Laura C. Bickel
Senior Counsel
Legal Department

August 12, 2020

VIA E-FILING

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

Re: In Re: Commission's Review of the Benefits and Costs of Net Metering Credit Calculation Pursuant to R.I. Gen. Laws § 39-26.4-3: Docket No. 5010

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid (the Company), enclosed for filing with the Rhode Island Public Utilities Commission (the Commission) please find the Company's responses to the fourth set of data requests issued by the Commission.

Consistent with the instructions issued by the Commission on March 16, 2020, this filing is being made electronically, at this time. Hard copies will be submitted as soon as possible.

If you have any questions, please contact me at: 781-907-2126. Thank you for your time and attention to this matter.

Very truly yours,

Laura C. Bickel
RI Bar # 10055

Enclosures

cc: Docket No. 5010 Service List

40 Sylvan Road, Waltham, MA 02451
T: 781-907-2126 ■ F: 781-296-8091 ■ laura.bickel@nationalgrid.com

Docket No. 5010 Service List as of 7/23/2020

Name	E-mail	Phone
PUC		
Luly Massaro, Clerk	Luly.Massaro@puc.ri.gov;	401-780-2107
Todd Bianco	Todd.Bianco@puc.ri.gov;	
Emma Rodvien	Emma.Rodvien@puc.ri.gov;	
Cynthia Wilson-Frias	Cynthia.WilsonFrias@puc.ri.gov;	
Raquel Webster	Raquel.Webster@nationalgrid.com;	
Vishal Ahirrao	Vishal.Ahirrao@nationalgrid.com;	
Ian Springsteel	ian.springsteel@nationalgrid.com;	
Timothy Roughan	Timothy.Roughan@nationalgrid.com;	
Brooke Skulley	brooke.skulley@nationalgrid.com;	
Kate Grant	Kate.Grant2@nationalgrid.com;	
Laura Bickel	Laura.Bickel@nationalgrid.com;	
Thomas Kender	Thomas.Kender@nationalgrid.com;	
John Kennedy	John.Kennedy@nationalgrid.com;	
Chris Kearns	Christopher.Kearns@energy.ri.gov;	
Shauna Beland	Shauna.Beland@energy.ri.gov;	
Nicholas Ucci	Nicholas.Ucci@energy.ri.gov;	
Carrie Gill	Carrie.Gill@energy.ri.gov;	
Jon Hagopian	Jon.Hagopian@dpuc.ri.gov;	
John Bell	John.Bell@dpuc.ri.gov;	
Nicole Verdi	Nicole.Verdi@governor.ri.gov;	
Maria Messick	Maria.Messick@governor.ri.gov;	
	mishag@brightplanetsolar.com;	
Alan McBride	amcbride@iso-ne.com;	
Andrew Bernstein	abernstein@kearsargeenergy.com;	
Annie Ratanasim	Annie.Ratanasim@commerceri.com;	
Ben Aparo	ben@edp-energy.com;	
Ben Swanson	ben.swanson@trinitysolarsystems.com;	
Blake Elder	belder@eq-research.com;	
Charles Nutter	cnutter@nexamp.com;	
Christian Capizzo	ccapizzo@psh.com;	
Christopher Warfel	cwarfel@entech-engineering.com;	
Dan Bosley	dbosley@necec.org;	
Dan Hendrick	dan.hendrick@clearwayenergy.com;	
Dana Weinberg	dana@sunwatt.solar;	
Daniel Pertwee	daniel.pertwee@palmettoventures.com;	
David Milner	dmilner@nugencapital.com;	
Devina Thakur	dthakur@ameresco.com;	
Doug Sabetti	doug@newportsolarri.com;	
E W Tatelbaum	etatelbaum@kearsargeenergy.com;	

Eric Beecher	eric@solpowersolar.com;	
Erika Niedowski	erika@communitysolaraccess.org;	
Ethan Gyles	egyles@nexamp.com;	
Evan Dube	evand@sunrun.com;	
Frank Epps	frank@edp-energy.com;	
Frank McMahon	fmcmahon@advocacysolutionsllc.com;	
Fred Unger	unger@hrtwd.com;	
George Zainyeh	gzainyeh@shslawfirm.com;	
Hannah Morini	hm@green-ri.com;	
Helen Anthony	helen@handylawllc.com;	
James Feinstein	james.feinstein@arcadia.com;	
Jeremy McDiarmid	jmcdiarmid@necec.org;	
Joel Lindsay	jlindsay@ameresco.com;	
Johanna Rosas	johanna@southernskyre.com;	
John Habib	jhabib@keeganwerlin.com;	
Julian Dash	jdash@cleaneconomydevelopment.com;	
Karen Bradbury	karen_bradbury@whitehouse.senate.gov;	
Kate Tohme	kate.tohme@state.ma.us;	
Kathryn Chelminski	kchelminski@ameresco.com;	
Kavita Ravi	kravi@bluewavesolar.com;	
Kenneth Payne	kennethfpayne@gmail.com;	
Kleo Taliadouros	ktaliadouros@ameresco.com;	
Laura Frazier	lfrazier@nugencapital.com;	
Laura Stern	laura@nautilussolar.com;	
Lindsay McGovern	lindsay@southernskyre.com;	
Louis DiPalma	louis_dipalma@yahoo.com;	
Mark DePasquale	md@green-ri.com;	
Mark Durrenberger	mark@newenglandcleanenergy.com;	
Mark Sylvia	msylvia@bluewavesolar.com;	
Matt Sullivan	ms@green-ri.com;	
Matthew Stern	mstern@keeganwerlin.com;	
Michael Daley	mdaley@ibew99.org;	
Michael Kerr	michael@nehydropower.com;	
Michelle Carpenter	mcarpenter@tpoint-e.com;	
Miguel Silva	Miguel.Silva@directenergy.com;	
Mike Lucini	mlucini@ismgroup.com;	
Nathan Phelps	nathan@votesolar.org;	
Palmer Moore	pmoore@nexamp.com;	
Paul Del Mar	pdelmar@ameresco.com;	
Paul Raducha	praducha@kearsargeenergy.com;	
Pete Fine	pete@ussolarworks.com;	
Peter Hughes	peter@sunwatt.solar;	
Philip Small	psmall@brownrudnick.com;	
Ralph Gillis	rg@green-ri.com;	
Ralph Palumbo	ralph@southernskyre.com;	

Rick Sellers	rhsellers@gmail.com;	
Russ Mamon	russ@edp-energy.com;	
Ryan Palumbo	ryan@southernskyre.com;	
Sarah O'Neil	seo@green-ri.com;	
Scott Milnes	smilnes@econoxgroup.com;	
Sean Burke	sburke@necec.org;	
Seth Handy	seth@handylawllc.com;	
Sheila Keane	sheila.keane@state.ma.us;	
Chris Rauscher	chris.rauscher@sunrun.com;	
Sue Lyons	sue@ussolarworks.com;	
Sydney Usatine	SUsatine@riib.org;	
Thomas Champlin	Thomaschamplin4@gmail.com;	
Tom Holt	tholt@kearsargeenergy.com;	
Tyler Haines	tyler.haines@fairstead.com;	
Weezie Nuara	wnuara@iso-ne.com;	
Nicholas Al Ferzly	nalferzly@seadvantage.com;	
Jim Kennerly	jkennerly@seadvantage.com;	
Matthew Jerzyk	mjerzyk@gmail.com;	
Amanda Vanega	avanega@eq-research.com;	
Tim Woolf	twoolf@synapse-energy.com;	
Courtney Lane	clane@synapse-energy.com;	

PUC 4-1

Request:

For each of the factors/charges listed below, please respond to the following questions regarding kWh load forecasting:

a. How does National Grid develop the kWh sales forecast (for the upcoming rate period) used in setting that factor/charge? Please describe the forecast methodology and what specific billing data is used.

b. When does National Grid develop the kWh sales forecast in relation to filing the proposed factor/charge with the Commission?

c. How does National Grid incorporate reductions from behind-the-meter net metering facilities in its kWh sales forecast for the factor/charge in question? What specific data does Grid utilize?

d. How does National Grid incorporate reductions from front-of-the-meter net metering facilities in its kWh sales forecast for the factor/charge in question? What specific data does Grid utilize?

Please respond to questions 4-1(a) – 4-1(d) for the following factors/charges:

i. Capacity charge (unitized to a $/kWh rate), as included in the base SOS rate

ii. SOS Administrative Cost Factor

iii. SOS Adjustment Factor

iv. Base Distribution charge (per-kWh charge)

v. Operating and Maintenance Expense Charge

vi. Operating and Maintenance Reconciliation Factor

vii. CapEx Factor Charge (per-kWh charge)

viii. CapEx Reconciliation Factor

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ix. RDM Adjustment Factor

x. Pension Adjustment Factor

xi. Storm Fund Replenishment Factor

xii. Arrearage Management Adjustment Factor

xiii. Low-Income Discount Recovery Factor

xiv. Base Transmission Charge (per-kWh charge)

xv. Transmission Adjustment Factor

xvi. Transmission Uncollectible Factor

xvii. Base Transition Charge

xviii. Transition Charge Adjustment

xix. Net Metering Charge

xx. LTC Recovery Factor

xxi. LTC Recovery Reconciliation Factor

xxii. Energy Efficiency Program Charge

Response:

a. Please see Attachment 4-1, a report titled, "Rhode Island Electric Distribution, FY2021 to FY2025, GWh Deliveries & Customer Counts, (Revenue & Rate Class)," which summarizes the process for developing the kWh sales forecast. Section 1 provides a summary of results and an overview of the methodology.

b. The kWh sales forecast is produced annually each fall. The Company uses the most recent kWh sales forecast available at the time of the filing for each of the factors/charges listed in subparts (i) through (xxii). One exception is the Base Transition Charge – subpart (xvii) -- which uses a forecast developed years ago and is sourced from the wholesale CTC reports that are submitted to the Commission and to the Division of Public Utilities and Carriers.

Prepared by or under the supervision of: Joseph Gredder

c. Projections for behind-the-meter net metering for solar PV installations are used to reduce the econometric forecast of customer loads. Historical data comes from the Company’s tracking databases, and projections for the future are based on: (1) applications in the queue, in the short-term; and (2) policy targets, for the long-term. See Section 1.4.2 of Attachment 4-1 for additional information.

d. For the sales forecast, the Company does not differentiate between net metering installations behind a specific customer’s home or business meter, and those located in front of those meters, yet still metered for injections into the distribution system. Net metering installations with CSS billing system accounts are considered load reducing for the purpose of the Company’s sales forecast.

Prepared by or under the supervision of: Joseph Gredder

RHODE ISLAND ELECTRIC DISTRIBUTION

FY2021 to FY2025 Forecast

GWh Deliveries & Customer Counts

(Revenue & Rate Class)

[Narragansett Electric Company]

September 2019

Economics & Load Forecasting
Advanced Data & Analytics

nationalgrid

REVISION HISTORY & GENERAL NOTES

Revision History

Version	Date	Changes
Original	09/20/2019	- ORIGINAL

General Notes:

- Historical data through August 2019; projections from September 2019 forward.
- Economic data is from Moody's vintage August 2019.
- Pricing data is internal data vintage August 2019.
- Energy Efficiency is internal data vintage August 2019.
- Solar – PV data is internal data vintage August 2019.
- Electric Vehicle data is POLK data vintage July 2019.
- Source data for retail deliveries is the internal CSS billing system aggregate monthly reports.
- "Weather-Normal" is based on the ten-year average of monthly degree days from years 2009 to 2018.
- The modeling process employs a "reconstruction" for DERs in the historical input data set.

Report Contact(s):

Jingrui (Rain) Xie
516-545-2288 jingrui.xie2@nationalgrid.com

Joseph F. Gredder
516-545-5102 joseph.gredder@nationalgrid.com

TABLE OF CONTENTS

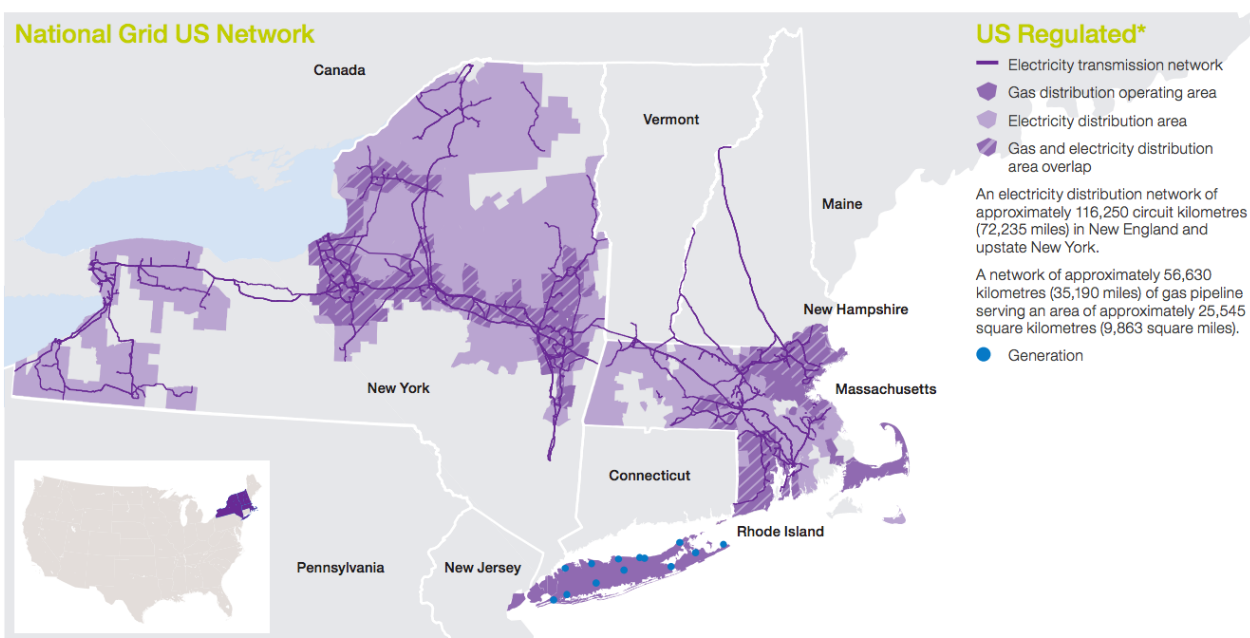
1. Summary

U.S. Electric Distribution System

National Grid's U.S. electric distribution system is comprised of four companies serving 3.5 million customers in Massachusetts, Rhode Island, and upstate New York. The four electric distribution companies are Narragansett Electric Company, serving 0.5 million customers in 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.

Narragansett Electric Company

Narragansett Electric Company (NECO) makes up 12% of electric deliveries in the U.S. for National Grid. It makes up 27% of its New England deliveries. Figure 1 shows National Grid's service territory in the U.S..



*Access to electricity and gas transmission and distribution assets on property owned by others is controlled through various agreements.

Source: National Grid

Figure 1: National Grid Service Territory

NECO's service territory in the state is approximately 42% residential, 49% commercial and 9% industrial. It serves all of the state of Rhode Island except one small municipality – Pascoag.

From fiscal year 2015 to fiscal year 2020, Narrangasett Electric weather normalized deliveries averaged a <u>negative</u> 0.9% annual growth. Residential deliveries have seen an annual <u>decline</u> of 0.8% over the last five years. Commercial deliveries averaged <u>negative</u> growth of 0.1% per year and industrial deliveries have seen an average <u>negative</u> growth of 4.6%.

In the next five years, annual growth is expected to continue to decline by 2.0% after impacts for Distributed Energy Resources (DERs). The DERs included are energy efficiency (EE) programs, solar – photovoltaics (PV) and electric vehicles (EV). Before the impacts of these DERs, it is projected that growth would have been <u>positive</u> 1.6% per year.

Figure 2 shows the annual total energy in both GWh and annual percent change. It can clearly be seen how annual values have been declining over time and are expected to continue to decline over the next five years.

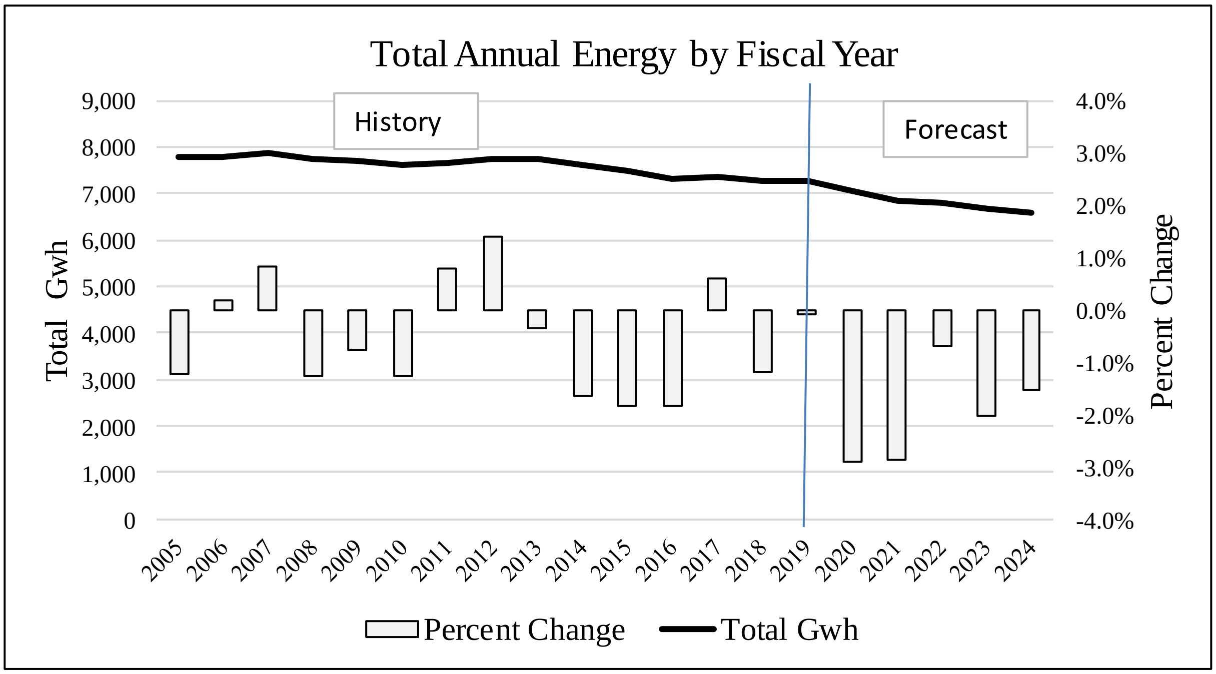


Figure 2: Annual Total Energy by Fiscal Year

Table 1 shows total historical and forecast deliveries for the Narrangasett Electric Company for each revenue class.

