The Narragansett Electric Company

d/b/a National Grid

INVESTIGATION AS TO THE PROPRIETY OF PROPOSED TARIFF CHANGES

Rebuttal
Testimony and Schedules of:

Depreciation - Ned W. Allis
Electric Sales Forecast - Joseph F. Gredder
Gas Sales Forecast - Theodore E. Poe, Jr.
IS - John Gilbert, Daniel J. DeMauro, Mukund Ravipaty
GBE - Anthony Johnston, Christopher J. Connolly
OPEX - Raymond J. Rosario, Jr., Alfred Amaral III,
Ryan M. Constable
HR - Maureen P. Heaphy
Revenue Requirement - Melissa A. Little

Book 2 of 7

May 9, 2018

Submitted to:
Rhode Island Public Utilities Commission
RIPUC Docket No. 4770

Submitted by:

REBUTTAL TESTIMONY

OF

NED W. ALLIS

Dated: May 9, 2018

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I. Introduction

Q. Please state your name and address.

A. My name is Ned W. Allis. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania 17011.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes. On November 27, 2017, I submitted direct testimony in this proceeding in support of the depreciation studies performed for The Narragansett Electric Company's[1] electric plant and gas plant (collectively, the Depreciation Studies).

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of Roxie McCullar submitted on behalf of the Division of Public Utilities and Carriers (Division). Specifically, I will address the three accounts (two gas accounts and one electric account) for which Ms. McCullar has recommended different depreciation rates from my estimates, and I will detail the problems with the net salvage analyses Ms. McCullar used to arrive at her recommendations.

Q. What is the impact of Ms. McCullar's recommendations?

A. To help provide context for the impact of Ms. McCullar's recommendations, I would first like to summarize the results of my Depreciation Studies. In the Depreciation Studies I

[1] The Narragansett Electric Company d/b/a National Grid constitutes the regulated operations that National Grid USA conducts in Rhode Island. In this case, I will refer to the regulated entity as the "Company," where the reference is to both gas and electric distribution operations on a collective basis. Where there is a need to refer to the "stand-alone" or individual electric or gas operations of The Narragansett Electric Company, I will use the terms "Narragansett Electric" or "Narragansett Gas," respectively, as appropriate.

performed, I have recommended a net decrease in depreciation expense for both gas plant and electric distribution and general plant.[2] Specifically, the recommended depreciation rates for gas plant result in a net decrease in depreciation expense of $71,463 as of December 31, 2016. The recommended depreciation rates for electric distribution and general plant accounts result in a net decrease in depreciation expense of approximately $706,651 as of December 31, 2016. Thus, the recommendations I have made in the depreciation studies do not directly contribute to increases in customer rates in this proceeding, and instead result in a moderate reduction to the Company's revenue requirement request.

Ms. McCullar has proposed adjustments for two gas plant accounts and one electric plant account.[3] In total, Ms. McCullar's recommendations reduce gas plant depreciation by an additional $3,359,289 and reduce electric plant depreciation by an additional $1,512,286 beyond my recommendations in the Depreciation Studies. Each of Ms. McCullar's adjustments is due to different proposals for the net salvage estimates for these accounts. Ms. McCullar has not challenged any of the service life estimates I have made in the depreciation studies.

As I will explain, Ms. McCullar's recommendations are not based on widely accepted

[2] Electric transmission plant is not included in this proceeding.

[3] Two of the accounts for which Ms. McCullar recommends an adjustment include multiple subaccounts. Because the net salvage estimates for each subaccount are developed at the account level, Ms. McCullar's adjustments for each of these accounts apply to each subaccount.

and properly implemented methods for estimating depreciation or estimating net salvage. Instead, Ms. McCullar has adjusted the historical net salvage data based on a methodology that has a number of mathematical and conceptual flaws and has not, to my knowledge, been accepted by any regulatory commission. As a result, the reductions to depreciation expense that she proposes are not reasonable adjustments.

Q. Are you sponsoring any schedules as part of your rebuttal testimony?

A. Yes. I am sponsoring the following schedules:

- Schedule NWA-3R – Calculation of average and future net salvage for Account 380, Services based on Table 6.11 of Wolf and Fitch and 2 percent inflation rate.
- Schedule NWA-4R – Calculation of average and future net salvage for Account 380, Services based on Table 6.11 of Wolf and Fitch and 2.5 percent inflation rate.
- Schedule NWA-5R – Calculation of average and future net salvage for Account 380, Services based on Table 6.11 of Wolf and Fitch and 3 percent inflation rate.
- Schedule NWA-6R – Calculation of average and future net salvage for Account 380, Services based on Table 6.11 of Wolf and Fitch and 4 percent inflation rate.

II. Net Salvage Estimates

Q. What is net salvage?

A. Net salvage as used in depreciation is defined as gross salvage less cost of removal. When an asset is retired, it may have scrap or reuse value, which is gross salvage. There is also a cost to retire the asset (also referred to as cost of removal). For example, the retirement of a distribution pole typically requires a multiple person crew and heavy equipment to remove the pole from the ground and cut the pole for disposal. There may also be disposal costs for the pole. All the costs associated with the retirement are cost of removal. I should note there may also be cost of removal even if an asset is not physically removed. For example, when gas mains are retired in place (i.e., they remain in the ground when retired), there are still costs to cut, cap, and purge gas from the retired main.

Q. How is net salvage estimated?

A. Net salvage is expressed as a percentage of the original cost retired. For example, if an account has a net salvage estimate of negative 50 percent, then a $1,000 asset would be expected to, on average, cost $500 to retire, net of any gross salvage. Net salvage estimates are based on a combination of statistical analysis of historical data, as well as informed judgment that incorporates other factors.

Q. How is the statistical analysis performed?

A. The traditional and widely accepted method of statistical analysis for net salvage is performed by comparing historical cost of removal and gross salvage to historical retirements as recorded in a utility's property records. For this analysis, cost of removal, gross salvage, and net salvage are expressed as a percentage of the original cost of plant retired. By analyzing both annual activity and longer and shorter-term averages of the experienced net salvage expressed as a percentage of retirements, this analysis of the data provides a statistical basis for the estimation of net salvage. This is the method of statistical analysis that I have used in the Depreciation Studies. I will refer to this method of analysis as the "traditional method of net salvage analysis" or the "traditional net salvage analysis" because it is the predominant method of net salvage analysis used for depreciation studies.

Q. Is this method of statistical analysis for net salvage that you have used in the Depreciation Studies supported by depreciation textbooks?

A. Yes. Ms. McCullar cites two depreciation textbooks in her testimony in support of her recommendations. These are the National Association of Regulatory Utility Commissioners' (NARUC) publication *Public Utility Depreciation Practices* and *Depreciation Systems* by Frank Wolf and Chester Fitch (Wolf and Fitch). Both textbooks support the method of statistical analysis I have used in the Depreciation Studies.

NARUC explains that "net salvage is expressed as a percentage of plant retired by dividing the dollars of net salvage by the dollars of original cost of plant retired."[4] Wolf and Fitch also explain that net salvage is expressed as a percentage of the original cost of plant retired, noting "the SR [Salvage Ratio] is the salvage divided by the original cost of the retirements and usually is expressed as a percentage."[5] Thus, both texts support the

[4] *Public Utility Depreciation Practices*, National Association of Regulatory Utility Commissioners, 1996, p. 18.

[5] *Depreciation Systems*, Frank Wolf and Chester Fitch, 1994, p. 261. Note that, in this context, Wolf and Fitch use

exact type of analysis I have used in the Company's Depreciation Studies.

Q. Do either of these textbooks support the net salvage analysis Ms. McCullar has performed?

A. No. Although Ms. McCullar cites to NARUC in certain instances, NARUC does not describe or support the actual type of analysis Ms. McCullar has performed. Similarly, as I will explain in more detail in Section II.C., although Ms. McCullar claims that her methodology is supported by Wolf and Fitch, she has not actually performed the analyses described in her cited portions of this text.

Q. How do Ms. McCullar's recommendations differ from yours?

A. Ms. McCullar has recommended different net salvage estimates for two gas plant accounts and one electric distribution plant account. Table 1 below summarizes the current estimates, my proposed estimates, and Ms. McCullar's estimates. The table also shows the overall average net salvage percentage from the Company's data based on the statistical analysis discussed above.

Table 1: Comparison of Net Salvage Estimates to Company Data

Account	Current Estimate	Company Data	Company Estimate	Division Estimate
368 Line Transformers	-30%	-55%	-50%	-30%
376 Mains	-65%	-76%	-70%	-50%
380 Services	-65%	-112%	-80%	-65%

the term "salvage" to mean "net salvage."

As Table 1 demonstrates, the Company's data indicates a more negative net salvage estimate than the current estimates for each of these accounts.[6] My recommendations result in net salvage estimates that are more consistent with the indications from the Company's data than the current estimates. I also note that my estimates are conservative in that they are less negative than the overall net salvage percentages in the Company's data for each of these accounts.

Q. How do Ms. McCullar's estimates compare to the Company's data?

A. For each of these accounts, Ms. McCullar's estimates are the same as or less negative than the currently approved estimates. That is, her recommendations move the net salvage estimates in the opposite direction one would expect based on the statistical analysis performed consistent with the methods described above.

Q. What is the reason Ms. McCullar's estimates are different from your estimates?

A. Based on Ms. McCullar's testimony, her estimates differ from mine due to adjustments she has made to the historical data for these three accounts. Specifically, Ms. McCullar has modified historical cost of removal and gross salvage to adjust for what she presumes to be differences between historical inflation and her estimate of what the inflation rate will be in the future. That is, the reason for the differences between my estimates and those of Ms. McCullar are the adjustments she makes to the historical data used in her

[6] The current estimates were developed at the functional level (i.e., for all of electric distribution plant instead of for each plant account), and as a result, provide a relatively limited indication of the net salvage for each specific plant account.

analyses. I am not familiar with a single regulatory jurisdiction that has adopted Ms. McCullar's approach to the net salvage analysis, and in the one instance in which her proposed method of analysis was proposed, it was rejected. This is not surprising, because her adjustments to the data suffer from flaws in her analysis that cause her results to be unreliable.

Q. Ms. McCullar also discusses other factors, such as the practice for retiring gas mains and services in place, as opposed to removing these assets from the ground when retired. Do these other factors provide justification for Ms. McCullar's net salvage estimates?

A. No. The factors Ms. McCullar discusses do not provide a reason to expect that future net salvage will be materially different from the historical net salvage included in the net salvage analyses, because the Company's future practices for retiring mains are expected to be similar to the Company's historical practices.[7] As a result, the fundamental difference between my estimates and those made by Ms. McCullar is the adjustments she has made to the historical net salvage data used for her analyses.

Q. What are the flaws in Ms. McCullar's analysis?

A. There are multiple flaws, which I will detail in the sections that follow. One flaw is that Ms. McCullar has focused only on the inflation rate and fails to recognize that the time period over which inflation occurs can have at least as much of an impact as the inflation

[7] I will address this concept in more detail in Section II.E.

rate. Further, Ms. McCullar supports her methodology for adjusting the data by citing a discussion of complex mathematical models for analyzing net salvage that are set forth in Wolf and Fitch. However, Ms. McCullar has not actually performed the analyses set forth in Wolf and Fitch that she claims to have used. Ms. McCullar's testimony fails to follow the instructions of the actual text and fails to incorporate important concepts set forth in Wolf and Fitch.

Lastly, Ms. McCullar's adjustments are based on her estimate of future inflation rates, and even relatively small changes in the estimate of future inflation can materially impact the results of her analysis. Because the assets in question for this case are relatively long-lived property that will be in service for 40 years or more, Ms. McCullar's analysis requires an accurate estimate of what the annual inflation rate will be for many decades. I am not familiar with any reliable professional inflation forecasts that cover such long periods of time. Further, there are numerous reasons to doubt her estimate of future inflation, and thus there is no compelling reason to substitute Ms. McCullar's forecast for the Company's actual historical experience.

A. <u>Ms. McCullar Overstates the Level of Inflation in the Traditional Net Salvage Analysis</u>

Q. What is the basis for Ms. McCullar's adjustments to the historical net salvage data?

A. Ms. McCullar bases her adjustments to the historical net salvage data on her contention that the level of historical inflation incorporated into the traditional net salvage analysis is higher than the level of future inflation that she expects to occur.[8] Ms. McCullar proposes a method of analysis to adjust the data so that the level of inflation in the historical data is replaced with a lower level of inflation that she expects to occur in the future.[9] However, Ms. McCullar's analysis suffers from two important flaws. First, Ms. McCullar fails to properly consider the difference in time periods between the age of retirements in the historical data and the expected lives of assets currently in service. Second, Ms. McCullar's analysis is contingent on the assumption that her estimate of future inflation, which is based on a relatively short-term inflation target, will be accurate for 40 years or more. The first of these flaws demonstrates that Ms. McCullar's analysis is fundamentally incorrect. The second flaw demonstrates that Ms. McCullar's analysis is, in my view, based on an assumption that is uncertain at best.

Q. What is inflation?

A. Inflation is defined to be a general increase in prices or fall in the purchasing value of money. In the context of Ms. McCullar's testimony, she uses the term to describe the change in costs over time (e.g., removal costs or the original cost of assets placed into service). As such, there are two key inputs in determining the <u>level</u> of inflation: (1) the rate of inflation and (2) the time period over which inflation occurs. Both have an impact

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[8] For example, on page 13 of her Direct Testimony, Ms. McCullar states that she "did consider the amount of high historic inflation incorporated in Company's historic net salvage analysis."

[9] For example, on page 12 of her Direct Testimony, Ms. McCullar describes her method by stating, "[o]nce the salvage amounts are stated at the same price level of the retired plant, and the impact of the high historic inflation levels have been removed, the next step is to use a more reasonable estimate of inflation to aid in forecasting the future net salvage amounts."

on the overall level of inflation. Importantly, Ms. McCullar's testimony and her calculations only focus on the first of these inputs.[10] Ms. McCullar does not properly consider that the time period over which inflation occurs can have just as much of an impact as the rate of inflation, if not more.

Q. How does Ms. McCullar support her contention that the historical inflation in the statistical analysis is higher than should be incorporated into the net salvage analysis?

A. Ms. McCullar observes that the inflation rate was high in the 1970s and 1980s. She then concludes that "National Grid's use of the net salvage analyses which includes these high historical inflation rates assumes that the same high inflation rates will continue in the future, this is not a reasonable assumption."[11] This statement is incorrect. Although there were some years in the past that had relatively high inflation rates, the overall time period over which any inflation included in the historical net salvage analysis occurred is typically less than the overall time period that Company's current assets will be in service. As a result, it is fundamentally incorrect to state that the historical net salvage analysis assumes that the same inflation rate will continue in the future.

Q. Why is the overall time period included in the net salvage analysis less than the

[10] Additionally, as I will discuss in Section II.B., there are reasons to doubt Ms. McCullar's use of the Consumer Price Index as a reasonable measure of the changes in removal costs over time. That is, there are also problems with Ms. McCullar's assumptions with regard to the rate of inflation.

[11] Direct Testimony of Roxie McCullar at 10:6-8.

overall time period that the Company's assets will be in service?

A. For most real-world property groups, the average age at which assets have historically been retired is less than the overall average service life of the group. As an example to illustrate this concept, consider a group of 20 poles. If one pole is retired each year over a 20-year period, then the group will have an average service life of 10 years.[12] However, if after the tenth year one were to observe the average age at which retirements have occurred, one would find that average age to be only five years.[13] Thus, the average age of retirements is less than the average service life.

Further, for assets that are currently in service, the overall average life expectancy (or the "probable life" of the group) will be greater than the average service life (unless every asset is brand new). The probable life is equal to the average service life at age zero, but increases with age. In this example, the probable life at age 10 is 15 years.[14]

To further explain this concept, consider that the average life expectancy of an American at birth is a little less than 80 years (to put this in depreciation terms, the average service life of an American is a little less than 80 years). However, a person who is 80 years of age is not expected to die the next day. Instead, their remaining life expectancy is longer

[12] The assets in this group will have lives of 0.5, 1.5, 2.5, . . ., 18.5, and 19.5 years, as one asset from the group will be retired at the midpoint of each year. The average of these lives is (0.5 x 1 + 1.5 x 1 + . . . + 18.5 x 1 + 19.5 x 1) / 20 = 10 years.

[13] At age 10, retirements recorded to date would have occurred at ages 0.5, 1.5, . . ., 8.5, and 9.5. The average of these ages is (0.5 x 1 + 1.5 x 1 + . . . + 8.5 x 1 + 9.5 x 1) / 10 = 5 years.

[14] At age 10, the remaining assets will have lives of 10.5, 11.5, . . ., 18.5, and 19.5 years. The average of these lives is (10.5 x 1 + 11.5 x 1 + . . . + 18.5 x 1 + 19.5 x 1) / 10 = 15 years.

than zero and their overall life expectancy (or probable life) is longer than 80 years.

