	1,697	**1,295**	(424)	0	33.8	0.0	(11.9)	39.9	(362)	-25.6%	0.0%	2.0%	0.0%	-0.7%	2.4%	-21.9%
2027	1,666	1,231	1,666	1,713	1,666	1,651	1,715	**1,312**	(435)	0	46.8	0.0	(14.8)	48.4	(354)	-26.1%	0.0%	2.8%	0.0%	-0.9%	2.9%	-21.3%
2028	1,680	1,235	1,680	1,743	1,680	1,662	1,739	**1,339**	(445)	0	63.1	0.0	(18.1)	58.5	(341)	-26.5%	0.0%	3.8%	0.0%	-1.1%	3.5%	-20.3%
2029	1,687	1,232	1,687	1,770	1,687	1,665	1,757	**1,364**	(455)	0	83.3	0.0	(21.7)	70.7	(322)	-27.0%	0.0%	4.9%	0.0%	-1.3%	4.2%	-19.1%
2030	1,699	1,235	1,699	1,807	1,699	1,674	1,784	**1,403**	(464)	0	107.6	0.0	(25.6)	85.2	(297)	-27.3%	0.0%	6.3%	0.0%	-1.5%	5.0%	-17.5%
2031	1,709	1,237	1,709	1,845	1,709	1,679	1,808	**1,442**	(473)	0	136.1	0.0	(29.9)	99.1	(267)	-27.6%	0.0%	8.0%	0.0%	-1.7%	5.8%	-15.6%
2032	1,718	1,237	1,718	1,886	1,718	1,684	1,831	**1,483**	(481)	0	168.1	0.0	(34.4)	112.3	(235)	-28.0%	0.0%	9.8%	0.0%	-2.0%	6.5%	-13.7%
2033	1,726	1,237	1,726	1,930	1,726	1,686	1,851	**1,526**	(489)	0	204.1	0.0	(39.4)	124.8	(199)	-28.3%	0.0%	11.8%	0.0%	-2.3%	7.2%	-11.5%
2034	1,731	1,234	1,731	1,973	1,731	1,686	1,867	**1,569**	(496)	0	242.6	0.0	(44.6)	136.6	(162)	-28.7%	0.0%	14.0%	0.0%	-2.6%	7.9%	-9.3%
2035	1,736	1,233	1,736	2,021	1,736	1,686	1,884	**1,615**	(503)	0	284.4	0.0	(50.2)	147.9	(121)	-29.0%	0.0%	16.4%	0.0%	-2.9%	8.5%	-7.0%
2036	1,741	1,231	1,741	2,069	1,741	1,685	1,899	**1,662**	(510)	0	328.3	0.0	(56.0)	158.6	(79)	-29.3%	0.0%	18.9%	0.0%	-3.2%	9.1%	-4.6%
2037	1,742	1,226	1,742	2,116	1,742	1,680	1,911	**1,706**	(517)	0	373.2	0.0	(62.3)	168.8	(37)	-29.6%	0.0%	21.4%	0.0%	-3.6%	9.7%	-2.1%
Avg. last 15 yrs	0.9%	-0.7%	0.9%	0.9%	0.9%	0.8%	0.9%	**-0.7%**														
Avg. last 10 yrs	1.3%	-0.6%	1.3%	1.4%	1.3%	1.3%	1.4%	**-0.5%**														
Avg. last 5 yrs	0.2%	-1.6%	0.2%	0.3%	0.2%	0.2%	0.3%	**-1.4%**														
BASE 2020																						
Avg. next 5 yrs	1.2%	0.7%	1.2%	1.6%	1.2%	1.1%	1.6%	**1.5%**														
Avg. next 10 yrs	0.9%	0.4%	0.9%	1.7%	0.9%	0.7%	1.4%	**1.8%**														
Avg. next 15 yrs	0.7%	0.2%	0.7%	1.9%	0.7%	0.5%	1.3%	**2.2%**														

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

Appendix B: Historical Peaks Days and Hours

Summer Peaks

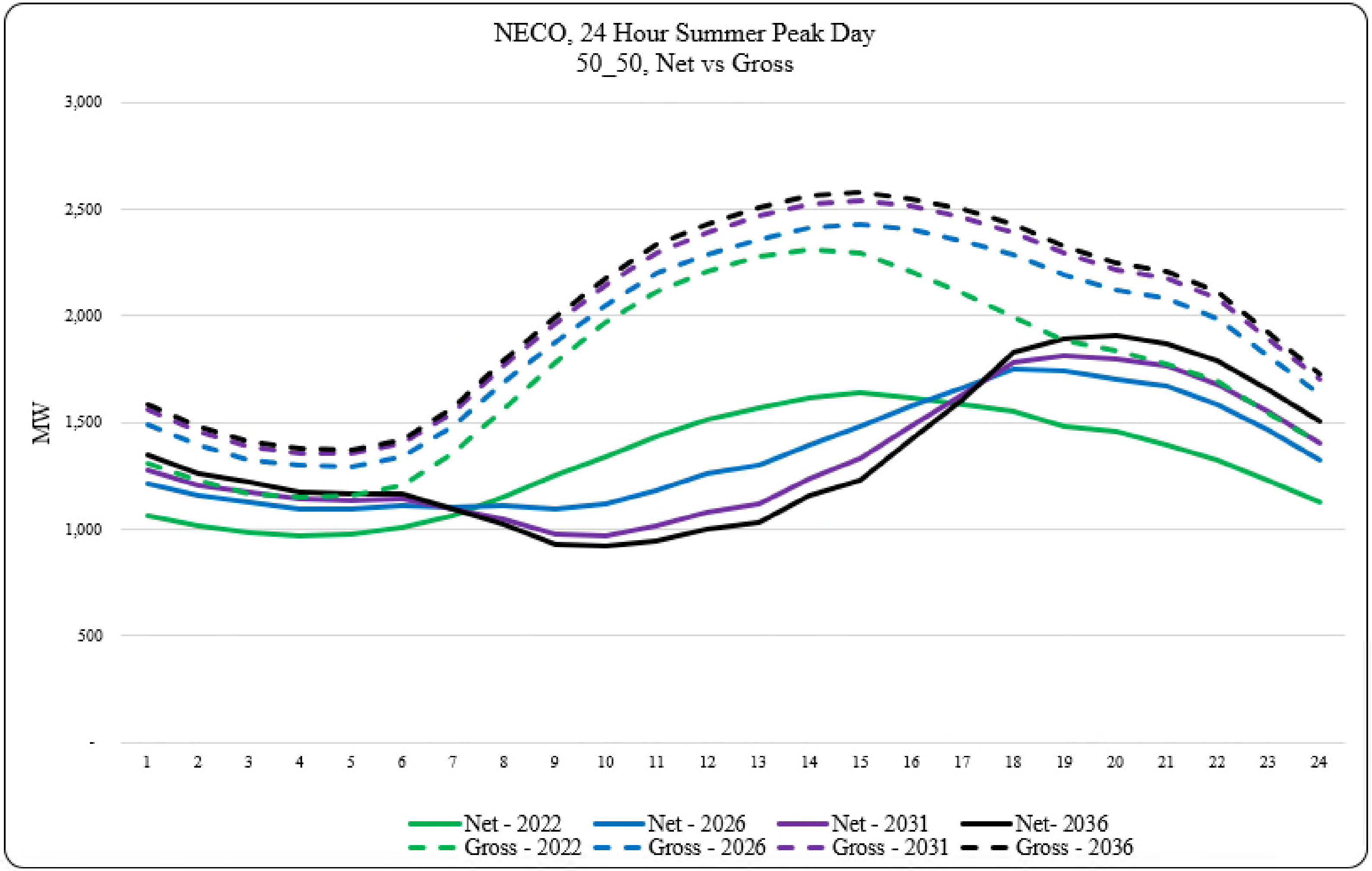
year	date	hour
2003	8/22/2003	15
2004	8/30/2004	15
2005	8/5/2005	15
2006	8/2/2006	15
2007	8/3/2007	15
2008	6/10/2008	15
2009	8/18/2009	15
2010	7/6/2010	15
2011	7/22/2011	16
2012	7/18/2012	15
2013	7/19/2013	15
2014	9/2/2014	16
2015	7/20/2015	15
2016	8/12/2016	16
2017	7/20/2017	16
2018	8/29/2018	17
2019	7/21/2019	18
2020	7/28/2020	15
2021	6/30/2021	16
2022	8/9/2022	15