Table 1: Total historical and forecasted deliveries by revenue classes (NECO)

ANNUAL GWh (*and percent growth*) FISCAL YEAR (Historicals & Projections: Weather-Normal) by Revenue Class After Energy Efficiency, Solar and Electric Vehicle Impacts														
FISCAL YEAR	RESIDENTIAL Non-Heating		Elec Heating		RESIDENTIAL Total		COMMERCIAL		INDUSTRIAL		StreetLighting & Other		TOTAL	
2005	2,778.8		233.1		3,011.9		3,523.1		1,271.6		64.2		7,870.7	
2006	2,759.5	-0.7%	222.0	-4.8%	2,981.5	-1.0%	3,528.7	0.2%	1,199.3	-5.7%	64.1	-0.1%	7,773.6	-1.2%
2007	2,813.3	1.9%	221.4	-0.3%	3,034.7	1.8%	3,555.0	0.7%	1,134.9	-5.4%	64.2	0.1%	7,788.8	0.2%
2008	2,860.9	1.7%	221.8	0.2%	3,082.8	1.6%	3,631.1	2.1%	1,076.0	-5.2%	63.3	-1.4%	7,853.2	0.8%
2009	2,801.3	-2.1%	199.8	-9.9%	3,001.2	-2.6%	3,654.2	0.6%	1,034.9	-3.8%	65.1	2.8%	7,754.7	-1.3%
2010	2,884.3	3.0%	201.3	0.7%	3,085.6	2.8%	3,635.3	-0.5%	918.5	-11.2%	56.6	-13.0%	7,695.8	-0.8%
2011	2,824.3	-2.1%	194.0	-3.6%	3,018.3	-2.2%	3,593.4	-1.2%	927.2	0.9%	59.4	4.9%	7,598.2	-1.3%
2012	2,895.5	2.5%	190.9	-1.6%	3,086.4	2.3%	3,602.1	0.2%	908.4	-2.0%	59.8	0.7%	7,656.8	0.8%
2013	2,989.7	3.3%	194.2	1.7%	3,183.9	3.2%	3,625.2	0.6%	894.8	-1.5%	59.3	-0.9%	7,763.1	1.4%
2014	2,949.4	-1.3%	192.6	-0.8%	3,142.0	-1.3%	3,632.2	0.2%	902.6	0.9%	59.5	0.3%	7,736.3	-0.3%
2015	2,883.4	-2.2%	190.3	-1.2%	3,073.7	-2.2%	3,639.2	0.2%	838.2	-7.1%	58.8	-1.2%	7,609.9	-1.6%
2016	2,854.6	-1.0%	184.2	-3.2%	3,038.9	-1.1%	3,605.9	-0.9%	765.6	-8.7%	58.5	-0.6%	7,468.8	-1.9%
2017	2,806.4	-1.7%	178.0	-3.4%	2,984.4	-1.8%	3,572.1	-0.9%	732.8	-4.3%	41.9	-28.4%	7,331.2	-1.8%
2018	2,822.0	0.6%	181.1	1.7%	3,003.1	0.6%	3,611.3	1.1%	707.8	-3.4%	52.3	25.0%	7,374.6	0.6%
2019	2,791.1	-1.1%	172.4	-4.8%	2,963.6	-1.3%	3,584.0	-0.8%	696.8	-1.6%	42.3	-19.2%	7,286.6	-1.2%
2020	2,789.5	-0.1%	166.9	-3.2%	2,956.5	-0.2%	3,616.4	0.9%	661.2	-5.1%	45.0	6.4%	7,279.0	-0.1%
2021	2,747.7	-1.5%	161.6	-3.2%	2,909.3	-1.6%	3,503.1	-3.1%	608.2	-8.0%	46.8	4.0%	7,067.4	-2.9%
2022	2,679.9	-2.5%	156.5	-3.1%	2,836.4	-2.5%	3,410.8	-2.6%	570.9	-6.1%	45.6	-2.5%	6,863.8	-2.9%
2023	2,679.4	0.0%	151.7	-3.1%	2,831.1	-0.2%	3,400.7	-0.3%	539.0	-5.6%	44.4	-2.6%	6,815.2	-0.7%
2024	2,639.9	-1.5%	147.1	-3.0%	2,787.0	-1.6%	3,338.4	-1.8%	508.0	-5.8%	43.2	-2.7%	6,676.6	-2.0%
2025	2,616.6	-0.9%	142.9	-2.9%	2,759.5	-1.0%	3,293.3	-1.4%	480.1	-5.5%	42.1	-2.8%	6,574.9	-1.5%
Annual Growth Rates:														
prior 15 years		0.0%		-2.2%		-0.1%		0.2%		-4.3%		-2.3%		-0.5%
prior 10 years		-0.3%		-1.9%		-0.4%		-0.1%		-3.2%		-2.3%		-0.6%
prior 5 years		-0.7%		-2.6%		-0.8%		-0.1%		-4.6%		-5.2%		-0.9%
BASE YEAR:	**2020**													
next 5 years		-1.3%		-3.1%		-1.4%		-1.9%		-6.2%		-1.4%		-2.0%

1.1 Forecast Methodology

The Company's electric deliveries and customer counts forecast is developed from econometric models relating monthly deliveries by company and class of service to regional economic and/or demographic variables, weather, and other explanatory variables. The models estimate the historical relationship between deliveries and these variables. The models then predict future deliveries based on forecasts of the explanatory variables. The residential non-electric heating, residential electric heating, and commercial models are specified as energy use-per-customer models. Separate models are developed for customer counts. The use-per-customer model results are multiplied by the customer count model results to determine overall energy deliveries. The industrial models are specified directly as total deliveries.

All energy models are specified after reconstituting the historical deliveries for Distributed Energy Resources (energy efficiency, solar-PV, and electric vehicles). That is, after adding back the impacts of these DERs to the historical input dataset. The model-produced GWh delivery forecast results are then adjusted to reflect projected cumulative DER impacts.

Class of service deliveries and customer forecasts are allocated to rate classes based on historical trends.

All models are checked for overall goodness of fit, statistical validity and reasonable of results.

1.2 Regional Economic Drivers

The historical and forecast economic explanatory variables are obtained from Moody's Analytics. Moody's provides economic forecasts at the U.S., state, metro, and county levels. The Company aligns these areas with each operating company to develop load forecasts. Key economic drivers are per capita income (PCI) for residential deliveries; non-manufacturing employment or gross state product (GSP) for commercial models; and manufacturing employment for industrial deliveries. Number-of-households or straight time series models drive most customer count forecasts. The price of electricity is also found to be a significant variable in several models. In addition, other variables including employment-per-household and population are also tested and included when appropriate. In general terms, for most economic indicators Moody's projects lower growth over the next two years than over the past several years. This is reflected in lower near-term forecasting results in the summary tables throughout this report. The figures below show economics for each of the Companies in each of the service territories in the Northeast in addition to the U.S. overall. This provides comparative values to the subject service territory.

Figure 3 below shows the PCI growth in the Companies service territories in the Northeast and the U.S. overall. PCI is an indicator of spending power of the consumers. In RI, the growth is expected to slightly drop in 2020 from its 2019 level. In 2021, it is expected to drop below 1.0% and then bounce back to about 1.0 – 2.0% per year for the rest of the planning horizon. This is similar to the U.S. average.

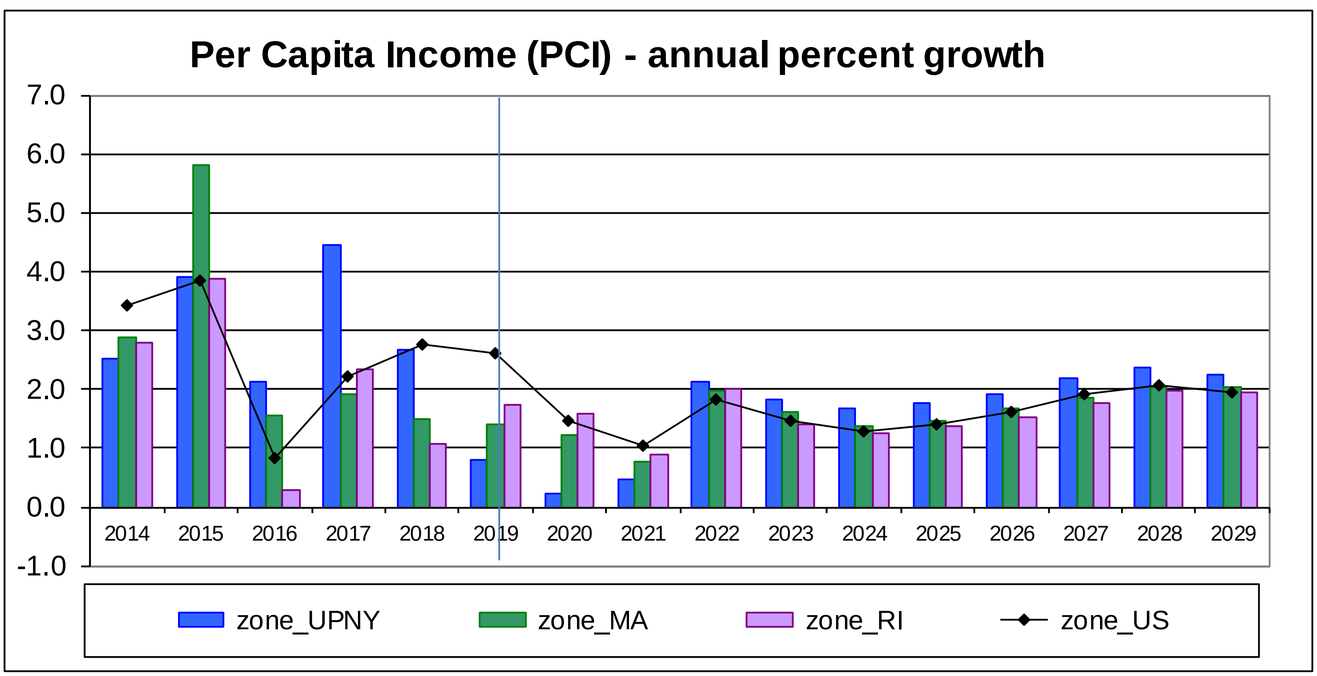


Figure 3: Per capita income (PCI) growth of UPNY, MA, RI, and the U.S.

Figure 4 summarizes Moody's forecast for number of households. Households can provide an indication of the overall load growth in a region as more households can translate into more residential load as well as more commercial load as more consumers support the local economy. Narrangasett is expected to have about the same level of growth in number of households as its 2019 level for the near term and lower growth than its 2019 level in the later years of the planning horizon. Over the whole planning horizon, the growth is less than the national average.

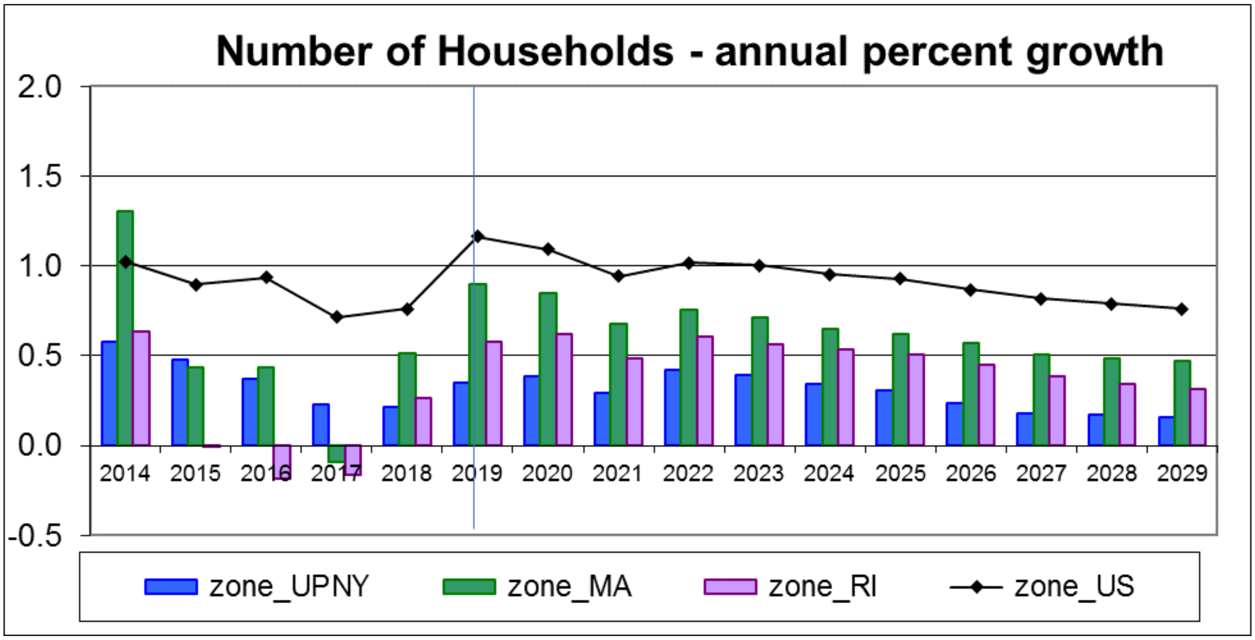


Figure 4: Number of households growth of UPNY, MA, RI, and the U.S.

Figure 5 summarizes the forecast for non-manufacturing employment. Higher employment is generally correlated to increased commercial load. Growth in RI is expected to be slightly higher in 2020 but much lower in 2021 than the previous near-term history. Then it is expected to move to a longer-term annual growth level of about 0.5% annually. This level is very much lower than that of the last five years and slightly lower than the national average.

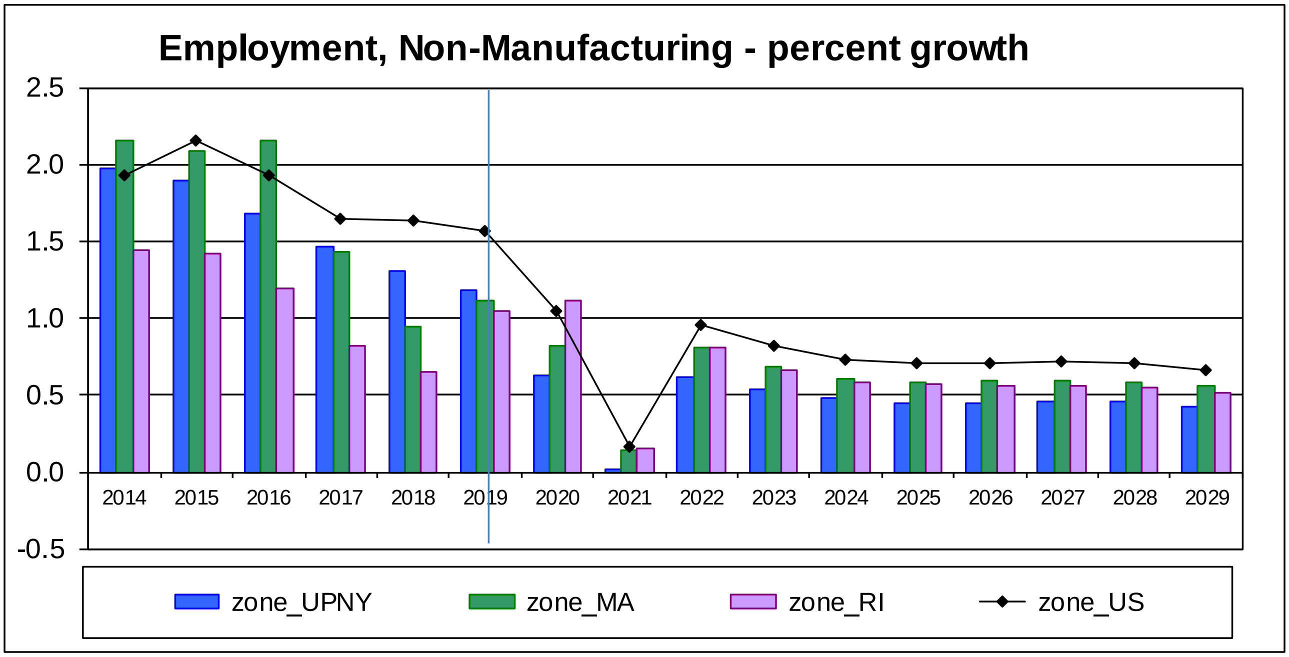


Figure 5: Non-manufacture employment growth of UPNY, MA, RI, and the U.S.

Figure 6 summarizes the forecast for gross state product (GSP). GSP can provide an overall indication of the strength of the economy. A stronger economy can translate to more load in all sectors, notwithstanding the offsetting impacts of DERs. Annual growth in RI is expected to grow till 2022. It then drops to a long-term growth rate of about 2.0% per year. It is expected to be slightly higher than the national average over the planning horizon.