Q. Do these same concepts also apply to utility property and to the net salvage analysis?

A. Yes. These same concepts are true for groups of utility property, in part because most property groups experience growth (both real and inflationary). For the net salvage analysis, the ages of retirements (as well as the historical inflation rate) determine the level of inflation in the historical analysis. The net salvage percentages resulting from the net salvage analysis are referred to as "realized net salvage," meaning that they represent the net salvage that has occurred to date.[15] The level of inflation incorporated into realized net salvage is a function of the age of historical retirements.

However, it is "future net salvage," the net salvage that will occur in the future for the assets currently in service, which both Ms. McCullar and I agree needs to be estimated in the depreciation study.[16] The level of inflation that will occur over the life of the assets in the property group is a function of the probable life, not the average age of retirements. For this reason, it is incorrect for Ms. McCullar to assert that the net salvage analysis projects the same inflation rate that has occurred in the past. By only focusing on the net salvage <u>rate</u>, Ms. McCullar fails to recognize that the time period over which inflation

[15] Technically the net salvage analysis may include only a subset of the realized net salvage incurred to date, in the event net salvage data is not available for the full history of a utility company.

[16] Ms. McCullar shows future net salvage included in her formula for remaining life depreciation calculations on page 5 of her Direct Testimony and uses the term "future net salvage" throughout her testimony. For example, on page 6 she states, "[t]he future net salvage percent and the average remaining life are estimates proposed in the Depreciation Study."

occurs for the realized net salvage in the net salvage analyses is typically less than the time period over which inflation will occur for future net salvage.

Q. Please provide an example to demonstrate that Ms. McCullar's assertion is incorrect.

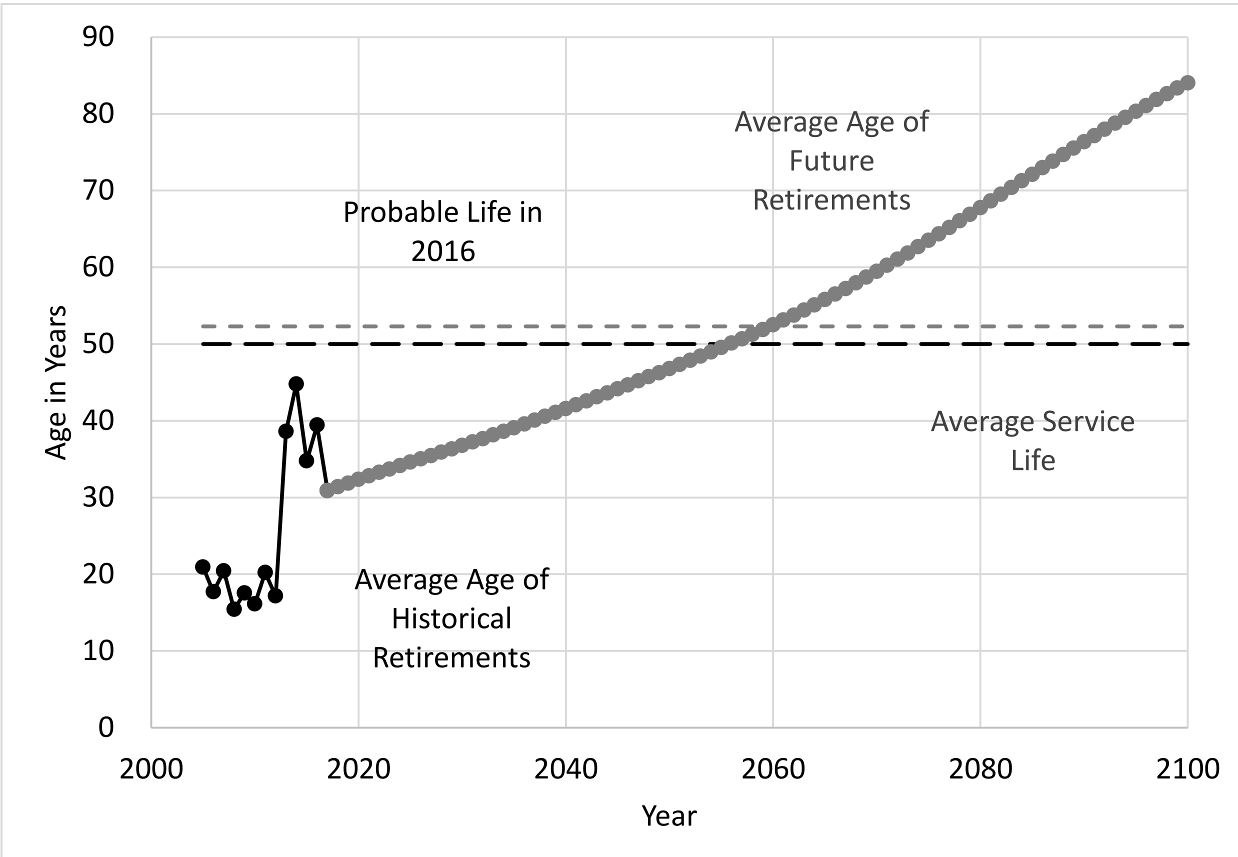
A. Consider as an example Account 380, Gas Services, which is an account for which Ms. McCullar proposes a different net salvage estimate than mine. The average service life estimate for this account is 50 years. The average probable life for the account is somewhat longer, and is about 52 years. Both the average service life and the probable life are longer than the time period over which assets included in the net salvage analysis were in service (that is, the age of historical retirements).

The net salvage analysis for this account is based on historical data recorded for the period 2005 to 2017. For this period, the average age of retirements in the historical analysis is about 29 years, which is considerably shorter than both the average service life and probable life for the account. Thus, the period of time over which inflation occurred for assets that have been historically retired, which is the 29-year average age of retirements, is considerably shorter than the probable life of assets in the account. To put this concept another way, the time period incorporated into the realized net salvage is, on average, 23 years shorter than the time period expected for future net salvage.

This concept is illustrated in the graph below, which shows the average age of retirements for this account by year for the years 2005 to 2017. The graph also shows, by year, the average age of retirements projected for assets currently in service based on the survivor curve estimate for this account. The average service life and probable life for the account are also included in the chart.[17] As the chart illustrates, while the average age of retirements is currently less than the average service life, over time the average age of retirements will increase and will become greater than the average service life. The overall average service life is obtained only once all the assets currently in service have been retired.

[17] Ms. McCullar has not challenged the survivor curve estimates for any account. Thus, the historical age of retirements and the projected age of future retirements are not in dispute in this proceeding.

Figure 1: Average Age of Historical and Future Retirements for Account 380, Services



The average age of historical retirements (which is shown for the years 2005 to 2017 and represented by the black line and markers on the chart) provides the basis for the historical net salvage analysis. As the chart illustrates, in the future the average age of retirements will increase and become much higher than the historical age of retirements (as shown by the gray line and markers). Similarly, both the average service life for the account and the probable life as of December 31, 2016 are higher than the average age of historical retirements.

Q. How does the difference in time period between the average age of retirements and the probable life impact future net salvage estimates based on the traditional net salvage analysis?

A. As demonstrated above, the age of retirements for assets included in the analysis of realized net salvage (i.e., the traditional net salvage analysis) is different from the age of future retirements. This difference in time period has an impact on the level of inflation that occurs and on the inflation rate inherent to a net salvage estimate based on the historical analysis. For example, if the inflation rate averaged 4 percent[18] over the 29-year average age of retirements, this does not mean that net salvage estimates would project 4 percent annual inflation for future net salvage. Instead, because 4 percent inflation over the 29-year average age of retirements is approximately the same as 2.2 percent inflation over the 52-year probable life,[19] a net salvage estimate based on the historical net salvage analysis would not project a 4 percent inflation rate, but instead would project a much lower inflation rate. For this reason, Ms. McCullar's contention that the traditional net salvage analysis that I have performed "assumes that the same high inflation rates will continue in the future"[20] is incorrect. Due to the difference in time period between the age of retirements and the probable life, to the extent inflation is projected when using the traditional net salvage analysis, it is typically at a lower rate than the historical inflation rate.

[18] A 4 percent inflation rate is actually quite a bit higher than the average inflation rate over the previous 29 years, which was 2.6 percent.

[19] 1.04^29≈1.022^52.

[20] Direct Testimony of Roxie McCullar at 10:6-8.

Q. How does Ms. McCullar's analysis fail to incorporate the impact of the time period over which inflation occurs?

A. Ms. McCullar's analysis focuses only on the inflation rates, and does not properly consider the difference in time periods between the average age of retirements in the statistical analysis and the probable life of assets currently in service. Consider the example discussed above for Account 380. For Ms. McCullar's calculations, she first removes the historical inflation that has occurred over an average period of 29 years. However, when she adjusts the data to substitute her 2 percent inflation rate estimate in place of the experienced historical inflation, she only does so for an average time period of 29 years. She does not use the probable life of 52 years, as she would need to do to perform this type of analysis correctly. As a result, Ms. McCullar effectively assumes that the average probable life of the assets in this account is only 29 years, which is much shorter than the average service life estimate of 50 years for this account and the average probable life of 52 years.

The result is that Ms. McCullar's analysis produces results that are less negative than had she properly considered the time period over which inflation has and will occur for the Company's assets. Given this flaw in her analysis, Ms. McCullar's results are unreliable and do not provide a reasonable basis for her net salvage estimates.

B. Ms. McCullar Has Not Used a Reasonable Long-Term Inflation Rate for Her Analysis

Q. What does Ms. McCullar recommend as a future inflation rate to use in her analysis?

A. Ms. McCullar recommends that a "reasonable estimate of inflation is 2%."[21] Her estimate is based on the inflation target established by the Federal Open Market Committee.[22]

Q. Do you agree that it is reasonable to substitute this estimate of inflation in the statistical analysis of historical data?

A. No. In addition to the flaws in Ms. McCullar's analysis discussed in the previous section, I do not think it is appropriate to simply assume that inflation will occur at a 2 percent annual rate for the next 40, 50, or 60 years. Ms. McCullar has not provided a compelling reason to assume that her inflation estimate will be more accurate than the Company's historical experience, nor has she provided a compelling reason to believe that future inflation will be significantly different than inflation that has occurred over previous long-term periods of time.

Q. Why do you state that the inflation forecast must be accurate for 40 years or more?

A. For the three accounts for which Ms. McCullar proposes an adjustment to my net salvage

[21] Direct Testimony of Roxie McCullar at 12:7.

[22] Direct Testimony of Roxie McCullar at 12:7-13:4.

estimates, the average service life estimates range from 40 to 60 years. However, these are only the estimates of average service lives. Because each account will have a dispersion of lives,[23] many assets will live even longer than the average. For these reasons, for Ms. McCullar's analysis to be valid her forecast of future inflation must be accurate for at least the 40 to 60-year average service lives (and actually even longer because many assets will live longer than the average).

Q. Why do you believe it is not appropriate to substitute Ms. McCullar's inflation rate estimate for the Company's historical experience?

A. There are four primary reasons that I do not believe that Ms. McCullar's inflation estimate is appropriate to use in lieu of the Company's historical data: (1) the inherent challenges in estimating inflation over the course of many decades; (2) that history does not support Ms. McCullar's estimate to be reasonable; (3) that the Consumer Price Index (CPI) is not the best measure of cost increases for utility projects; and (4) that an inflation target should not be used as a proxy for future inflation.

Q. What is the uncertainty with estimating future inflation over many decades?

A. An estimate of future inflation over a period of 40 years or more would require an understanding of economic conditions many decades in the future. Given the uncertainty the future brings, it would be impossible to accurately predict economic conditions four decades from now. I do not believe it is appropriate to simply assume that the Federal

[23] A "dispersion of lives" refers to the fact that many assets will have shorter lives than the average life, and many will have longer lives than the average life.

Open Market Committee's current inflation target will predict the inflation rate over a period of 40 years or more.

As further evidence of the inherent difficulty of long-term inflation forecasts, the Federal Reserve also compiles inflation forecasts from a survey of professional forecasters.[24] The longest-term such forecasts in the survey are for 10 years – a much shorter period of time than the time period for which Ms. McCullar's estimate must be accurate for her analysis to have any validity. Given that the Federal Reserve does not publish inflation forecasts for a period longer than 10 years, it does not seem reasonable to me for Ms. McCullar to simply assume that the Federal Open Market Committee's current inflation target will predict future inflation over a much longer period of time.

The historical record of these inflation forecasts provides further evidence for this concept. First, the median forecast of long-term inflation in recent years is higher than Ms. McCullar's proposal. For example, the most recent median of 10-year inflation forecasts compiled by the Federal Reserve is 2.34 percent, which is higher than Ms. McCullar's inflation estimate.[25] Further, past forecasts show that inflation often ends up being different than expected. For example, inflation forecasts in the 1950s and 1960s were lower than actual inflation that occurred in the 1970s and 1980s. It is similarly

[24] The Livingston Survey, published by the Philadelphia Federal Reserve, can be found at: https://www.philadelphiafed.org/research-and-data/real-time-center/livingston-survey.
[25] See page 10 of the December 2017 release of the Livingston Survey, which can be found at: https://www.philadelphiafed.org/research-and-data/real-time-center/livingston-survey.

possible that the inflation that occurs over the coming decades will be higher than Ms. McCullar's estimate (and the Federal Open Market Committee's target).

Q. Please explain how history does not support Ms. McCullar's proposal.

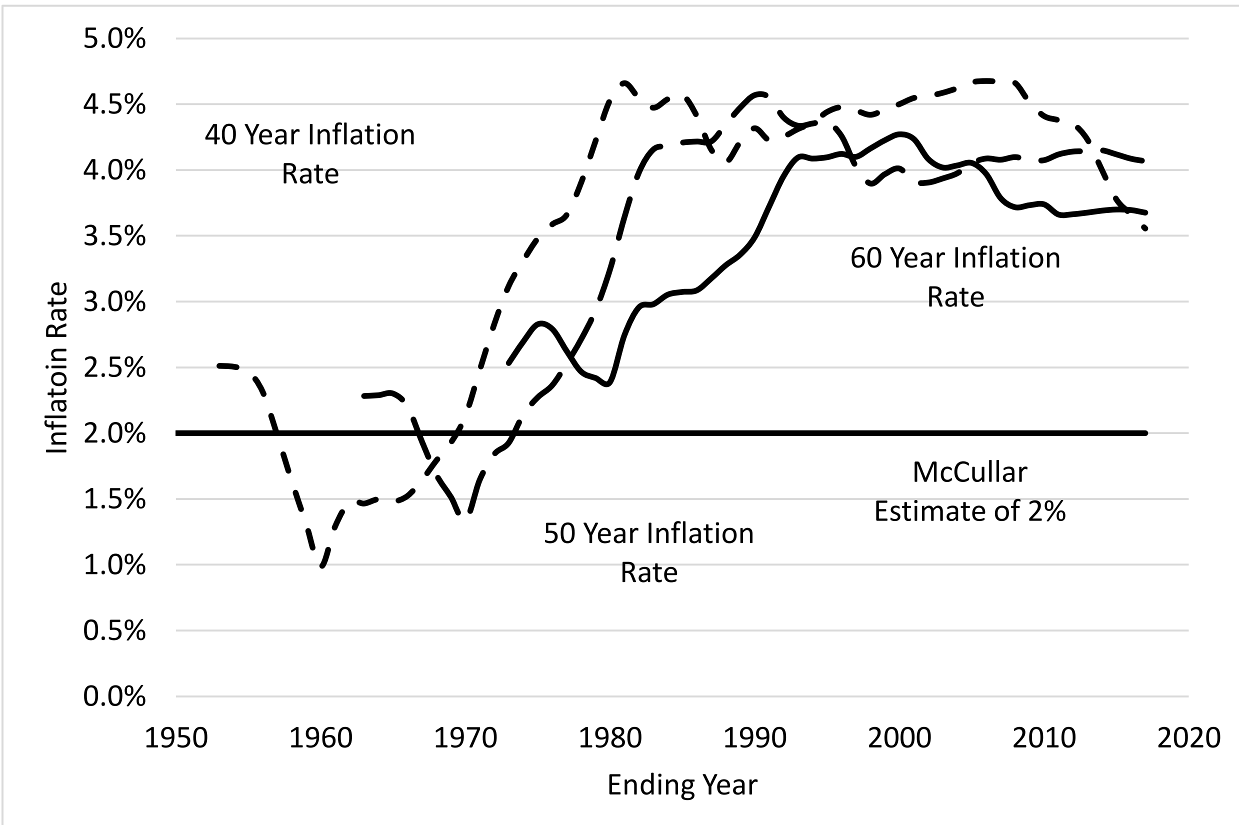
A. Again, for Ms. McCullar's analyses to have any validity, her inflation estimate must be reasonable for a period of 40 years or more. In support of her estimate, Ms. McCullar states that "the CPI has averaged around 2 percent per year for at least the last 20 years."[26] However, this is too short a period of time to assess the reasonableness of a long-term forecast when determining net salvage for utility property that has average service lives that are much longer than 20 years.