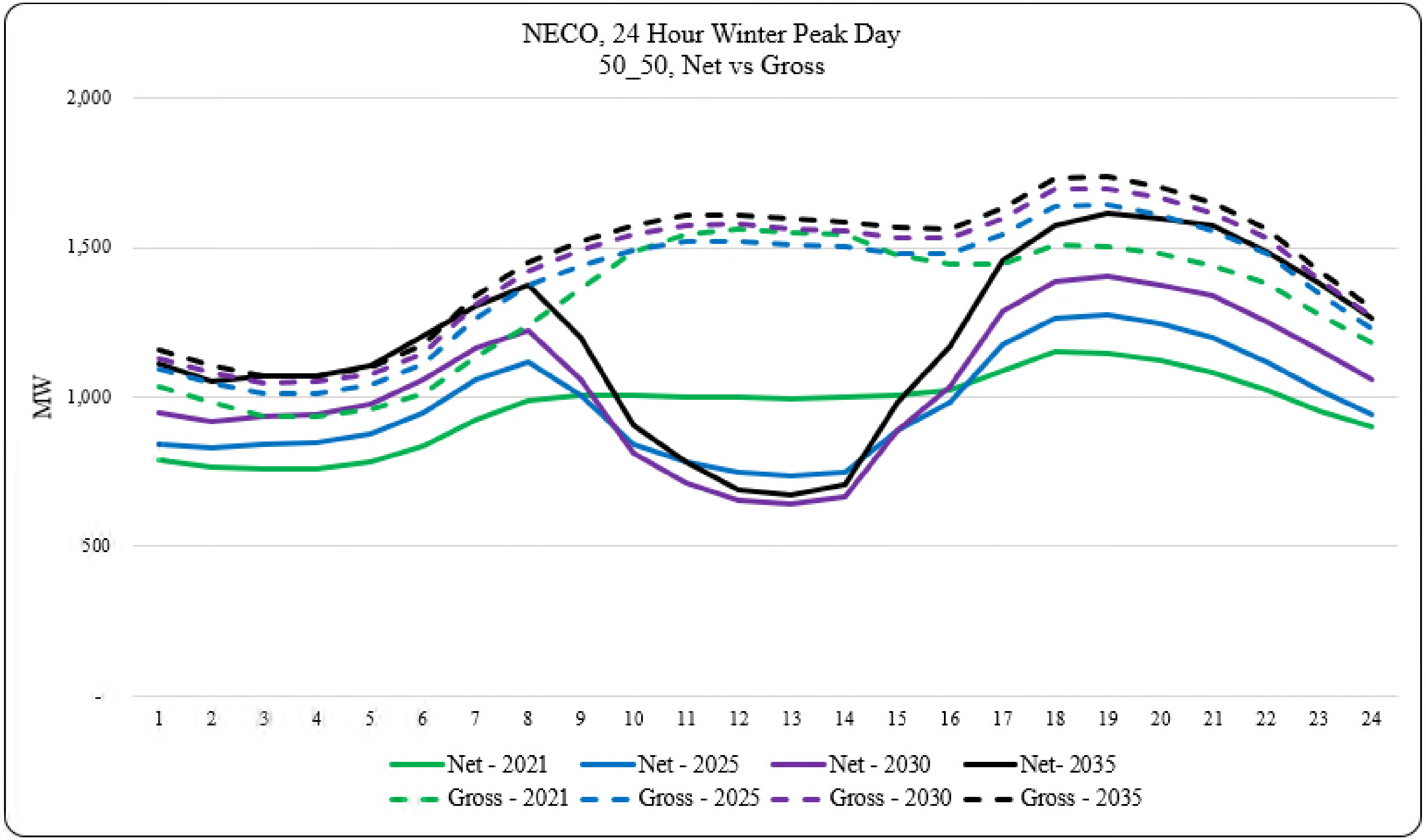
Winter Peaks

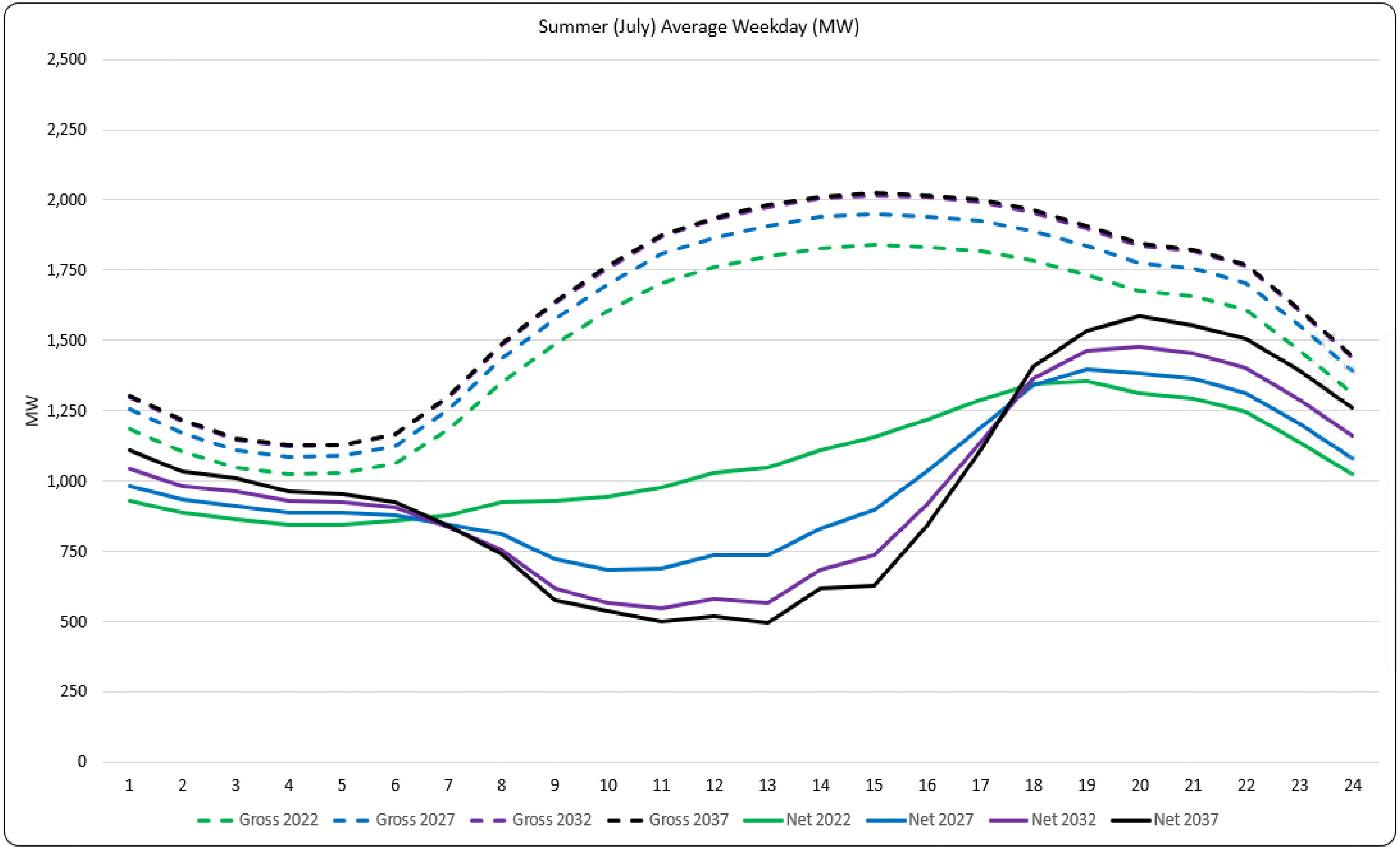
year	date	hour
2003	1/15/2004	19
2004	12/20/2004	19
2005	12/14/2005	18
2006	2/5/2007	19
2007	1/3/2008	19
2008	12/8/2008	18
2009	12/29/2009	19
2010	1/24/2011	19
2011	1/4/2012	18
2012	1/24/2013	19
2013	12/17/2013	18
2014	1/8/2015	18
2015	2/15/2016	19
2016	12/15/2016	18
2017	1/2/2018	19
2018	1/21/2019	18
2019	12/19/2019	19
2020	1/29/2021	19
2021	1/11/2022	18

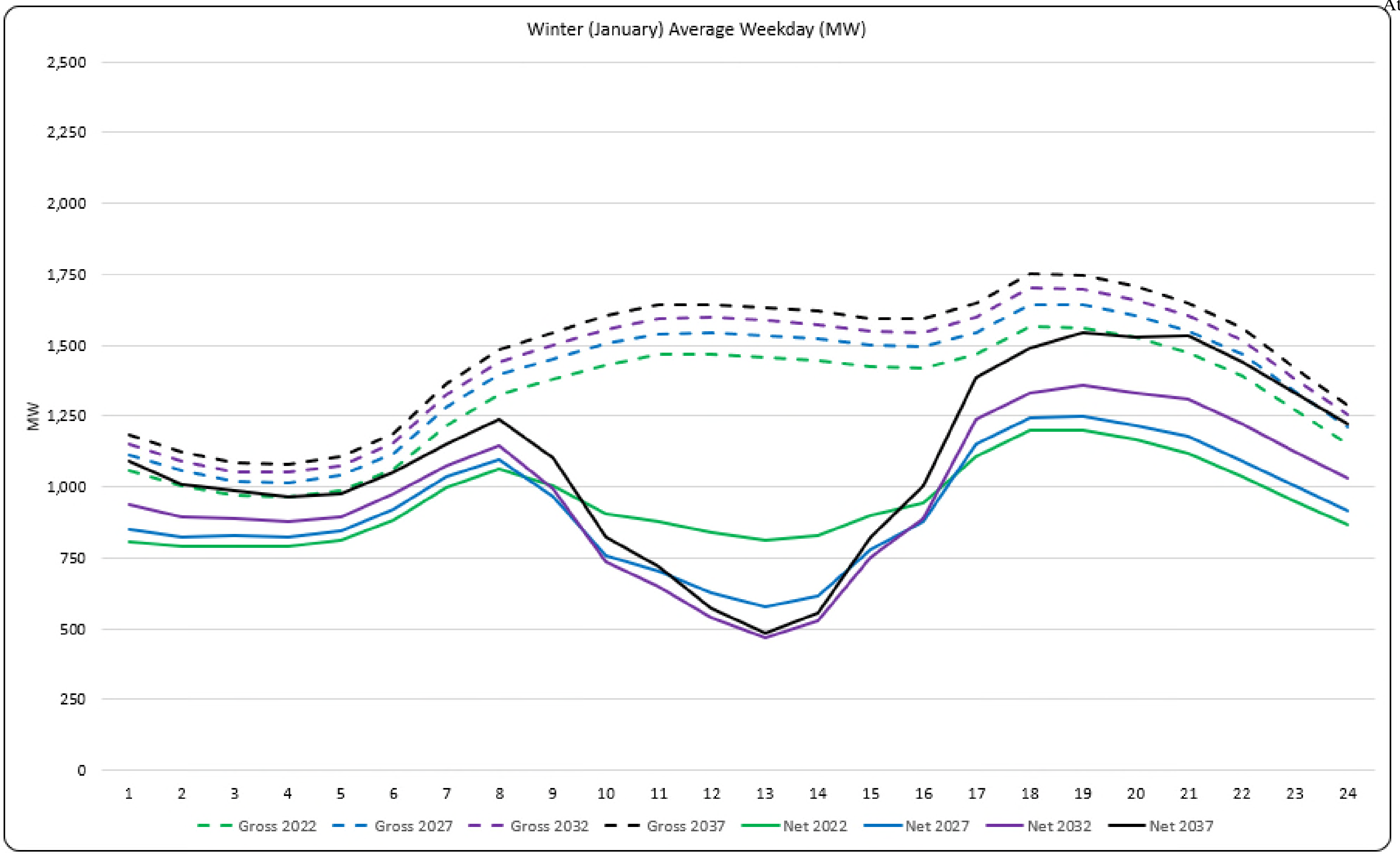
Appendix C: Load Shapes for Typical Day Types

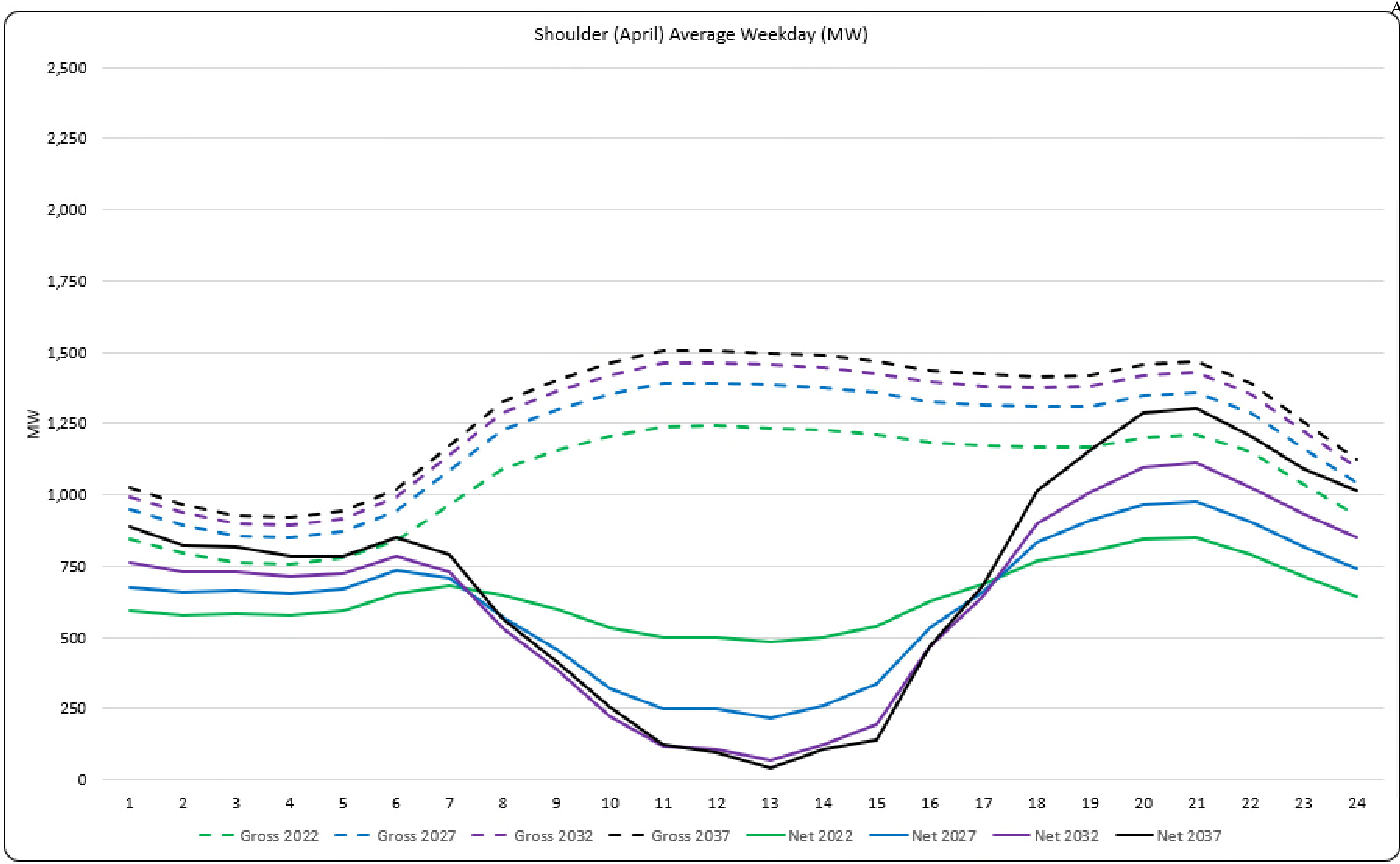
(for Base Case)