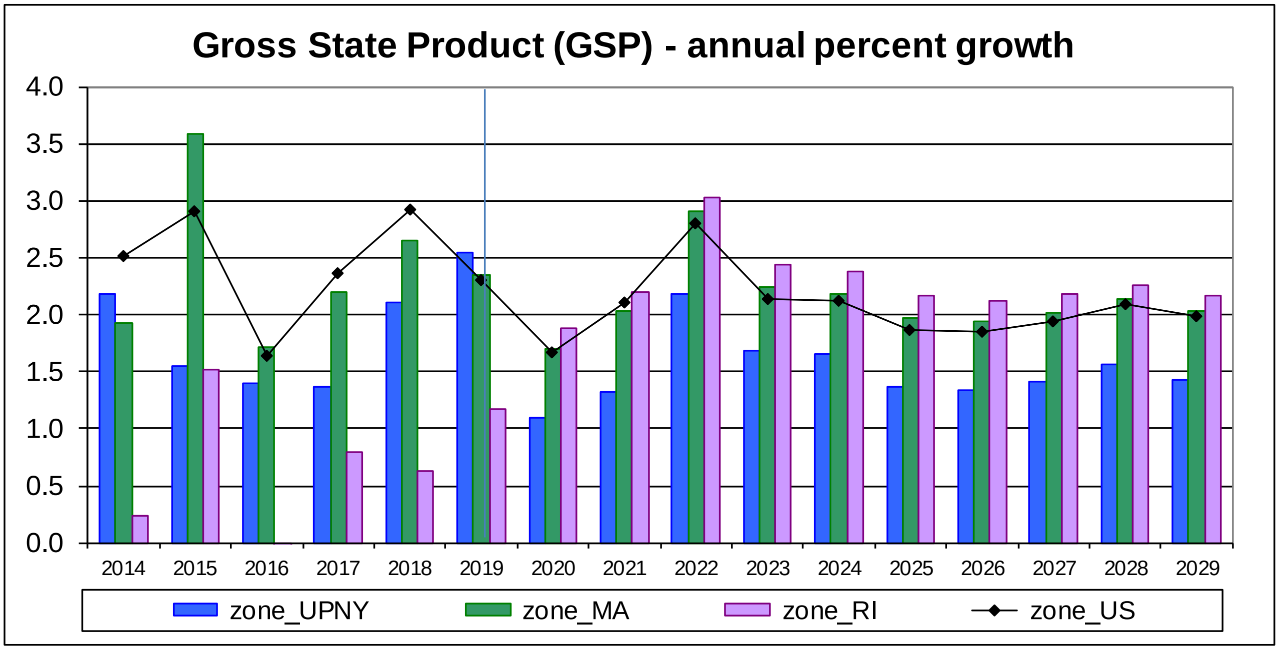


Figure 6: GSP growth of UPNY, MA, RI, and the U.S.

Figure 7 summarizes the forecast for manufacturing employment. Growth in all regions, including the country, is expected to be decidedly negative in all years of the planning horizon. It is particularly lower in year 2021 before moving to a longer-term negative growth of about 1.5% per year. These forward-looking projections are decidedly lower than the previous five years of manufacturing employment levels.

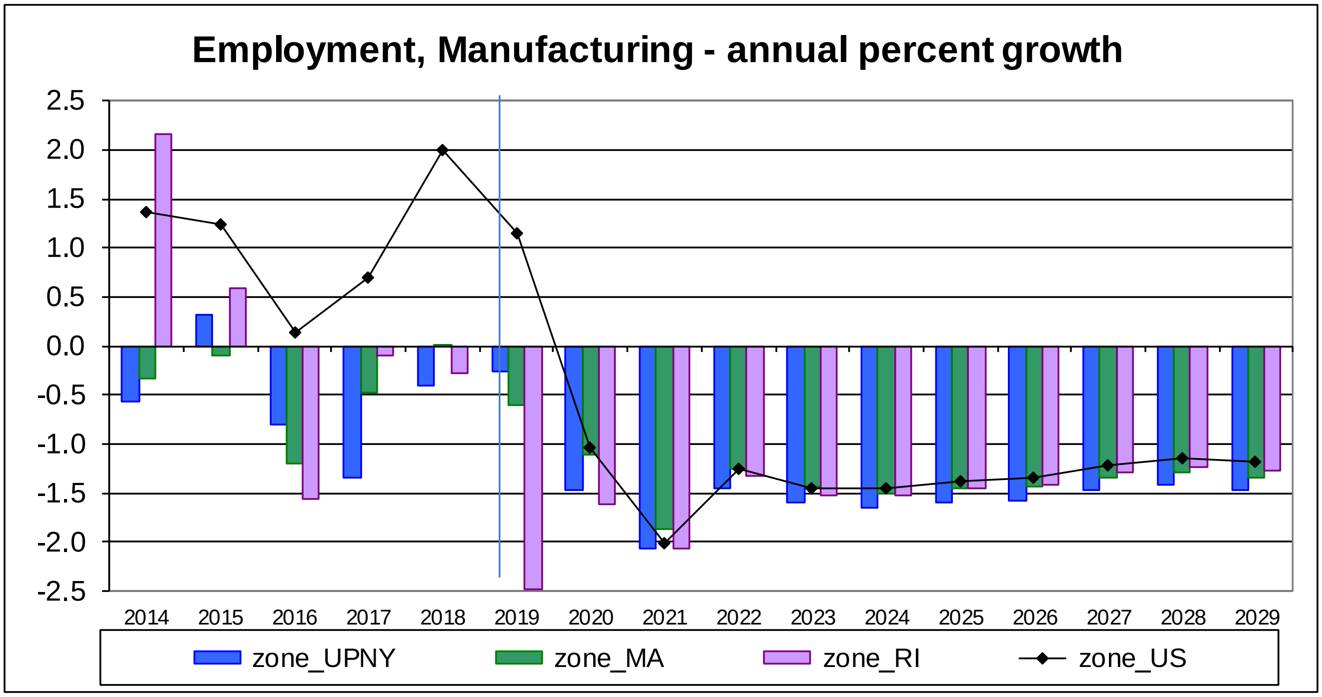


Figure 7: Manufacturing employment growth of UPNY, MA, RI, and the U.S.

1.3 Weather Assumptions

Weather data is collected from the major weather stations located within the Company's service territory and used to model, forecast, and weather-normalize GWh deliveries. The relevant weather stations is Providence.

Seasonal heating and cooling degree days are used to model the relationship between energy deliveries and weather. Cooling degree-days (CDD) are equal to average daily temperature minus 65 degrees (however no less than zero). The more cooling degree days over a given period, the hotter the daily temperatures are. Heating degree-days (HDD) are equal to 65 degrees minus average daily temperature (but no lower than zero). The more heating degree days over a given period, the colder it is.

Since customers are billed on a cycle throughout the month, billed GWh deliveries reflect energy consumed during part of the current month and part of the previous month. Heating and cooling degree days must reflect this same consumption pattern. This is accomplished by using meter reading schedules to match daily degree days with the days between reading dates for each one of the 20 billing cycles, then taking the average of degree days over the 20 cycles.

The forecast report provides historical data in terms of actual and weather-adjusted (or weather-normalized) energy results. It also provides future projections on a weather-normalized basis. Results are weather-normalized by taking the ten-year average of heating and cooling degree days and incorporating these into the regression models. By updating the normal values each year with the most current history any changes in longer-term trends in weather are captured.

Figures 8 & 9 below show the annual actual and weather-normal heating and cooling degree days used in the analysis in this report for NECO. Actual HDD and CDD are the actual degree days by billing months for each year and normal HDD and CDD are the ten-year average degree days by billing months from 2009 to 2018.

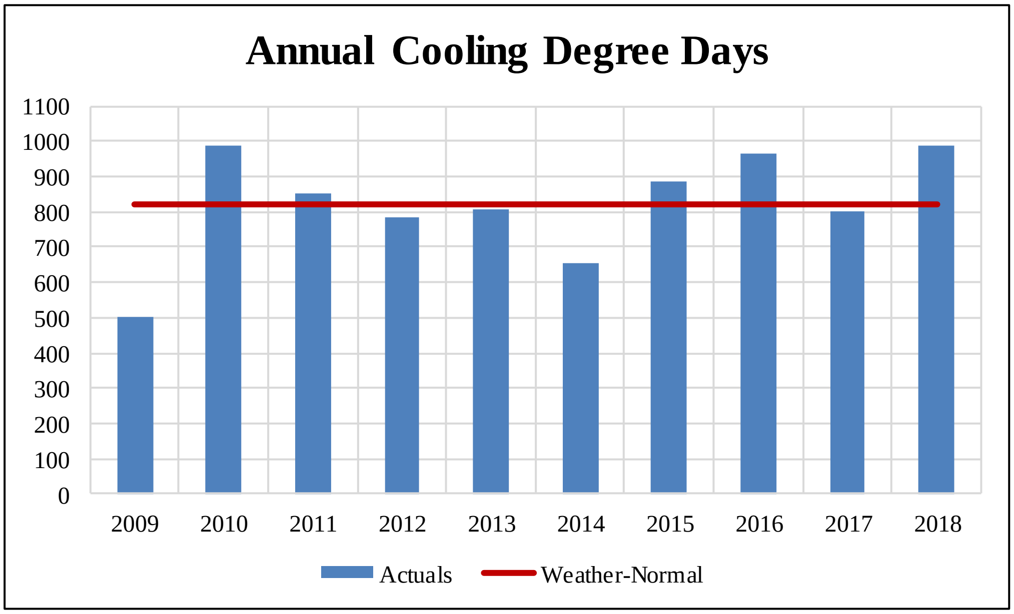


Figure 8: NECO annual cooling degree days

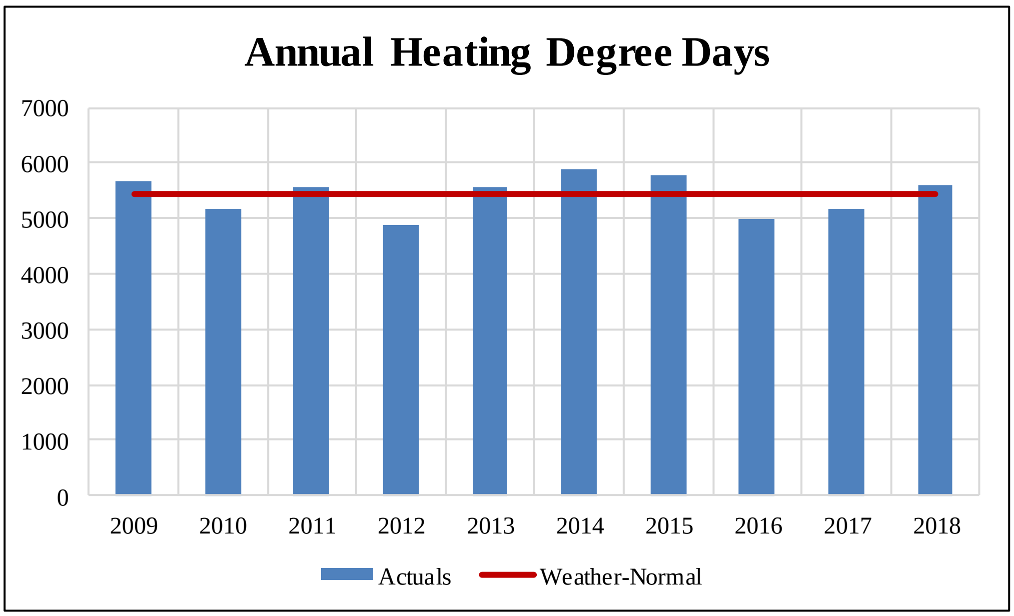


Figure 9: NECO Annual Heating Degree Days

Figure 10 shows the cyclical nature of the weather normalized cooling and heating degree days. The forecasts are based on billing month (solid lines). For comparative purposes, calendar month billing days are also shown. In general, the billing month degree-days have a lag compared to the calendar month degree-days. This is because the billing degree months have part current month and part prior month in them due the nature of bill reads. For example, the billing month of July would have degree days in both July and the prior month June, while calendar month July would have only July days.

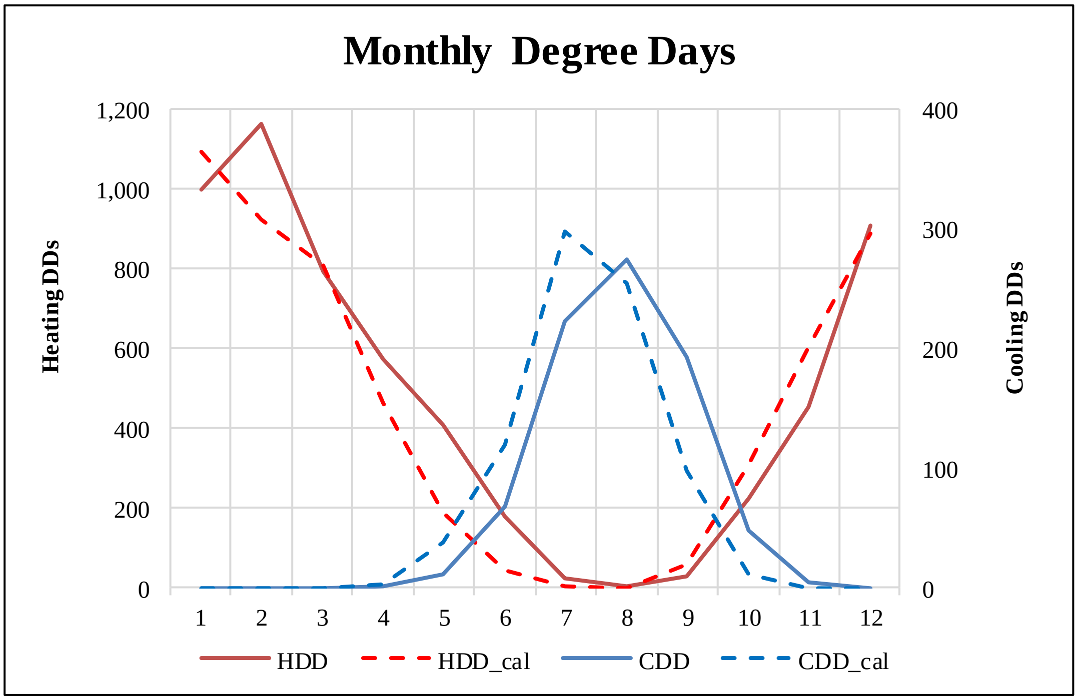


Figure 10: NECO Monthly Degree Days

1.4. Distributed Energy Resources (DERs)

In New England, there are a number of policies, programs, and technologies that are impacting customer energy consumption. These include but are not limited to energy efficiency (EE), solar–photovoltaics (PV) and electric vehicles (EV). These collectively are termed distributed energy resources (DERs) because they impact the loads at the customer level, as opposed to at traditional, centralized power supplies. Demand Response (DR) and Energy Storage (ES) are accounted for the in the peak forecast but do not materially impact energy consumption and are therefore not included here.

1.4.1. Energy Efficiency (EE)

National Grid has been running EE programs in its Narragansett jurisdiction for a number of years and will continue to do so for the foreseeable future. In the short-term (one to three years) energy efficiency targets are based on approved company programs. Over the longer term, the Company uses recent trends to estimate future incremental annual reductions. These future annual reductions decline slowly over time to account for saturation and the expectation of increasing costs to achieve each additional unit of savings. The regional ISOs use a similar methodology.

Figure 11 shows the expected annual deliveries and DER impacts to NECO energy consumption by year. As of 2019, it is estimated that these EE programs have reduced consumption by 2151 GWh annually, or 22.3% relative to a scenario with no EE programs implemented. By 2024, it is expected that this reduction will grow to 2972 GWh annually, or 28.5% of what load would have been had these programs not been implemented. Over the five-year planning horizon these reductions lower annual growth from positive 1.6% to negative 0.1% per year.

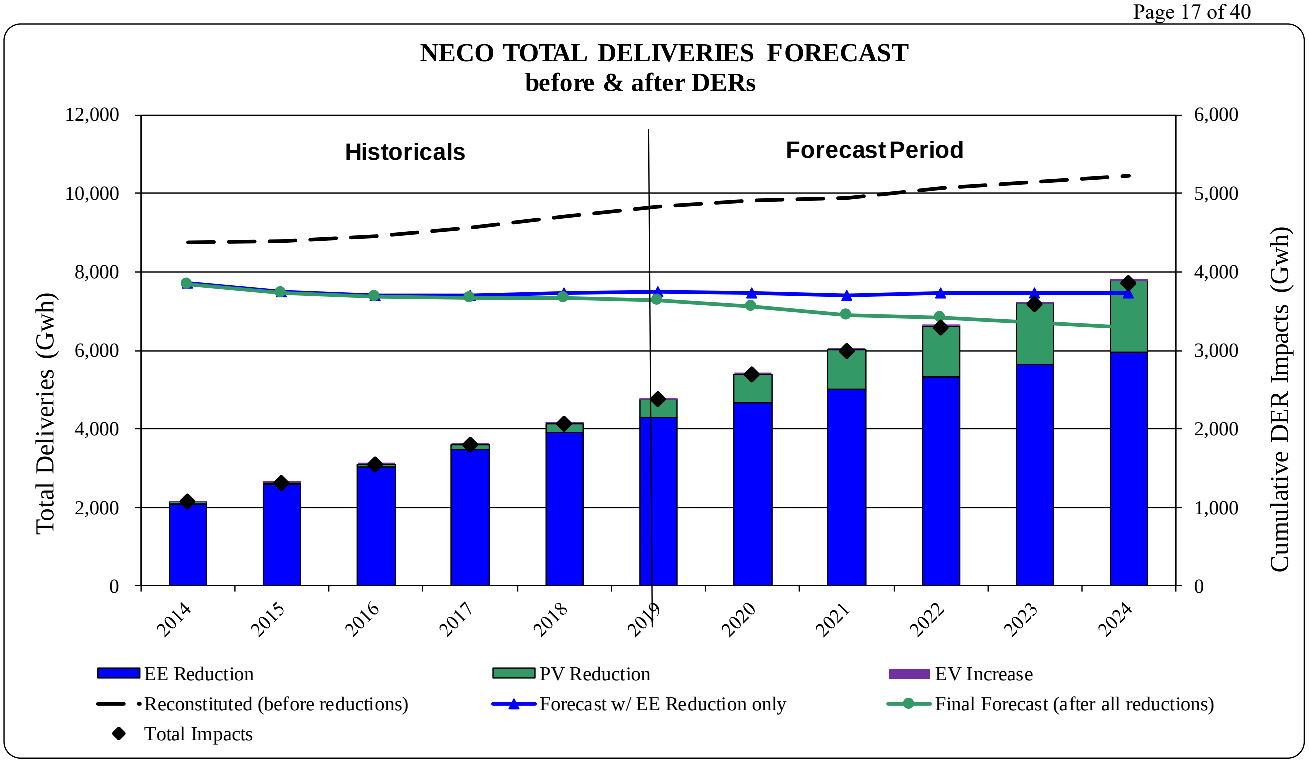


Figure 11: NECO Total Deliveries and DERs forecast

1.4.2 Solar – Photovoltaics (PV)

There has been a rapid increase in the adoption of solar PV[1] throughout the state. The Company tracks previous PV adoption which is the basis of the historical values shown. In the near term, that is the first two years of the forecast, or years 2020 and 2021, PV projections are based on expected installations from the current DG tracking queue. In the longer term, this level of annual installations is assumed to persist until year 2023 at which point it is assumed the market begins to saturate and annual installations begin to decline. As of 2019, Company's Rhode Island service territory has about 224 MW installed PV. This is expected to grow to about 744 MWs by 2024. Annual energy associated with these installed PV MWs are estimated based on a 15% capacity factor. That is, while the unit may run at 100% during peak sunlight hours and at 0% during the night hours, over the full course of the year its runtime averages about 15%. Figure 12 shows the expected installed nameplate MW for PVs.