A more complete analysis of the CPI data Ms. McCullar used for her testimony is provided in Figure 2 below. The chart shows the annual inflation rate for every 40-, 50-, and 60-year period included in the CPI data (which begins in 1913). The chart also compares these inflation rates to Ms. McCullar's inflation estimate of 2 percent. As the chart demonstrates, for every 60-year period available (shown as a solid black line), inflation has been higher than Ms. McCullar's estimate of 2 percent. Further, for every 40-year period (shown as the smaller-dashed line) that began after 1930 and for every 50-year period (shown as the larger-dashed line) that began after 1924, the annual inflation rate has been higher than Ms. McCullar's estimate.[27] The only 40- and 50-year periods

[26] Direct Testimony of Roxie McCullar at 13:3-4.
[27] The years shown in the graph are the ending years of the 40-, 50-, or 60-year period. Thus, for example, the 40-year period shown with an ending year of 1970 began in 1930.

for which inflation was lower than Ms. McCullar's estimates include the Great Depression and the associated deflationary period.

Figure 2: Long-Term Inflation Rates Over 40-, 50- and 60-Year Periods



Thus, for Ms. McCullar's long-term inflation forecast to be accurate, future inflation would need to be lower than almost every 40-, 50-, or 60-year period since 1913. Ms. McCullar has not provided sufficient reason to expect that the long-term future will be significantly different from the long-term past, and accordingly she has not provided sufficient justifications for her decision to significantly alter the Company's historical net salvage data.

Q. Why is CPI not necessarily the best inflation index to use for Ms. McCullar's analysis?

A. When estimating net salvage, the goal is to estimate what the cost of retiring the Company's assets (net of any gross salvage) will be at the time the assets are retired. To the extent removal costs change over time, they do not necessarily change at the rate of inflation. For example, utility labor costs may increase faster than general price inflation, and work requirements may add to the cost of retiring assets. For these reasons, the CPI index used by Ms. McCullar, which measures general price changes throughout the economy for many different goods and services, is not necessarily the appropriate index to use for the analysis she has performed. Indeed, Wolf and Fitch (whom Ms. McCullar relies on in support of her analysis) make a similar observation. The authors note that "[a]n important question centers on which inflation factor to use." After explaining CPI, Wolf and Fitch then state:

> It is desirable to obtain specialized indexes that reflect the inflation rates in special segments of the economy, and in fact firms specialize in estimating these factors. Different indexes may apply to gross salvage and cost of retiring and the appropriate index for gross salvage in one account will generally differ from that another account.[28]

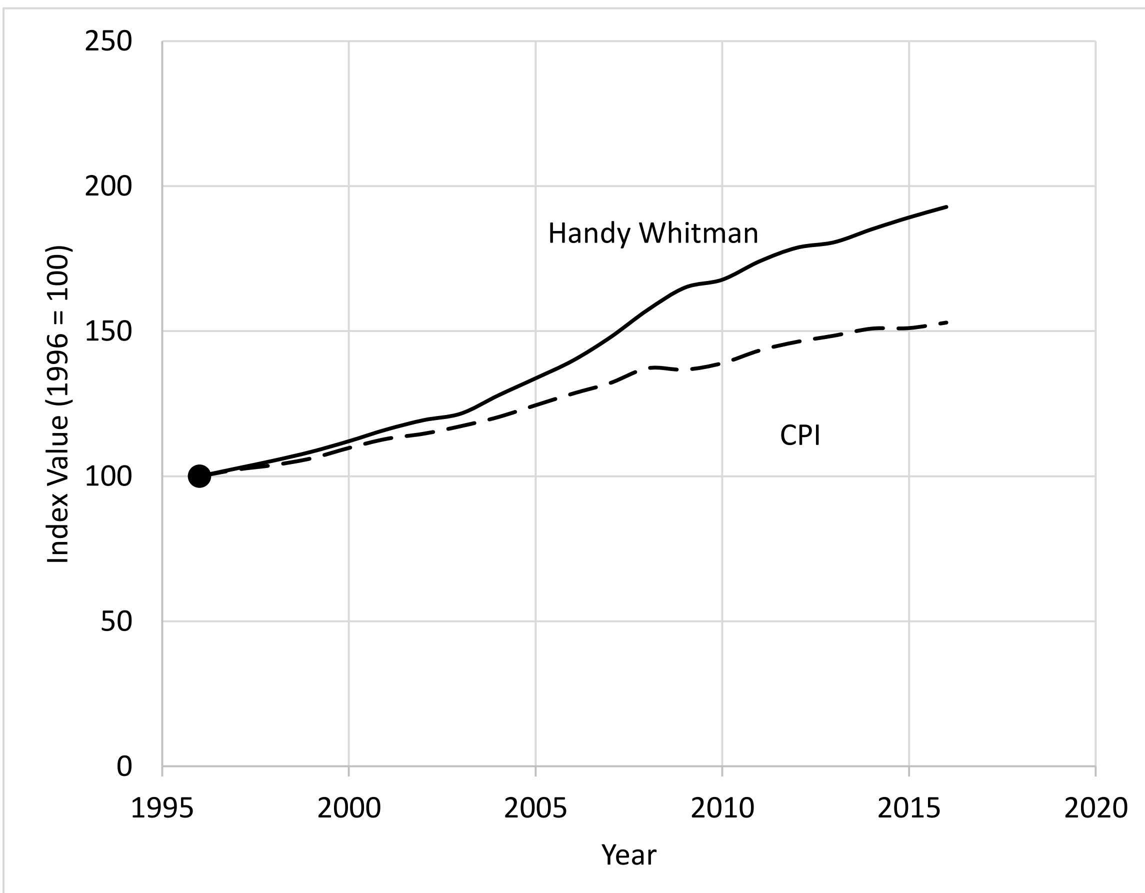
One such index is the Handy Whitman construction cost index, which has increased at a faster rate than CPI in recent years. For example, while Ms. McCullar cites the average inflation rate based on CPI over the past 20 years,[29] the chart below demonstrates that the Handy Whitman Index for Account 380, Services (shown as the solid black line in the

[28] *Depreciation Systems*, Frank Wolf and Chester Fitch, 1994, p. 61.

[29] Direct Testimony of Roxie McCullar at 13:3-4.

chart), has increased at a faster pace over the same period.[30] Indeed, while the CPI has increased at an annual rate of somewhat more than 2 percent over this period of time, the Handy Whitman Index has increased at an annual rate of more than 3 percent. This provides further evidence that the 2 percent inflation estimate made by Ms. McCullar is not appropriate for her analysis.

Figure 3: Comparison of CPI and Handy Whitman Index for Account 380, Services, 1996-2016



[30] The Handy Whitman Index for Plastic Services for the North Atlantic region is used for this chart. 2016 is the most recent full year available for the Handy Whitman Index.

Q. What is the problem with using an inflation target as an estimate of long-term future inflation?

A. Many of the problems with Ms. McCullar's approach of using an inflation target as a proxy for long-term inflation are similar to those discussed previously, such as the uncertainty in predicting long-term economic conditions and the question of whether the CPI is an appropriate cost index to use for Ms. McCullar's analysis. Again, the median forecast compiled by the Federal Reserve is for a higher inflation rate than the Federal Open Market Committee's target. However, another problem arises because the Federal Open Market Committee's goal is not just to hit its inflation target. Other economic factors also are considered by the Federal Open Market Committee, as noted in the Federal Open Market Committee statement provided by Ms. McCullar:

> In setting monetary policy, the Committee seeks to mitigate deviations of inflation from its longer-run goal and deviations of employment from the Committee's assessments of its maximum level. These objectives are generally complementary. However, under circumstances in which the Committee judges that the objectives are not complementary, it follows a balanced approach in promoting them, taking into account the magnitude of the deviations and the potentially different time horizons over which employment and inflation are projected to return to levels judged consistent with its mandate.[31]

Thus, this statement acknowledges that the 2 percent inflation target is a target, not the actual inflation rate that will occur over a long-term period of time, and also affirms that the inflation rate is not the only economic goal of the Federal Open Market Committee.

Q. Based on these considerations, are Ms. McCullar's adjustments to the historical

[31] Schedule RMM-4.

data reasonable?

A. No. As I have explained in the previous section, there are significant flaws that discredit Ms. McCullar's analysis. However, even if Ms. McCullar had performed her analysis correctly, there is not a sufficient basis to assume, as Ms. McCullar does, that inflation will average 2 percent per year over the next 40 years or more. Doing so assumes that the future will be very different from almost any long-term historical period. Instead, the most reasonable basis for the Company's net salvage estimates is the analysis of the unadjusted historical data that I have used in the Depreciation Studies.

C. Ms. McCullar Does Not Follow the Instructions in Wolf and Fitch

Q. What authority does Ms. McCullar rely on in support of the analysis she has performed?

A. Ms. McCullar cites Wolf and Fitch as an authority that supports her analysis. She states that Wolf and Fitch "discusses a method that first converts 'the observed dollars to constant dollars' which removes the high historic inflation rates, and then use a more reasonable estimate of the inflation."[32] There are two significant problems with Ms. McCullar's assertion that Wolf and Fitch supports her analysis. First, this is not an accurate characterization of Wolf and Fitch, who do not state anywhere in the text that the intent of the analysis to which Ms. McCullar cites is to "use a more reasonable estimate of the inflation." Instead, a more complete reading of Wolf and Fitch makes clear that the primary intent of the net salvage models presented by the authors is to

[32] Direct Testimony of Roxie McCullar at 11:12-14.

account for the concepts I discussed in Section II.A., namely, that the differences in time periods between the age of historical retirements and the average age of future retirements impacts the traditional net salvage analysis.

The second problem is that Ms. McCullar's analysis is not what is actually presented in Wolf and Fitch. Instead, Ms. McCullar's analysis appears to be her own creation and is fundamentally flawed. If she had followed the instructions in the text, her analysis would have produced very different results.

Q. What is the context of the Wolf and Fitch chapter cited by Ms. McCullar?

A. In support of her analysis, Ms. McCullar cites Chapter 14 of Wolf and Fitch, which is titled "Salvage Analysis and Forecasting."[33] This chapter is focused on detailed mathematical models that can be used to estimate future net salvage. As the first sentence of the chapter explains:

> This chapter discusses the analysis of aged salvage data and illustrates the use of a mathematical model to help estimate future salvage.[34]

The models described in the text are complex and not only require aged net salvage data, but also require a detailed analysis of the mortality characteristics of the property group studied and the factors that that have an impact on realized net salvage and future net salvage. However, the intent of these models is not to use a different estimate of inflation, as Ms. McCullar asserts, but instead to account for the fact that realized net

[33] Wolf and Fitch use the term "salvage" to refer to "net salvage," i.e., gross salvage net of cost of removal.

[34] *Depreciation Systems*, Frank Wolf and Chester Fitch, 1994, p. 260.

salvage is not always representative of average and future net salvage (due primarily to the lower age of historical retirements than the age of future retirements).[35] In concluding the chapter, Wolf and Fitch summarize this concept as follows:

> Salvage ratios are a function of inflation. For long-lived property, the salvage associated with the longest lived property is affected most. However, this may not be reflected in the data for some time. A mathematical model that includes the effect of salvage can be a valuable forecasting tool. Salvage data by age contains information helpful for constructing and verifying a mathematical model.[36]

As this passage makes clear, the purpose of the mathematical model is to incorporate the impact of inflation on future net salvage for long-lived property that is not reflected in the historical data due to the age of historical retirements. Ms. McCullar's analysis focuses only on changing the inflation rate, without accounting for the impact of the age of retirements on realized net salvage as compared to future net salvage. Thus, not only is Ms. McCullar's analysis flawed, but it is not supported by Wolf and Fitch.

Q. Are the models described in Wolf and Fitch widely used for net salvage analysis in utility rate proceedings?

A. No. Although these models can be useful tools for estimating future net salvage, they are not widely used because of their complexity and because the data required to properly use the models is not normally available. As the opening sentence of Chapter 14 of Wolf and Fitch makes clear, the models described by Wolf and Fitch require "aged salvage data,"

[35] While these models can accommodate changes to any variable (such as the inflation rate or the time period), the full texts of Wolf and Fitch make clear that their focus is on the ages of past and future retirements as the most important variables.

[36] *Depreciation Systems*, Frank Wolf and Chester Fitch, 1994, p. 267.

meaning that for every cost of removal and gross salvage transaction analyzed, the age of retirements is known. Aged salvage data is typically not available for a depreciation study, a fact which is observed by Wolf and Fitch:

> Salvage analysis starts with an examination of the data reflecting total annual costs. Often these are the only data available.[37]

Wolf and Fitch explain the type of net salvage analysis that should be used to analyze data reflecting total annual costs, which is the analysis I have used in the Depreciation Studies. I also note that Wolf and Fitch provide an example (Table 14.3 in the text), which is the same analysis I have performed for the Depreciation Studies.[38]

Q. Does the Company have aged net salvage data?

A. No. Aged net salvage data not only requires the age of each retirement to be known, but also that each cost of removal and gross salvage transaction can be associated with each retirement by age. It is rare for this type of data to be available due to the nature of real-world utility operations and the record-keeping that would be required to maintain aged net salvage data. Consider, as an example, a project to reconductor overhead distribution lines on a city block. The work involved in such a project would often result in the retirement not only of the overhead wire, but also poles (which may be replaced either because larger poles are needed or because some poles are deteriorated) and other assets such as line transformers. Because the conductor, poles, and transformers may not have

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[37] *Depreciation Systems*, Frank Wolf and Chester Fitch, 1994, p. 261.

[38] *Depreciation Systems*, Frank Wolf and Chester Fitch, 1994, p. 261, which references Table 14.3 on page 271 of the same text.

been installed at the same time, and because these assets are associated with different plant accounts, it would be very difficult (if not impossible) to track and associate costs for each removal activity to the age of each asset being retired. For this reason, aged net salvage data is rarely available for a depreciation study. This is one reason why the method of analysis I have used in the Depreciation Studies, which Wolf and Fitch explains is the analysis that is used if aged net salvage data is not available, is the most widely used method of analysis for depreciation studies.

Q. What does Wolf and Fitch advise should be considered if aged net salvage data is not available, as is the case for the Company?

A. Wolf and Fitch make clear that the analyst must consider the age of historical retirements, and that these ages are typically less than the average service life (and thus also shorter than the probable life). This underscores my point that, contrary to Ms. McCullar's assertion, the intent of the models described by Wolf and Fitch is to account for the difference in time periods in the historical net salvage analysis and not to change the historical inflation rate. Specifically, Wolf and Fitch state:

> Often the only available data are the total annual gross salvage and cost of retiring. An example of this type of data is shown in Table 14.3. When analyzing unaged salvage, remember that realized salvage depends on the age of the retirements. Realized salvage starts at zero and does not reach the average until the final unit in the group is retired. Thus, the average age of the annual retirements and the average life of the group are important variables. Continuous property groups showing growth typically have large differences between the average age of the retirements and the average life of the group.[39]

[39] *Depreciation Systems*, Frank Wolf and Chester Fitch, 1994, p. 267 (emphasis added).

Q. Had Ms. McCullar attempted to more accurately follow the instructions in Wolf and Fitch, would her results be different from what she has proposed?

A. Yes. To demonstrate this point, I will provide an example for Account 380, Services.[40] As noted previously, the Company does not have aged net salvage data. This adds uncertainty to the use of this type of mathematical model, and, as Wolf and Fitch note, also means that the analyst cannot verify that the model is correct.[41] For these reasons, I present the results of this mathematical model for illustrative purposes to demonstrate the problems with Ms. McCullar's analysis and to demonstrate that, had she faithfully followed the instructions in Wolf and Fitch, her analysis would have produced very different results. However, I do not intend to have this analysis replace the results of my Depreciation Studies, which, again, are based on the appropriate net salvage methodology for the data available.

That said, Ms. McCullar cites page 265 of Wolf and Fitch in her assertion that she has used the analysis set forth in this text. When using the analysis described on that page of Wolf and Fitch, one would, as a first step, convert the net salvage data to constant dollars (meaning that net salvage and retirements are expressed at the same price level). In her work papers, Ms. McCullar has done a constant dollar calculation for this account for

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[40] I use this account because there are challenges that arise when analyzing the other two accounts with a detailed model. Specifically, for Account 376, Mains, there are multiple subaccounts which each have different service lives. This makes the analysis more complex. Account 368 also has different subaccounts. Additionally, one of the transactions in the historical data is for a large retirement as the result of an inventory process for line transformers. Due to the nature of this transaction, it is difficult to align these retirements with the associated cost of removal and gross salvage, which makes the analysis using a more detailed model more challenging.

[41] *Depreciation Systems*, Frank Wolf and Chester Fitch, 1994, p. 266.