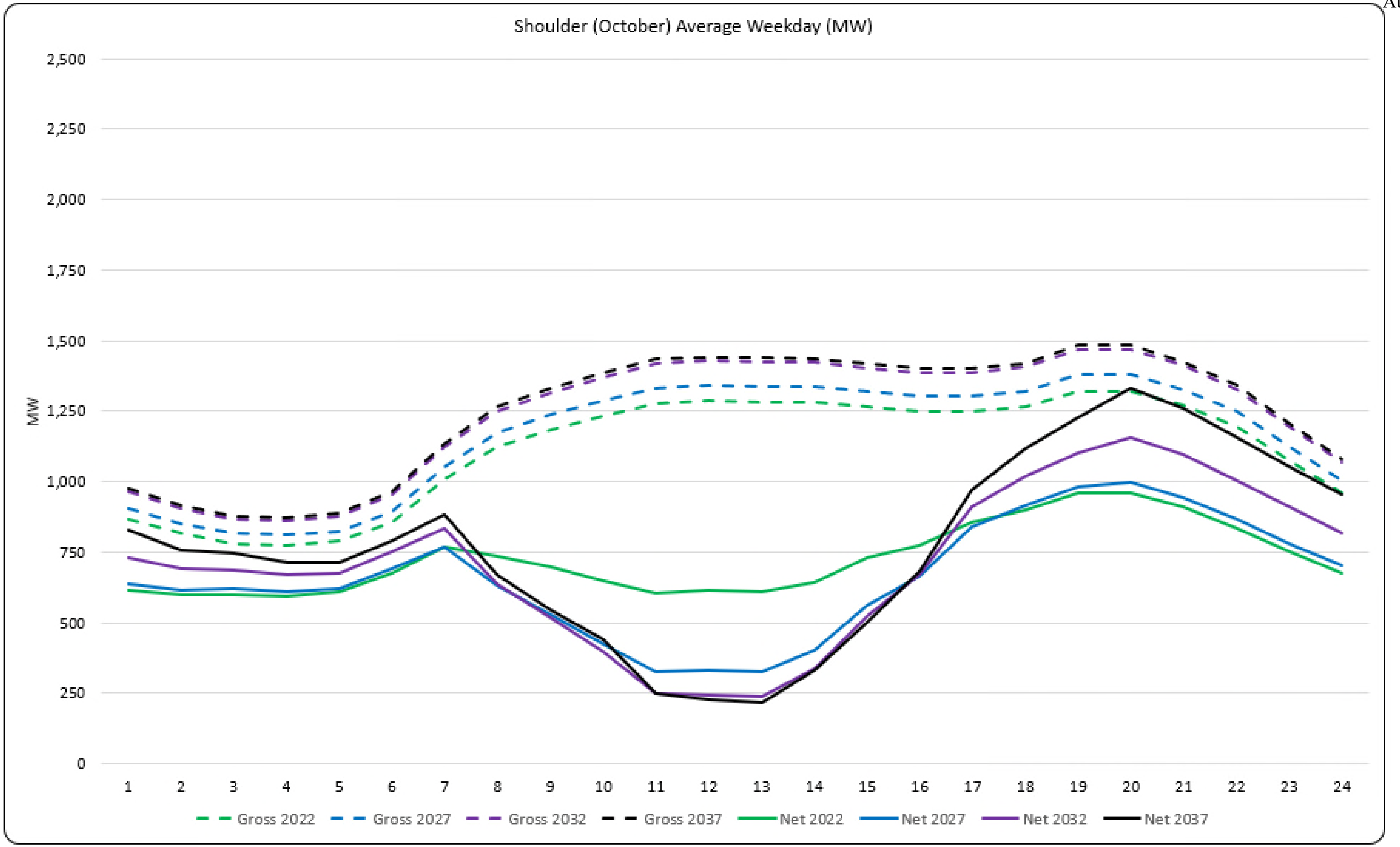

NECO, 24 Hour Summer Peak Day
50_50, Net vs Gross
MW
3,000
2,500
2,000
1,500
1,000
500
-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Net - 2022
Net - 2026
Net - 2031
Net- 2036
Gross - 2022
Gross - 2026
Gross - 2031
Gross - 2036


NECO, 24 Hour Winter Peak Day
50_50, Net vs Gross
2,000
1,500
1,000
500
-
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
Net - 2021
Net - 2025
Net - 2030
Net- 2035
Gross - 2021
Gross - 2025
Gross - 2030
Gross - 2035

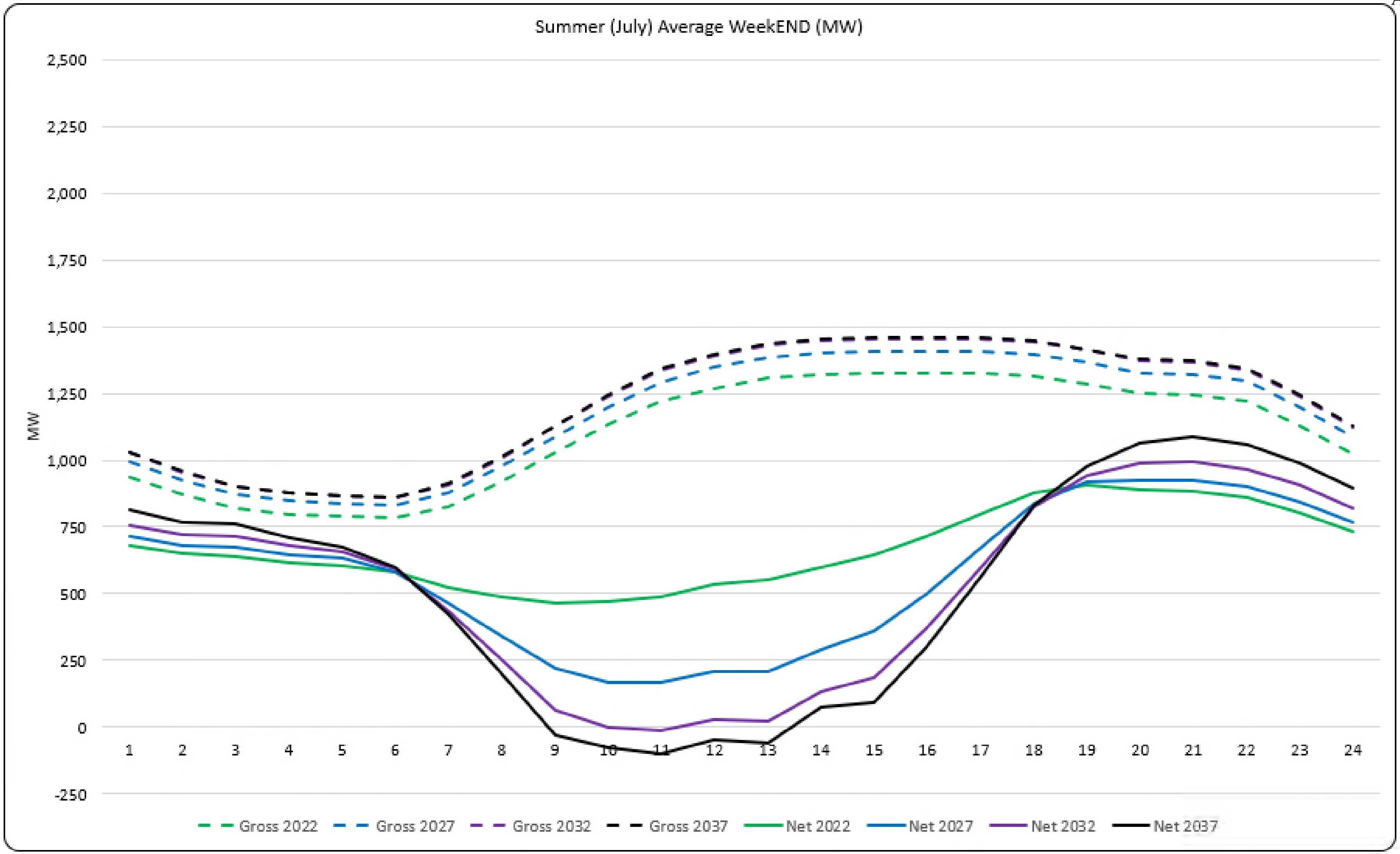

Summer (July) Average Weekday (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2022
Gross 2027
Gross 2032
Gross 2037
Net 2022
Net 2027
Net 2032
Net 2037


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 2022
Gross 2027
Gross 2032
Gross 2037
Net 2022
Net 2027
Net 2032
Net 2037

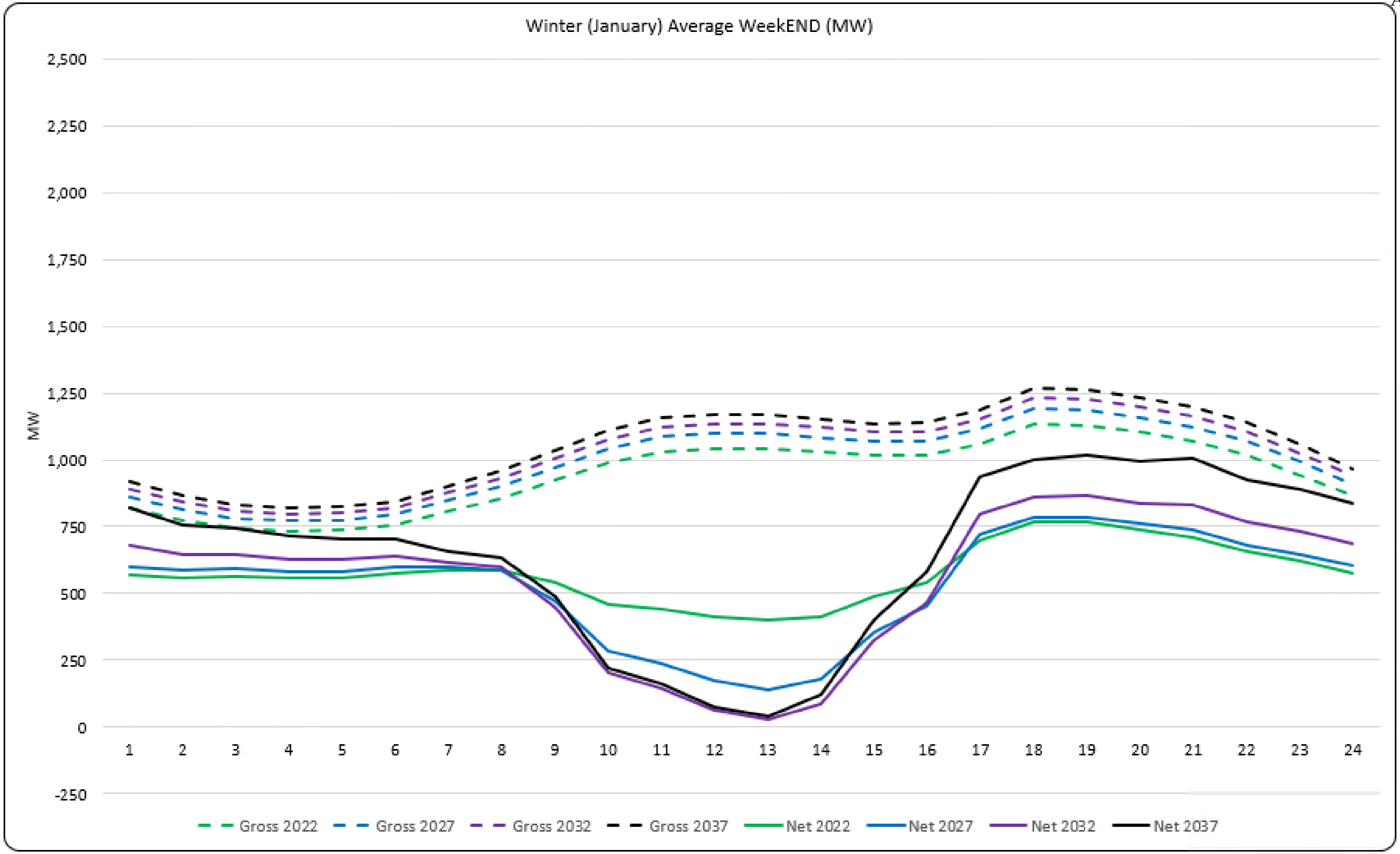

Shoulder (April) Average Weekday (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2022
Gross 2027
Gross 2032
Gross 2037
Net 2022
Net 2027
Net 2032
Net 2037