[1] The Company limits this discussion to the impacts of solar distributed generation because it is the single largest contributor and the fastest growing of all distributed generation technologies at this time.

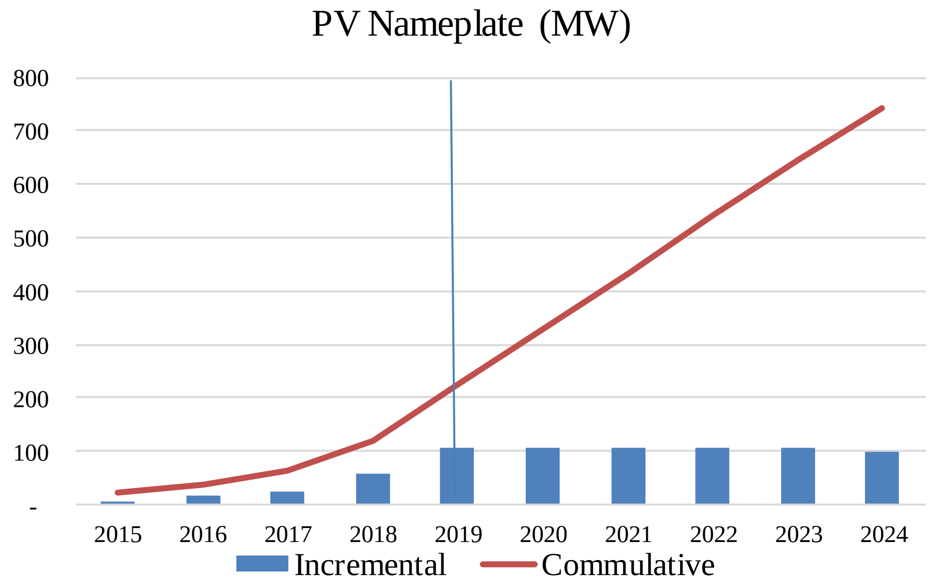


Figure 12: Rhode Island PV Nameplate in MW (in service territory)

Figure 11 above shows the expected NECO loads and solar reductions to annual consumption by year. As of 2019, it is estimated that this technology may have already reduced loads by 229 GWh, or 2.4% annually. By 2024 it is expected that these reductions may grow to 913 GWh, or 8.7% annually of what consumption would have been had this technology not been installed. Over the five-year planning horizon these reductions lower annual growth from 1.6% to a 0.2% per year.

While PV is a form of distributed generation, it appears as a load reduction from the network perspective. Thus, the underlying load is still there, but is not provided by the network anymore. This is an important distinction because when viewing the aggregate DER impacts in the graph above and in the appendices: only the EE and the EV are direct load impacts while the PV is another power option to serve the remaining load. For example, Appendix A shows an aggregate reduction of 37.0% in year 2024 for NECO, however only 28.5% (the EE) is a load reduction, 0.2% is a load increase (the EV), and the remaining 8.7% is the PV being used to serve the customer load.

1.4.3 Electric Vehicles (EV)

The forecast results are further adjusted for the penetration of plug-in electric vehicles (PEVs). 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 base case projection for EVs assumes a continuation of the near term annual increasing trend for new installations of EVs. Over the last few years, EV sales have been growing more each year. This trend is assumed to continue over the five-year planning horizon. As of 2019, EV's in the Company's Rhode Island service territory are estimated at about 1,900 vehicles. This is expected to grow to about 8,300 by 2024, or five years from now.

As of 2019, it is estimated that EVs have increased loads by 5 GWh, or 0.1% annually. By 2024 it is expected that these increases may grow to 23 GWh, or 0.2% annually of what consumption would have been had this technology not been adopted.

Figure 13 shows the expected EV vehicles by year.

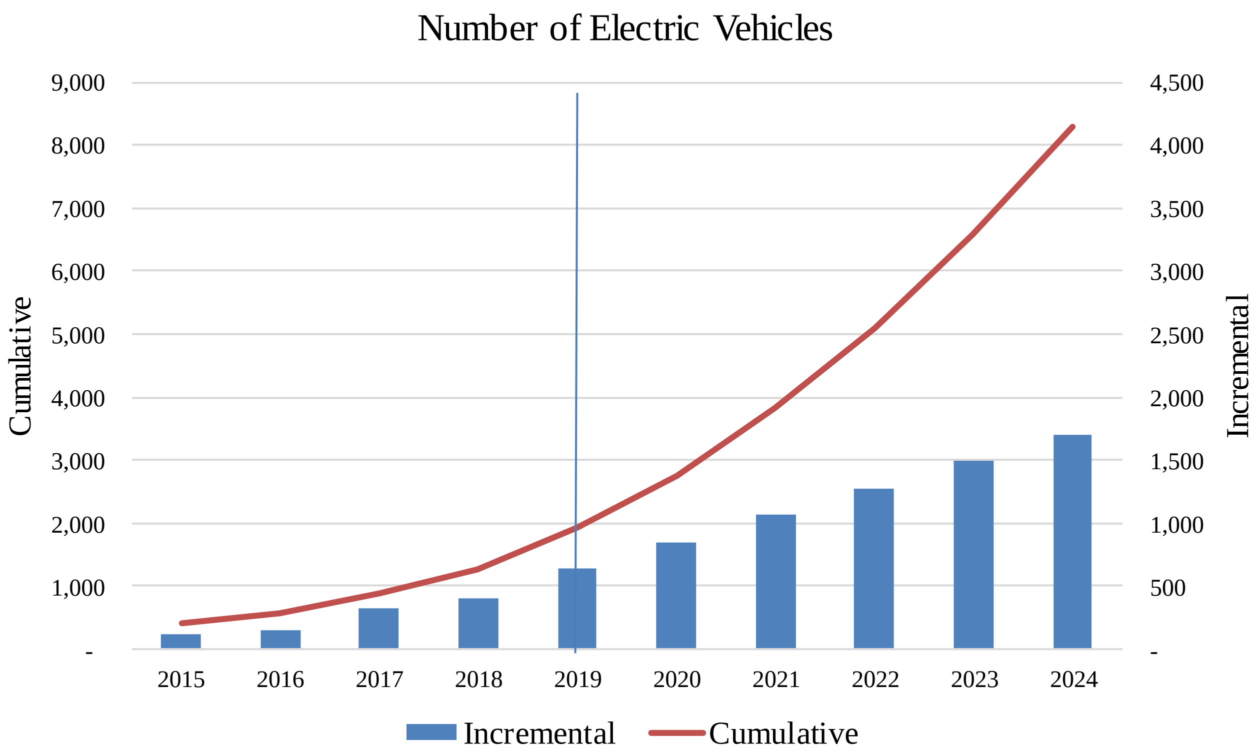


Figure 13: Rhode Island Number of Electric Vehicles (in service territory)

Appendices A shows additional detail for the DERs.

The DER projections included in this forecast are based on current trends, approved programs, and existing state policy targets. It is considered the most probable scenario at this time and is not intended to be inclusive of other activities including expanded renewables due to climate and other regional discussions. The Company is actively monitoring these processes and will incorporate, as appropriate, new policies as they become more likely.

2. Narragansett Electric Company

2.1 Forecasted Fiscal Year Deliveries by Revenue Class

ANNUAL GWh (*and percent growth*) FISCAL YEAR (Historicals & Projections: Weather-Normal) by Revenue Class
After Energy Efficiency, Solar and Electric Vehicle Impacts

FISCAL YEAR	RESIDENTIAL Non-Heating		Elec Heating		RESIDENTIAL Total		COMMERCIAL		INDUSTRIAL		StreetLighting & Other		TOTAL	
2005	2,778.8		233.1		3,011.9		3,523.1		1,271.6		64.2		7,870.7	
2006	2,759.5	-0.7%	222.0	-4.8%	2,981.5	-1.0%	3,528.7	0.2%	1,199.3	-5.7%	64.1	-0.1%	7,773.6	-1.2%
2007	2,813.3	1.9%	221.4	-0.3%	3,034.7	1.8%	3,555.0	0.7%	1,134.9	-5.4%	64.2	0.1%	7,788.8	0.2%
2008	2,860.9	1.7%	221.8	0.2%	3,082.8	1.6%	3,631.1	2.1%	1,076.0	-5.2%	63.3	-1.4%	7,853.2	0.8%
2009	2,801.3	-2.1%	199.8	-9.9%	3,001.2	-2.6%	3,654.2	0.6%	1,034.9	-3.8%	65.1	2.8%	7,754.7	-1.3%
2010	2,884.3	3.0%	201.3	0.7%	3,085.6	2.8%	3,635.3	-0.5%	918.5	-11.2%	56.6	-13.0%	7,695.8	-0.8%
2011	2,824.3	-2.1%	194.0	-3.6%	3,018.3	-2.2%	3,593.4	-1.2%	927.2	0.9%	59.4	4.9%	7,598.2	-1.3%
2012	2,895.5	2.5%	190.9	-1.6%	3,086.4	2.3%	3,602.1	0.2%	908.4	-2.0%	59.8	0.7%	7,656.8	0.8%
2013	2,989.7	3.3%	194.2	1.7%	3,183.9	3.2%	3,625.2	0.6%	894.8	-1.5%	59.3	-0.9%	7,763.1	1.4%
2014	2,949.4	-1.3%	192.6	-0.8%	3,142.0	-1.3%	3,632.2	0.2%	902.6	0.9%	59.5	0.3%	7,736.3	-0.3%
2015	2,883.4	-2.2%	190.3	-1.2%	3,073.7	-2.2%	3,639.2	0.2%	838.2	-7.1%	58.8	-1.2%	7,609.9	-1.6%
2016	2,854.6	-1.0%	184.2	-3.2%	3,038.9	-1.1%	3,605.9	-0.9%	765.6	-8.7%	58.5	-0.6%	7,468.8	-1.9%
2017	2,806.4	-1.7%	178.0	-3.4%	2,984.4	-1.8%	3,572.1	-0.9%	732.8	-4.3%	41.9	-28.4%	7,331.2	-1.8%
2018	2,822.0	0.6%	181.1	1.7%	3,003.1	0.6%	3,611.3	1.1%	707.8	-3.4%	52.3	25.0%	7,374.6	0.6%
2019	2,791.1	-1.1%	172.4	-4.8%	2,963.6	-1.3%	3,584.0	-0.8%	696.8	-1.6%	42.3	-19.2%	7,286.6	-1.2%
2020	2,789.5	-0.1%	166.9	-3.2%	2,956.5	-0.2%	3,616.4	0.9%	661.2	-5.1%	45.0	6.4%	7,279.0	-0.1%
2021	2,747.7	-1.5%	161.6	-3.2%	2,909.3	-1.6%	3,503.1	-3.1%	608.2	-8.0%	46.8	4.0%	7,067.4	-2.9%
2022	2,679.9	-2.5%	156.5	-3.1%	2,836.4	-2.5%	3,410.8	-2.6%	570.9	-6.1%	45.6	-2.5%	6,863.8	-2.9%
2023	2,679.4	0.0%	151.7	-3.1%	2,831.1	-0.2%	3,400.7	-0.3%	539.0	-5.6%	44.4	-2.6%	6,815.2	-0.7%
2024	2,639.9	-1.5%	147.1	-3.0%	2,787.0	-1.6%	3,338.4	-1.8%	508.0	-5.8%	43.2	-2.7%	6,676.6	-2.0%
2025	2,616.6	-0.9%	142.9	-2.9%	2,759.5	-1.0%	3,293.3	-1.4%	480.1	-5.5%	42.1	-2.8%	6,574.9	-1.5%

Annual Growth Rates:	Non-Heating	Elec Heating	Residential Total	Commercial	Industrial	StreetLighting & Other	Total
prior 15 years	0.0%	-2.2%	-0.1%	0.2%	-4.3%	-2.3%	-0.5%
prior 10 years	-0.3%	-1.9%	-0.4%	-0.1%	-3.2%	-2.3%	-0.6%
prior 5 years	-0.7%	-2.6%	-0.8%	-0.1%	-4.6%	-5.2%	-0.9%
BASE YEAR:	**2020**						
next 5 years	-1.3%	-3.1%	-1.4%	-1.9%	-6.2%	-1.4%	-2.0%

2.2 Forecasted Fiscal Year Customer Counts by Revenue Class

ANNUAL CUSTOMER COUNTS, FISCAL YEAR by Revenue Class

CALENDAR YEAR	RESIDENTIAL Non-Heating		RESIDENTIAL Elec Heating		RESIDENTIAL Total		COMMERCIAL		INDUSTRIAL		StreetLighting & Other		TOTAL	
2005	400,594		18,478		419,072		54,244		2,350		1,159		476,825	
2006	403,784	0.8%	18,451	-0.1%	422,235	0.8%	54,759	1.0%	2,297	-2.3%	1,162	0.2%	480,454	0.8%
2007	405,059	0.3%	18,305	-0.8%	423,364	0.3%	55,275	0.9%	2,198	-4.3%	1,149	-1.1%	481,987	0.3%
2008	406,168	0.3%	18,150	-0.8%	424,318	0.2%	55,885	1.1%	2,142	-2.6%	1,114	-3.0%	483,459	0.3%
2009	408,619	0.6%	18,178	0.2%	426,797	0.6%	56,244	0.6%	2,064	-3.6%	1,190	6.8%	486,295	0.6%
2010	409,291	0.2%	18,109	-0.4%	427,400	0.1%	56,379	0.2%	2,033	-1.5%	1,223	2.8%	487,035	0.2%
2011	406,085	-0.8%	17,938	-0.9%	424,023	-0.8%	56,801	0.7%	2,003	-1.5%	1,135	-7.2%	483,962	-0.6%
2012	410,556	1.1%	18,003	0.4%	428,559	1.1%	57,599	1.4%	1,985	-0.9%	1,117	-1.6%	489,260	1.1%
2013	413,044	0.6%	18,010	0.0%	431,054	0.6%	57,897	0.5%	1,948	-1.9%	1,134	1.6%	492,033	0.6%
2014	415,337	0.6%	18,037	0.1%	433,374	0.5%	58,302	0.7%	1,928	-1.0%	1,159	2.2%	494,762	0.6%
2015	416,084	0.2%	18,006	-0.2%	434,090	0.2%	58,296	0.0%	1,891	-1.9%	1,155	-0.3%	495,431	0.1%
2016	417,402	0.3%	17,972	-0.2%	435,374	0.3%	58,853	1.0%	1,866	-1.3%	1,147	-0.7%	497,240	0.4%
2017	413,966	-0.8%	17,792	-1.0%	431,757	-0.8%	58,700	-0.3%	1,834	-1.7%	1,121	-2.3%	493,412	-0.8%
2018	415,241	0.3%	17,745	-0.3%	432,986	0.3%	59,263	1.0%	1,796	-2.1%	1,101	-1.8%	495,146	0.4%
2019	420,409	1.2%	17,793	0.3%	438,201	1.2%	59,930	1.1%	1,788	-0.5%	1,064	-3.4%	500,982	1.2%
2020	421,646	0.3%	17,718	-0.4%	439,364	0.3%	60,278	0.6%	1,762	-1.5%	1,053	-1.0%	502,457	0.3%
2021	424,187	0.6%	17,632	-0.5%	441,819	0.6%	60,577	0.5%	1,713	-2.8%	1,028	-2.4%	505,137	0.5%
2022	425,615	0.3%	17,582	-0.3%	443,196	0.3%	60,870	0.5%	1,681	-1.9%	1,007	-2.1%	506,754	0.3%
2023	427,042	0.3%	17,531	-0.3%	444,574	0.3%	61,349	0.8%	1,649	-1.9%	985	-2.1%	508,557	0.4%
2024	428,470	0.3%	17,481	-0.3%	445,951	0.3%	61,676	0.5%	1,618	-1.9%	964	-2.2%	510,208	0.3%
2025	429,898	0.3%	17,430	-0.3%	447,328	0.3%	62,001	0.5%	1,586	-1.9%	942	-2.2%	511,857	0.3%

Annual Growth Rates:

	Non-Heating	Elec Heating	Residential Total	Commercial	Industrial	StreetLighting & Other	Total
prior 15 years	0.3%	-0.3%	0.3%	0.7%	-1.9%	-0.6%	0.3%
prior 10 years	0.3%	-0.2%	0.3%	0.7%	-1.4%	-1.5%	0.3%
prior 5 years	0.3%	-0.3%	0.2%	0.7%	-1.4%	-1.8%	0.3%
BASE YEAR:	**2020**						
next 5 years	0.4%	-0.3%	0.4%	0.6%	-2.1%	-2.2%	0.4%

2.3 Forecasted Fiscal Year Deliveries by Rate Class

ANNUAL GWh (*and percent growth*) FISCAL YEAR (Historicals & Projections: Weather-Normal) by Rate Code
After Energy Efficiency, Solar and Electric Vehicle Impacts