Exhibit RMM-8. The result of her calculation is a total net salvage amount for the period 2005-16 of $5,227,746.[42] Dividing this amount by the total recorded 2005-16 retirement amount of $14,229,296 results in an average realized net salvage percentage of negative 37 percent when expressed in constant dollars.

Based on this analysis, one might conclude that the analysis results in an average realized net salvage, expressed in constant dollars, of negative 35 percent. However, this is only the net salvage for an asset retired at age 0. Most assets currently in service are older than an age of zero, and will be in service for many more years. Accordingly, Wolf and Fitch explain that a table of average and future net salvage by age must be constructed, which can be used to develop an average net salvage and future net salvage for the entire group. Wolf and Fitch presents an example of the type of table that would be constructed when using the Broad Group Model used in the depreciation study, which is presented in Table 6.11 on page 163 of the text. Ms. McCullar has not performed this step of the analysis.

Q. What would be the result of constructing a table like Table 6.11 in Wolf and Fitch for Account 380, Services?

A. Using a negative 35 percent net salvage estimate that would occur for assets at age zero, I have constructed a similar table as Wolf and Fitch's Table 6.11 for Account 380,

[42] This amount in Ms. McCullar's work papers is the resulting net salvage once adjusted by the CPI to the estimated year each retired asset was originally installed. As a result, this amount is in constant dollars when compared to the recorded retirements.

Services. The result is provided as Schedule NWA-3R, which uses Ms. McCullar's estimate of 2 percent as an annual inflation rate.[43] While I disagree with Ms. McCullar's estimate of future inflation for the reasons discussed in the previous section, the use of the same inflation rate for this calculation helps to illustrate that she has failed to properly perform the analysis set forth in Wolf and Fitch.

The result of the calculations in Schedule NWA-3R is an average net salvage of negative 98 percent, which is more negative than Ms. McCullar's estimate of negative 65 percent. It is also more negative to my net salvage estimate of negative 80 percent. Again, this analysis was performed with an inflation rate of 2 percent. A change to this inflation rate would result in different results. I have illustrated this concept in the Table 2 below, which also shows the results of using a 2.5 percent inflation rate, a 3 percent inflation rate, and a 4 percent inflation rate. The detailed calculations based on Table 6.11 of Wolf and Fitch are provided in Schedules NWA-4R, NWA-5R, and NWA-6R. Table 2 also shows, for comparison, the results of Ms. McCullar's flawed analysis.

Table 2: Comparison of Net Salvage Estimates to Analysis Described in Wolf and Fitch

			Corrected Wolf and Fitch Analysis			
Company Estimate	Division Estimate	Division Analysis	2% Inflation Rate	2.5% Inflation Rate	3% Inflation Rate	4% Inflation Rate
-80%	-65%	-61%	-98%	-127%	-166%	-285%

[43] Using a 2 percent inflation rate for all ages and all vintages is an additional assumption when using this model. Because many assets in the account are old (for example, those installed in the 1960s and 1970s), they have already experienced inflation at a higher rate than 2 percent. Using a 2 percent inflation rate for all ages for all vintages is, as a result, likely too low for many vintages and effectively assumes that future inflation will be less than 2 percent. However, the additional analyses required to correct for this discrepancy would even further complicate the model.

These analyses help to illustrate a couple of important points. First, for each inflation rate scenario, the result is more negative net salvage than the results of Ms. McCullar's analysis. The results are also more negative than both my estimate and Ms. McCullar's estimates. Thus, had Ms. McCullar properly followed the instructions in Wolf and Fitch, her analysis would have produced very different results, and as a result her estimate would have been quite different (and likely more negative than my estimate).

The second point is that the results of using a detailed model such as those described in Wolf and Fitch can be sensitive to the estimated inflation rate. As I have explained, Ms. McCullar's inflation rate estimate is inappropriate, and as Table 2 above demonstrates, changes to the inflation rate can produce significant changes to the results (and would, in fact, support net salvage estimates that are much more negative than what I have proposed).

Finally, due to factors such as the limitations of the availability of aged net salvage data, the traditional net salvage analysis I have used is most appropriate for the Company's Depreciation Studies. While there can be value to the mathematical models described by Wolf and Fitch, the lack of aged net salvage data and the uncertainty in inflation estimates means that the results of using these models in this proceeding are, in my professional judgment, less reliable and less appropriate than using the traditional net salvage analysis that I have employed (and which is also supported by Wolf and Fitch).

Q. For her analysis, did Ms. McCullar perform calculations similar to Table 6.11 in Wolf and Fitch?

A. No. Instead, Ms. McCullar's calculations only use the age of historical retirements and, as a result, fail to calculate an average or future net salvage ratio as described in Wolf and Fitch. In support of her calculations, Ms. McCullar cites page 265 of Wolf and Fitch, which explains that "[d]epreciation calculations require an estimate of the average salvage ratio (ASR) and future salvage ratio (FSR) for each vintage," and further explains that when the Broad Group model is used (as is the case in the Depreciation Studies), then "the same salvage schedule is applied to each vintage." Wolf and Fitch then provide Table 6.11 (upon which the calculations in Table 2 above were based) as an example of how the average and future net salvage should be calculated. Given these instructions in Wolf and Fitch, Ms. McCullar should have performed calculations similar to Table 6.11 in Wolf and Fitch, which I have created for Schedules NWA-3R, NWA-4R, NWA-5R, and NWA-6R (and for which the average salvage ratios are summarized in Table 2 above). She did not do so.

In data request National Grid 3-4(b), Ms. McCullar was asked to explain why she did not perform the actual calculations described in Wolf and Fitch, given that she cites page 265 of this text to provide support for her approach. Ms. McCullar's response does not provide a reasonable basis for ignoring this step in the analysis and is contradicted by statements in her testimony. Specifically, Ms. McCullar's response to National Grid 3-4(b) states the following:

> Table 6.11 of Wolf and Fitch's *Depreciation Systems* is a method of calculating the average future net salvage. Ms. McCullar's testimony in the quoted section is discussing the analysis of the actual historic net salvage amounts, so Table 6.11 of Wolf and Fitch's Depreciation Systems is not relevant in the analysis of the historic salvage.[44]

Ms. McCullar's response appears to imply that estimating future net salvage is not relevant to her calculations and her analysis. However, this is directly contradicted not only by Wolf and Fitch, but by her own testimony. Ms. McCullar uses the term future net salvage throughout her testimony, which should make clear that her intent was, in fact, to estimate future net salvage. For example, the portion of Ms. McCullar's testimony that describes her analysis states the following:

> [o]nce the salvage amounts are stated at the same price level of the retired plant, and the impact of the high historic inflation levels have been removed, the next step is to use a more reasonable estimate of inflation to aid in forecasting the future net salvage amounts.[45]

Thus, Ms. McCullar explicitly states that she intends to estimate future net salvage. For this reason, Table 6.11 should be relevant to her analysis, but she neglected to use it in her calculations.

Q. Given the context of Wolf and Fitch discussed above, has Ms. McCullar followed the instructions and advice of this text?

A. No. Not only has Ms. McCullar based her estimates and analyses on an inappropriate methodology that is not consistent with the instructions in the text she uses as an authority, but she has failed to follow Wolf and Fitch's guidance to consider the average

[44] See the Division's response to National Grid 3-4 (emphasis in original).
[45] See the Direct Testimony of Roxie McCullar at 12:1-4 (emphasis added).

age of annual retirements as compared to the average life of the group. As I have described previously, her analysis is flawed on the merits, and should not be considered in estimating future net salvage. This is one reason that, to my knowledge, Ms. McCullar's proposed net salvage methodology has not been accepted by any regulatory commission.

D. Ms. McCullar's Net Salvage Methodology Has Been Previously Rejected

Q. Is the method of analysis proposed by Ms. McCullar widely accepted in the industry?

A. No. In fact, I am not familiar with many cases in which her proposed method of analysis has even been proposed, much less accepted. Although through the years Ms. McCullar's firm has proposed a variety of different unorthodox approaches to determining net salvage (which also have gained limited acceptance), I am familiar with only one case in which Ms. McCullar's firm proposed the same (or similar) analysis to what Ms. McCullar has proposed in the instant case. That case was a 2007 rate case in Missouri for AmerenUE (now AmerenMO).[46] The Missouri Public Service Commission (MPSC) rejected their proposal.

As the MPSC explained, Ms. McCullar's colleague, William Dunkel, recommended that:

> the Commission adjust the accrual method of calculating future net salvage by substituting a projection of future inflation for the historic

[46] MPSC Case No. ER-2007-0002.

> inflation actually experienced when conducting an analysis of net salvage.[47]

The MPSC rejected Mr. Dunkel's proposal, explaining:

> The proposal to substitute projections of future inflation for historic rates of inflation is flawed by an overstatement of the average age of historical retirements used in the formulas for substituting projected future inflation for historic rates of inflation. As explained by AmerenUE's witness, William Stout, MIEC [Missouri Industrial Energy Consumers] and Public Counsel would use average service life as the average age of future retirements. The average age of future retirements is not the average service life, but rather is the average probable life. The average probable life is the same as average service life when an asset is first placed in service, but as time passes the average probable life continues to increase beyond the average service life. This is the same effect experienced in human life expectancy. At birth, a child may have a life expectancy of 70 years, but a 69 year old may still have a life expectancy of more than one year. The use of probable life would result in the inclusion of more future inflation than was recognized by MIEC and Public Counsel and would invalidate their proposed adjustments.
>
> Even more fundamentally, MIEC and Public Counsel have failed to demonstrate any reason to believe their estimates of future inflation are a more reliable predictor of future inflation than the past history used by Staff and AmerenUE in their calculations. Expert predictions of future inflation can be little more than guesswork. It is impossible to accurately predict what inflation might occur 30 or 40 years in the future. No doubt if an esteemed panel of experts had been polled in 1960 they never would have predicted the severe inflation of the 1970s and 1980s. Similarly, today's experts cannot possibly foresee whatever inflation may occur in 2023. The Commission finds past history to be a better predictor of future inflation for ratemaking purposes.[48]

Q. Has Ms. McCullar provided any other cases in which her proposed method of net salvage analysis was proposed or accepted by a regulatory commission?

[47] Report and Order, MPSC Case No. ER-2007-0002, Issued May 22, 2007, p. 90.
[48] Report and Order, MPSC Case No. ER-2007-0002, Issued May 22, 2007, pp. 92-93.

A. No. Ms. McCullar did not provide any such examples in her testimony. In data request National Grid 3-6(a), she was asked if she was aware of:

> [a]ny other utility cases (in any jurisdiction) in which Ms. McCullar or another witness made a proposal to use the same net salvage analysis Ms. McCullar has proposed in the instant case (i.e., using the same net salvage analysis shown in Schedules RMM-5, RMM-8 and RMM-10, which "removes the high historic inflation rates, and then use[s] a more reasonable estimate of the inflation").[49]

In response, Ms. McCullar did not answer the question that was asked of her, and did not provide any examples of a commission adopting the specific proposal she has made in the instant case. Instead, Ms. McCullar provided a list of commission orders in which different net salvage methodologies were proposed and considered. For three of these cases, the net salvage method proposed by Ms. McCullar's firm were based on either expensing net salvage or on a variation of expensing net salvage.[50] For three of the other cases, the net salvage proposals were based on a present value method of determining net salvage accruals instead of using the traditional straight-line method.[51] Additionally, in the Michigan case cited by Ms. McCullar, her firm's proposal was rejected.

In none of these cases were the proposals made by Ms. McCullar or another party the

[49] See the Division's response to National Grid 3-6.
[50] In the cases cited by Ms. McCullar in Connecticut, New Jersey, and Pennsylvania, the proposed net salvage methodologies were either based on recovering net salvage after it was recorded, or were based on methodologies that produced very similar results to doing so.
[51] In the Maryland and District of Columbia cases cited by Ms. McCullar, present value methods were used. A present value method was also proposed by Ms. McCullar's firm in Michigan, but was rejected by the Michigan Public Service Commission.

same method of analyzing net salvage as Ms. McCullar has proposed in the instant case. Based on her response, the only rational conclusion is that Ms. McCullar is not actually aware of a single instance in which a regulatory commission has accepted the specific methodology that she has used in the instant case.[52] At a minimum, Ms. McCullar has provided no support that her proposal has ever been adopted in any regulatory jurisdiction. In contrast, the traditional method I have used is widely accepted and is the predominant method used in the industry.

Q. Are you familiar with any rate cases in which a regulatory commission held that the inflation that will occur over an assets' full service life should be considered when determining future net salvage costs?

A. Yes. In a 2013 Federal Energy Regulatory Commission (FERC) opinion, the FERC held not only that future net salvage costs should be stated at the future cost level at which they will be incurred, but that not doing so would result in intergenerational inequity. While the issue at hand in the 2013 FERC case dealt specifically with the costs to retire power plants, the same concepts would apply to the net salvage for any type of property. This order is noteworthy for multiple reasons. The first is that FERC's Uniform System of Accounts sets forth accounting requirements that require net salvage to be included in depreciation.[53] In this 2013 opinion, FERC further explains that net salvage must be

[52] Ms. McCullar also cites to a portion of a transcript from a recent case in Maine in which inflation was discussed as it relates to net salvage. However, based on a review of that case, it does not appear that the same type of analysis was used as Ms. McCullar has proposed. Instead, her firm proposed a different method in that case that produces the same or similar results to expensing net salvage.

[53] Definition 37 of the Uniform System of Accounts states that "*Service value* means the difference between original cost and net salvage value of electric plant." General Instruction 22A of the Uniform System of Accounts states that

future net salvage determined at the expected future cost. That is, FERC supports the concepts I have explained in my testimony and supports that the full service life of future retirements should be considered when estimating future net salvage. Further, I note that in the 2013 FERC case, FERC approved a future inflation rate estimate of 3 percent, which is higher than the 2 percent inflation rate Ms. McCullar proposes. A 3 percent inflation rate would result in Ms. McCullar's analysis producing different results, and further underscores my points that there is uncertainty in estimating long term inflation and that Ms. McCullar has not provided justification to assume that inflation will occur at a 2 percent rate over the next 40 years or more.

In the 2013 Opinion at paragraph 175, FERC stated:

> We affirm the Presiding Judge's finding that Entergy has demonstrated that the decommissioning cost estimate should be escalated three percent annually to the retirement dates estimated for Entergy Arkansas' steam production units. Based on the record before us, we agree with the Presiding Judge that it is reasonable for the current decommissioning costs to be inflated to reflect future costs of decommissioning at the time of retirement in order to avoid intergenerational inequities between current and future ratepayers.[54]

Q. You indicated that Ms. McCullar's firm has proposed other unorthodox approaches to estimating net salvage. Are you familiar with any recent cases in which her proposals have been rejected?

A. Yes. Ms. McCullar's firm has not been consistent in the types of methods used in

"[u]tilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property."

[54] FERC Opinion No. 523, issued January 8, 2013, pp. 76-77, P. 175.

developing net salvage estimates in different cases in recent years. As an example, in a recent case in Washington for Puget Sound Energy, Ms. McCullar proposed a different method of estimating net salvage in which she compared the annual depreciation accruals resulting from her net salvage estimates to the annual amounts of net salvage the company had recently incurred. Ms. McCullar's method proposed in that case is not an appropriate method of estimating future net salvage, as future net salvage costs should typically be expected to be higher (i.e., more negative) than recent net salvage costs. Accordingly, Ms. McCullar's proposal in that case was rejected:

> 164. Public Counsel's proposed alternative to the Settlement Stipulation's treatment of net salvage of mass assets used in natural gas operations appears to be based on testimony by Ms. McCullar that we find to be vague in its methodology, not supported by authoritative accounting literature, and supported by unwarranted assumptions. Mr. Spanos' estimates of net salvage for natural gas mass assets, in contrast, does not suffer from these deficiencies.
>
> 165. In addition, Ms. McCullar's comparison of net salvage accruals to net salvage expenditures PSE [Puget Sound Energy] incurred during recent years would effectively recover net salvage as an operating expense, not a depreciation expense. We do not accept this result.
>
> 166. Thus, we reject Public Counsel's alternative viewpoint and approve the Settlement Stipulation with respect to net salvage of mass assets that support PSE's natural gas operations.[55]

This case is of note because, while she does not present a similar proposal in her testimony in the instant case, Ms. McCullar does state that she also considered "the

[55] See page 60 of the Final Order of the Washington Utilities and Transportation Commission in Dockets UE-170033 and UE-170034, issued on December 5, 2017. Although other parties in that case reached a settlement agreement that adopted most of the recommendations in PSE's depreciation study, the Washington Public Counsel (Ms. McCullar's client in that case) did not agree to the settlement and continued to argue for Ms. McCullar's position.

average actual net salvage expense incurred over the most recent time periods."[56] Based on Ms. McCullar's testimony, it does not appear that this consideration had a material impact on her recommendations, which were instead based on the flawed analysis I have rebutted in my testimony. However, in the event Ms. McCullar attempts to bolster her case in surrebuttal testimony by comparing net salvage accruals to recent net salvage costs, it is important for the Public Utilities Commission to recognize that a similar proposal made by Ms. McCullar recently was rejected.