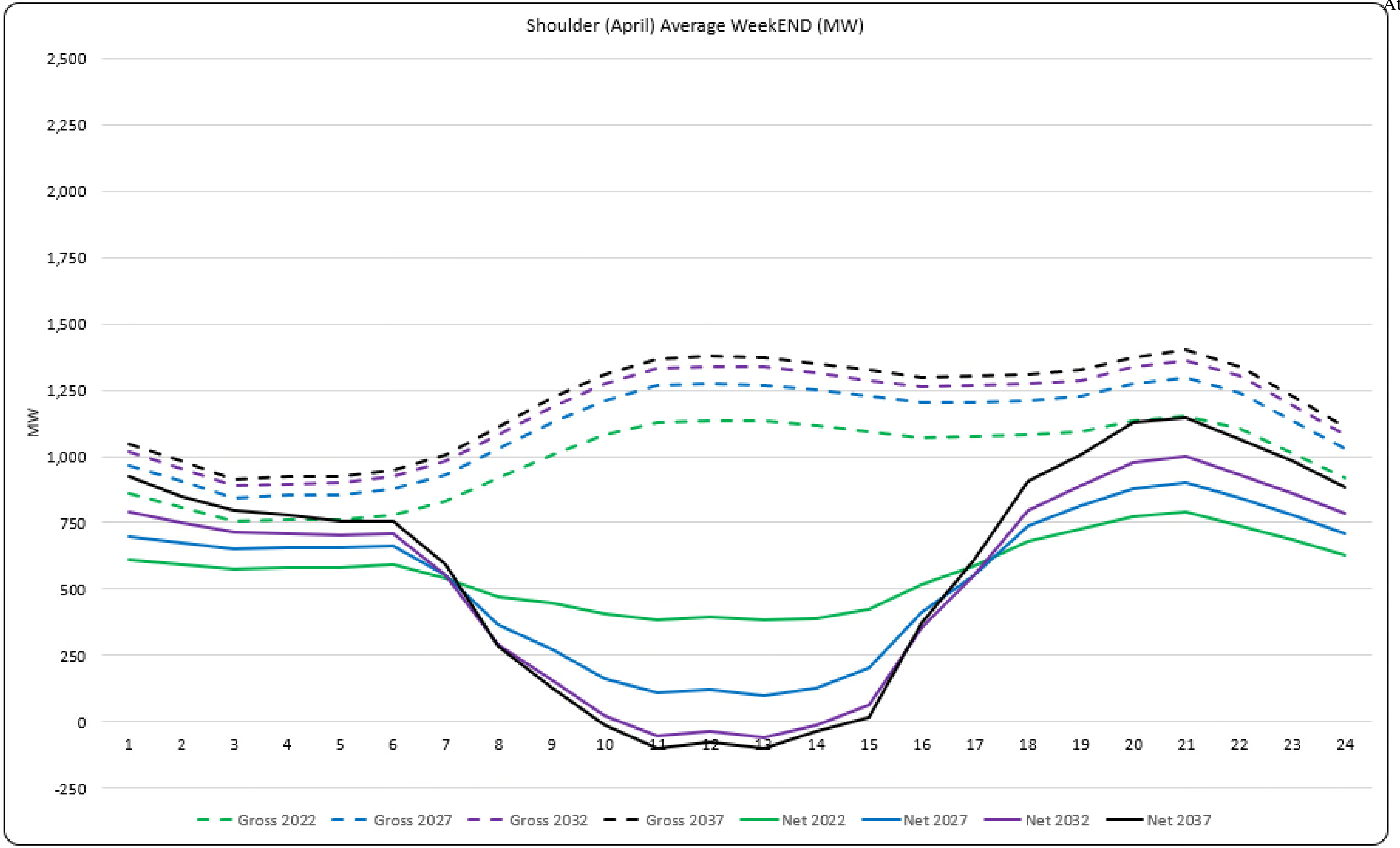


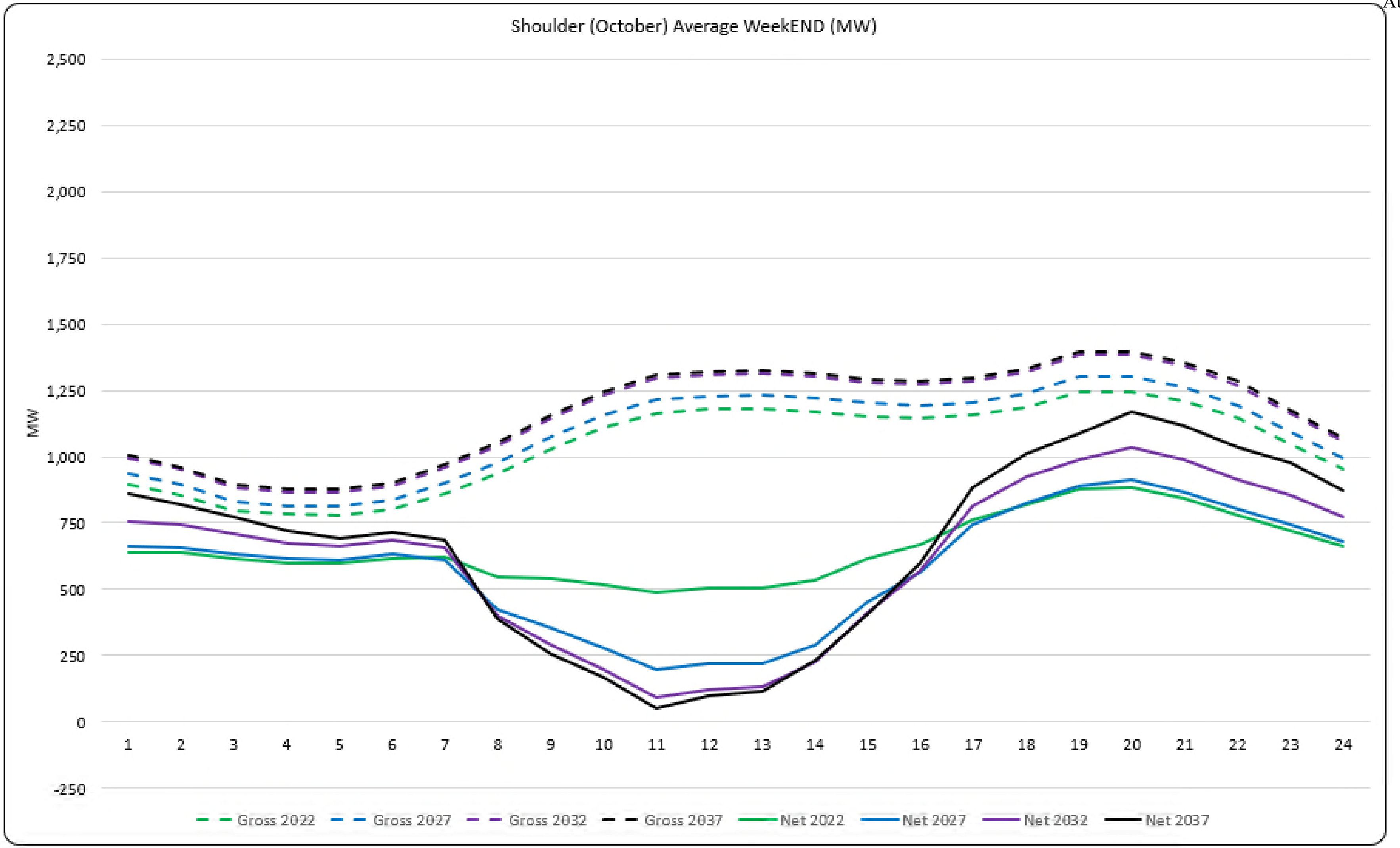
Confidential



Confidential


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 2022
Gross 2027
Gross 2032
Gross 2037
Net 2022
Net 2027
Net 2032
Net 2037

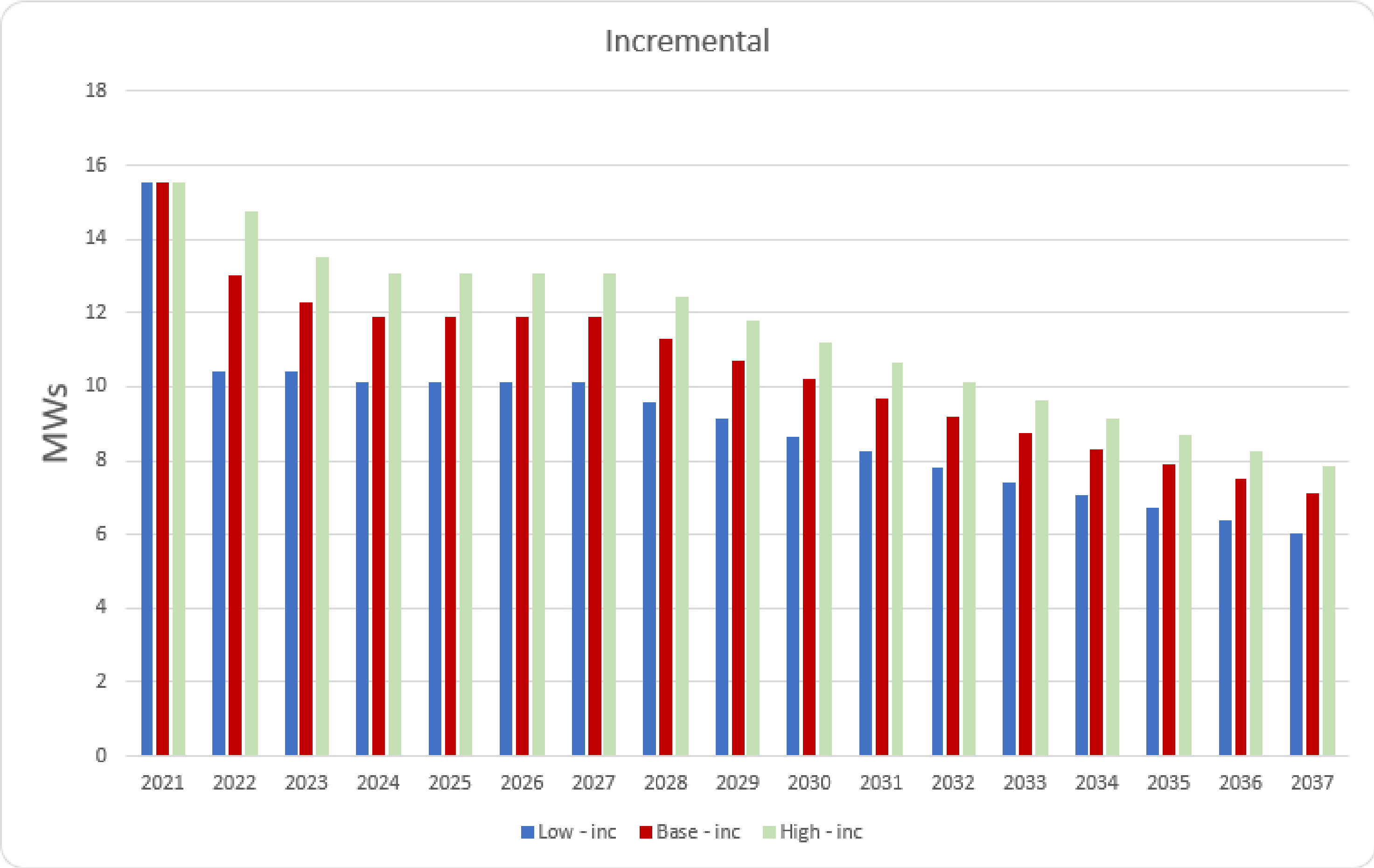

Shoulder (April) Average WeekEND (MW)
MW
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
-250
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gross 2022
Gross 2027
Gross 2032
Gross 2037
Net 2022
Net 2027
Net 2032
Net 2037


Shoulder (October) Average WeekEND (MW)
2,500
2,250
2,000
1,750
1,500
1,250
1,000
750
500
250
0
-250
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 2022
Gross 2027
Gross 2032
Gross 2037
Net 2022
Net 2027
Net 2032
Net 2037