FISCAL YEAR	A16		A60		C06		C08		G02		G32		G62	B32		B62	X01		SL		OTHER	TOTAL	
2005	2,807.5		213.7		648.8		6.8		1,315.8		2,543.1		221.9	18.9		-	22.5		71.0		-	7,870.7	
2006	2,774.2	-1.2%	214.6	0.4%	638.4	-1.6%	6.7	-1.1%	1,313.1	-0.2%	2,466.0	-3.0%	235.9	17.3	-8.1%	10.9	22.5	-0.3%	71.5	0.7%	1.8	7,773.6	-1.2%
2007	2,786.7	0.5%	239.9	11.8%	533.0	-16.5%	6.7	0.5%	1,395.4	6.3%	2,122.0	-13.9%	447.3	3.4	-80.4%	137.9	23.9	6.2%	74.0	3.4%	18.7	7,788.8	0.2%
2008	2,858.4	2.6%	216.8	-9.6%	547.3	2.7%	6.3	-5.5%	1,411.8	1.2%	2,134.5	0.6%	419.2	6.1	78.7%	140.2	25.0	4.9%	70.2	-5.2%	17.3	7,853.2	0.8%
2009	2,811.3	-1.6%	193.9	-10.6%	537.3	-1.8%	6.9	8.3%	1,859.9	31.7%	1,776.0	-16.8%	377.4	4.8	-20.2%	79.0	25.8	3.0%	69.2	-1.4%	13.1	7,754.7	-1.3%
2010	2,853.7	1.5%	242.5	25.1%	551.5	2.6%	(2.2)	-132.5%	1,348.2	-27.5%	2,043.4	15.1%	419.5	5.9	22.6%	135.9	26.3	1.9%	68.8	-0.5%	2.2	7,695.8	-0.8%
2011	2,765.9	-3.1%	262.6	8.3%	552.6	0.2%	4.7	-311.2%	1,316.7	-2.3%	2,039.9	-0.2%	418.3	7.0	18.8%	140.2	22.8	-13.4%	67.4	-2.0%	-	7,598.2	-1.3%
2012	2,819.1	1.9%	276.0	5.1%	557.2	0.8%	3.8	-19.2%	1,310.6	-0.5%	2,045.1	0.3%	424.0	7.7	8.8%	124.4	23.0	0.9%	66.1	-2.0%	-	7,656.8	0.8%
2013	2,890.0	2.5%	303.7	10.1%	577.1	3.6%	3.5	-7.7%	1,307.1	-0.3%	2,039.8	-0.3%	443.0	7.8	2.4%	101.1	22.8	-0.8%	67.2	1.6%	-	7,763.1	1.4%
2014	2,860.1	-1.0%	291.7	-4.0%	585.9	1.5%	3.6	2.5%	1,301.7	-0.4%	2,026.9	-0.6%	463.7	5.1	-35.4%	107.4	22.8	0.3%	67.5	0.5%	-	7,736.3	-0.3%
2015	2,782.9	-2.7%	300.4	3.0%	590.8	0.8%	3.5	-2.3%	1,308.8	0.5%	2,030.8	0.2%	445.4	8.9	76.4%	48.2	23.9	4.4%	66.3	-1.7%	-	7,609.9	-1.6%
2016	2,746.3	-1.3%	301.5	0.4%	578.6	-2.1%	3.6	1.5%	1,304.6	-0.3%	1,995.5	-1.7%	436.0	13.3	48.4%	-	23.7	-0.8%	65.9	-0.7%	-	7,468.8	-1.9%
2017	2,776.0	1.1%	217.4	-27.9%	578.9	0.1%	3.9	10.4%	1,285.8	-1.4%	1,951.8	-2.2%	430.7	13.5	1.5%	-	23.8	0.5%	49.5	-24.8%	-	7,331.2	-1.8%
2018	2,808.3	1.2%	204.1	-6.1%	612.2	5.7%	5.5	39.4%	1,286.6	0.1%	1,933.6	-0.9%	427.7	14.4	6.9%	-	24.2	1.7%	57.9	16.9%	-	7,374.6	0.6%
2019	2,765.1	-1.5%	208.3	2.1%	630.6	3.0%	4.7	-13.9%	1,267.1	-1.5%	2,070.1	7.1%	252.0	18.0	25.0%	-	22.3	-8.0%	48.5	-16.2%	-	7,286.6	-1.2%
2020	2,753.3	-0.4%	212.4	2.0%	650.9	3.2%	5.5	16.0%	1,263.0	-0.3%	2,305.4	11.4%	-	15.2	-15.3%	-	23.5	5.4%	49.9	2.8%	-	7,279.0	-0.1%
2021	2,711.5	-1.5%	207.0	-2.5%	626.4	-3.8%	5.4	-2.0%	1,223.5	-3.1%	2,204.6	-4.4%	-	14.6	-4.2%	-	22.4	-4.4%	52.0	4.3%	-	7,067.4	-2.9%
2022	2,643.5	-2.5%	201.8	-2.5%	609.3	-2.7%	5.2	-2.6%	1,188.5	-2.9%	2,128.9	-3.4%	-	14.1	-3.6%	-	21.8	-2.6%	50.6	-2.8%	-	6,863.8	-2.9%
2023	2,638.5	-0.2%	201.5	-0.2%	606.6	-0.4%	5.1	-2.0%	1,181.1	-0.6%	2,097.5	-1.5%	-	13.9	-1.7%	-	21.8	-0.3%	49.3	-2.6%	-	6,815.2	-0.7%
2024	2,597.3	-1.6%	198.4	-1.5%	594.9	-1.9%	5.0	-2.4%	1,156.7	-2.1%	2,041.5	-2.7%	-	13.5	-2.8%	-	21.4	-1.8%	47.9	-2.8%	-	6,676.6	-2.0%
2025	2,571.6	-1.0%	196.5	-1.0%	586.3	-1.4%	4.9	-2.4%	1,138.4	-1.6%	1,996.4	-2.2%	-	13.2	-2.3%	-	21.1	-1.4%	46.6	-2.8%	-	6,574.9	-1.5%

Annual Growth Rates:	A16	A60	C06	C08	G02	G32	B32	X01	SL	TOTAL
prior 15 years	-0.1%	0.0%	0.0%	-1.4%	-0.3%	-0.7%	-1.4%	0.3%	-2.3%	-0.5%
prior 10 years	-0.4%	-1.3%	1.7%	6.2%	-0.7%	1.2%	9.9%	-1.1%	-3.2%	-0.6%
prior 5 years	-0.2%	-6.7%	2.0%	9.3%	-0.7%	2.6%	11.2%	-0.3%	-5.5%	-0.9%
BASE YEAR:	**2020**									
next 5 years	-1.4%	-1.5%	-2.1%	-2.3%	-2.1%	-2.8%	-2.9%	-2.1%	-1.4%	-2.0%

2.4 Forecasted Fiscal Year Customer Counts by Rate Class

ANNUAL CUSTOMER COUNTS, FISCAL YEAR by Rate Code

FISCAL YEAR	A16		A60		C06		C08		G02		G32		G62	B32		B62	X01		SL		OTHER	TOTAL	
2005	387,571		31,695		47,155		864		7,909		1,100		5	5		-	1		520		-	476,825	
2006	390,008	0.6%	32,449	2.4%	47,430	0.6%	879	1.7%	8,041	1.7%	1,098	-0.2%	6	4	-4.5%	0	1	2.1%	517	-0.7%	20	480,454	0.8%
2007	385,874	-1.1%	37,926	16.9%	46,499	-2.0%	991	12.8%	8,906	10.8%	1,089	-0.8%	13	2	-53.6%	2	1	13.3%	457	-11.5%	227	481,987	0.3%
2008	390,360	1.2%	34,260	-9.7%	47,186	1.5%	943	-4.9%	8,897	-0.1%	1,121	2.9%	14	3	28.8%	2	1	-0.7%	454	-0.7%	219	483,459	0.3%
2009	395,443	1.3%	31,776	-7.3%	47,303	0.2%	1,011	7.2%	8,921	0.3%	1,151	2.7%	13	3	-2.8%	2	1	-2.1%	489	7.8%	182	486,295	0.6%
2010	390,360	-1.3%	37,516	18.1%	47,674	0.8%	1,015	0.5%	8,808	-1.3%	1,113	-3.3%	12	6	140.1%	2	1	0.3%	526	7.5%	-	487,035	0.2%
2011	383,681	-1.7%	40,715	8.5%	48,239	1.2%	885	-12.8%	8,777	-0.4%	1,112	-0.1%	12	5	-19.2%	2	1	-0.5%	532	1.2%	-	483,962	-0.6%
2012	387,348	1.0%	41,459	1.8%	49,180	2.0%	812	-8.3%	8,786	0.1%	1,103	-0.8%	13	5	7.0%	2	1	0.3%	550	3.4%	-	489,260	1.1%
2013	387,246	0.0%	44,117	6.4%	49,480	0.6%	794	-2.2%	8,683	-1.2%	1,109	0.6%	13	5	-6.9%	1	1	-0.3%	584	6.2%	-	492,033	0.6%
2014	390,967	1.0%	42,742	-3.1%	49,904	0.9%	814	2.5%	8,625	-0.7%	1,097	-1.1%	13	4	-19.6%	1	1	0.3%	595	1.8%	-	494,762	0.6%
2015	389,333	-0.4%	45,130	5.6%	49,916	0.0%	803	-1.3%	8,538	-1.0%	1,097	0.1%	12	5	14.2%	1	1	-0.3%	595	0.0%	-	495,431	0.1%
2016	389,492	0.0%	46,261	2.5%	50,189	0.5%	816	1.7%	8,793	3.0%	1,079	-1.7%	12	5	6.5%	-	1	-4.5%	592	-0.5%	-	497,240	0.4%
2017	397,579	2.1%	34,593	-25.2%	50,205	0.0%	830	1.7%	8,543	-2.8%	1,077	-0.2%	12	5	-1.5%	-	1	3.9%	568	-4.0%	-	493,412	-0.8%
2018	401,332	0.9%	32,037	-7.4%	50,846	1.3%	811	-2.4%	8,509	-0.4%	1,068	-0.8%	13	5	9.7%	-	1	-0.5%	525	-7.5%	-	495,146	0.4%
2019	405,699	1.1%	32,819	2.4%	51,516	1.3%	828	2.1%	8,531	0.3%	1,097	2.7%	7	5	-12.7%	-	1	-0.3%	479	-8.7%	-	500,982	1.2%
2020	405,524	0.0%	34,038	3.7%	51,980	0.9%	833	0.6%	8,504	-0.3%	1,099	0.2%	-	5	7.2%	-	1	0.7%	473	-1.3%	-	502,457	0.3%
2021	408,640	0.8%	33,436	-1.8%	52,120	0.3%	816	-2.1%	8,560	0.7%	1,097	-0.1%	-	5	-3.2%	-	1	0.5%	463	-2.2%	-	505,137	0.5%
2022	409,914	0.3%	33,541	0.3%	52,349	0.4%	805	-1.3%	8,589	0.3%	1,096	-0.1%	-	5	0.1%	-	1	0.5%	454	-2.0%	-	506,754	0.3%
2023	411,192	0.3%	33,646	0.3%	52,733	0.7%	794	-1.3%	8,643	0.6%	1,098	0.2%	-	5	0.4%	-	1	0.8%	444	-2.1%	-	508,557	0.4%
2024	412,466	0.3%	33,752	0.3%	52,991	0.5%	783	-1.4%	8,678	0.4%	1,098	0.0%	-	5	0.1%	-	1	0.5%	435	-2.1%	-	510,208	0.3%
2025	413,741	0.3%	33,857	0.3%	53,246	0.5%	773	-1.4%	8,711	0.4%	1,098	0.0%	-	5	0.1%	-	1	0.5%	425	-2.2%	-	511,857	0.3%
Annual Growth Rates:																							
prior 15 years		0.3%		0.5%		0.7%		-0.2%		0.5%		0.0%			0.4%			0.7%		-0.6%			0.3%
prior 10 years		0.4%		-1.0%		0.9%		-2.0%		-0.4%		-0.1%			-2.3%			-0.1%		-1.0%			0.3%
prior 5 years		0.8%		-5.5%		0.8%		0.7%		-0.1%		0.0%			1.5%			-0.2%		-4.5%			0.3%
BASE YEAR:	**2020**																						
next 5 years		0.4%		-0.1%		0.5%		-1.5%		0.5%		0.0%			-0.5%			0.6%		-2.1%			0.4%

Appendices

APPENDIX A: DERs

NECO TOTAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

Calendar Year	Reconstituted (before reductions)	DELIVERIES (50/50): Forecast w/ EE Reduction only	Forecast w/ PV Reduction only	Forecast w/ EV Increase only	Final Forecast (after all reductions)	DER IMPACTS: EE	PV	EV	Total Impacts	EE % of Reconstituted Deliveries	PV % of Reconstituted Deliveries	EV % of Reconstituted Deliveries	TTL % of Reconstituted Deliveries
2004	7,988	7,906	7,988	7,988	**7,906**	82	0	0	82	1.0%	0.0%	0.0%	1.0%
2005	7,886	7,744	7,886	7,886	**7,744**	142	0	0	142	1.8%	0.0%	0.0%	1.8%
2006	7,961	7,751	7,961	7,961	**7,751**	210	0	0	210	2.6%	0.0%	0.0%	2.6%
2007	8,161	7,884	8,161	8,161	**7,883**	278	1	0	278	3.4%	0.0%	0.0%	3.4%
2008	8,094	7,754	8,093	8,094	**7,753**	340	1	0	341	4.2%	0.0%	0.0%	4.2%
2009	8,128	7,716	8,127	8,128	**7,715**	412	1	0	413	5.1%	0.0%	0.0%	5.1%
2010	8,118	7,625	8,117	8,118	**7,624**	493	1	0	494	6.1%	0.0%	0.0%	6.1%
2011	8,229	7,647	8,227	8,229	**7,645**	582	2	0	584	7.1%	0.0%	0.0%	7.1%
2012	8,435	7,744	8,432	8,435	**7,741**	691	3	0	694	8.2%	0.0%	0.0%	8.2%
2013	8,565	7,734	8,554	8,565	**7,723**	831	10	0	841	9.7%	0.1%	0.0%	9.8%
2014	8,748	7,700	8,728	8,749	**7,680**	1,049	20	1	1,068	12.0%	0.2%	0.0%	12.2%
2015	8,789	7,496	8,762	8,790	**7,471**	1,292	26	1	1,318	14.7%	0.3%	0.0%	15.0%
2016	8,923	7,412	8,884	8,925	**7,375**	1,511	39	1	1,548	16.9%	0.4%	0.0%	17.4%
2017	9,136	7,402	9,070	9,138	**7,338**	1,734	66	2	1,798	19.0%	0.7%	0.0%	19.7%
2018	9,416	7,463	9,295	9,419	**7,346**	1,953	121	3	2,070	20.7%	1.3%	0.0%	22.0%
2019	9,656	7,504	9,427	9,661	**7,281**	2,151	229	5	2,375	22.3%	2.4%	0.1%	24.6%
2020	9,808	7,473	9,441	9,815	**7,113**	2,335	367	7	2,695	23.8%	3.7%	0.1%	27.5%
2021	9,899	7,393	9,396	9,909	**6,899**	2,507	503	10	3,000	25.3%	5.1%	0.1%	30.3%
2022	10,123	7,453	9,482	10,136	**6,826**	2,670	641	14	3,297	26.4%	6.3%	0.1%	32.6%
2023	10,287	7,462	9,509	10,305	**6,702**	2,825	778	18	3,585	27.5%	7.6%	0.2%	34.9%
2024	10,437	7,464	9,524	10,459	**6,574**	2,972	913	23	3,862	28.5%	8.7%	0.2%	37.0%

Annual Growth Rates:

	Reconstituted	Forecast w/ EE Reduction only	Forecast w/ PV Reduction only	Forecast w/ EV Increase only	Final Forecast
prior 15 years	1.3%	-0.3%	1.1%	1.3%	**-0.5%**
prior 10 years	1.7%	-0.3%	1.5%	1.7%	**-0.6%**
prior 5 years	2.0%	-0.5%	1.6%	2.0%	**-1.1%**
BASE YEAR: 2019					
next 5 years	1.6%	-0.1%	0.2%	1.6%	**-2.0%**

NECO RESIDENTIAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

Calendar Year	DELIVERIES (50/50): Reconstituted (before reductions)	Forecast w/ EE Reduction only	Forecast w/ PV Reduction only	Forecast w/ EV Increase only	Final Forecast (after all reductions)	DER IMPACTS: EE	PV	EV	Total Impacts	EE % of Reconstituted Deliveries	PV % of Reconstituted Deliveries	EV % of Reconstituted Deliveries	TTL % of Reconstituted Deliveries
2004	3,048	3,016	3,048	3,048	**3,016**	32	0	0	32	1.0%	0.0%	0.0%	1.0%
2005	3,017	2,961	3,017	3,017	**2,961**	56	0	0	56	1.9%	0.0%	0.0%	1.9%
2006	3,088	3,006	3,088	3,088	**3,005**	83	0	0	83	2.7%	0.0%	0.0%	2.7%
2007	3,184	3,077	3,183	3,184	**3,077**	107	0	0	107	3.3%	0.0%	0.0%	3.4%
2008	3,162	3,034	3,162	3,162	**3,034**	128	0	0	128	4.0%	0.0%	0.0%	4.1%
2009	3,221	3,067	3,220	3,221	**3,067**	153	1	0	154	4.8%	0.0%	0.0%	4.8%
2010	3,219	3,036	3,219	3,219	**3,035**	184	1	0	184	5.7%	0.0%	0.0%	5.7%
2011	3,280	3,064	3,279	3,280	**3,063**	217	1	0	217	6.6%	0.0%	0.0%	6.6%
2012	3,427	3,171	3,426	3,427	**3,170**	256	1	0	257	7.5%	0.0%	0.0%	7.5%
2013	3,456	3,143	3,454	3,456	**3,143**	312	1	0	313	9.0%	0.0%	0.0%	9.1%
2014	3,497	3,099	3,495	3,498	**3,098**	398	2	1	399	11.4%	0.0%	0.0%	11.4%
2015	3,541	3,038	3,538	3,542	**3,036**	503	3	1	505	14.2%	0.1%	0.0%	14.3%
2016	3,635	3,017	3,625	3,636	**3,008**	618	10	1	627	17.0%	0.3%	0.0%	17.3%
2017	3,745	3,009	3,723	3,747	**2,988**	736	23	2	757	19.7%	0.6%	0.0%	20.2%
2018	3,870	3,025	3,834	3,873	**2,993**	845	35	3	877	21.8%	0.9%	0.1%	22.7%
2019	3,941	2,996	3,888	3,945	**2,946**	946	54	4	995	24.0%	1.4%	0.1%	25.3%
2020	4,046	3,009	3,957	4,052	**2,926**	1,037	89	6	1,120	25.6%	2.2%	0.1%	27.7%
2021	4,097	2,976	3,963	4,105	**2,851**	1,121	134	9	1,246	27.4%	3.3%	0.2%	30.4%
2022	4,202	3,001	4,023	4,214	**2,833**	1,202	179	12	1,370	28.6%	4.3%	0.3%	32.6%
2023	4,283	3,004	4,059	4,298	**2,795**	1,279	224	15	1,488	29.9%	5.2%	0.4%	34.7%
2024	4,358	3,006	4,089	4,377	**2,756**	1,352	269	19	1,602	31.0%	6.2%	0.4%	36.8%

Annual Growth Rates:

	Reconstituted	Forecast w/ EE Reduction only	Forecast w/ PV Reduction only	Forecast w/ EV Increase only	Final Forecast
prior 15 years	1.7%	0.0%	1.6%	1.7%	**-0.2%**
prior 10 years	2.0%	-0.2%	1.9%	2.0%	**-0.4%**
prior 5 years	2.4%	-0.7%	2.1%	2.4%	**-1.0%**
BASE YEAR:	**2019**				
next 5 years	2.0%	0.1%	1.0%	2.1%	**-1.3%**

NECO COMMERCIAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

Calendar Year	DELIVERIES (50/50): Reconstituted (before reductions)	Forecast w/ EE Reduction only	Forecast w/ PV Reduction only	Forecast w/ EV Increase only	Final Forecast (after all reductions)	DER IMPACTS: EE	PV	EV	Total Impacts	EE % of Reconstituted Deliveries	PV % of Reconstituted Deliveries	EV % of Reconstituted Deliveries	TTL % of Reconstituted Deliveries
2004	3,563	3,526	3,563	3,563	**3,526**	37	0	0	37	1.0%	0.0%	0.0%	1.0%
2005	3,579	3,517	3,579	3,579	**3,517**	63	0	0	63	1.8%	0.0%	0.0%	1.8%
2006	3,634	3,539	3,634	3,634	**3,539**	94	0	0	95	2.6%	0.0%	0.0%	2.6%
2007	3,754	3,626	3,754	3,754	**3,626**	128	0	0	128	3.4%	0.0%	0.0%	3.4%
2008	3,777	3,618	3,777	3,777	**3,618**	159	0	0	159	4.2%	0.0%	0.0%	4.2%
2009	3,851	3,655	3,851	3,851	**3,655**	196	0	0	196	5.1%	0.0%	0.0%	5.1%
2010	3,841	3,604	3,840	3,841	**3,604**	236	0	0	237	6.2%	0.0%	0.0%	6.2%
2011	3,904	3,623	3,903	3,904	**3,622**	281	1	0	282	7.2%	0.0%	0.0%	7.2%
2012	3,947	3,610	3,946	3,948	**3,609**	337	2	0	339	8.5%	0.0%	0.0%	8.6%
2013	4,026	3,622	4,019	4,026	**3,615**	404	7	0	411	10.0%	0.2%	0.0%	10.2%
2014	4,179	3,669	4,164	4,179	**3,654**	510	15	0	525	12.2%	0.4%	0.0%	12.6%
2015	4,251	3,628	4,232	4,251	**3,609**	623	19	0	642	14.7%	0.4%	0.0%	15.1%
2016	4,311	3,603	4,288	4,311	**3,580**	708	24	0	732	16.4%	0.5%	0.0%	17.0%
2017	4,428	3,632	4,393	4,428	**3,597**	796	35	0	831	18.0%	0.8%	0.0%	18.8%
2018	4,554	3,666	4,484	4,554	**3,596**	888	70	0	958	19.5%	1.5%	0.0%	21.0%
2019	4,726	3,756	4,580	4,726	**3,611**	970	146	1	1,115	20.5%	3.1%	0.0%	23.6%
2020	4,803	3,755	4,571	4,804	**3,524**	1,048	233	1	1,280	21.8%	4.8%	0.0%	26.6%
2021	4,857	3,734	4,546	4,858	**3,424**	1,123	311	1	1,433	23.1%	6.4%	0.0%	29.5%
2022	4,984	3,791	4,594	4,986	**3,402**	1,193	390	2	1,582	23.9%	7.8%	0.0%	31.7%
2023	5,077	3,816	4,607	5,079	**3,349**	1,261	469	2	1,728	24.8%	9.2%	0.0%	34.0%
2024	5,161	3,836	4,613	5,164	**3,291**	1,325	548	3	1,871	25.7%	10.6%	0.1%	36.2%

Annual Growth Rates:	Reconstituted	Forecast w/ EE Reduction only	Forecast w/ PV Reduction only	Forecast w/ EV Increase only	Final Forecast
prior 15 years	1.9%	0.4%	1.7%	1.9%	**0.2%**
prior 10 years	2.1%	0.3%	1.7%	2.1%	**-0.1%**
prior 5 years	2.5%	0.5%	1.9%	2.5%	**-0.2%**
BASE YEAR:	**2019**				
next 5 years	1.8%	0.4%	0.1%	1.8%	**-1.8%**

NECO INDUSTRIAL Deliveries (weather-normalize, 50/50) (GWh) (before & after DERs)

	------------- DELIVERIES (50/50) -------------					------------------- DER IMPACTS ---				EE % of	PV % of	EV % of	TTL % of
Calendar Year	Reconstituted (before reductions)	Forecast w/ EE Reduction only	Forecast w/ PV Reduction only	Forecast w/ EV Increase only	Final Forecast (after all reductions)	EE	PV	EV	Total Impacts	Reconstituted Deliveries			
2004	1,313	1,299	1,313	1,313	**1,299**	14	0	0	14	1.0%	0.0%	0.0%	1.0%
2005	1,226	1,203	1,226	1,226	**1,203**	23	0	0	23	1.8%	0.0%	0.0%	1.9%
2006	1,175	1,142	1,175	1,175	**1,142**	33	0	0	33	2.8%	0.0%	0.0%	2.8%
2007	1,161	1,117	1,161	1,161	**1,117**	44	0	0	44	3.8%	0.0%	0.0%	3.8%
2008	1,090	1,037	1,090	1,090	**1,037**	53	0	0	53	4.9%	0.0%	0.0%	4.9%
2009	992	929	992	992	**929**	63	0	0	63	6.3%	0.0%	0.0%	6.3%
2010	1,005	932	1,005	1,005	**932**	73	0	0	73	7.3%	0.0%	0.0%	7.3%
2011	985	900	985	985	**900**	85	0	0	85	8.6%	0.0%	0.0%	8.6%
2012	1,001	903	1,001	1,001	**903**	98	0	0	99	9.8%	0.0%	0.0%	9.9%
2013	1,024	908	1,022	1,024	**907**	115	2	0	117	11.3%	0.2%	0.0%	11.4%
2014	1,013	872	1,009	1,013	**868**	141	4	0	145	13.9%	0.4%	0.0%	14.3%
2015	938	772	934	938	**767**	166	5	0	171	17.7%	0.5%	0.0%	18.2%
2016	930	745	924	930	**740**	184	6	0	190	19.8%	0.6%	0.0%	20.4%
2017	923	721	915	923	**713**	202	8	0	210	21.9%	0.9%	0.0%	22.7%
2018	943	723	928	943	**708**	220	15	0	235	23.4%	1.6%	0.0%	24.9%
2019	941	705	911	941	**676**	236	29	0	265	25.1%	3.1%	0.0%	28.2%
2020	912	662	867	912	**617**	250	45	0	295	27.4%	4.9%	0.0%	32.3%
2021	900	637	841	900	**578**	263	58	0	321	29.2%	6.5%	0.0%	35.7%
2022	891	617	820	892	**546**	275	72	0	346	30.8%	8.0%	0.0%	38.8%
2023	884	598	799	884	**515**	285	84	0	369	32.3%	9.5%	0.0%	41.7%
2024	875	580	780	876	**485**	295	96	0	390	33.7%	10.9%	0.1%	44.6%

Annual Growth Rates:					
prior 15 years	-2.2%	-4.0%	-2.4%	-2.2%	**-4.3%**
prior 10 years	-0.5%	-2.7%	-0.8%	-0.5%	**-3.1%**
prior 5 years	-1.5%	-4.2%	-2.0%	-1.5%	**-4.9%**
BASE YEAR:	**2019**				
next 5 years	-1.4%	-3.8%	-3.1%	-1.4%	**-6.4%**

APPENDIX B: MODELS

Model: NECO ELECTRIC RESIDENTIAL USE per CUST, recon Method (Est.Period: Jan2003 to aug19

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	92589.1393	DFE	192
MSE	482.23510	Root MSE	21.95985
SBC	1837.70466	AIC	1811.31812
MAE	16.4846852	AICC	1812.07205
MAPE	2.51161268	HQC	1821.99635
Durbin-Watson	1.9365	Transformed Regression R-Square	0.9454
		Total R-Square	0.9621

Parameter Estimates

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	-754.3249	63.7241	-11.84	<.0001	
IDX_PCI	1	8.3395	0.5034	16.57	<.0001	idx_PCI
hdd_season	1	-60.0336	6.6293	-9.06	<.0001	
cdd_season*cdd_49	1	1.1431	0.0244	46.85	<.0001	
hdd_season*hdd_49	1	0.2255	0.008517	26.48	<.0001	
Bdays	1	17.0042	1.4794	11.49	<.0001	Number of Billing Days
jan07	1	64.0470	20.0968	3.19	0.0017	

Model: NECO ELECTRIC REH USE per CUST, recon Method (Est.Period: Jan2003 to aug19

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	366372.69	DFE	194
MSE	1889	Root MSE	43.45709
SBC	2102.2153	AIC	2082.4254
MAE	32.9810009	AICC	2082.86063
MAPE	3.39617126	HQC	2090.43407
Durbin-Watson	1.9736	Transformed Regression R-Square	0.9641
		Total R-Square	0.9813

Parameter Estimates						
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	430.6489	13.8558	31.08	<.0001	
time_trend_2012	1	13.6218	2.1681	6.28	<.0001	
cdd_49	1	1.4812	0.0501	29.54	<.0001	RevMo Cooling Degree Days, NECo
hdd_49	1	0.9656	0.0140	68.76	<.0001	RevMo Heating Degree Days, NECo
nov	1	-70.5208	10.1620	-6.94	<.0001	

Model: NECO ELECTRIC COMMERCIAL USE per CUST, recon Method (Est.Period: Jan2003 to aug19

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	5437206.63	DFE	189
MSE	28768	Root MSE	169.61217
SBC	2667.96464	AIC	2631.68315
MAE	127.036559	AICC	2633.08741
MAPE	2.19371744	HQC	2646.36572
Durbin-Watson	1.9178	Transformed Regression R-Square	0.8943
		Total R-Square	0.9099

Parameter Estimates

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	-3901	444.9997	-8.77	<.0001	
IDX_PCI	1	57.1449	2.5059	22.80	<.0001	idx_PCI
cdd_49	1	5.0342	0.1916	26.28	<.0001	RevMo Cooling Degree Days, NECo
hdd_49	1	0.4921	0.0500	9.84	<.0001	RevMo Heating Degree Days, NECo
Bdays	1	129.7744	12.5840	10.31	<.0001	Number of Billing Days
oct	1	288.4729	49.5223	5.83	<.0001	
apr08	1	552.2593	168.7832	3.27	0.0013	
sep08	1	582.7822	170.0745	3.43	0.0007	
aug14	1	-1041	169.2627	-6.15	<.0001	
oct14	1	692.8539	174.1338	3.98	<.0001	

Model: NECO ELECTRIC INDUSTRIAL KWH, recon Method (Est.Period: Jan2003 to aug19

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	4793.97298	DFE	189
MSE	25.36494	Root MSE	5.03636
SBC	1261.21645	AIC	1224.93496
MAE	3.7811062	AICC	1226.33922
MAPE	4.29761305	HQC	1239.61753
Durbin-Watson	1.9844	Transformed Regression R-Square	0.8396
		Total R-Square	0.8413

Parameter Estimates						
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	35.5796	4.3799	8.12	<.0001	
IDX_empl_manuf	1	0.5299	0.0258	20.51	<.0001	idx_EMPL_MANUF
p_elec_gas_ratio_i	1	-7.5265	1.6004	-4.70	<.0001	p_elec_gas_ratio_i
cdd_49	1	0.0247	0.003657	6.75	<.0001	RevMo Cooling Degree Days, NECo
feb03	1	-13.1520	5.1331	-2.56	0.0112	
feb14	1	18.1732	5.0670	3.59	0.0004	
mar08	1	-25.9370	5.0621	-5.12	<.0001	
apr08	1	23.3057	5.0631	4.60	<.0001	
apr09	1	-39.8524	5.0715	-7.86	<.0001	
may09	1	30.3708	5.0690	5.99	<.0001	

Model: NECO ELECTRIC RESIDENTIAL CUSTOMER COUNT (Est.Period: Jan2003 to aug19

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	2134167981	DFE	188
MSE	11351957	Root MSE	3369
SBC	3867.76416	AIC	3828.18436
MAE	2309.01756	AICC	3829.8528
MAPE	0.54075661	HQC	3844.2017
Durbin-Watson	1.9990	Transformed Regression R-Square	0.8290
		Total R-Square	0.8172

Parameter Estimates

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	-2318986	96219	-24.10	<.0001
time_trend	1	1377	48.2253	28.56	<.0001
dec	1	-2526	971.0548	-2.60	0.0100
dec10	1	-14513	3490	-4.16	<.0001
mar11	1	-15020	3373	-4.45	<.0001
dec16	1	-16692	3507	-4.76	<.0001
mar17	1	-19344	3389	-5.71	<.0001
oct17	1	-20083	3393	-5.92	<.0001
dec17	1	-18146	3513	-5.17	<.0001
mar18	1	-16480	3395	-4.85	<.0001
jun18	1	-19743	3397	-5.81	<.0001

Model: NECO ELECTRIC REH CUSTOMER COUNT (Est.Period: Jan2003 to aug19

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	3511110.1	DFE	191
MSE	18383	Root MSE	135.58309
SBC	2569.91531	AIC	2540.23045
MAE	87.0091833	AICC	2541.17782
MAPE	0.48445568	HQC	2552.24346
Durbin-Watson	2.0303	Transformed Regression R-Square	0.7494
		Total R-Square	0.7995

Parameter Estimates					
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	118723	4795	24.76	<.0001
time_trend	1	-50.4248	2.4030	-20.98	<.0001
jan08	1	-548.4344	133.9589	-4.09	<.0001
nov08	1	928.1552	135.9315	6.83	<.0001
dec08	1	-572.5873	135.9276	-4.21	<.0001
jun10	1	-324.7406	133.8609	-2.43	0.0162
dec10	1	-614.5723	133.8545	-4.59	<.0001
mar11	1	-510.5203	133.8532	-3.81	0.0002

Model: NECO ELECTRIC COMMERICAL CUSTOMER COUNT (Est.Period: Jan2003 to aug19

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	56556307.8	DFE	193
MSE	293038	Root MSE	541.32972
SBC	3115.27098	AIC	3092.18276
MAE	401.015419	AICC	3092.7661
MAPE	0.70231688	HQC	3101.52621
Durbin-Watson	2.1980	Transformed Regression R-Square	0.8523
		Total R-Square	0.9266

Parameter Estimates

Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|	Variable Label
Intercept	1	36288	1295	28.02	<.0001	
IDX_PCI	1	236.7036	13.9206	17.00	<.0001	idx_PCI
prerecession	1	-1538	158.7504	-9.69	<.0001	
dec	1	-636.7001	130.8434	-4.87	<.0001	
nov15	1	1288	515.9737	2.50	0.0134	
jun18	1	-2248	514.6740	-4.37	<.0001	

Model: NECO ELECTRIC INDUSTRIAL CUSTOMER COUNT (Est.Period: Jan2003 to aug19

The AUTOREG Procedure

Yule-Walker Estimates			
SSE	108261.149	DFE	195
MSE	555.18538	Root MSE	23.56237
SBC	1853.58203	AIC	1837.09045
MAE	17.0943503	AICC	1837.39973
MAPE	0.85908369	HQC	1843.76434
Durbin-Watson	2.4752	Transformed Regression R-Square	0.8658
		Total R-Square	0.9862

Parameter Estimates					
Variable	DF	Estimate	Standard Error	t Value	Approx Pr > |t|
Intercept	1	64943	3418	19.00	<.0001
time_trend	1	-31.5440	1.7112	-18.43	<.0001
prerecession	1	113.5241	16.7091	6.79	<.0001
dec08	1	-137.8819	19.1677	-7.19	<.0001

APPENDIX C: Regression Statistics Discussion

All models are checked for overall goodness of fit, statistical validity and reasonable of results. In general, the following items are reviewed for each model.

1) Overall Goodness of Fit: Does the model adequately capture the explanatory aspects for the dependent variable? For example, for the residential use-per-customer model, do the explanatory economics, demographics, weather, calendar, and other independent variables adequately explain the monthly energy use. Several statistical tests can be used to gauge this. For this forecast, "Adjusted R-squared" is the primary test used. Values are expressed as a fraction of 1.0 and values closest to 1.0 are best. In theory, a 1.0 means that the variables being used explain 100% the energy use. For the most part residential models generally have Adjusted R-Squared values of 0.9 or higher, commercial models 0.85 or higher and industrial models 0.75 or better (*these are somewhat subjective, but based on past experience*).

2) Correlation and Causality: Are the explanatory variables correlated with energy usage? That is, as a variable goes up or down, does the energy do the same? Are the variables causal? For example, can it be said that as summer weather gets hotter, would the expectation be that energy use would go up due to air conditioning and other cooling loads? For this forecast, correlation statistics are reviewed for correlation strength. Both general industry practice and experience are used to gauge causation.

3) Statistical Significance of Explanatory Variables: Are the independent variables statistically significant? p-values and T-statistics are used to determine this. Lower p-values indicate higher statistical significance. Generally, p-values less than or equal to 0.05 are considered statistically significant. However, in certain cases, explanatory variables with higher values (up to 0.10 or 0.15) may be useful to a model if that variable is known provide explanatory value.

4) Outliers and Influential Observations: There are times when several of the observations in the historical input dataset may be in error (ex: billing error) and have an undue influence on the outcome. An analysis of the residuals as well as statistical tests are used to determine this (statistical tests include R-Student and Cook's D). Outliers are corrected if possible or assigned a categorical 0 or 1 to exclude them from the model if they cannot be corrected.

5) Autocorrelation: Since energy usage is a time-series, the residuals may not be independent of time and can be autocorrelated, meaning the residuals can be correlated with prior observations of themselves, which can distort results. The Durbin-Watson statistic is used to test for autocorrelation (values of 2.0 indicate no influence, while values less than 1.6 or greater than 2.4 indicate possible autocorrelation). Autocorrelation is corrected with an autoregressive error model.

6) Additional Analysis: Additional analysis is done to ensure goodness of fit and the robustness of the model including a residual analysis, testing for heteroscedasticity, normality, and multicollinearity.