E. <u>The Company's Practice of Retiring Most Mains and Services in Place</u>

Q. Ms. McCullar states that additional information she considered in developing her net salvage estimates was that the Company generally retires gas mains and services in place, as opposed to removing these assets from the ground when retired.[57] Does this information support her proposals for less negative net salvage estimates than those you have proposed?

A. No. Although Ms. McCullar correctly observes that most of the Company's gas mains and services in Accounts 376 and 380 are retired in place, she does not provide any reason to expect that this practice would result in cost of removal being materially different in the future than has been the case in the past. It is also unclear how the Company's practices for retiring these assets impacted Ms. McCullar's analysis, if they impacted her results at all. Ms. McCullar does not explain how the practice of retiring

[56] Direct Testimony of Roxie McCullar at 13:11-12.
[57] Direct Testimony of Roxie McCullar at 15:1-19 and 17:11-18:7.

mains and services is factored into her estimates, other than to state that she considered this practice and to observe that the practice of retiring mains and services in place is "consistent with the net salvage data."[58]

Q. Has the Company historically retired most mains and services in place?

A. Yes. As a result, the costs associated with retiring these assets in place are already incorporated into the historical net salvage data and the results of the statistical net salvage analyses. Again, this appears to be acknowledged by Ms. McCullar, who observes that the practice of retiring mains and services in place is "consistent with the net salvage data."[59]

Q. Has Ms. McCullar provided any reason to expect that the Company's practice would be different in the future than has been the case historically?

A. No. Based on her testimony, I believe that Ms. McCullar and I agree that the practice of retiring mains and services in place will be similar going forward as has been the case in the past. Thus, the practice of retiring gas mains and services does not provide a reason to deviate from the results of the statistical net salvage analyses.

Q. Did you consider the Company's practices for retiring mains and services when developing your net salvage estimates?

A. Yes. The Company historically has retired most gas mains and services in place, which

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[58] Direct Testimony of Roxie McCullar at 15:18-19 and 18:6-7.
[59] Direct Testimony of Roxie McCullar at 15:18-19 and 18:6-7.

also is consistent with the operations of many other natural gas utilities. Because this has been the Company's historical practice, the costs of retirement associated with retiring mains and services in place are already incorporated into the analyses of the historical net salvage data. This consistent practice for retirements, therefore, provides a reason to expect that the historical net salvage analyses provide a reasonable basis for the estimation of future net salvage. Ms. McCullar's proposals to use less negative net salvage estimates for gas mains and services are not the result of her observation of the practice for retiring mains and services. Instead, Ms. McCullar's estimates are based on her net salvage analyses, the flaws of which I have detailed in this rebuttal testimony.

III. <u>Conclusion</u>

Q. Are Ms. McCullar's net salvage proposals appropriate and reasonable?

A. No. As I have discussed in detail, Ms. McCullar's proposals are based on a flawed net salvage analysis and on assumptions of future inflation that do not stand up to scrutiny. Ms. McCullar's proposed method of net salvage analysis is not widely accepted, and is not even consistent with the instructions of the authority she cites in support of it. For these reasons, Ms. McCullar's net salvage estimates are not appropriate and should be rejected. In contrast, the net salvage estimates I have recommended are consistent with longstanding depreciation practices, based on widely accepted methods, consistent with the recommendations of authoritative depreciation textbooks, and are most reasonable based on the data available for the depreciation studies.

Q. Do you have any other comments on Ms. McCullar's recommendations?

A. Yes. Based on her testimony, Ms. McCullar's recommendations are narrow in scope and based primarily, if not entirely, on the adjustments to the net salvage data she has made. I have explained in detail the flaws in Ms. McCullar's analyses and why these adjustments are not appropriate. However, my understanding is that Ms. McCullar has the opportunity to submit surrebuttal testimony in this proceeding. As I have discussed previously, Ms. McCullar's firm has not been consistent in various proceedings with the methodologies they have used to develop their net salvage recommendations. As a result, I am concerned that Ms. McCullar may use the opportunity of surrebuttal testimony to introduce new analyses in an effort to support her proposals.

Given this concern, I want to make clear that the method I have used in the Depreciation Studies to estimate net salvage represents the industry standard method of determining future net salvage. I would not expect any alternative methodologies introduced by Ms. McCullar to stand up to scrutiny or to have widespread acceptance. Similar to her analysis in her direct testimony in this proceeding, other methodologies her firm has proposed elsewhere have had conceptual and mathematical flaws. Further, as I have discussed in Section II.D., other proposals made by Ms. McCullar have been previously rejected in other jurisdictions.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Rebuttal Schedules of
Ned W. Allis

Index of Schedules

Schedule NWA-3R	Calculation of average and future net salvage for Account 380, Services based on Table 6.11 of Wolf and Fitch and 2 percent inflation rate
Schedule NWA-4R	Calculation of average and future net salvage for Account 380, Services based on Table 6.11 of Wolf and Fitch and 2.5 percent inflation rate
Schedule NWA-5R	Calculation of average and future net salvage for Account 380, Services based on Table 6.11 of Wolf and Fitch and 3 percent inflation rate
Schedule NWA-6R	Calculation of average and future net salvage for Account 380, Services based on Table 6.11 of Wolf and Fitch and 4 percent inflation rate

Schedule __ (NWA-3R)

Calculation of average and future net salvage for Account 380, Services

based on Table 6.11 of Wolf and Fitch and 2 percent inflation rate

The Narragansett Electric Company - Gas Plant

Account 380 Services

Calculation of Average and Future Net Salvage Based on Table 6.11 of Wolf and Fitch

Annual Inflation Rate	2.00%
Net Salvage at Age 0	-35.00%

Age (a)	% Surviving (b)	% Retired (c)	NS % (d)	Weighted NS % (e)	Realized NS (f)	Future NS (g)
0	100.0000	0.0155	-35.00%	-0.01%	0.00%	-97.67%
0.5	99.9845	0.0351	-35.70%	-0.01%	-35.00%	-97.67%
1.5	99.9494	0.0414	-36.41%	-0.02%	-35.49%	-97.70%
2.5	99.9080	0.0484	-37.14%	-0.02%	-35.90%	-97.72%
3.5	99.8596	0.0565	-37.89%	-0.02%	-36.33%	-97.75%
4.5	99.8031	0.0655	-38.64%	-0.03%	-36.78%	-97.79%
5.5	99.7376	0.0757	-39.42%	-0.03%	-37.24%	-97.82%
6.5	99.6619	0.0870	-40.20%	-0.03%	-37.73%	-97.87%
7.5	99.5749	0.0997	-41.01%	-0.04%	-38.24%	-97.92%
8.5	99.4752	0.1137	-41.83%	-0.05%	-38.76%	-97.98%
9.5	99.3615	0.1292	-42.66%	-0.06%	-39.31%	-98.04%
10.5	99.2323	0.1463	-43.52%	-0.06%	-39.87%	-98.11%
11.5	99.0860	0.1650	-44.39%	-0.07%	-40.46%	-98.19%
12.5	98.9210	0.1855	-45.28%	-0.08%	-41.06%	-98.28%
13.5	98.7355	0.2078	-46.18%	-0.10%	-41.68%	-98.38%
14.5	98.5276	0.2321	-47.11%	-0.11%	-42.31%	-98.49%
15.5	98.2956	0.2583	-48.05%	-0.12%	-42.97%	-98.61%
16.5	98.0373	0.2867	-49.01%	-0.14%	-43.63%	-98.75%
17.5	97.7506	0.3172	-49.99%	-0.16%	-44.32%	-98.89%
18.5	97.4334	0.3499	-50.99%	-0.18%	-45.02%	-99.05%
19.5	97.0835	0.3850	-52.01%	-0.20%	-45.74%	-99.23%
20.5	96.6985	0.4225	-53.05%	-0.22%	-46.47%	-99.41%
21.5	96.2761	0.4624	-54.11%	-0.25%	-47.21%	-99.62%
22.5	95.8137	0.5049	-55.19%	-0.28%	-47.98%	-99.84%
23.5	95.3088	0.5500	-56.30%	-0.31%	-48.75%	-100.07%
24.5	94.7588	0.5978	-57.42%	-0.34%	-49.54%	-100.33%
25.5	94.1610	0.6485	-58.57%	-0.38%	-50.35%	-100.60%
26.5	93.5125	0.7022	-59.74%	-0.42%	-51.17%	-100.89%
27.5	92.8103	0.7589	-60.94%	-0.46%	-52.01%	-101.20%
28.5	92.0514	0.8189	-62.15%	-0.51%	-52.86%	-101.53%
29.5	91.2325	0.8823	-63.40%	-0.56%	-53.73%	-101.89%
30.5	90.3502	0.9494	-64.67%	-0.61%	-54.61%	-102.26%
31.5	89.4008	1.0202	-65.96%	-0.67%	-55.51%	-102.66%
32.5	88.3806	1.0951	-67.28%	-0.74%	-56.43%	-103.09%
33.5	87.2855	1.1744	-68.62%	-0.81%	-57.36%	-103.54%
34.5	86.1111	1.2581	-70.00%	-0.88%	-58.32%	-104.01%
35.5	84.8530	1.3465	-71.40%	-0.96%	-59.29%	-104.52%
36.5	83.5066	1.4397	-72.82%	-1.05%	-60.28%	-105.05%
37.5	82.0669	1.5377	-74.28%	-1.14%	-61.28%	-105.62%
38.5	80.5292	1.6407	-75.77%	-1.24%	-62.31%	-106.21%
39.5	78.8885	1.7482	-77.28%	-1.35%	-63.36%	-106.85%
40.5	77.1403	1.8601	-78.83%	-1.47%	-64.42%	-107.52%
41.5	75.2802	1.9756	-80.40%	-1.59%	-65.50%	-108.23%
42.5	73.3046	2.0941	-82.01%	-1.72%	-66.61%	-108.98%
43.5	71.2105	2.2144	-83.65%	-1.85%	-67.73%	-109.77%
44.5	68.9962	2.3351	-85.32%	-1.99%	-68.86%	-110.61%
45.5	66.6611	2.4545	-87.03%	-2.14%	-70.02%	-111.49%
46.5	64.2066	2.5708	-88.77%	-2.28%	-71.18%	-112.43%
47.5	61.6358	2.6816	-90.55%	-2.43%	-72.36%	-113.41%
48.5	58.9542	2.7845	-92.36%	-2.57%	-73.55%	-114.45%
49.5	56.1697	2.8769	-94.21%	-2.71%	-74.75%	-115.55%
50.5	53.2929	2.9561	-96.09%	-2.84%	-75.94%	-116.70%
51.5	50.3368	3.0194	-98.01%	-2.96%	-77.14%	-117.91%
52.5	47.3175	3.0643	-99.97%	-3.06%	-78.34%	-119.18%

The Narragansett Electric Company - Gas Plant

Account 380 Services

Calculation of Average and Future Net Salvage Based on Table 6.11 of Wolf and Fitch

Annual Inflation Rate	2.00%
Net Salvage at Age 0	-35.00%

Age (a)	% Surviving (b)	% Retired (c)	NS % (d)	Weighted NS % (e)	Realized NS (f)	Future NS (g)
53.5	44.2532	3.0887	-101.97%	-3.15%	-79.53%	-120.51%
54.5	41.1645	3.0906	-104.01%	-3.21%	-80.71%	-121.90%
55.5	38.0739	3.0690	-106.09%	-3.26%	-81.87%	-123.36%
56.5	35.0049	3.0231	-108.21%	-3.27%	-83.01%	-124.87%
57.5	31.9818	2.9532	-110.38%	-3.26%	-84.13%	-126.44%
58.5	29.0286	2.8601	-112.58%	-3.22%	-85.23%	-128.08%
59.5	26.1686	2.7454	-114.84%	-3.15%	-86.29%	-129.77%
60.5	23.4232	2.6117	-117.13%	-3.06%	-87.31%	-131.52%
61.5	20.8115	2.4619	-119.48%	-2.94%	-88.29%	-133.33%
62.5	18.3496	2.2994	-121.86%	-2.80%	-89.23%	-135.19%
63.5	16.0502	2.1281	-124.30%	-2.65%	-90.13%	-137.10%
64.5	13.9221	1.9518	-126.79%	-2.47%	-90.97%	-139.05%
65.5	11.9703	1.7742	-129.32%	-2.29%	-91.77%	-141.05%
66.5	10.1961	1.5985	-131.91%	-2.11%	-92.51%	-143.09%
67.5	8.5976	1.4277	-134.55%	-1.92%	-93.20%	-145.17%
68.5	7.1700	1.2639	-137.24%	-1.73%	-93.83%	-147.29%
69.5	5.9061	1.1087	-139.98%	-1.55%	-94.42%	-149.44%
70.5	4.7975	0.9630	-142.78%	-1.37%	-94.95%	-151.62%
71.5	3.8345	0.8273	-145.64%	-1.20%	-95.43%	-153.84%
72.5	3.0072	0.7015	-148.55%	-1.04%	-95.85%	-156.09%
73.5	2.3057	0.5855	-151.52%	-0.89%	-96.23%	-158.39%
74.5	1.7202	0.4792	-154.55%	-0.74%	-96.56%	-160.72%
75.5	1.2411	0.3824	-157.65%	-0.60%	-96.84%	-163.10%
76.5	0.8587	0.2954	-160.80%	-0.48%	-97.08%	-165.54%
77.5	0.5632	0.2187	-164.01%	-0.36%	-97.27%	-168.02%
78.5	0.3445	0.1528	-167.29%	-0.26%	-97.41%	-170.56%
79.5	0.1917	0.0986	-170.64%	-0.17%	-97.52%	-173.17%
80.5	0.0931	0.0564	-174.05%	-0.10%	-97.59%	-175.85%
81.5	0.0367	0.0267	-177.53%	-0.05%	-97.64%	-178.62%
82.5	0.0100	0.0088	-181.08%	-0.02%	-97.66%	-181.51%
83.5	0.0012	0.0012	-184.71%	0.00%	-97.66%	-184.71%
84.5	0.0000				-97.67%	
			Average NS =	**-97.67%**		

Schedule __ (NWA-4R)

Calculation of average and future net salvage for Account 380, Services

based on Table 6.11 of Wolf and Fitch and 2.5 percent inflation rate

The Narragansett Electric Company - Gas Plant

Account 380 Services

Calculation of Average and Future Net Salvage Based on Table 6.11 of Wolf and Fitch