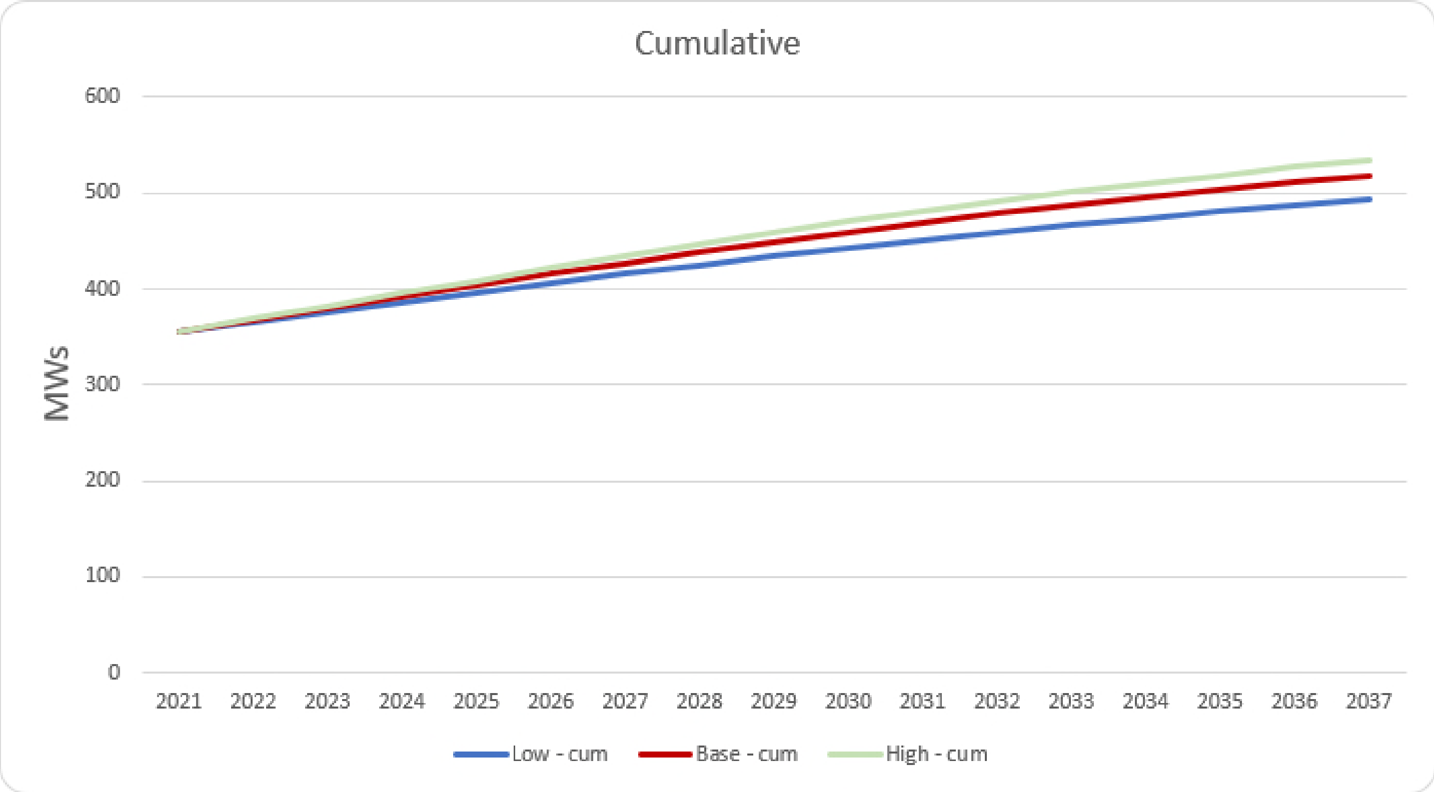
Appendix D: DER Scenarios Inputs

Energy Efficiency (NECO)

Summer Peaks Mws						
Year	**Low - inc**	**Low - cum**	**Base-inc**	**Base -cum**	**High - inc**	**High - cum**
2021	16	354	16	354	16	354
2022	10	365	13	367	15	369
2023	10	375	12	380	14	383
2024	10	385	12	392	13	396
2025	10	395	12	403	13	409
2026	10	406	12	415	13	422
2027	10	416	12	427	13	435
2028	10	425	11	439	12	447
2029	9	434	11	449	12	459
2030	9	443	10	460	11	470
2031	8	451	10	469	11	481
2032	8	459	9	478	10	491
2033	7	467	9	487	10	501
2034	7	474	8	495	9	510
2035	7	480	8	503	9	519
2036	6	487	7	511	8	527
2037	6	493	7	518	8	535

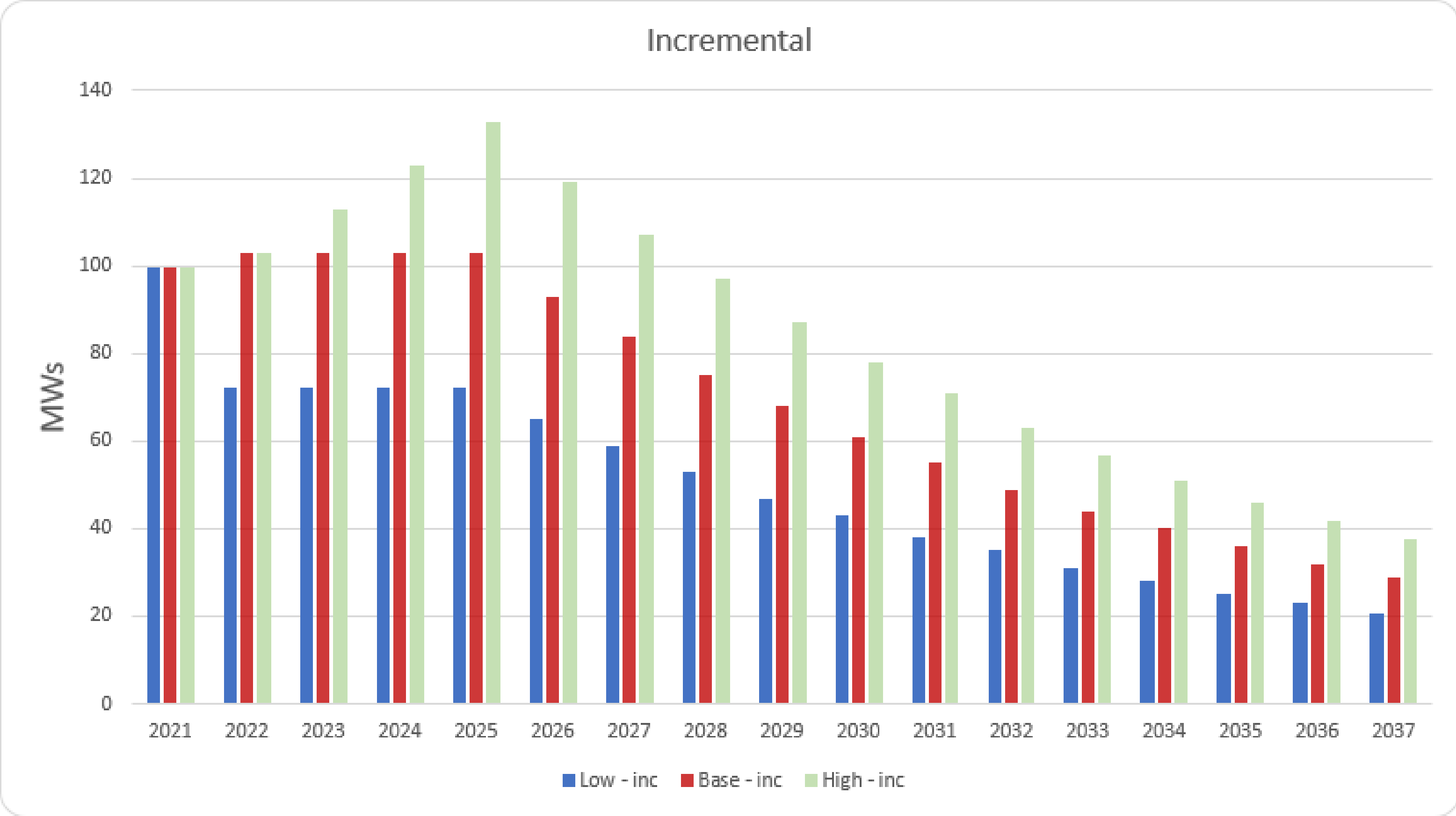


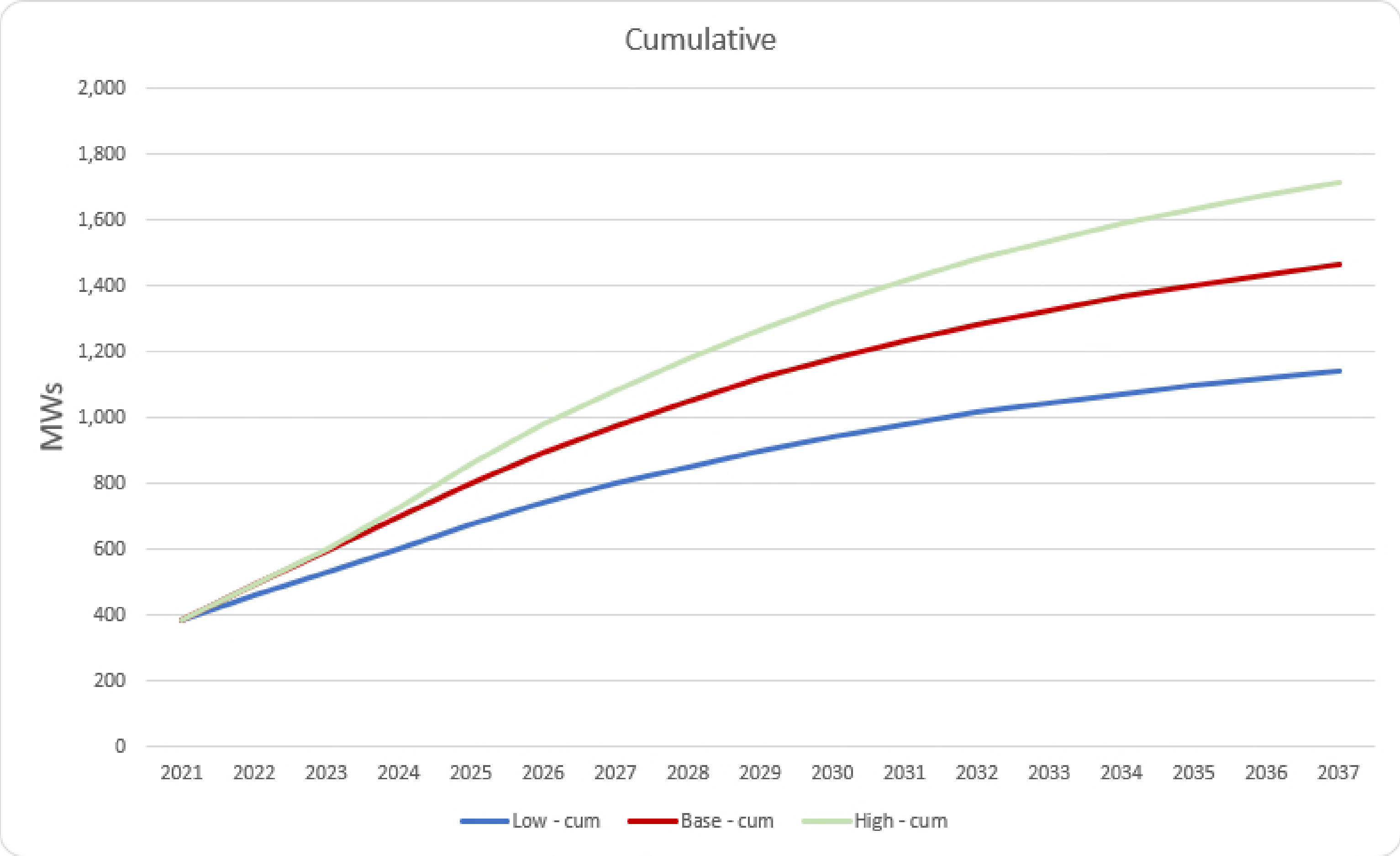
Confidential


Cumulative
MWs
600
500
400
300
200
100
0
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
Low - cum
Base - cum
High - cum

Solar – PV (NECO)
Installed Nameplate MWs

Connected Nameplate (MW)						
Year	**Low - inc**	**Low - cum**	**Base - inc**	**Base - cum**	**High - inc**	**High - cum**
2021	99	387	99	387	99	387
2022	72	459	103	490	103	490
2023	72	531	103	593	113	603
2024	72	603	103	696	123	726
2025	72	675	103	799	133	859
2026	65	740	93	892	119	978
2027	59	799	84	976	107	1,085
2028	53	852	75	1,051	97	1,182
2029	47	899	68	1,119	87	1,269
2030	43	942	61	1,180	78	1,347
2031	38	980	55	1,235	71	1,418
2032	35	1,015	49	1,284	63	1,481
2033	31	1,046	44	1,328	57	1,538
2034	28	1,074	40	1,368	51	1,589
2035	25	1,099	36	1,404	46	1,635
2036	23	1,122	32	1,436	42	1,677
2037	21	1,143	29	1,465	38	1,715


Incremental
140
120
100
80
60
40
20
0
MWs
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
Low - inc
Base - inc
High - inc


Cumulative
MWs
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
Low - cum
Base - cum
High - cum