7) Reasonable Results: Is the resulting forecast reasonable? Is the forecast similar to historical trends? For example, if the residential customer counts have been growing annually at 0.5% per year over the last five years it would be expected, barring any significant changes in the economy or other explanatory variables, to continue to grow similarly over the next few years of the forecast. Major departures from historical trends require an explanation (for example a change in economic outlook or other facto

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PUC 4-2

Request:

For each of the factors/charges listed below, please respond to the following questions regarding kW demand forecasting:

a. How does National Grid develop the kW demand forecast (for the upcoming rate period) used in setting that factor/charge? Please describe the forecast methodology and what specific billing data is used.

b. When does National Grid develop the kW demand forecast in relation to filing the proposed factor/charge with the Commission?

c. How does National Grid incorporate reductions from behind-the-meter net metering facilities in its kW demand forecast for the factor/charge in question? What specific data does Grid utilize?

Please respond to questions 4-2(a) – 4-2(c) for the following factors/charges:

i. Base Distribution charge (per-kW charge)

ii. CapEx Factor Charge (per-kW charge)

iii. Base Transmission Charge (per-kW charge)

Response:

For each of the factors/charges described below, the Company develops the forecasted kW demand for the relevant rate period as follows:

a. The Company develops the forecasted kW demand using the following steps: First, an "Hours Use" calculation is performed for each rate class that is billed by a demand metric, using the most recently available actual annual kWh billed, divided by billed annual kW demand. For example:

1,958,668,481 kWh billed annually/ 5,572,650 kW billed annually = 351 Hours Use

Next, the forecasted kWh for the rate period is divided by the Calculated Hours Use to determine a forecasted kW Demand. For example:

1,939,578,858 kWh forecasted per rate period/351 Hours Use = 5,518,338 forecasted kW demand per rate period

i. Base Distribution charge (per-kW charge) – to determine the Hours Use, the Company uses billed distribution kWh delivery and kW demand charges during the Test Year.

ii. CapEx Factor Charge (per-kW charge) – to determine the Hours Use, the Company uses billed CapEx kWh delivery and kW demand charges for the most recent 12-month period available at the time of the proposed ISR Plan Rate filing.

iii. Base Transmission Charge (per-kW charge) - to determine the Hours Use, the Company uses billed Transmission kWh delivery and kW demand charges for the most recent completed calendar year available at the time of Annual Retail Rate Filing.

b. When does National Grid develop the kW demand forecast in relation to filing the proposed factor/charge with the Commission?

i. Base Distribution charge (per-kW charge) – the Company calculates the forecasted Base Distribution demand during the months leading up to a General Rate Case filing with the Commission. The kWh forecast used in the calculation is developed annually, usually in the fall, by the Company's Economics and Load Forecasting organization.

ii. CapEx Factor Charge (per-kW charge) – the Company calculates the forecasted CapEx demand during the weeks leading up to the Annual Infrastructure, Safety, and Reliability Plan filing with the Commission, due no later than December 31. The kWh forecast used in the calculation is developed annually, usually in the fall, by the Company's Economics and Load Forecasting organization.

iii. Base Transmission Charge (per-kW charge) - the Company calculates the forecasted Base Transmission Charge demand during the weeks leading up to the Annual Electric Retail Rate filing with the Commission, due no later than February 15. The kWh forecast used in the calculation is developed annually, usually in the fall, by the Company's Economics and Load Forecasting organization.

c. The Company uses actual metered and billed load data when calculating the Hours Use per rate class, as described in part a. One of the impacts of behind-the-meter generation is a reduction in overall system load. As a result, metered loads already reflect the impacts of distributed generation, including behind-the-meter net metering generation. Additionally, the forecast that is developed annually by the Company's Economics and Load Forecasting organization includes anticipated reductions in load related to forecasted distributed generation.

i. Base Distribution charge (per-kW charge) – no additional data related to actual or forecast load reduction is used in the development of the kW Demand forecast.

ii. CapEx Factor Charge (per-kW charge) – no additional data related to actual or forecast load reduction is used in the development of the kW Demand forecast.

iii. Base Transmission Charge (per-kW charge) – no additional data related to actual or forecast load reduction is used in the development of the kW Demand forecast.

PUC 4-3

Request:

National Grid publishes class-average hourly 8760 load data (referred to as "class average load shapes") on its Wholesale Energy Supply Extranet webpage (link: https://www9.nationalgridus.com/energysupply/load_estimate.asp). Referencing these class average load shapes, please explain the following:

a. How does National Grid construct class average load shapes for customer classes that do not have interval metering? What real customer data is utilized?

b. How often does National Grid calculate a new class average load shape for each of its customer classes? If so, what does this "updating" process entail?

c. Specifically, how does National Grid account for behind-the-meter net metering capacity in developing its class average load shapes? What data on behind-the-meter net metering capacity does National Grid use, if any? If the process is different among customer rate classes, please specify.

d. What is the relationship, if any, between the process with which National Grid develops its class average load shapes and the analysis of "load research sample data" (linking kW demand to monthly kWh usage) that it presented in Docket No. 4568?

Response:

a. National Grid's approach is to construct class average loads shapes using interval data analysis for stratified samples of each customer class.

b. Our process involves developing new class average load shapes on a monthly basis, with website updates every six months.

c. Our process does not account for behind-the-meter net metering capacity.

d. The process which National Grid used for Docket No. 4568 is consistent with what is described here.

Prepared by or under the supervision of: John Maupin

PUC 4-4

Request:

At present, can a customer receive monthly bill credits from a behind-the-meter net metering facility and a remote net metering facility simultaneously?

Response:

Yes, as long as the combined value of credits from the behind-the-meter facility and the remote net metering facility do not exceed the customer's annual electric usage.

Prepared by or under the supervision of: Timothy Roughan

PUC 4-5

Request:

National Grid publishes its Method for Estimating ICAP for ISO-NE Reporting online, in which it details the variables that underlie the ICAP tag estimation methodology for different rate classes. Regarding this methodology, please explain the following:

a. NLD Adjustment Factor is defined as = Unaccounted for energy and losses factor. It is used to reconcile the estimates to National Grid's total demands by Load Zone at the time of the ISO-NE peak (i.e. target/actual).

   i. Please explain what this means.

b. Confirm the value of the distribution line loss factor used in estimating customer ICAP tags. If the value is different across customer classes, please specify.

c. In addition to a distribution line loss factor, does National Grid also use a transmission loss factor in estimating customer ICAP tags? If yes, what is the value of the transmission line loss factor? If the value is different across customer classes, please specify.

d. What is the value of the "NLD Adjustment Factor" used in estimating customer ICAP tags? How does National Grid calculate the NLD Adjustment Factor?

e. For rate classes without interval data, National Grid utilizes a "class average peak kW" value in calculating ICAP tags. What specifically does "class average peak kW" refer to? How does Grid calculate it for each class, using what billing data?

f. For each SOS Group, please list each rate class contained in the Group and specify whether National Grid has the necessary interval data to calculate individual customers' ICAP tags for that class.

g. For any SOS Group in which National Grid has the necessary interval data to calculate individual ICAP tags for *at least one* of the member rate classes, please clarify which ICAP estimation methodology National Grid utilizes for the Group *as a whole* (calculating individual customers' ICAP tags vs. using "class average peak kW" data to estimate the Group's ICAP tag).

Response:

Prepared by or under the supervision of: John Maupin

a.

i. ISO-NE calculates the wholesale load for each zone at the time of the annual peak. After adding up all of the National Grid retail meters in each load zone and applying distribution loss factors, there is always a remaining discrepancy between the zone total as calculated by National Grid's retail meters versus ISO-NE's wholesale load calculation. The NLD Adjustment Factor is used to reconcile the retail load zone totals with the ISO-NE load zone totals.

b. Industrial customers receive a distribution loss adjustment factor of 1.038, and all other customers receive a distribution loss adjustment factor of 1.069.

Customer Class	Rate Class	Distribution Losses
Residential	A-16	1.069
Residential	A-60	1.069
Commercial	C-06	1.069
Commercial	G-02	1.069
Commercial	Streetlighting	1.069
Industrial	B-32 / G-32	1.038

c. ISO-NE provides transmission losses every day to National Grid based on its own calculation. National Grid does not include these when calculating ICAP tags. Per ISO-NE ICAP manual M-20, Attachment C, section 1.a, "The customer's contribution to peak load shall reflect the hourly integrated electric consumption, on the peak day and hour as specified by ISO, adjusted for losses and unaccounted for energy below the PTF." Because ISO-NE specifies to reflect only load below the PTF, National Grid's ICAP calculations do not include transmission losses as a part of the load that it submits. Additionally, the Open Access Transmission Tariff, section II.15.3 states that "[r]eal power losses are associated with all transmission service. Neither the ISO nor the Transmission Owners nor the Schedule 20A Service Providers are obligated to provide real power losses. The cost of PTF losses shall be recovered through the Loss Component of the Locational Marginal Prices provided for in ISO New England Operating Documents."

d. Please see the responses to part a.i., above. National Grid calculates the NLD Adjustment Factor by taking the ratio of the ISO-NE's wholesale load in a zone, over the load in a zone as calculated by National Grid's retail meters, after adjusting for distribution losses. Below is an illustration of the formula.

$$NLD\ ADJ\ Factor = \frac{ISO - NE\ Zone\ Total\ at\ Peak}{\sum(retail\ meter\ load * distribution\ loss\ factor)}$$

e. "Class Average Peak kW" refers to the average peak demand for customers within a given rate class. The class average is calculated by grouping all non-interval metered customers into their respective rate classes and then taking the average demand across all customers within each rate class at the time of the peak.

f. National Grid has three SOS customer classes: Residential, Commercial, and Industrial. National Grid's retail delivery rates within these SOS classes are as follows:

   Residential – (A-16, A-60)
   Commercial – (C-06, G-02, S-05, S-06, S-10, S-14)
   Industrial – (B-32, G-32, X-01)

   In all retail delivery rate classes, the Company uses interval data to calculate individual customer ICAP tags where available; if not, the Company uses load shaped estimated data, instead.

g. The Company uses interval meter data to calculate a customer's ICAP tag, where available. If interval meter data is not available, then the Company uses load shaped estimated data, instead.

Prepared by or under the supervision of: John Maupin

PUC 4-6

Request:

Since removing capacity from its Full Requirements Services contracts with SOS Suppliers (Docket No. 4809), National Grid is assessed capacity charges directly by ISO-NE on behalf of each SOS Group. It then collects the cost of its assessed capacity charge(s) from customers through SOS rates. Please explain the following:

a. When, and how frequently, is National Grid assessed capacity charge(s) by ISO-NE for each SOS Group? If the timing of assessment is different across customer classes, please specify.

b. Please describe the ratemaking process through which National Grid "unitizes" the fixed capacity charges assessed to it by ISO-NE into a volumetric ($/kWh) rate that gets incorporated into its base SOS rate. To support your response, please provide a numeric example of this "unitization" for a SOS Group with a fixed SOS rate and a separate example for a SOS Group with a variable SOS rate.

Response:

a. ISO-NE directly assesses capacity charges to National Grid only for the 10% of residential and commercial load it procures in the spot market. Capacity charges for the residential and commercial customers are combined and invoiced at the same time. There are two capacity charges assessed to National Grid: initial and reconciled. The initial capacity charge is invoiced on the first Monday after the ninth day of the month following the obligation month. For example, on July 13th National Grid was invoiced for June's initial capacity charge. The reconciled capacity charge is invoiced on the Data Reconciliation Process Bill Date as specified on the ISO-NE's Metering and Resettlement Deadlines Calendar. For example, on July 13th National Grid was invoiced for February's reconciled capacity charge.

Full Requirement Services suppliers continue to be invoiced directly by the ISO-NE for the load of the bid blocks they serve and pass through the capacity costs to National Grid. The suppliers provide invoices to National Grid for capacity charges on or before the later of (i) the tenth day after the obligation month, and (ii) two business days after the receipt from the ISO-NE of the applicable settlement reports related to capacity charges for the obligation month.

Prepared by or under the supervision of: James Ruebenacker

b. National Grid first estimates for each customer group the Customer Capacity Load Obligation Charge for each month by estimating the various inputs in the ISO-NE capacity settlement calculation. National Grid unitizes the estimated fixed capacity charges into a volumetric ($/MWH) rate by dividing the Customer Capacity Load Obligation Charge for each customer group for each month by each group's wholesale monthly load forecast. This capacity rate is added to the $/MWH SOS bid rate (and estimate of spot market if applicable) and then adjusted by a line loss factor to create the SOS Base Rate for a month.

Below is an example of a fixed and variable (monthly) SOS Base Rate for the Commercial Group.

	October	November	December	January	February	March
Est. Capacity Costs ($)	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000
Est. MWH	75,000	80,000	90,000	95,000	80,000	85,000
Capacity Rate ($ / MWH)	33.33	31.25	27.78	26.32	31.25	29.41
SOS Bids and Spot Market ($/MWH)	30.00	40.00	60.00	70.00	70.00	50.00
Total Rate ($ / MWH)	63.33	71.25	87.78	96.32	101.25	79.41
Loss Factor	1.10	1.10	1.10	1.10	1.10	1.10
Variable SOS Base Rate (cents / kWh)	6.966	7.837	9.655	10.594	11.137	8.735
Fixed SOS Base Rate (cents / kWh)						9.224

PUC 4-7

Request:

Assuming a constant net regional clearing price and constant capacity load obligations among all other consumers in ISO-NE, please describe National Grid's understanding of when and how a given unit of customer load reduction on its distribution system (coincident with the ISO-NE system peak) would impact the capacity portion of SOS rates for customers?

Response:

Customer load reduction on the Company's distribution system coincident with the ISO-NE system peak, assuming a constant Net Regional Clearing Price and constant capacity load obligations among all other consumers in ISO-NE, results in a decrease in the Customer Capacity Load Obligation in future capacity commitment periods, which lowers the Customer Capacity Load Obligation (CLO) Charges. However, any reduced CLO Charges, as a result of a lower load, will either be shifted to the remaining ISO-NE load or will impact the Net Regional Clearing Price due to the various Reconfiguration Auctions.

Several of the inputs used to determine the Customer Capacity Load Obligation will be impacted by customer load reductions. The Customer Capacity Load Obligation is multiplied by the Net Regional Clearing Price to determine the Customer CLO Charge for a given month. The impacted inputs are:

- Customer Average Peak Contribution,
- Capacity Zone Peak Contribution, and
- Pool Peak Contribution.

The timing of the impacts to SOS rates varies with the inputs. A customer load reduction in a given year will impact:

- the Customer Average Peak Contribution in the first capacity commitment period following the given year,
- the Capacity Zone Peak Contribution in the first and second capacity commitment periods following the given year, and
- the Pool Peak Contribution in the second capacity commitment period following the given year.

Below is an example of the timing of customer load reduction in 2020 on future capacity commitment periods:

	Capacity Commitment Period	
	June 2021 - May 2022	June 2022 - May 2023
Customer Average Peak Contribution	X	
Capacity Zone Peak Contribution	X	X
Pool Peak Contribution		X

PUC 4-8

Request:

In setting its SOS Administrative Cost Factor, National Grid allocates its estimate of "other administrative expenses" (for the upcoming rate year) among SOS Groups based on each Group's share of actual SOS revenue during the most recent calendar year. Please clarify whether this cost allocation is based on each Group's share of *total* SOS revenue (SOS base revenue + adjustment factor revenue + administrative cost factor revenue + RES revenue) or on their share of SOS *base* revenue.

Response:

In its Annual Calculation of Standard Offer Service Administrative Cost Factor, included as part of the Annual Electric Retail Rate Filing, the Company includes three cost components for recovery:

1) Estimated Commodity Related Uncollectible Expense for the upcoming calendar year
2) Estimated Other Administrative Expense for the upcoming calendar year
3) Refund or recovery of over-or-under recovered administrative costs incurred in the existing calendar year.

The three components of Other Administrative Expenses are shown in Attachment PUC 4-8, Page 1.

Estimated GIS Cost is based on the current calendar year GIS expense as billed by the ISO-NE, allocated amongst the Residential, Commercial, and Industrial rate groups based on each group's share of invoiced Standard Offer Service Base expense.

Estimated Cash Working Capital Impact is based on the Cash Working Capital Analysis provided annually in the Retail Rate Filing in a separate schedule, allocated amongst the Residential, Commercial, and Industrial rate groups based on Billed Standard Offer Service Base revenue per rate group.

> Estimated Other Administrative costs (2) are based on current calendar year other administrative expenses, such as direct labor expense incurred in the administration of Standard Offer Service, allocated amongst the Residential, Commercial, and Industrial rate groups based on each group's share of invoiced Standard Offer Service Base expense.

Prepared by or under the supervision of: Adam S. Crary

Estimated Commodity Related Uncollectible Expense (1) for the upcoming calendar year is developed as shown in Attachment PUC 4-8, Page 2.

First, forecasted revenue per rate class is estimated by multiplying forecasted Standard Offer Service kWh in Column (a) by an estimated Standard Offer Rate in Column (b). The estimated Standard Offer Rate consists of:

1) The currently proposed Base Standard Offer rate (when available), or the equivalent rate in the prior year as a proxy when not available
2) The currently proposed Standard Offer Service Adjustment Factor
3) The currently effective Renewable Energy Standard Charge

The sum total of estimated standard offer revenue, per rate group, is then multiplied by the approved Uncollectible Rate, which results in the Estimate Commodity Related Uncollectible Expense.