Annual Inflation Rate	2.50%
Net Salvage at Age 0	-35.00%

Age (a)	% Surviving (b)	% Retired (c)	NS % (d)	Weighted NS % (e)	Realized NS (f)	Future NS (g)
0	100.0000	0.0155	-35.00%	-0.01%	0.00%	-127.15%
0.5	99.9845	0.0351	-35.88%	-0.01%	-35.00%	-127.16%
1.5	99.9494	0.0414	-36.77%	-0.02%	-35.61%	-127.19%
2.5	99.9080	0.0484	-37.69%	-0.02%	-36.13%	-127.23%
3.5	99.8596	0.0565	-38.63%	-0.02%	-36.67%	-127.27%
4.5	99.8031	0.0655	-39.60%	-0.03%	-37.23%	-127.32%
5.5	99.7376	0.0757	-40.59%	-0.03%	-37.82%	-127.38%
6.5	99.6619	0.0870	-41.60%	-0.04%	-38.44%	-127.45%
7.5	99.5749	0.0997	-42.64%	-0.04%	-39.09%	-127.52%
8.5	99.4752	0.1137	-43.71%	-0.05%	-39.76%	-127.61%
9.5	99.3615	0.1292	-44.80%	-0.06%	-40.47%	-127.70%
10.5	99.2323	0.1463	-45.92%	-0.07%	-41.20%	-127.81%
11.5	99.0860	0.1650	-47.07%	-0.08%	-41.95%	-127.93%
12.5	98.9210	0.1855	-48.25%	-0.09%	-42.74%	-128.07%
13.5	98.7355	0.2078	-49.45%	-0.10%	-43.54%	-128.22%
14.5	98.5276	0.2321	-50.69%	-0.12%	-44.38%	-128.38%
15.5	98.2956	0.2583	-51.96%	-0.13%	-45.24%	-128.57%
16.5	98.0373	0.2867	-53.26%	-0.15%	-46.12%	-128.77%
17.5	97.7506	0.3172	-54.59%	-0.17%	-47.03%	-128.99%
18.5	97.4334	0.3499	-55.95%	-0.20%	-47.97%	-129.23%
19.5	97.0835	0.3850	-57.35%	-0.22%	-48.92%	-129.50%
20.5	96.6985	0.4225	-58.79%	-0.25%	-49.91%	-129.78%
21.5	96.2761	0.4624	-60.25%	-0.28%	-50.91%	-130.10%
22.5	95.8137	0.5049	-61.76%	-0.31%	-51.95%	-130.43%
23.5	95.3088	0.5500	-63.31%	-0.35%	-53.00%	-130.80%
24.5	94.7588	0.5978	-64.89%	-0.39%	-54.08%	-131.19%
25.5	94.1610	0.6485	-66.51%	-0.43%	-55.19%	-131.61%
26.5	93.5125	0.7022	-68.17%	-0.48%	-56.32%	-132.06%
27.5	92.8103	0.7589	-69.88%	-0.53%	-57.48%	-132.54%
28.5	92.0514	0.8189	-71.62%	-0.59%	-58.66%	-133.06%
29.5	91.2325	0.8823	-73.41%	-0.65%	-59.87%	-133.61%
30.5	90.3502	0.9494	-75.25%	-0.71%	-61.11%	-134.20%
31.5	89.4008	1.0202	-77.13%	-0.79%	-62.38%	-134.83%
32.5	88.3806	1.0951	-79.06%	-0.87%	-63.67%	-135.49%
33.5	87.2855	1.1744	-81.04%	-0.95%	-65.00%	-136.20%
34.5	86.1111	1.2581	-83.06%	-1.04%	-66.35%	-136.95%
35.5	84.8530	1.3465	-85.14%	-1.15%	-67.74%	-137.75%
36.5	83.5066	1.4397	-87.27%	-1.26%	-69.16%	-138.60%
37.5	82.0669	1.5377	-89.45%	-1.38%	-70.62%	-139.50%
38.5	80.5292	1.6407	-91.69%	-1.50%	-72.10%	-140.46%
39.5	78.8885	1.7482	-93.98%	-1.64%	-73.62%	-141.47%
40.5	77.1403	1.8601	-96.33%	-1.79%	-75.18%	-142.55%
41.5	75.2802	1.9756	-98.73%	-1.95%	-76.77%	-143.69%
42.5	73.3046	2.0941	-101.20%	-2.12%	-78.40%	-144.90%
43.5	71.2105	2.2144	-103.73%	-2.30%	-80.06%	-146.19%
44.5	68.9962	2.3351	-106.33%	-2.48%	-81.75%	-147.55%
45.5	66.6611	2.4545	-108.98%	-2.68%	-83.47%	-148.99%
46.5	64.2066	2.5708	-111.71%	-2.87%	-85.22%	-150.52%
47.5	61.6358	2.6816	-114.50%	-3.07%	-86.99%	-152.14%
48.5	58.9542	2.7845	-117.36%	-3.27%	-88.79%	-153.85%
49.5	56.1697	2.8769	-120.30%	-3.46%	-90.61%	-155.66%
50.5	53.2929	2.9561	-123.31%	-3.64%	-92.44%	-157.57%
51.5	50.3368	3.0194	-126.39%	-3.82%	-94.27%	-159.58%
52.5	47.3175	3.0643	-129.55%	-3.97%	-96.11%	-161.70%

The Narragansett Electric Company - Gas Plant

Account 380 Services

Calculation of Average and Future Net Salvage Based on Table 6.11 of Wolf and Fitch

Annual Inflation Rate	2.50%
Net Salvage at Age 0	-35.00%

Age (a)	% Surviving (b)	% Retired (c)	NS % (d)	Weighted NS % (e)	Realized NS (f)	Future NS (g)
53.5	44.2532	3.0887	-132.79%	-4.10%	-97.95%	-163.93%
54.5	41.1645	3.0906	-136.11%	-4.21%	-99.78%	-166.26%
55.5	38.0739	3.0690	-139.51%	-4.28%	-101.59%	-168.71%
56.5	35.0049	3.0231	-143.00%	-4.32%	-103.38%	-171.27%
57.5	31.9818	2.9532	-146.57%	-4.33%	-105.14%	-173.94%
58.5	29.0286	2.8601	-150.24%	-4.30%	-106.87%	-176.73%
59.5	26.1686	2.7454	-153.99%	-4.23%	-108.55%	-179.62%
60.5	23.4232	2.6117	-157.84%	-4.12%	-110.18%	-182.63%
61.5	20.8115	2.4619	-161.79%	-3.98%	-111.75%	-185.74%
62.5	18.3496	2.2994	-165.83%	-3.81%	-113.26%	-188.95%
63.5	16.0502	2.1281	-169.98%	-3.62%	-114.70%	-192.26%
64.5	13.9221	1.9518	-174.23%	-3.40%	-116.06%	-195.67%
65.5	11.9703	1.7742	-178.58%	-3.17%	-117.35%	-199.16%
66.5	10.1961	1.5985	-183.05%	-2.93%	-118.56%	-202.74%
67.5	8.5976	1.4277	-187.63%	-2.68%	-119.69%	-206.41%
68.5	7.1700	1.2639	-192.32%	-2.43%	-120.74%	-210.15%
69.5	5.9061	1.1087	-197.12%	-2.19%	-121.70%	-213.96%
70.5	4.7975	0.9630	-202.05%	-1.95%	-122.58%	-217.85%
71.5	3.8345	0.8273	-207.10%	-1.71%	-123.37%	-221.82%
72.5	3.0072	0.7015	-212.28%	-1.49%	-124.09%	-225.87%
73.5	2.3057	0.5855	-217.59%	-1.27%	-124.72%	-230.01%
74.5	1.7202	0.4792	-223.03%	-1.07%	-125.27%	-234.23%
75.5	1.2411	0.3824	-228.60%	-0.87%	-125.75%	-238.56%
76.5	0.8587	0.2954	-234.32%	-0.69%	-126.14%	-242.99%
77.5	0.5632	0.2187	-240.18%	-0.53%	-126.47%	-247.54%
78.5	0.3445	0.1528	-246.18%	-0.38%	-126.71%	-252.21%
79.5	0.1917	0.0986	-252.33%	-0.25%	-126.90%	-257.02%
80.5	0.0931	0.0564	-258.64%	-0.15%	-127.02%	-261.99%
81.5	0.0367	0.0267	-265.11%	-0.07%	-127.10%	-267.13%
82.5	0.0100	0.0088	-271.74%	-0.02%	-127.13%	-272.54%
83.5	0.0012	0.0012	-278.53%	0.00%	-127.15%	-278.53%
84.5	0.0000				-127.15%	

Average NS = -127.15%

Schedule __ (NWA-5R)

Calculation of average and future net salvage for Account 380, Services

based on Table 6.11 of Wolf and Fitch and 3 percent inflation rate

The Narragansett Electric Company - Gas Plant

Account 380 Services

Calculation of Average and Future Net Salvage Based on Table 6.11 of Wolf and Fitch

Annual Inflation Rate	3.00%
Net Salvage at Age 0	-35.00%

Age (a)	% Surviving (b)	% Retired (c)	NS % (d)	Weighted NS % (e)	Realized NS (f)	Future NS (g)
0	100.0000	0.0155	-35.00%	-0.01%	0.00%	-165.94%
0.5	99.9845	0.0351	-36.05%	-0.01%	-35.00%	-165.96%
1.5	99.9494	0.0414	-37.13%	-0.02%	-35.73%	-166.01%
2.5	99.9080	0.0484	-38.25%	-0.02%	-36.36%	-166.06%
3.5	99.8596	0.0565	-39.39%	-0.02%	-37.01%	-166.12%
4.5	99.8031	0.0655	-40.57%	-0.03%	-37.69%	-166.19%
5.5	99.7376	0.0757	-41.79%	-0.03%	-38.41%	-166.28%
6.5	99.6619	0.0870	-43.05%	-0.04%	-39.17%	-166.37%
7.5	99.5749	0.0997	-44.34%	-0.04%	-39.96%	-166.48%
8.5	99.4752	0.1137	-45.67%	-0.05%	-40.79%	-166.60%
9.5	99.3615	0.1292	-47.04%	-0.06%	-41.66%	-166.74%
10.5	99.2323	0.1463	-48.45%	-0.07%	-42.57%	-166.90%
11.5	99.0860	0.1650	-49.90%	-0.08%	-43.51%	-167.07%
12.5	98.9210	0.1855	-51.40%	-0.10%	-44.49%	-167.27%
13.5	98.7355	0.2078	-52.94%	-0.11%	-45.50%	-167.48%
14.5	98.5276	0.2321	-54.53%	-0.13%	-46.55%	-167.73%
15.5	98.2956	0.2583	-56.16%	-0.15%	-47.64%	-167.99%
16.5	98.0373	0.2867	-57.85%	-0.17%	-48.76%	-168.29%
17.5	97.7506	0.3172	-59.59%	-0.19%	-49.92%	-168.61%
18.5	97.4334	0.3499	-61.37%	-0.21%	-51.11%	-168.97%
19.5	97.0835	0.3850	-63.21%	-0.24%	-52.34%	-169.35%
20.5	96.6985	0.4225	-65.11%	-0.28%	-53.61%	-169.78%
21.5	96.2761	0.4624	-67.06%	-0.31%	-54.92%	-170.24%
22.5	95.8137	0.5049	-69.08%	-0.35%	-56.26%	-170.73%
23.5	95.3088	0.5500	-71.15%	-0.39%	-57.64%	-171.27%
24.5	94.7588	0.5978	-73.28%	-0.44%	-59.05%	-171.85%
25.5	94.1610	0.6485	-75.48%	-0.49%	-60.51%	-172.48%
26.5	93.5125	0.7022	-77.75%	-0.55%	-62.01%	-173.15%
27.5	92.8103	0.7589	-80.08%	-0.61%	-63.54%	-173.87%
28.5	92.0514	0.8189	-82.48%	-0.68%	-65.12%	-174.65%
29.5	91.2325	0.8823	-84.95%	-0.75%	-66.74%	-175.47%
30.5	90.3502	0.9494	-87.50%	-0.83%	-68.41%	-176.36%
31.5	89.4008	1.0202	-90.13%	-0.92%	-70.12%	-177.30%
32.5	88.3806	1.0951	-92.83%	-1.02%	-71.88%	-178.31%
33.5	87.2855	1.1744	-95.62%	-1.12%	-73.68%	-179.38%
34.5	86.1111	1.2581	-98.49%	-1.24%	-75.54%	-180.52%
35.5	84.8530	1.3465	-101.44%	-1.37%	-77.44%	-181.74%
36.5	83.5066	1.4397	-104.48%	-1.50%	-79.40%	-183.03%
37.5	82.0669	1.5377	-107.62%	-1.65%	-81.41%	-184.41%
38.5	80.5292	1.6407	-110.85%	-1.82%	-83.48%	-185.88%
39.5	78.8885	1.7482	-114.17%	-2.00%	-85.61%	-187.44%
40.5	77.1403	1.8601	-117.60%	-2.19%	-87.79%	-189.10%
41.5	75.2802	1.9756	-121.12%	-2.39%	-90.04%	-190.87%
42.5	73.3046	2.0941	-124.76%	-2.61%	-92.34%	-192.75%
43.5	71.2105	2.2144	-128.50%	-2.85%	-94.70%	-194.75%
44.5	68.9962	2.3351	-132.36%	-3.09%	-97.11%	-196.87%
45.5	66.6611	2.4545	-136.33%	-3.35%	-99.58%	-199.13%
46.5	64.2066	2.5708	-140.42%	-3.61%	-102.10%	-201.53%
47.5	61.6358	2.6816	-144.63%	-3.88%	-104.67%	-204.08%
48.5	58.9542	2.7845	-148.97%	-4.15%	-107.28%	-206.79%
49.5	56.1697	2.8769	-153.44%	-4.41%	-109.93%	-209.65%
50.5	53.2929	2.9561	-158.04%	-4.67%	-112.61%	-212.69%
51.5	50.3368	3.0194	-162.78%	-4.91%	-115.31%	-215.90%
52.5	47.3175	3.0643	-167.66%	-5.14%	-118.03%	-219.28%

The Narragansett Electric Company - Gas Plant

Account 380 Services

Calculation of Average and Future Net Salvage Based on Table 6.11 of Wolf and Fitch

Annual Inflation Rate	3.00%
Net Salvage at Age 0	-35.00%

Age (a)	% Surviving (b)	% Retired (c)	NS % (d)	Weighted NS % (e)	Realized NS (f)	Future NS (g)
53.5	44.2532	3.0887	-172.69%	-5.33%	-120.76%	-222.86%
54.5	41.1645	3.0906	-177.88%	-5.50%	-123.49%	-226.62%
55.5	38.0739	3.0690	-183.21%	-5.62%	-126.20%	-230.58%
56.5	35.0049	3.0231	-188.71%	-5.70%	-128.89%	-234.73%
57.5	31.9818	2.9532	-194.37%	-5.74%	-131.55%	-239.08%
58.5	29.0286	2.8601	-200.20%	-5.73%	-134.16%	-243.63%
59.5	26.1686	2.7454	-206.21%	-5.66%	-136.72%	-248.38%
60.5	23.4232	2.6117	-212.39%	-5.55%	-139.21%	-253.32%
61.5	20.8115	2.4619	-218.76%	-5.39%	-141.63%	-258.46%
62.5	18.3496	2.2994	-225.33%	-5.18%	-143.95%	-263.79%
63.5	16.0502	2.1281	-232.09%	-4.94%	-146.18%	-269.29%
64.5	13.9221	1.9518	-239.05%	-4.67%	-148.31%	-274.98%
65.5	11.9703	1.7742	-246.22%	-4.37%	-150.32%	-280.84%
66.5	10.1961	1.5985	-253.61%	-4.05%	-152.21%	-286.87%
67.5	8.5976	1.4277	-261.22%	-3.73%	-153.99%	-293.05%
68.5	7.1700	1.2639	-269.05%	-3.40%	-155.63%	-299.39%
69.5	5.9061	1.1087	-277.12%	-3.07%	-157.16%	-305.88%
70.5	4.7975	0.9630	-285.44%	-2.75%	-158.56%	-312.52%
71.5	3.8345	0.8273	-294.00%	-2.43%	-159.83%	-319.33%
72.5	3.0072	0.7015	-302.82%	-2.12%	-160.97%	-326.29%
73.5	2.3057	0.5855	-311.91%	-1.83%	-161.99%	-333.44%
74.5	1.7202	0.4792	-321.26%	-1.54%	-162.88%	-340.76%
75.5	1.2411	0.3824	-330.90%	-1.27%	-163.65%	-348.29%
76.5	0.8587	0.2954	-340.83%	-1.01%	-164.30%	-356.04%
77.5	0.5632	0.2187	-351.05%	-0.77%	-164.82%	-364.02%
78.5	0.3445	0.1528	-361.58%	-0.55%	-165.23%	-372.25%
79.5	0.1917	0.0986	-372.43%	-0.37%	-165.53%	-380.75%
80.5	0.0931	0.0564	-383.60%	-0.22%	-165.73%	-389.56%
81.5	0.0367	0.0267	-395.11%	-0.11%	-165.86%	-398.73%
82.5	0.0100	0.0088	-406.97%	-0.04%	-165.92%	-408.41%
83.5	0.0012	0.0012	-419.17%	0.00%	-165.94%	-419.17%
84.5	0.0000				-165.94%	
			Average NS =	**-165.94%**		

Schedule __ (NWA-6R)

Calculation of average and future net salvage for Account 380, Services

based on Table 6.11 of Wolf and Fitch and 4 percent inflation rate

The Narragansett Electric Company - Gas Plant

Account 380 Services

Calculation of Average and Future Net Salvage Based on Table 6.11 of Wolf and Fitch