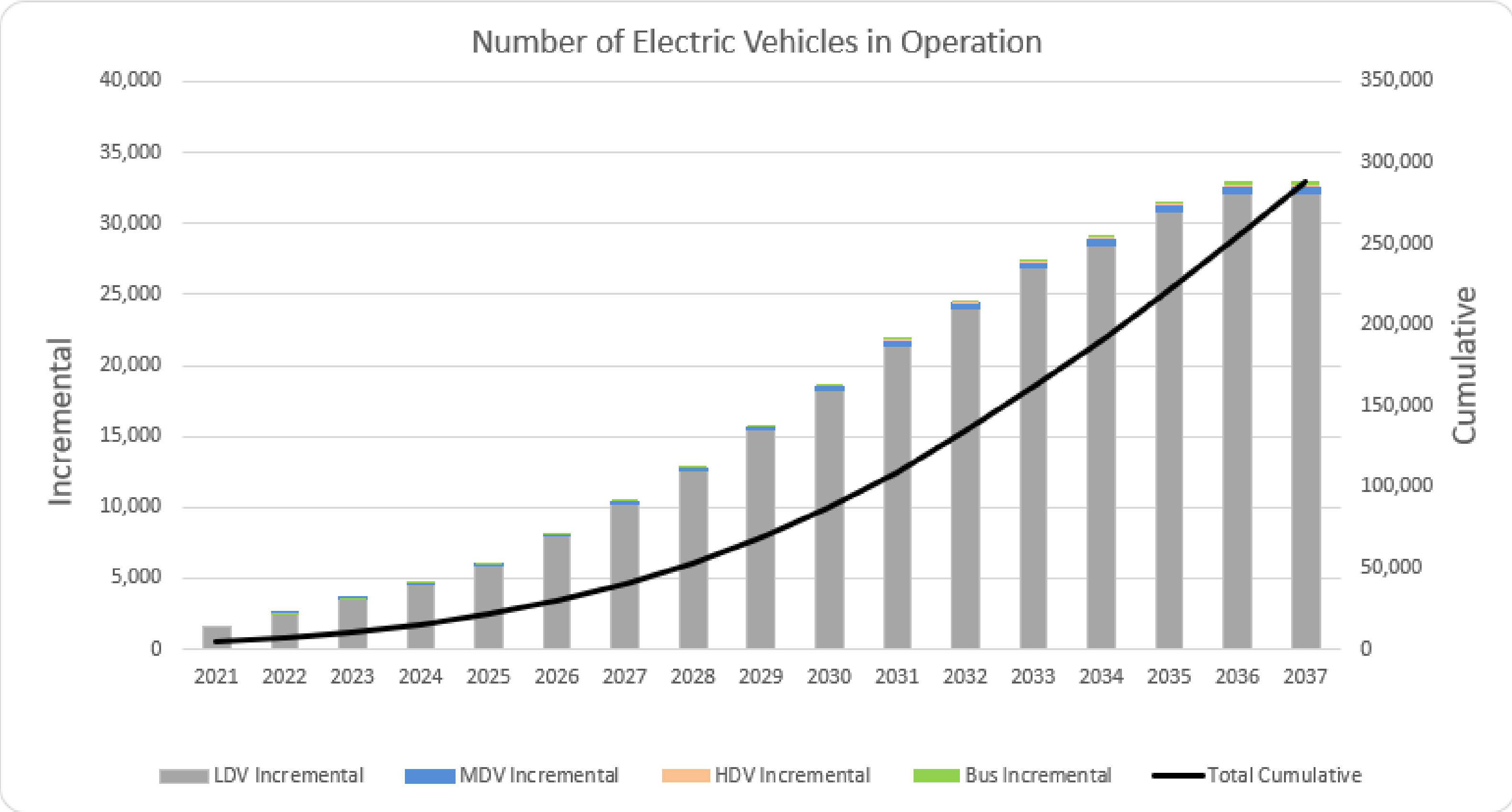
Electric Vehicles (NECO)

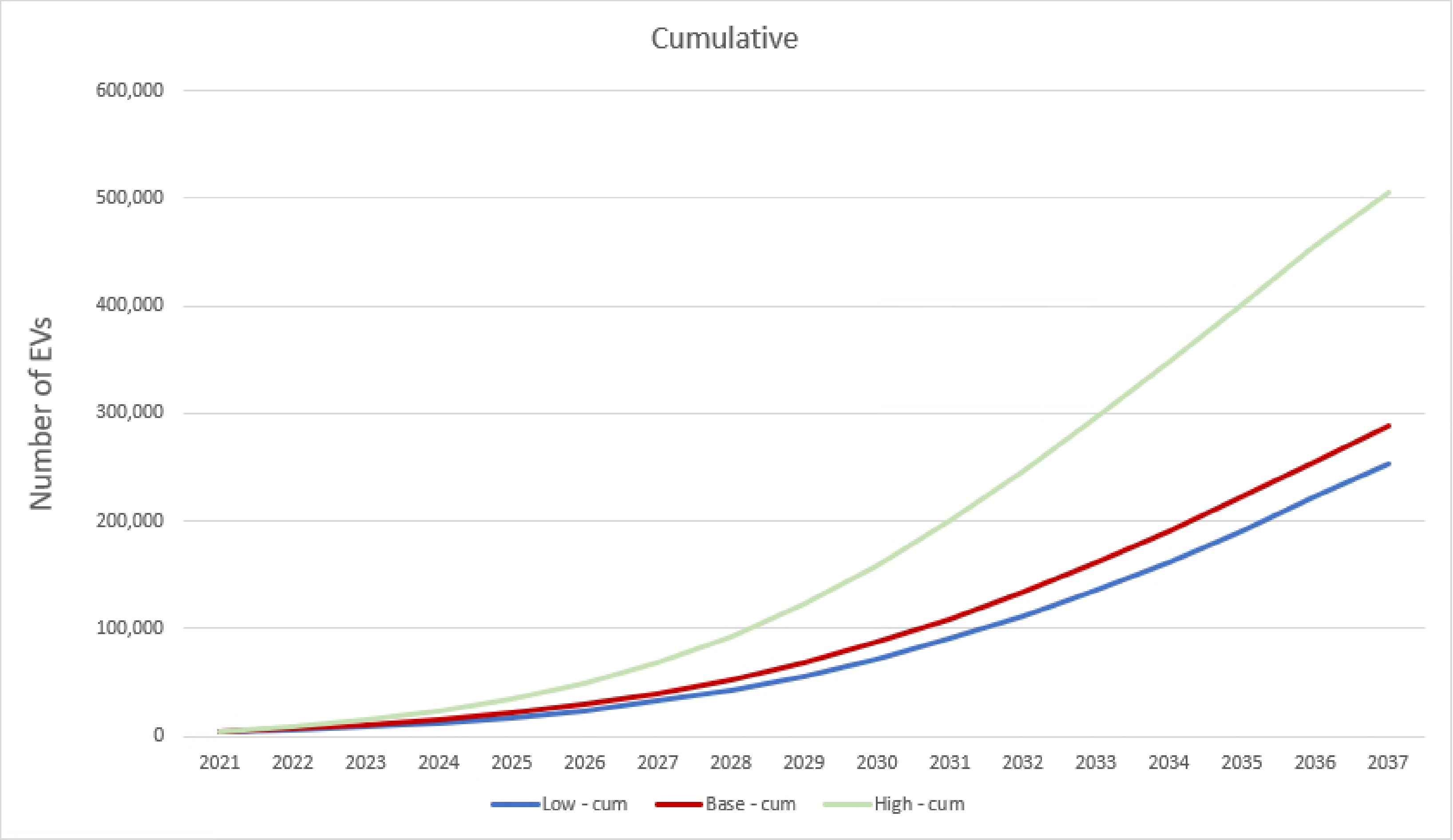
Number of Vehicles

Year	Low - inc	Low - cum	Base - inc	Base -cum	High - inc	High - cum
2021	1,570	4,634	1,570	4,634	1,570	4,634
2022	1,809	6,443	2,507	7,141	3,971	8,605
2023	2,776	9,218	3,566	10,706	6,503	15,108
2024	3,845	13,063	4,683	15,389	8,484	23,592
2025	5,007	18,071	6,017	21,407	10,882	34,475
2026	6,428	24,498	8,189	29,595	14,993	49,468
2027	8,508	33,006	10,468	40,063	19,398	68,866
2028	10,490	43,496	12,893	52,956	24,245	93,111
2029	12,974	56,471	15,768	68,725	30,008	123,118
2030	15,627	72,097	18,698	87,422	36,026	159,144
2031	18,815	90,912	21,920	109,342	41,755	200,899
2032	21,228	112,140	24,572	133,914	46,066	246,965
2033	23,966	136,106	27,454	161,368	49,329	296,294
2034	26,071	162,177	29,191	190,559	51,167	347,461
2035	28,862	191,039	31,588	222,147	54,241	401,703
2036	31,124	222,163	32,935	255,082	53,380	455,082
2037	30,662	252,826	32,968	288,051	50,346	505,428

Number of Light Duty Vehicles

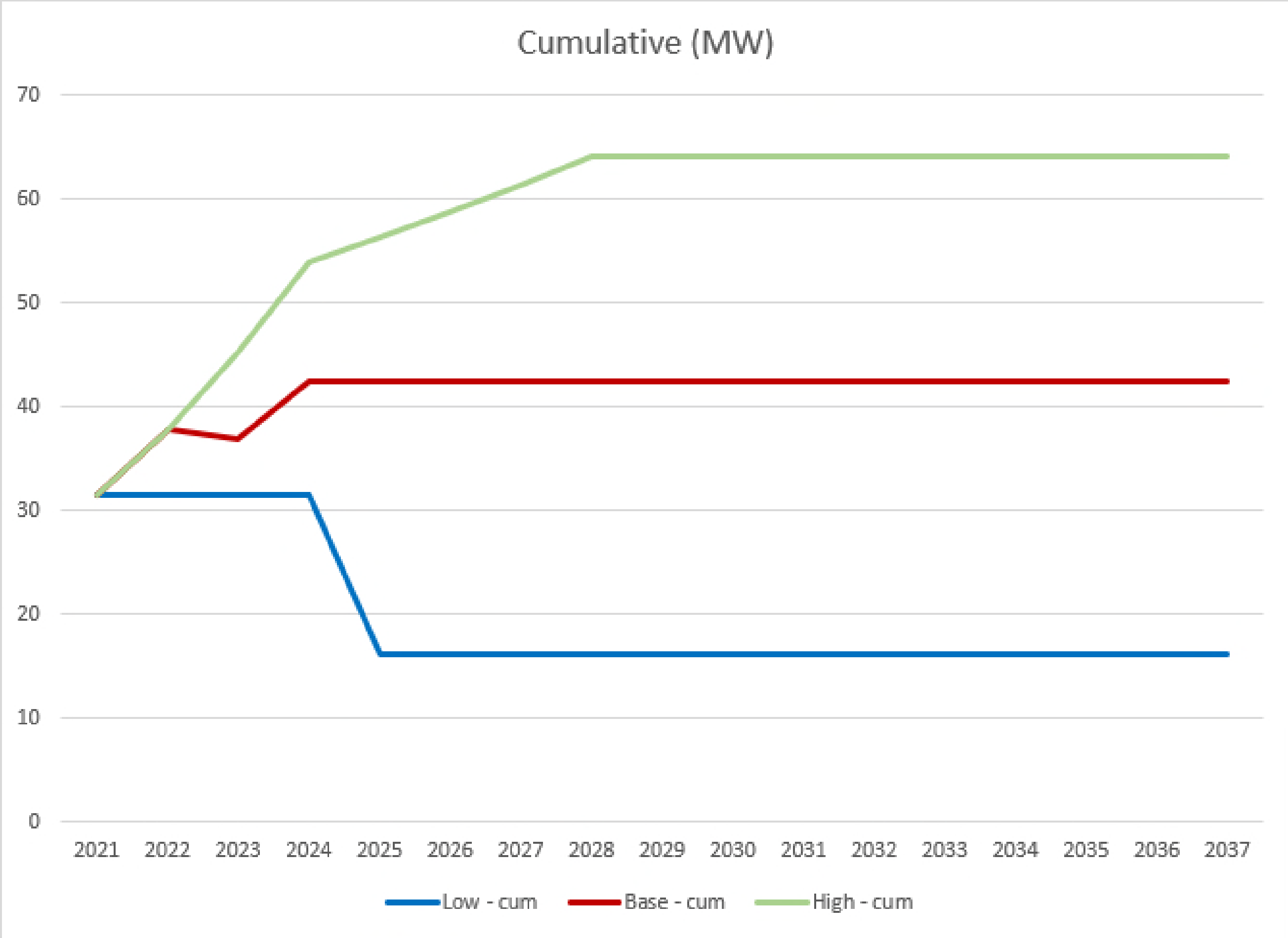
Year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum
2021	1,570	4,634	1,570	4,634	1,570	4,634
2022	1,774	6,408	2,472	7,106	3,861	8,495
2023	2,717	9,125	3,507	10,613	6,353	14,848
2024	3,753	12,878	4,591	15,204	8,300	23,148
2025	4,873	17,751	5,883	21,087	10,654	33,802
2026	6,253	24,004	8,014	29,101	14,625	48,427
2027	8,283	32,287	10,243	39,344	18,882	67,309
2028	10,207	42,494	12,610	51,954	23,581	90,890
2029	12,627	55,121	15,421	67,375	29,155	120,045
2030	15,212	70,333	18,283	85,658	35,033	155,078
2031	18,334	88,667	21,439	107,097	40,666	195,744
2032	20,680	109,347	24,024	131,121	44,881	240,625
2033	23,354	132,701	26,842	157,963	48,048	288,673
2034	25,399	158,100	28,519	186,482	49,807	338,480
2035	28,134	186,234	30,860	217,342	52,814	391,294
2036	30,345	216,579	32,156	249,498	51,884	443,178
2037	29,834	246,413	32,140	281,638	48,833	492,011