The Narragansett Electric Company
CALCULATION OF STANDARD OFFER SERVICE ADMINISTRATIVE COST FACTOR
For the Period April 1, 2020 through March 31, 2021

		Total (a)	Residential (b)	Commercial (c)	Industrial (d)
(1)	Estimated GIS Cost	$32,040	$21,846	$7,953	$2,241
(2)	Estimated CWC	$3,315,864	$2,301,210	$799,123	$215,531
(3)	Estimate of Other Administrative Costs	$364,871	$244,134	$93,941	$26,796
(4)	Total Other Administrative Expenses	$3,712,775	$2,567,190	$901,017	$244,568

(1) Schedule REP-5, Pages 6 through 8, Column (g), Line (14)
(2) Schedule REP-6, Page 1, Lines (15), (14), and (13)
(3) Schedule REP-5, Pages 6 through 8, Column (i), Line (14)
(4) Line (1) + Line (2) + Line (3)

The Narragansett Electric Company
CALCULATION OF STANDARD OFFER SERVICE ADMINISTRATIVE COST FACTOR
For the Period April 1, 2020 through March 31, 2021

Section 1: Estimated Commodity Cost/Revenue for April 1, 2020 through March 31, 2021

		Residential Customer Group			Commercial Customer Group			Industrial Customer Group			Total Estimated
		Estimated SO kWhs	Estimated SO Rate	Estimated SO Cost/Rev	Estimated SO kWhs	Estimated SO Rate	Estimated SO Cost/Rev	Estimated SO kWhs	Estimated SO Rate	Estimated SO Cost/Rev	SO Cost/Revenue
		(a)	(b)	(c)=(a) x (b)	(d)	(e)	(f)=(d) x (e)	(g)	(h)	(i)=(g) x (h)	(j)= (c) + (f) + (i)
(1)	Apr-2020	205,973,456	$0.07266	$14,966,031	80,436,589	$0.06737	$5,419,013	35,744,645	$0.08965	$3,204,507	$23,589,551
(2)	May-2020	170,185,706	$0.07266	$12,365,693	74,748,906	$0.06737	$5,035,834	33,874,409	$0.06760	$2,289,910	$19,691,437
(3)	Jun-2020	191,679,390	$0.07266	$13,927,424	77,523,501	$0.06737	$5,222,758	34,964,233	$0.06009	$2,101,001	$21,251,183
(4)	Jul-2020	273,786,617	$0.07266	$19,893,336	92,993,625	$0.06737	$6,264,981	41,190,543	$0.07252	$2,987,138	$29,145,455
(5)	Aug-2020	276,476,071	$0.07266	$20,088,751	91,063,920	$0.06737	$6,134,976	40,453,613	$0.06743	$2,727,787	$28,951,514
(6)	Sep-2020	247,953,227	$0.07266	$18,016,281	87,931,335	$0.06737	$5,923,934	38,933,678	$0.07457	$2,903,284	$26,843,499
(7)	Oct-2020	181,219,789	$0.07266	$13,167,430	82,988,444	$0.06737	$5,590,931	36,794,582	$0.08011	$2,947,614	$21,705,975
(8)	Nov-2020	179,552,090	$0.07266	$13,046,255	80,016,854	$0.06737	$5,390,735	35,383,254	$0.08337	$2,949,902	$21,386,892
(9)	Dec-2020	218,603,831	$0.07266	$15,883,754	85,135,571	$0.06737	$5,735,583	37,149,954	$0.09995	$3,713,138	$25,332,475
(10)	Jan-2021	249,321,934	$0.07266	$18,115,732	88,466,120	$0.06737	$5,959,963	38,114,273	$0.12497	$4,763,141	$28,838,836
(11)	Feb-2021	227,648,420	$0.07266	$16,540,934	82,593,461	$0.06737	$5,564,321	35,955,623	$0.12381	$4,451,666	$26,556,921
(12)	Mar-2021	212,574,194	$0.07266	$15,445,641	78,046,093	$0.06737	$5,257,965	34,391,369	$0.09828	$3,379,984	$24,083,590
(13)	Total	2,634,974,725		$191,457,262	1,001,944,419		$67,500,994	442,950,176		$38,419,072	$297,377,328

Section 2: Estimated Commodity-Related Uncollectible Expense for April 1, 2019 through March 31, 2020

(14)	Estimated Rate Year Cost/Revenue	$191,457,262	$67,500,994	$38,419,072	
(15)	Uncollectible Rate	1.30%	1.30%	1.30%	
(16)	Rate Year Commodity-Related	$2,488,944	$877,513	$499,448	$3,865,905

Section 1:
Columns (a), (d) and (g), Lines (1) through (12) = Schedule REP-3, Page 2
Column (b): the sum of the proposed April 1, 2020 base Standard Offer rate of 7.497¢ (Docket No. 4935, filed January 15, 2020, Attachment 1, Page 3, Line (11), Column (g)), the current 2019 RES rate of 0.063¢, and the proposed SOS Adjustment charge of (0.294¢)
Column (e): the sum of the proposed April 1, 2020 base Standard Offer rate of 6.580¢ (Docket No. 4935, filed January 15, 2020, Attachment 1, Page 4, Line (10), Column (g)), the current 2019 RES rate of 0.063¢, and the proposed SOS Adjustment charge of 0.094¢
Column (h): the sum of the proposed April 1, 2020 through June 30, 2020 base Standard Offer rates (Docket No. 4935, filed January 15, 2020, Attachment 1, Page 6, Line (1)), the current 2019 RES rate of 0.063¢, and the proposed SOS Adjustment charge of 0.381¢. The July-2020 through Mar-2021 estimated SOS Base charges are based on the actual July-2019 through Mar-2020 SOS base charges

Section 2:
(14) Line (13)
(15) Uncollectible rate approved in Docket No. 4770
(16) Line (14) x Line (15)

PUC 4-9

Request:

National Grid reconciles real SOS expenses against actual SOS revenue through its Standard Offer Service Adjustment Factor. When Grid queries its company records to measure the actual billed SOS revenue for the reconciling year, what SOS rate is it using: the total Standard Offer Service rate (SOS base rate + SOS adjustment factor + SOS administrative cost factor + RES rate), or the SOS base rate?

Response:

In the annual Standard Offer Service Reconciliation, Base Reconciliation - All Classes, the Company reconciles SOS expenses against SOS Base Revenues, which do not include revenues associated with SOS Adjustment Factor, SOS Administrative Cost Factor, or Renewable Energy Standard Charge.

PUC 4-10

Request:

National Grid reconciles its real O&M and CapEx expenses in a given rate year against actual billed O&M and CapEx revenues through its O&M reconciliation and CapEx reconciliation factors. When setting both reconciliation factors, National Grid queries its company records to measure the actual billed O&M and CapEx revenues for the reconciling year, the product of actual kWh sales and the relevant O&M and CapEx charges. Please clarify whether the charges against which actual O&M and CapEx revenues are "measured" contain just the base O&M and CapEx charges, or the sum of the base charges plus their respective reconciliation factors.

Response:

In its annual Electric Infrastructure, Safety, and Reliability Plan Reconciliation filing, the Company reconciles the actual Fiscal Year O&M and CapEx revenue requirement against billed revenue reflective of only base O&M and CapEx charges.

Prepared by or under the supervision of: Adam S. Crary

PUC 4-11

Request:

Regarding National Grid's Storm Fund, please answer the following questions:

a. Using the most up-to-date cost estimates, what is the incremental Operations and Maintenance cost of a severe storm in Rhode Island (the likes of which would be funded through the Storm Fund)? Please specify the assumptions and data that underly the estimate.

b. Since Super Storm Sandy, how has the incremental Operations and Maintenance cost of severe storms in Rhode Island changed, if at all?

c. Does National Grid project storm costs for each fiscal year? If so, please provide the internal projects for the past three fiscal years along with the actual costs charged against the fund for each of those years.

Response:

The Company interprets this question to be inquiring about the estimated costs included in storm deficiency amounts that the Company reports to the PUC, such as the $112,629,156 storm cost deficit reported in the Company's Final Storm Cost Accounting filing for February 2017 to October 2017 Storm Events, which it filed on June 25, 2020 on Schedule 2-D, Page 1, column j of that filing.

a. The significant incremental O&M costs of a storm fund qualifying weather event include incremental labor and incremental labor overhead costs and the costs of third-party overhead line vendors, third party forestry contractors, and the costs of other regulated utilities from around the U.S. and Canada who provide mutual aid storm restoration assistance. Incremental costs also include purchases made by certain Company personnel who utilize purchasing cards, referred to as P-cards, that are credit cards used to pay for meals, lodging and other miscellaneous costs. Less significant incremental O&M costs include materials and supplies costs, transportation costs and employee expenses. Incremental labor costs include Overtime from Direct Company's employees and all labor from Service Company and National Grid Affiliates. Incremental labor overhead costs are FAS 112, Payroll Taxes, Health Insurance, Group Life Insurance, 401k Thrift Plan, Variable Pay, Time Not Worked, and Workers Comp. These costs include the labor-related overheads associated with payroll of personnel who performed storm-related work and are employed by the Company's affiliates, which directly benefits the Company. However, National Grid will make an adjustment to charges to the

Storm Fund to remove base labor overheads of National Grid USA Service Company, Inc. employees to the extent those charges are already being recovered through Narragansett's Electric's base distribution rates (See Docket No. 4686). More complete descriptions for each type of incremental storm costs are provided in the filings the Company makes with the PUC of its final accounting of storm fund qualifying weather events.

The Company primarily only estimates the costs of un-invoiced storm restoration services of third-party contractors and mutual aid utilities. Incremental labor and labor overhead costs are entered into the Company's accounting system in the period that the costs are incurred and are effectively known when incurred (i.e., they are not estimates). P-card charges, which as described above are credit card charges, are also known by the end of the next credit card billing cycle and are known, actual charges at that time (i.e. are not estimates). Estimates are temporary only until actual invoices are received from the third-party contractors and mutual aid utilities. It may take several months after a major storm event occurs for the Company to receive all invoices from third-party contractors and mutual aid utilities for that storm.

The Company recovers an allowance in rates that is ultimately reconciled to actual costs incurred. Customers will never pay more than actual costs incurred. The Company recently reported an estimated storm deficit of $112.6 million in a June 25, 2020 final cost accounting of qualifying storm events that occurred in calendar year 2017 in Docket No. 2509. This deficit represents storm restoration costs incurred, in excess of amounts recovered from customers. However, if the Company were to recover from customers more than the amount of actual storm costs incurred (i.e., if the storm fund were in a surplus position rather than a deficit), any amount of storm fund recoveries in excess of actual costs incurred would be reserved on the Company's books to be used to pay for future storms, and would accrue interest to the benefit of customers. In the end, customers never pay for estimated storm restoration costs and they pay (or receive) interest only on the actual amount of costs charged to the storm fund and never pay (or receive) interest on estimated costs.

b. Incremental costs have not changed since Super Storm Sandy.

c. As described in part a. above, the Company primarily only estimates the costs of un-invoiced storm restoration services of third-party contractors and mutual aid utilities. All other costs are substantially known by the end of the month following a major storm event. All costs are subject to an internal review to determine the appropriateness of the charges to the storm fund, so there may be adjustments to actual incurred costs as part of that process.

Prepared by or under the supervision of: Jeff Oliveira

PUC 4-12

Request:

To allocate its estimated transmission expenses among individual rate classes for an upcoming transmission rate period, National Grid develops class-specific Coincident Peak Allocators based on each class' load factor at the time of coincident peak demand. Referencing Schedule REP-11 (page 2) in the 2020 Retail Rate Filing (Docket No. 5005), please explain the following:

a. How does National Grid calculate the "Class 12CP (coincident peak)" value? What billing data does it use?

b. Does the 12CP data correspond to National Grid's system peak, the ISO-NE system peak, or something else?

c. How, if at all, does National Grid's "Class 12 CP" estimation methodology account for load reduction from behind-the-meter net metering facilities? Is that load reduction reconstituted? Please explain.

Response:

a. The formula for "Class 12 CP" for each class is as follows:

Class 12 CP = [Forecasted kWh] divided by [Average Load Factor at 12 CP] divided by 8760 (hours), where:

1. "Average Load Factor at 12 CP" is a weighted average of the three most recent rate cases; and
2. The most recent rate case (i.e., the twelve month period that ended on 6/30/2017) carries a weight of 33.4%, while the two prior rate cases carry weights of 33.3% each.

The Company uses the end-of-month closing customer counts, multiplied by the corresponding "Class Average Load Shape CP Value."

b. The 12CP demands are coincident with the Company's (i.e., The Narragansett Electric Company's) peak.

c. National Grid's estimation methodology does not apply an adjustment for load reduction from behind-the-meter net metering facilities.

Prepared by or under the supervision of: John Maupin

PUC 4-13

Request:

Please clarify the following questions regarding the "monthly PTF kW load" values that ISO-NE uses to allocate Pool Transmission Facility (PTF) costs to National Grid:

a. How does ISO-NE calculate "monthly PTF kW load" values? Please explain what system data underly these values.

b. Do the "monthly PTF kW load" values correspond to National Grid's monthly system peak, monthly system peak coincident with the ISO-NE monthly peak, or something else?

c. Is "monthly PTF kW load" adjusted for line losses? If so, please explain the adjustment methodology and provide the loss factor(s).

d. How, if at all, are "monthly PTF kW load" values adjusted for load reduction from behind-the-meter net metering facilities? Is that load reduction reconstituted? Please explain.

Response:

a. Transmission Owners, like New England Power Company ("NEP"), submit their regional network loads to ISO-NE monthly. As defined in Section II.21.2 of the ISO-NE Open Access Transmission Tariff ("OATT"), a network customer's "Monthly Regional Network Load" is its hourly load (including its designated Regional Network Load not physically interconnected with the PTF under Section II.18.3 of this OATT) with the coincident aggregate load of all network customers served in each Local Network in the hour in which the coincident load is at its maximum for the month (Monthly Peak).

b. National Grid reports Regional Network Load ("RNL") asset data to ISO-NE from each asset's associated metered data at the time of National Grid's monthly system peak.

c. The network customer, and by extension ISO-NE, is responsible for allocating PTF line losses as depicted in Section 19 of Schedule 21 - NEP tariff: "Real Power Losses are associated with all Transmission Service. NEP is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all Transmission Service as calculated by NEP." Additionally, "Determination of losses across NEP's PTF system will be according to the procedure set by the ISO. In cases where the ISO or the Tariff does not allocate PTF losses, PTF losses will be assigned at 3%."

Prepared by or under the supervision of: Michael V. Artuso

d. In Schedule 21 - NEP, there are no adjustments made to monthly PTF kW load values due to the load reduction effect of net metering. Behind-the-meter net metering generation is not reconstituted into Schedule 21 - NEP.

PUC 4-14

Request:

Has National Grid ever developed a forecast or utilized an existing forecast of Regional Network Service (RNS) rates ($/kW-yr) for purposes of transmission ratemaking? If yes, please provide a copy of the RNS/PTF forecast(s).

Response:

The Narragansett Electric Company ("Company") d/b/a National Grid annually utilizes a forecast of the Regional Network Service ("RNS") rate to calculate estimated PTF Demand charges to the Company as part of the Annual Retail Rate Filing ("ARRF") submitted to the Commission. The estimated PTF Demand Charges are a component of the total transmission expenses forecasted to be charged to the Company which is used to calculate the base Transmission Service Charge for the period April 1 through March 31 of each rate year. The forecasted RNS rate is based on the forecasted PTF additions across New England, as estimated by the New England transmission owners, to be included in the annual formula rate.

The 2020 ARRF was submitted to the Commission in RIPUC Docket No. 5005. Please reference Attachment PUC 4-14-1 for the calculation of the estimated RNS rate included in Schedule MVA-3 of the ARRF.

Prepared by or under the supervision of: Michael V. Artuso

Schedule MVA-3

PTF Rate Calculation Estimated for the Year 2020

New England Power Company
PTF Rate Calculation
Estimated for the Year 2020

Ln #			
	Development of Estimated PTF Rate:		
1	Total Regional Network Service Rate through May 31, 2020	$111.94	/KW-YR
	ESTIMATED Increase in ISO Rate Effective June 1, 2020		
2	Total ESTIMATED PTO Plant Additions	$ 1,076,000,000	
3	Estimated Carrying Charge	13.75%	
4	/ 2018 ISO Network Load	19,542,342	
5	Additional Estimated ISO Regional Network Service Rate	$7.57	/KW-YR
6	Regional Network Service Rate in effect June 1, 2020 through May 31, 2021	$119.51	/KW-YR

Line 1 = ISO-NE Section II Open Access Transmission Tariff Rates Posting June 17, 2019
Line 2 = PTO Forecast RWG Presentation July 16-17, 2019 = Forecasted Plant Additions 2020
Line 3 = PTO Forecast RWG Presentation July 16-17, 2019 = Forecasted Revenue Requirement 2020 / Line 2
Line 4 = PTO Supplemental Filing to June 14, 2019 Informational Filing dated July 31, 2019 (Docket RT04-2-000 et al.)
Line 5 = Line 2 * Line 3 / Line 4
Line 6 = Line 1 + Line 5

PUC 4-15

Request:

For customer classes G02, G32, and B32, National Grid recovers transmission expenses through both kWh and kW charges. In setting the kW transmission charge for these classes, National Grid must forecast the class' kW demand for the forthcoming rate period. Referencing page 1 of Schedule REP-11 in Docket No. 5005, please explain the following:

a. Do the "forecast kW" (line 7) estimates used here for transmission ratemaking purposes represent the same values as the billing demand estimates used in setting per-kW distribution charges?

b. What is the relationship between these "forecast kW" (i.e., the demand values used in transmission ratemaking) and the 12-month total "monthly PTF kW load" in column 1, line 13 of Schedule MVA-2 (i.e., the demand values used in PTF transmission cost allocation)? Conceptually, should the "forecast kW" for a given calendar year (across all of National Grid's rate classes, not just those classes from whom transmission expenses get recovered via kW charge) equal the sum of the 12-month total "monthly PTF kW load" values for that year? Please explain.

Response:

a. Please see the Company's response to PUC 4-2(a), section iii, for a description of how the company forecasts Transmission Demand for the upcoming annual rate period, which runs from April 1 through March 31.

Please see the Company's response to PUC 4-2(a), section i, for a description of how the company forecasts Base Distribution Demand for the Rate Years included in a General Rate case.

b. "Forecast kW 2020" on line 7 page 1 of Schedule REP-11 will not equal the "monthly PTF KW load" sum on line 13 page 1 of Schedule MVA-2 due to the different calculation methodology used of each item.

"Monthly PTF kW load" on page 1 of Schedule MVA-2 is collected by ISO-NE when Transmission Owners submit their regional network loads. As defined in Section II.21.2 of the ISO-NE OATT, a "Network Customer's "Monthly Regional Network Load is its hourly load (including its designated Regional Network Load not physically interconnected with the PTF under Section II.18.3 of this OATT) with the coincident aggregate load of all Network Customers served in each Local Network in the hour in which the coincident load is at its maximum for the month ("Monthly Peak").

"Forecast kW 2020" is calculated by National Grid's Economics and Load Forecasting organization based on per-kW charge, as detailed in the Company's response to PUC 4-2.