Annual Inflation Rate	4.00%
Net Salvage at Age 0	-35.00%

Age (a)	% Surviving (b)	% Retired (c)	NS % (d)	Weighted NS % (e)	Realized NS (f)	Future NS (g)
0	100.0000	0.0155	-35.00%	-0.01%	0.00%	-284.57%
0.5	99.9845	0.0351	-36.40%	-0.01%	-35.00%	-284.60%
1.5	99.9494	0.0414	-37.86%	-0.02%	-35.97%	-284.69%
2.5	99.9080	0.0484	-39.37%	-0.02%	-36.82%	-284.79%
3.5	99.8596	0.0565	-40.95%	-0.02%	-37.70%	-284.91%
4.5	99.8031	0.0655	-42.58%	-0.03%	-38.63%	-285.05%
5.5	99.7376	0.0757	-44.29%	-0.03%	-39.62%	-285.21%
6.5	99.6619	0.0870	-46.06%	-0.04%	-40.66%	-285.39%
7.5	99.5749	0.0997	-47.90%	-0.05%	-41.77%	-285.60%
8.5	99.4752	0.1137	-49.82%	-0.06%	-42.93%	-285.84%
9.5	99.3615	0.1292	-51.81%	-0.07%	-44.16%	-286.11%
10.5	99.2323	0.1463	-53.88%	-0.08%	-45.45%	-286.42%
11.5	99.0860	0.1650	-56.04%	-0.09%	-46.80%	-286.76%
12.5	98.9210	0.1855	-58.28%	-0.11%	-48.21%	-287.14%
13.5	98.7355	0.2078	-60.61%	-0.13%	-49.69%	-287.57%
14.5	98.5276	0.2321	-63.03%	-0.15%	-51.23%	-288.05%
15.5	98.2956	0.2583	-65.55%	-0.17%	-52.83%	-288.58%
16.5	98.0373	0.2867	-68.18%	-0.20%	-54.51%	-289.17%
17.5	97.7506	0.3172	-70.90%	-0.22%	-56.25%	-289.82%
18.5	97.4334	0.3499	-73.74%	-0.26%	-58.06%	-290.53%
19.5	97.0835	0.3850	-76.69%	-0.30%	-59.94%	-291.31%
20.5	96.6985	0.4225	-79.76%	-0.34%	-61.90%	-292.17%
21.5	96.2761	0.4624	-82.95%	-0.38%	-63.92%	-293.10%
22.5	95.8137	0.5049	-86.27%	-0.44%	-66.02%	-294.11%
23.5	95.3088	0.5500	-89.72%	-0.49%	-68.20%	-295.22%
24.5	94.7588	0.5978	-93.30%	-0.56%	-70.46%	-296.41%
25.5	94.1610	0.6485	-97.04%	-0.63%	-72.80%	-297.70%
26.5	93.5125	0.7022	-100.92%	-0.71%	-75.22%	-299.09%
27.5	92.8103	0.7589	-104.95%	-0.80%	-77.73%	-300.59%
28.5	92.0514	0.8189	-109.15%	-0.89%	-80.33%	-302.20%
29.5	91.2325	0.8823	-113.52%	-1.00%	-83.02%	-303.93%
30.5	90.3502	0.9494	-118.06%	-1.12%	-85.81%	-305.79%
31.5	89.4008	1.0202	-122.78%	-1.25%	-88.70%	-307.79%
32.5	88.3806	1.0951	-127.69%	-1.40%	-91.69%	-309.92%
33.5	87.2855	1.1744	-132.80%	-1.56%	-94.79%	-312.21%
34.5	86.1111	1.2581	-138.11%	-1.74%	-98.01%	-314.66%
35.5	84.8530	1.3465	-143.64%	-1.93%	-101.34%	-317.27%
36.5	83.5066	1.4397	-149.38%	-2.15%	-104.79%	-320.07%
37.5	82.0669	1.5377	-155.36%	-2.39%	-108.37%	-323.07%
38.5	80.5292	1.6407	-161.57%	-2.65%	-112.08%	-326.27%
39.5	78.8885	1.7482	-168.04%	-2.94%	-115.93%	-329.69%
40.5	77.1403	1.8601	-174.76%	-3.25%	-119.91%	-333.36%
41.5	75.2802	1.9756	-181.75%	-3.59%	-124.04%	-337.28%
42.5	73.3046	2.0941	-189.02%	-3.96%	-128.31%	-341.47%
43.5	71.2105	2.2144	-196.58%	-4.35%	-132.73%	-345.95%
44.5	68.9962	2.3351	-204.44%	-4.77%	-137.29%	-350.75%
45.5	66.6611	2.4545	-212.62%	-5.22%	-141.99%	-355.87%
46.5	64.2066	2.5708	-221.12%	-5.68%	-146.83%	-361.35%
47.5	61.6358	2.6816	-229.97%	-6.17%	-151.81%	-367.20%
48.5	58.9542	2.7845	-239.17%	-6.66%	-156.92%	-373.44%
49.5	56.1697	2.8769	-248.73%	-7.16%	-162.14%	-380.09%
50.5	53.2929	2.9561	-258.68%	-7.65%	-167.48%	-387.19%
51.5	50.3368	3.0194	-269.03%	-8.12%	-172.91%	-394.73%
52.5	47.3175	3.0643	-279.79%	-8.57%	-178.41%	-402.75%

The Narragansett Electric Company - Gas Plant

Account 380 Services

Calculation of Average and Future Net Salvage Based on Table 6.11 of Wolf and Fitch

Annual Inflation Rate	4.00%
Net Salvage at Age 0	-35.00%

Age (a)	% Surviving (b)	% Retired (c)	NS % (d)	Weighted NS % (e)	Realized NS (f)	Future NS (g)
53.5	44.2532	3.0887	-290.98%	-8.99%	-183.99%	-411.27%
54.5	41.1645	3.0906	-302.62%	-9.35%	-189.60%	-420.29%
55.5	38.0739	3.0690	-314.73%	-9.66%	-195.24%	-429.84%
56.5	35.0049	3.0231	-327.32%	-9.90%	-200.89%	-439.94%
57.5	31.9818	2.9532	-340.41%	-10.05%	-206.51%	-450.58%
58.5	29.0286	2.8601	-354.03%	-10.13%	-212.08%	-461.79%
59.5	26.1686	2.7454	-368.19%	-10.11%	-217.58%	-473.57%
60.5	23.4232	2.6117	-382.91%	-10.00%	-222.98%	-485.92%
61.5	20.8115	2.4619	-398.23%	-9.80%	-228.25%	-498.85%
62.5	18.3496	2.2994	-414.16%	-9.52%	-233.38%	-512.34%
63.5	16.0502	2.1281	-430.73%	-9.17%	-238.33%	-526.41%
64.5	13.9221	1.9518	-447.96%	-8.74%	-243.08%	-541.04%
65.5	11.9703	1.7742	-465.87%	-8.27%	-247.63%	-556.21%
66.5	10.1961	1.5985	-484.51%	-7.74%	-251.94%	-571.93%
67.5	8.5976	1.4277	-503.89%	-7.19%	-256.01%	-588.19%
68.5	7.1700	1.2639	-524.04%	-6.62%	-259.82%	-604.97%
69.5	5.9061	1.1087	-545.01%	-6.04%	-263.37%	-622.29%
70.5	4.7975	0.9630	-566.81%	-5.46%	-266.65%	-640.15%
71.5	3.8345	0.8273	-589.48%	-4.88%	-269.65%	-658.57%
72.5	3.0072	0.7015	-613.06%	-4.30%	-272.38%	-677.58%
73.5	2.3057	0.5855	-637.58%	-3.73%	-274.83%	-697.21%
74.5	1.7202	0.4792	-663.08%	-3.18%	-276.99%	-717.50%
75.5	1.2411	0.3824	-689.61%	-2.64%	-278.86%	-738.52%
76.5	0.8587	0.2954	-717.19%	-2.12%	-280.45%	-760.30%
77.5	0.5632	0.2187	-745.88%	-1.63%	-281.74%	-782.91%
78.5	0.3445	0.1528	-775.71%	-1.19%	-282.76%	-806.41%
79.5	0.1917	0.0986	-806.74%	-0.80%	-283.52%	-830.88%
80.5	0.0931	0.0564	-839.01%	-0.47%	-284.03%	-856.43%
81.5	0.0367	0.0267	-872.57%	-0.23%	-284.35%	-883.24%
82.5	0.0100	0.0088	-907.48%	-0.08%	-284.50%	-911.77%
83.5	0.0012	0.0012	-943.78%	-0.01%	-284.56%	-943.78%
84.5	0.0000				-284.57%	
			Average NS =	**-284.57%**		

REBUTTAL TESTIMONY

OF

JOSEPH F. GREDDER

Dated: May 9, 2018

Table of Contents

I. <u>Introduction</u>

Q. Please state your name, position, and business address.

A. My name is Joseph F. Gredder. I am Manager of Electric Regulatory Support in the Advanced Data and Analytics group in the Business Services function for National Grid USA Service Company, Inc. (Service Company), a subsidiary of National Grid USA (National Grid). My business address is 175 East Old Country Road, Hicksville, New York 11801.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this rebuttal testimony on behalf of The Narragansett Electric Company d/b/a National Grid (the Company).

Q. Are you the same Joseph F. Gredder who previously filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the direct testimony of Karl R. Rábago, Executive Director, Pace Energy and Climate Center, who submitted pre-filed direct testimony on behalf of New Energy Rhode Island (NERI) in response to the Company's forecast of electric deliveries and customer counts the Company presented in its direct testimony in support of its requested revenue requirement and rate design for Narragansett Electric.

Q. Would you please explain the naming conventions that you will be using in your testimony to identify the various entities involved in this proceeding?

A. This proceeding is a ratemaking proceeding for the electric and gas distribution operations of The Narragansett Electric Company, which constitute the regulated operations that National Grid conducts in Rhode Island. In this case, I will refer to the regulated entity as the "Company," where the reference is to both electric and gas distribution operations on a collective basis. Where there is a need to refer to the "stand-alone" or individual electric operations of The Narragansett Electric Company, I will use the term "Narragansett Electric". Where I refer to "National Grid USA," I will use the term "National Grid;" where I refer to "National Grid plc," I will use that specific term.

II. Summary and Overview of Testimony

Q. Please provide an overview of your response to Mr. Rábago's testimony regarding the Company's forecast of electric deliveries and customer counts used to support the revenue requirement and rate design for Narragansett Electric presented in the Company's filing.

A. Please see below for a discussion of each item. In summary, I recommend that the PUC accept the Company's original testimony and positions as is.

A. <u>Response to Mr. Rábago's Direct Testimony</u>

Q. Please provide a brief summary of Mr. Rábago's testimony.

A. Mr. Rábago argues that the Company's forecasting assumptions and methodologies do not incorporate distributed energy resources appropriately in alignment with Rhode Island's Power Sector Transformation goals. Specifically, Mr. Rábago criticizes the Company's use of ten-year averages to forecast cooling degree and heating degree days, suggesting that it should investigate using averages from as long as a 30-year period to account for the impacts of climate change. Mr. Rábago further criticizes the Company's use of weather normalization to forecast customer demand, contending that the Company should complement its forecasting with some unidentified "innovative" alternative forecasting methods for addressing climate variability. Mr. Rábago further suggests that the Company's use of actual data from its PUC-approved energy efficiency programs and ISO-NE forecasts is an improper basis to forecast energy efficiency and solar photovoltaic (PV) penetration, but provides no specific preferred alternative. Overall, Mr. Rábago concludes that the Company's forecasts did not account for Power Sector Transformation, but he provides no recommendation for an alternative approach.

Q. Do any of Mr. Rábago's criticisms have merit?

A. No. Mr. Rábago's suggestions are unsupported and speculative. The Company's forecasting methodologies are aligned with best practices in the utility industry, and, as Mr. Rábago admits in his testimony, those practices fairly account for weather anomalies that result from climate change. Although Mr. Rábago suggests that the Company should include alternative methods to complement its existing forecasting practices, he provides no specifics as to what alternative methods the Company should employ. Further, Mr. Rábago's testimony does not describe accurately the Company's forecasting methodologies and, therefore, ignores certain characteristics of those methodologies that contradict Mr. Rábago's concerns.

Q. Can you explain how the Company's forecasting methods produce the most reliable prediction of Rhode Island's future level of reliance on energy efficiency and clean distributed renewable energy generation?

A. Yes. The Company's forecasting methods incorporate PUC-approved short-term energy efficiency program goals and ISO-NE's long-term methods and targets for PV generation projections. As described in my response to data request NERI 3-5 in this proceeding, the ISO-NE forecasting process includes multiple market participants, including, but not limited to State agencies, such as the Rhode Island Office of Energy Resources, distributed generation developers, financers, environmental groups, and regulators. The ISO-NE process fully considers all State policy and market trends. In short, contrary to Mr. Rábago's assertions, the Company's forecasts fully consider the potential of energy efficiency, solar energy generation, gas efficiency programs, and market development.

Q. How do the Company's forecasting methods reflect an internalization of the goals and direction of Power Sector Transformation?

A. The Company's forecasting methods take into account all relevant and reliable information to develop the most accurate forecast possible. That includes the Company's reasonable expectation for the impacts of Power Sector Transformation. Power Sector Transformation does not have specific goals for energy efficiency and solar energy generation. The most reliable indicators of increased reliance on energy efficiency and solar generation for the period covered by the proposed rates and rate design are the energy efficiency programs approved by the PUC and the ISO-NE forecasts for solar generation. Accordingly, the Company's use of those data points is the most reasonable and reliable forecasting method.

Q. **Why is the Company's use of ten-year averages to forecast heating and cooling degree days and to develop weather coefficients preferable to the use of longer averages, like 30-year averages?**

A. Mr. Rábago's testimony on this point is inconsistent and confusing. First, he describes the Company's use of ten-year averages as preferable to the use of 30-year averages by other utilities. Then, he suggests that the Company should consider using averages as long as 30 years to calculate averages used for forecasts and weather coefficients. Those positions are contradictory. Notably, notwithstanding Mr. Rábago's contradictory position, the Company's use of a ten-year average for determining weather normalization is the same window used in the sales forecast and is appropriate for the time period involved here – the twelve-month period ended August 31, 2019 (the Rate Year) and the two twelve-month period ended August 31, 2020 and August 31, 2021 (collectively, the

Data Years). Importantly, the basis for rate design is predicated on the use of "normal" weather. The Company uses a longer (20 year) window for its weather adjustment process for the peak forecast.

Q. Mr. Rábago testifies regarding the Company's reliance on weather normalization to develop forecasts and recommends that the Company should investigate opportunities to adapt its methods to climate trends and supplement its assessment with alternative methods. Do you agree with this recommendation?

A. No. The Company does not rely solely on "normal," or average weather for its peak forecasting process. The peak forecasting process is used as the basis for reliability and capital planning for the network. For that process, in addition to "normal" weather, the Company also incorporates two extreme weather scenarios into its forecasting methodology. These include a 90/10, or a "1 in 10" scenario and a 95/5, or a "1 in 20" scenario. These scenarios provide for peak forecasts based on severely hot summers and are the basis for transmission and distribution planning. These are intended to be scenarios where the likelihood of exceeding them is much lower than normal (average). The 90/10 and 95/5 extreme weather scenarios fully include the variability and changing nature of weather in their calculation by including, among other items, the variability of the peak producing weather over the last twenty years.

Q. Why are the use of the PUC-approved energy efficiency budgets and the ISO-NE forecasts the most reliable data points for forecasting the impacts of Power Sector Transformation?

A. In addition to the reasons identified above regarding why the use of these data points is the most reliable basis to generate forecasts, generally, these data points also are best suited to account for the impacts of Power Sector Transformation for at least two additional reasons. First, the PUC-approved energy efficiency programs are a reflection of actual planned future energy efficiency activity, without additional speculation about uncertain additional energy efficiency implementation that might result because of Power Sector Transformation. Second, the ISO-NE solar forecasts are based on data about planned development (not guesswork) regarding potential additional projects the might be induced by Power Sector Transformation.

Q. Do you agree with Mr. Rábago's suggestion that the PUC open an investigation or other proceeding to review the issue of utility forecasting to inform future rate case filings? Why or why not?

A. No. I am the Company's representative on the ISO-NE's Load Forecasting Committee. This working group is open to the public and meets approximately five to six times per year to discuss forecasting best practices. The working group also reviews the annual forecasting process that ISO-NE uses for each of the New England states. These forecasts include the impacts of distributed energy resources. This working group enables the Company to stay abreast of the most up-to-date forecasting techniques being used in New England. I am also one of the Company's representatives on the ISO-NE's Energy Efficiency Working Group and ISO-NE's Distributed Generation Working Group, which discusses in detail the projections for PV in each of the New England states. Both of these working groups are open public committees, which share best practices in the region. The Company leverages the knowledge and experience gained from participation in these committees and working groups when it prepares distributed energy resource projections. The Company is, therefore, on the forefront of trends in forecasting methodology, including projections for energy efficiency and solar generation that result from increased distributed energy resource development. There is, therefore, no reason for the PUC to open an investigation or proceeding to review utility forecasting.

Q. Mr. Rábago claims that the Company's assumptions of declining growth in efficiency and solar PV are markedly out of step with the policy in Rhode Island and the PUC's agenda for Power Sector Transformation. He also recommends that the Company should develop alternative scenario forecasts that align with Power Sector Transformation and increasing growth in distributed energy resource markets, with a view toward developing more reasonable forecasts of energy sales. What is your response to this recommendation?

A. The Company projects continued installations of energy efficiency and solar PV. In my pre-filed direct testimony in Schedule JFG-10, energy efficiency savings are projected to increase from their 2017 level of 1,718 GWh in annual reductions to 2,509 GWh annually by year 2021. This increases the energy efficiency share of sales reductions from 18.7 percent in 2017 to more than 25 percent by year 2021.

As a result of solar PV, the Company projects electric sales reductions to increase from 75 GWh (or 0.8 percent of sales) in 2017 to 252 GWh (or 2.5 percent of sales) by year 2021. That is a projected increase in PV savings of more than 300 percent. The use of the word “declining” throughout Mr. Rábago’s testimony masks the fact that the Company clearly projects continued, significant growth in both energy efficiency and solar-PV reductions.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

REBUTTAL TESTIMONY

OF

THEODORE E. POE, JR.