Number of Electric Vehicles in Operation
Incremental
Cumulative
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
LDV Incremental
MDV Incremental
HDV Incremental
Bus Incremental
Total Cumulative


Cumulative
Number of EVs
600,000
500,000
400,000
300,000
200,000
100,000
0
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
Low - cum
Base - cum
High - cum

Demand Response (NECO)

Year	Low - cum	Base - cum	High - cum
2021	32	32	32
2022	32	38	38
2023	32	37	45
2024	32	42	54
2025	16	42	56
2026	16	42	59
2027	16	42	61
2028	16	42	64
2029	16	42	64
2030	16	42	64
2031	16	42	64
2032	16	42	64
2033	16	42	64
2034	16	42	64
2035	16	42	64
2036	16	42	64
2037	16	42	64


Cumulative (MW)
70
60
50
40
30
20
10
0
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
Low - cum
Base - cum
High - cum

Energy Storage (NECO)[10]

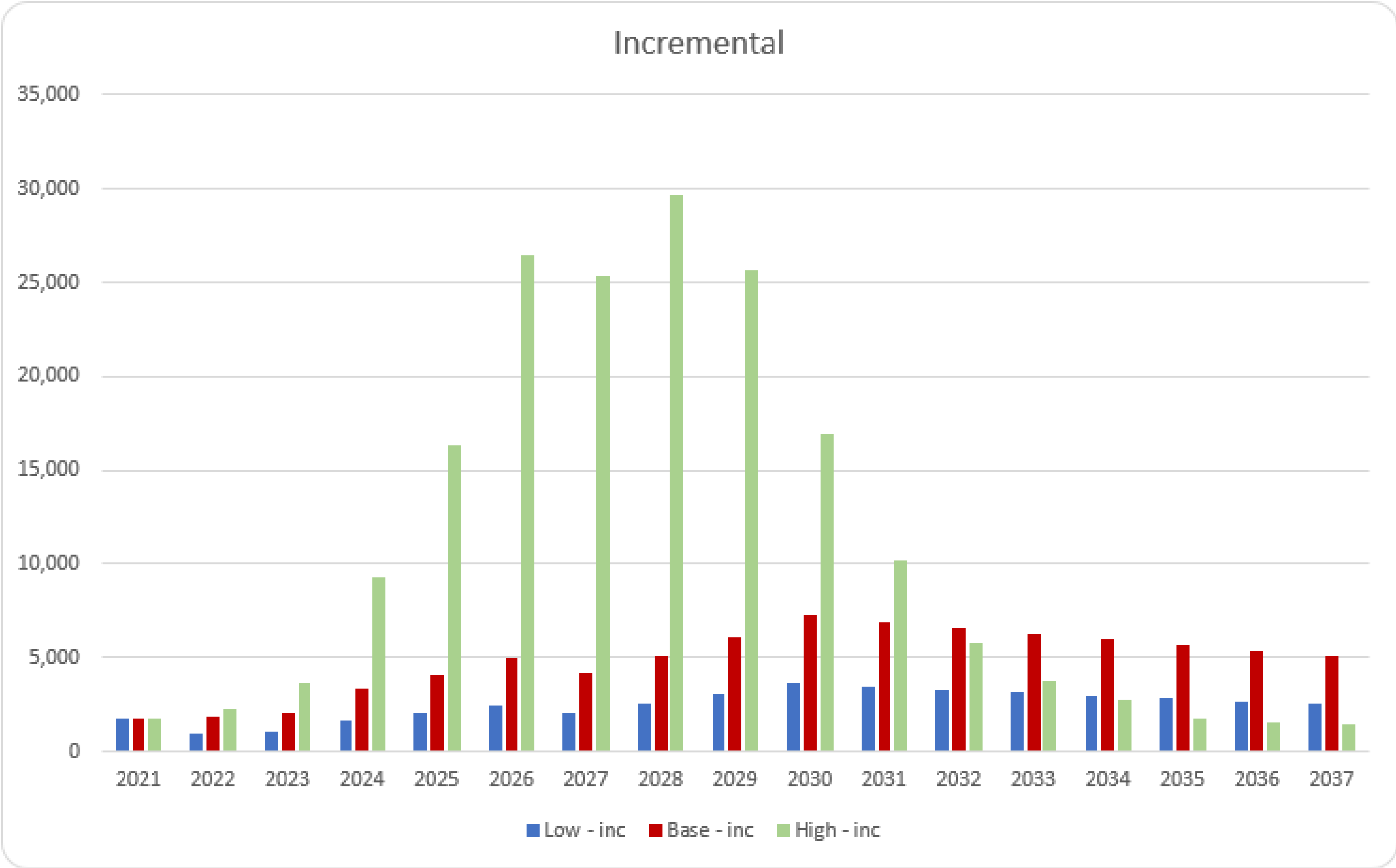
Year	Base - inc	Base - cum
2021	1.58	2.68
2022	2.00	4.68
2023	2.24	6.92
2024	2.59	9.52
2025	3.14	12.66
2026	3.49	16.15
2027	4.04	20.19
2028	4.39	24.58
2029	4.94	29.52
2030	5.29	34.81
2031	5.84	40.65
2032	6.19	46.84
2033	6.74	53.58
2034	7.09	60.67
2035	7.64	68.31
2036	7.99	76.30
2037	8.54	84.84

[10] Another small amount of storage is being captured in the Company's demand response program in Rhode Island.

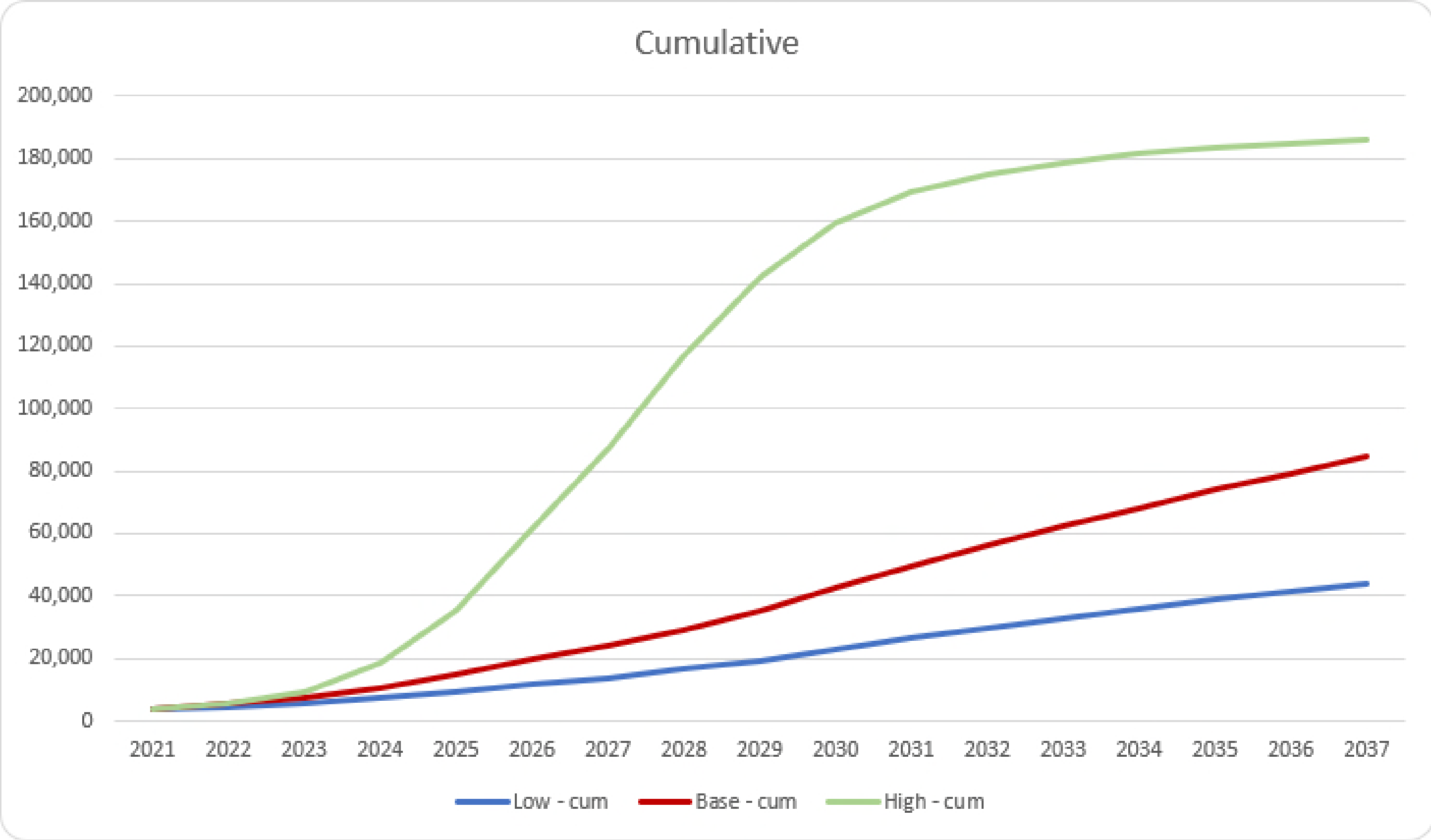
Electric Heat Pumps (NECO)

Number of Electric Heat Pumps

Year	Low - inc	Low - cum	Base - inc	Base - cum	High - inc	High - cum
2021	1,761	3,609	1,761	3,609	1,761	3,609
2022	922	4,531	1,843	5,452	2,217	5,826
2023	1,018	5,548	2,035	7,487	3,705	9,532
2024	1,670	7,218	3,340	10,827	9,286	18,818
2025	2,058	9,276	4,116	14,943	16,305	35,122
2026	2,513	11,789	5,025	19,969	26,443	61,565
2027	2,110	13,899	4,220	24,188	25,402	86,967
2028	2,532	16,431	5,064	29,252	29,651	116,619
2029	3,038	19,469	6,076	35,329	25,704	142,323
2030	3,646	23,115	7,292	42,620	16,876	159,199
2031	3,464	26,578	6,927	49,548	10,152	169,351
2032	3,290	29,869	6,581	56,128	5,803	175,154
2033	3,126	32,995	6,252	62,380	3,724	178,879
2034	2,970	35,964	5,939	68,319	2,744	181,623
2035	2,821	38,785	5,642	73,962	1,720	183,343
2036	2,680	41,465	5,360	79,322	1,521	184,863
2037	2,546	44,011	5,092	84,414	1,445	186,308



Confidential


Cumulative
200,000
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
Low - cum
Base - cum
High - cum

Appendix E: DER Scenarios Development

Energy Efficiency

- For the behavioral program, the value stays the same as in 2023 from 2024-2037 assuming there is no growth in the program.
- For the residential persistent program and commercial persistent, the value from 2023 is used until 2027 assuming the programs remain steady with no growth and then there is a slow decline from 2028 to 2037.
- (Both these assumptions were carried over based on looking at last year’s forecasting)
- High case was determined by multiplying base by 1.1 for years 2022 and 2023
- Low case was determined by dividing base by approx. 1.2 for years 2022 and 2023

Solar-PV

Base

- The 2022 forecast is based on historical numbers, more specifically the year-to-date interconnected MW, going back to 2016. We are currently seeing a reduction in the number of complex applications (>25 kW), while in regards to simplified applications (<=25 kW) we are seeing a significant increase in the number of applications and interconnected MW.
- In the longer term, new installations are assumed to start to taper off due to saturation, increasing marginal costs, and/or the uncertainties on the continuation of existing public policies.

High

- The near term (2022-2025), we see a potential reduction in inflationary costs that were attributed to the pandemic, in turn generating more viable projects. In addition, additional incentives through the Inflation Reduction Act could potentially generate more demand for solar installations.
- In the longer term, new installations are assumed to start to taper off due to saturation, increasing marginal costs, and/or the uncertainties on the continuation of existing public policies.

Low

- In the longer term, new installations are assumed to start to taper off due to saturation, increasing marginal costs, and/or the uncertainties on the continuation of existing public policies.

Electric Vehicles

Light-duty Vehicles

Base

- The base case is developed from Bloomberg's 2021 Long-term Electric Vehicle Outlook (BNEF-2021). The EV sales share of light-duty vehicle (LDV) sales is assumed to follow BNEF-2021 estimates and vehicle scrap is also assumed based on BNEF-2021's estimates to develop the net EV in-operation numbers. In this case, the zero-emission vehicle sales share of LDV sales is assumed to achieve 31% by 2030 and 59% by 2035.

High

- The high case assumes an accelerated full-electrification scenario in which the zero-emission vehicle sales share of LDV sales is assumed to achieve 64% by 2030 and 100% by 2035. It also aligns with BNEF-2021's "Net Zero" scenario and California drafted ACC-II regulation.

Low

- The low case is a moderate transportation electrification case developed from BNEF-2021. In this case, the zero-emission vehicle sales share of LDV sales is assumed to reach 25% by 2030 and 54% by 2035.

Medium-duty and Heavy-duty Vehicles, and E-buses

The adoptions of medium-duty EV (MDEV) and heavy- duty EV (HDEV) and E-buses are based on BNEF-2021 estimates and the MOU policy targets. Two cases were developed for the adoption's forecasts of these electric vehicle types. The base case is more of a market-driven case of adopting MDEV, HDEV, and E-buses. In this case, the MDEV, HDEV, and E-buses are estimated to be about 16%, 17%, and 26% of MDV, HDV, and buses, respectively, by the end of the load forecast horizon. The high case is an accelerated electrification scenario for medium- and heavy-duty vehicles and E-buses. In this case, the MDEV, HDEV, and E-buses are estimated to be about 38%, 20%, and 63% of MDV, HDV, and buses, respectively, by the end of the load forecast horizon.

Overall, the base light-duty EV case and the base medium- and heavy-duty EVs and E-buses case is considered as the base EV case. The high light-duty EV case and the high medium- and heavy-duty EVs and E-buses case is considered as the low EV case. The low light-duty EV case and the base medium- and heavy-duty EVs and E-buses case is considered as the low EV case.

Demand Response

- Base - For the short term (i.e. until 2024), the approved Company targets from the SME Program Administrator for DR is used as the projection. Post year 2024, no additional incremental MW are added. It is assumed that the program's market potential is at its maximum and the projections are held constant through year 2036.
- High - 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 15% less incremental new participation each year versus the prior year.
- Low - For the short-term, the 2021 level is held constant through year 2024. Then post 2024, there is assumed to be a discontinuation of the Company incentivized program. 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, DR impacts can end once funding is discontinued. Thus, post year 2024, it is assumed that residential type DR would move to zero. However, for commercial related programs, there may still be sufficient non-Company market pricing incentives for some customers to continue to implement DR. It is assumed that post 2024, a level of 60% of the 2024 commercial level continues into the future planning horizon.

- To get 2024 assumption for DR used trends from the prior year and values from the 2022 and 2023 BC models as noted in the spreadsheet. For EVs and ESVEs I used a similar trend from the prior year as it didn't seem reasonable that these both were 0 in 2022 and 2023.

Energy Storage

Base

- Currently there is minimal historical data in regards to the number of interconnected energy storage applications, as well as interconnected MW. Therefore, the forecast was developed assuming linear growth over the next several years.

High

- Based on assumption that there will be additional demand for add-on storage, mainly in regards to residential roof top solar, where the homeowner already has an existing PV system.
- Potential for increased demand in regards to large-scale BESS (Battery Energy Storage Systems) projects.

Low

- Assuming that there is no significant uptick in future demand and that the current trend will continue into future years.

There is currently no explicit state energy storage policy targets in RI, nor any Company run programs to promote this DER. In year 2020 about 0.53 MW of storage was installed. For the base case this same level of about half MW per year is continued into the future. No low or high cases are included. It is noted that there is a small amount of storage being captured in the Company's Demand Response program in RI.

Electric Heat Pumps

Residential:

- 2021 values were from 2021 year end report; 2022-2023 values are from BC models.
- For base, there is a steady increase until 2030 to hit RI's goal and then steady decrease from 2031-2037.
- For high, increases with high growth from 2026-2029 and then begins to decrease in 2030 due to market saturation.
- For low, half of base value.
- HP installs did not include OER funding.

Commercial:

- 2022 uses the predicted kWh in 2022 BC model for VSRs since majority in 2022 were VSRs divided by 2022 average of kWh per install. I first used the total kWh and got 90 but that seemed really high since there have only been 26 installs this year.
- 2023 values came from 2023 BC model predicted savings of kWh from HPs divided by 2022 average of kWh per install.
- Values from 2024 onward use trend from prior year with steady increase until 2033 and then steady decline from 2034-2037.
- HP installs did not include OER funding.

Appendix F: Power Supply Areas (PSAs)

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

			2022 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	2023	2024	2025	2026	2027	'23 to '27	'28 to '32	33 to '37
RI	Blackstone Valley	RI	93.2%	102.6%	105.3%	1.0	(0.8)	(0.4)	(0.8)	0.2	(0.2)	0.1	0.1
RI	Newport	RI	93.2%	102.6%	105.3%	2.0	0.1	0.5	(0.1)	0.8	0.7	0.6	0.3
RI	Providence	RI	93.2%	102.6%	105.3%	1.4	(0.4)	(0.0)	(0.5)	0.4	0.2	0.3	0.2
RI	Western Narraganset	RI	93.2%	102.6%	105.3%	2.1	0.2	0.6	(0.0)	0.9	0.8	0.7	0.4

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

			2022 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	2023	2024	2025	2026	2027	'23 to '27	'28 to '32	'33 to '37
RI	Blackstone Valley	RI	93.2%	102.6%	105.3%	1.5	(0.2)	0.2	(0.3)	0.6	0.3	0.4	0.2
RI	Newport	RI	93.2%	102.6%	105.3%	2.6	0.7	1.0	0.4	1.3	1.2	0.9	0.5
RI	Providence	RI	93.2%	102.6%	105.3%	2.0	0.2	0.5	(0.0)	0.9	0.7	0.6	0.3
RI	Western Narraganset	RI	93.2%	102.6%	105.3%	2.7	0.8	1.1	0.5	1.4	1.3	1.0	0.6

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

			2021/22 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	2022	2023	2024	2025	2026	'22 to '26	'27 to '31	'32 to '36
RI	Blackstone Valley	RI	99.6%	103.5%	104.6%	1.2	0.9	0.6	0.6	1.2	0.8	1.7	2.5
RI	Newport	RI	99.6%	103.5%	104.6%	2.3	2.0	1.6	1.4	2.0	1.5	2.3	2.8
RI	Providence	RI	99.6%	103.5%	104.6%	1.7	1.4	1.0	1.0	1.5	1.0	2.0	2.7
RI	Western Narraganset	RI	99.6%	103.5%	104.6%	2.4	2.1	1.7	1.5	2.1	1.5	2.4	2.9

Division 1-5

Request:

For each major substation project completed in the past 5 years, provide the date it was initially introduced in an ISR Plan and the initial schedule, along with the final completion date.

Response:

Please see the table below for the information requested. The Company is defining major substation projects as projects with estimates above $10 million and execution spanning two fiscal years.

Project Name	Initial Introduction into ISR Plan	Initial Schedule Completion Date	Final Completion Date
South St Substation	FY 2015	FY 2020	FY 2023
Chase Hill (Hopkinton) Substation	FY 2013	FY 2017	FY 2020
New London Ave Substation	FY 2014	FY 2018	FY 2020
Jepson Substation	FY 2016	FY 2022	FY 2022

Prepared by or under the supervision of: Nicole Gooding

Division 1-6

Request:

For each major substation currently in progress, provide the date it was initially introduced into an ISR Plan, the initial schedule proposed, and the current scheduled completion date.

Response:

Please see the table below for the information requested. The Company is defining major substation projects as projects with estimates above $10 million and execution spanning over at least two fiscal years.

Project Name	Initial Introduction into ISR Plan	Initial Schedule Completion Date	Current Completion Date
Southeast Substation	FY 2017	FY 2021	FY 2025
Dyer St Substation	FY 2017	FY 2021	FY 2025
Admiral St Substation	FY 2019	FY 2025	FY 2026
Phillipsdale Substation	FY 2024	FY 2028	FY 2029
Kingston Substation	FY 2024	FY 2028	FY 2029

Please note, both the Phillipsdale and Kingston Substation projects were included but not progressed in the Docket No. 22-53 EL FY 2024 ISR Plan. Both projects have been reintroduced in the Docket No. 23-48 EL FY 2025 ISR Plan.

Prepared by or under the supervision of: Nicole Gooding

Division 1-7

Request:

What are the system improvements required by the Distributed Generators ("DG") in the current ISR plan absent any interconnections?

Response:

There are no system improvements required by Distributed Generators ("DG") in the current ISR plan absent any interconnections. The system improvements in the ISR are for system needs, however they often do create generation hosting capacity. This generation hosting capacity can be used by any future DG interconnection.

Prepared by or under the supervision of: Ryan Constable

Division 1-8

Request:

If the DG is net metered, how are any of the costs of providing distribution/transmission services necessary to deliver the power produced by the DG to other consumers allocated to the DG?

Response:

In order to interconnect the net metered DG, the costs for interconnection are assessed pursuant to the definitions in R.I.P.U.C 2258 Standards for Connecting Distributed Generation for "System Improvement" and "System Modification". Costs for interconnection solely benefiting the net metered DG are deemed a System Modification and borne by the DG customer. Costs for interconnection that also benefit other retail customers, and are economically justified upgrades, are deemed System Improvement and the costs are rate based. Once the net metered DG is interconnected, like any other retail customer, all per-kWh charges associated with the delivery or supply component of the customer's bill, charged by the Company for costs of providing distribution/transmission, is allocated to the DG based on the monthly net kWh meter reading.

Prepared by or under the supervision of: Erica Russell Salk and Kathy Castro

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Division 1-9

Request:

Since the System Improvements in the ISR plan that are proposed to be accelerated due to the interconnections are paid for by the DG and reimbursed at a depreciated rate at the time that these improvements are planned to be implemented absent any DG interconnections, what happens if events such as failure of load materializing as anticipated, substituted Non-wires alternatives, or changes in technology delays or eliminates the need for these improvements at some time in the future?

Response:

As identified in the Tiverton Area Study, the System Improvements were recommended not only to serve load but also to mitigate thermal (capacity) limits, contingency response capability, and voltage issues identified on the existing Tiverton circuits. Therefore, it is unlikely that these improvements will no longer be needed some time in the future. The Company does not intend to perform a restudy.

Division 1-10

Request:

How are the costs allocated between System Modifications and System Improvements?

Response:

As described in Division 1-8, the costs for interconnection are assessed pursuant to the definitions in R.I.P.U.C 2258 Standards for Connecting Distributed Generation for "System Improvement" and "System Modification". Costs for interconnection solely benefiting the net metered DG are deemed a System Modification and borne by the DG customer. Costs for interconnection that also benefit other retail customers, and are economically justified upgrades, are deemed System Improvement and the costs are rate based.

Specifically for the Tiverton project, as described in PUC 1-2, the cost allocations between System Modifications and System Improvements are as follows:

Division 1-10, page 2

	Scope	**Total Cost (M)**
System Modification Subject to Petition	Substation – New feeder position	$1.024
	Line – Civil & Cable Procure - 21,000 feet of a manhole and duct system with 3 conductor 1000 kcmil rubber insulated copper cable	$15.381
	Line – Electrical – Installation of 21,000 feet of 3 conductor 1000 kcmil rubber insulated copper cable	$1.540
	Total	$17.945
System Modification excluded from Cost Sharing	Difference between overhead and underground system on Route 177 and Brayton Road.	$3.284
	Equipment at Interconnecting Customer's Property	$0.370
	Total	$3.654
System Improvement not subject to Petition	22,900 feet line extension and reconductoring	$2.181

<u>Certificate of Service</u>

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Joanne M. Scanlon

December 21, 2023
Date

Docket No. 23-37-EL Rhode Island Energy – Petition for Acceleration Due to DG Project – Tiverton Projects - Service List updated 12/14/2023

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