Dated: May 9, 2018

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I. <u>Introduction</u>

Q. Please state your name and business address.

A. My name is Theodore E. Poe, Jr. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes. On November 27, 2017, I submitted direct testimony in this proceeding in support of The Narragansett Electric Company d/b/a National Grid's[1] (the Company) historical and forecast gas customer count and customer demand data used to support the revenue requirement and rate design for Narragansett Gas presented in this proceeding. My testimony demonstrates the thorough process Narragansett Gas undertakes to develop the gas sales forecast used in the allocated cost of service study and rate design process to determine rates that will produce revenue for each rate class as determined in the revenue allocation process.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the direct testimony submitted to the Public Utilities Commission (PUC) in this proceeding by Karl R. Rabago on behalf of New Energy Rhode Island (NERI) on Narragansett Gas' forecasting assumptions and methodologies.

[1] The Narragansett Electric Company d/b/a National Grid constitutes the regulated operations that National Grid USA conducts in Rhode Island. In this case, I will refer to the regulated entity as the "Company," where the reference is to both gas and electric distribution operations on a collective basis. Where there is a need to refer to the "stand-alone" or individual electric or gas operations of The Narragansett Electric Company, I will use the terms "Narragansett Electric" or "Narragansett Gas," respectively, as appropriate.

In particular, my rebuttal testimony substantiates Narragansett Gas' forecasting methodology and responds to certin assertions made by Mr. Rabago in his testimony.

II. Gas Sales Forecast Assumptions and Methodology

Q. Does Mr. Rabago agree with Narragansett Gas' use of a 10-year average for determining weather normalization?

A. Yes. Mr. Rabago agrees that Narragansett Gas' use of a 10-year average for determining weather normalization is appropriate for the short term.

Q. Does Mr. Rabago make any suggestions as to the foundation for Narragansett Gas' forecast of cooling degree and heating degree days?

A. Yes. Despite finding that Narragansett Gas' use of a 10-year average is reasonable and preferable to a 30-year average, Mr. Rabago believes that Narragansett Gas should investigate the use of longer averages, such as 30 years, in calculating the averages used for forecasts and in developing weather coefficients.

Q. Does Narragansett Gas agree with Mr. Rabago's suggestion to take into account a longer average?

A. No. For this proceeding, Narragansett Gas established its 10-year normal heating degree days using data ending March 31, 2017 (see Direct Testimony of Theodore E. Poe, Jr. (Poe Direct Testimony) at page 15). This 10-year window is used in Narragansett Gas' sales forecast and is appropriate for the short-term nature of this proceeding, namely, the twelve-month period ended August 31, 2019 (the Rate Year) and the two twelve-month periods ended August 31, 2020 and August 31, 2021 (the Data Years). Note that the basis for rate design is predicated on the use of "normal" weather. For the determination of its design weather standards (i.e., design day and design year), Narragansett Gas uses a longer window – namely, a moving 40-year average. This balances the need to reflect climate changes with the stability of Narragansett Gas' standards in its forecast. The use of 40 years of data is appropriate in identifying the probability of rare events like a design day or a design year. Using a moving average of the 40 years of data allows changes in climate to be reflected in the design standards.

Q. Mr. Rabago's testimony takes issue with Narragansett Gas' use of regression analysis on historical weather data to develop "normal" weather estimates, and he suggests that such estimates should be complemented by alternative and innovative tools for assessing climate variability and trends and integrating this information into its forecasts. Do you agree with Mr. Rabago's characterization of Narragansett Gas' reliance on "normal" weather estimates?

A. No. Narragansett Gas does not rely on "normal," or average, weather for its design weather forecasting process. Rather, Narragansett Gas uses the design weather forecasting process as the basis for reliability of its resources portfolio and capital planning for the gas distribution network. For the design weather forecasting process, Narragansett Gas develops its design planning standards based on its benefit/cost analyses to establish its design day (i.e., the largest one-day throughput requirements of the system) and its design year (i.e., the necessary annual inventory requirements for underground storage and supplementals).

Q. Is Narragansett Gas willing to review its weather normalization methods and use of 10-year historical forecast, as suggested by Mr. Rabago?

A. Yes. As mentioned earlier, Mr. Rabago agrees with Narragansett Gas' use of a 10-year average for determining weather normalization. This 10-year window is used in Narragansett Gas' sales forecast and is appropriate for the short-term nature of this proceeding, i.e., the Rate Year and Data Years. In any event, Narragansett Gas internally reviews its forecasting process on an annual basis, including its weather normalization and its design planning standards, to ensure the reasonableness of its forecasts. In addition, every two years, Narragansett Gas submits its Long-Range Resource and Requirements Plan (Long-Range Plan) for review by the PUC and Division of Public Utilities and Carriers (Division). Most recently, on March 30, 2018, Narragansett Gas filed its Long-Range Plan with the PUC for the forecast period 2017/18 to 2026/27 in Docket No. 4816.

Q. Do you agree with Mr. Rabago's statement that, because Narragansett Gas has not seen any significant delivery reduction effects for residential customers due to efficiency programs, the forecast does not include any efficiency effects for those customers?

A. No. As Narragansett Gas' historical volume data reflects the impact of its historical energy efficiency programs on the market, Narragansett Gas will adjust its forecast for future energy efficiency programs when those programs lead to demand reductions greater than its historical reductions. Through this process, Narragansett Gas ensures that it does not double count the impact of its energy efficiency programs on its volume forecast (see Poe Direct Testimony at page 9). Narragansett Gas' energy efficiency goals are established in a separate proceeding.

Q. What is Narragansett Gas' response to Mr. Rabago's recommendation that the PUC establish an investigatory or other proceeding to review and recommend improvements in utility forecasting, in particular to address the impacts of Power Sector Transformation and climate change?

A. As I mentioned earlier, every two years Narragansett Gas submits its Long-Range Plan for review by the PUC and Division, during which Narragansett Gas is open to recommendations for improvements in forecasting. Narragansett Gas' most recent Long-Range Plan currently is subject to review before the PUC and Division in Docket No. 4816.

III. Conclusion

Q. Does this conclude your testimony?

A. Yes.

JOINT REBUTTAL TESTIMONY

OF

JOHN GILBERT

DANIEL J. DEMAURO

AND

MUKUND RAVIPATY

Dated: May 9, 2018

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I. <u>Introduction</u>

John Gilbert

Q. Please state your name and business address.

A. My name is John Gilbert. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid UK as Senior Vice President and acting U.S. Chief Information Officer. In this position, I am responsible for leading and continuously improving the performance of the Information Services (IS) organization, overseeing internal IS workforce development, and partnering with other aspects of National Grid's organization to develop, build, and implement new technologies and IS strategies to support business initiatives and customer needs.

Q. Please describe your educational background and professional experience.

A. In 1989, I received an HND (Degree equivalent) in Electronic Engineering from Anglia Ruskin University in the United Kingdom (UK). From 1984 to 1989, I worked in Electronic Engineering for Marconi International Marine. From 1989 to 1994, I worked for Digital Equipment Co. Ltd. as a System Engineer and later as a Software Consultant. In 1994, I joined Reuters and held a number of Senior Technology Leadership roles spanning a period of 19 years. I joined National Grid in 2013 as the Head of UK Customer Service Management. In 2015, I became the Global Head of IS Service

Delivery, where I was accountable for all production Information Technology (IT) services for National Grid in both the UK and the United States (US). I transferred to the US in 2017, and, in 2018, I became the acting US Chief Information Officer.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (PUC) or any other regulatory commission?

A. No. I have not previously testified before the PUC or any other regulatory commission.

Q. Do you adopt the testimony of Anuraag Bhargava, who submitted initial joint pre-filed direct testimony in this docket together with Daniel J. DeMauro and Mukund Ravipaty?

A. Yes. I adopt the testimony of Anuraag Bhargava, who is no longer employed by National Grid.

Daniel J. DeMauro

Q. Mr. DeMauro, please state your full name and business address.

A. My name is Daniel J. DeMauro. My business address is 300 Erie Boulevard West, Syracuse, New York 13202.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes. I submitted joint pre-filed direct testimony on November 27, 2017 together with Mr. Bhargava and Mr. Ravipaty.

Mukund Ravipaty

Q. Mr. Ravipaty, please state your full name and business address.

A. My name is Mukund Ravipaty. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes. I submitted joint pre-filed direct testimony on November 27, 2017 together with Mr. Bhargava and Mr. DeMauro.

Q. On whose behalf are you submitting this joint rebuttal testimony?

A. We are submitting this joint rebuttal testimony on behalf of The Narragansett Electric Company d/b/a National Grid (the Company).

Q. What is the purpose of your rebuttal testimony?

A. Our rebuttal testimony responds to the joint direct testimony of Michael R. Ballaban and David Effron, who testified on behalf of the Rhode Island Division of Public Utilities and Carriers (Division) regarding the prudency of new Information Services (IS) investments.

II. Summary and Overview of Testimony

Q. Please provide an overview of the recommendations contained in the direct testimony of Michael R. Ballaban and David Effron regarding the Company's proposed IS investments and the revenue requirement for those investments, excluding the Gas Business Enablement Program.

A. The Division proposes adjustments to the Company's revenue requirement and recommends:

- That the PUC limit the Company's cost recovery of capital in the twelve-month period ended August 31, 2019 (the Rate Year) to 85 percent of the allocated Service Company Rents revenue requirement to Narragansett Electric and Narragansett Gas, as filed by the Company in Docket No. 4770 for IS and GBE investments placed in-service after the Test Year;
- That the PUC allow the Company to create a regulatory asset to defer the balance of charges for future recovery subject to the Company's demonstration of cost and implementation results in the event actual IS and GBE costs related to these investments are greater than 85%, but do not exceed filed amounts;
- That the PUC require the Company to create a regulatory liability to defer the balance of charges for the benefit of customers; and
- That the PUC order the Company to obtain an independent audit of IT services and cybersecurity.

Q. Please summarize your response to Mr. Ballaban and Mr. Effron's testimony regarding the prudency of National Grid's IS investments.

A. National Grid can deliver the IS project portfolio that it has proposed in the case. The proposed limitation on cost recovery to 85 percent of capital in the Rate Year for allocated Service Company Rents revenue requirement is unjustified and improper. National Grid has taken steps to increase its project delivery capacity by hiring additional Program Delivery staff and Program Assurance staff. These added positions will ensure that National Grid will deliver its planned portfolio on a timely and cost effective basis.

National Grid also has vendor partners available to ensure effective delivery of National Grid's technology modernization and digital transformation strategy.

Lastly, the PUC should reject the Division's recommendation that the Company perform an independent audit of information Technology (IT) services and cybersecurity. An independent audit of IT services and cybersecurity is unwarranted and unnecessary because, as described below, National Grid has established significant process review and audit procedures in the past few years that will assure the project and cost management discipline for National Grid's IS investments that the Division asserts would result from the independent audit. As a result, an independent audit would not produce any incremental value in terms of protection for Rhode Island customers.

Q. Would you please explain the naming conventions that you will be using in your testimony to identify the various entities involved in this proceeding?

A. This proceeding is a ratemaking proceeding for the electric and gas distribution operations of The Narragansett Electric Company, which constitute the regulated operations that National Grid conducts in Rhode Island. In this case, we will refer to the regulated entity as the "Company," where the reference is to both electric and gas distribution operations on a collective basis. Where there is a need to refer to the "stand-alone" or individual electric or gas operations of The Narragansett Electric Company, we will use the terms "Narragansett Electric" or "Narragansett Gas," respectively, as appropriate. Where we refer to "National Grid USA," we will use the term "National Grid;" where we refer to "National Grid plc," we will use that specific term.

III. <u>Response to Mr. Ballaban's and Mr. Effron's Direct Testimony</u>

Q. Do you agree with Mr. Ballaban's and Mr. Effron's recommendation that the PUC should reduce the total budget for all new IS projects included in the Rate Year by 15 percent?

A. No. Mr. Ballaban and Mr. Effron do not consider that, in Fiscal Years (FY) 2014 and 2015, National Grid's IS resources were focused intently on addressing post-implementation issues with the U.S. Foundation Program (USFP). Therefore, investment on IS projects other than USFP was held in abeyance to assure that projects did not proceed without the requisite management resources. This contributed to the relatively lower capital budgets in FY 2014 and FY 2015. This circumstance will not exist in the Rate Year and the two twelve-month periods ended August 31, 2020 and August 31, 2021 (the Data Years). As a result, there is no basis to conclude that National Grid will not fulfill the IS budget plan in the Rate Year and Data Years.

Ultimately, the proposed adjustment would mean that the Company: (1) will not reasonably recover the costs of necessary, prudent, and beneficial investments for customers; and/or (2) will not be able to address adequately aged infrastructure and application issues that create operational risk and system downtime. The proposed IS investments are critical to National Grid's ability to undertake future enhancements to National Grid's systems and to address emerging business demand for technological improvements.

In particular, National Grid's proposed investments to upgrade IS infrastructure and applications are necessary to enable benefits to customers from initiatives such as the Customer Contact Center Technology Upgrade, providing adequate cybersecurity and physical security protections to customer data and business operations, and enhancing integration to improve user experience with significant investments, such as Gas Business Enablement. As Mr. Ballaban and Mr. Effron acknowledge, National Grid's sanctioning process to vet proposed projects and develop project budgets "is reasonable and appears to be followed for the IS projects under review in this Filing" [Testimony of Ballaban and Effron at 29]. The full amount of the proposed budgets is necessary to implement these proposed projects.

Q. Do you agree with Mr. Ballaban and Mr. Effron that there are several planned projects in the spending plan that National Grid may not complete before the next rate case?

A. No. National Grid recognizes that its IS project expenditures are increasing in number, scope, and size to keep pace with rapidly developing advancements in technology and innovative solutions that ultimately improve operations, customer service, and efficiency. Accordingly, National Grid developed a plan to hire incremental staff to deliver the expected step change in IS capability to deliver more IS projects to meet the increasing demand for technological expenditures. Since June 30, 2017, the IS function has hired and retained 38 of the 64 incremental full time equivalents (FTEs) requested in the filing, including 15 additional project delivery staff and 14 additional Digital Risk & Security FTEs. The bandwidth and capacity of the IS organization has increased over historical levels and provides the means to deliver an increased workload. In addition, IS Sourcing contracts allow us to supplement additional contract resources in periods of peak demand to maintain operations and deliver projects to schedule efficiently during periods where high numbers of projects are in progress concurrently. This is especially important for areas such as cybersecurity, where a competitive marketplace makes retention of highly valued resources more challenging, but the immediacy of the need can be filled through contract labor.

Q. Why do you disagree with the Division's recommendation that the PUC should order the Company to hire an independent consulting firm with appropriate

expertise to perform an audit of the IT function and services, including without limitation cybersecurity services and the Gas Business Enablement Program?

A. The Division's recommendation is off-base for several reasons; however, the primary reason is that National Grid has already created this role and institutionalized it within its IS work process. This means that the hiring of an independent consulting firm would create a redundant, perhaps even problematic duplication of functions that would not be likely to produce incremental value for customers. Specifically, National Grid has undertaken the following actions:

First, in September 2017, National Grid engaged the Global Consultancy firm A.T. Kearney to perform a comprehensive review of the Digital Risk and Security function and, in particular, the Cybersecurity program and strategy. A.T. Kearney focuses on strategic and operational CEO-agenda issues facing businesses, governments, and institutions around the globe. A.T. Kearney thoroughly analyzed National Grid's Digital Risk and Security and the Cybersecurity Program. Specifically, this assessment involved the following:

- Review of National Grid's three-year transformation program that aims to strengthen the overall security posture and effectiveness of Digital Risk and Security and the strategy to establish the foundational capabilities that enable Digital Risk and Security to make informed cyber-risk based decisions.
- Review of National Grid's proposed three-year investment plan and identification of potential gaps that, when addressed, will yield a

comprehensive, resilient Cybersecurity Strategy.

- Examination of the Cybersecurity Strategy to leverage industry standards such as the National Institute of Standards and Technology (NIST) Cybersecurity Framework, Defense-in-depth Architecture Model and ISO 27001.
- Review of the Digital Risk and Security Operating Model to address capability, architecture, and process elements.
- Based on the NIST Cybersecurity Framework, A.T. Kearney completed an assessment of the multi-year investment plan to identify potential gaps and recommend prioritization of initiatives and focus areas.
- Alignment of Strategic Sourcing and Workforce planning with industry levels and best practice models.
- Assessment of governance to embed core elements of cyber defense and risk management in governance modules.

In light of this thorough, third-party assessment of National Grid's IS investment plan, the Division's recommendation for an independent outside audit is unnecessary, duplicative and unlikely to lead to incremental value for customers.

Second, National Grid has a comprehensive IS Process Excellence review. The members of the review team are trained in Lean Six Sigma process review and perform the types of review suggested by the Division in greater depth, more efficiently and with more significant impact than an audit performed by an outside firm – without the additional time and added expense associated with vetting and hiring such an audit firm.

Third, external auditors for Financial Audit and Sarbanes-Oxley Control are charged with reviewing National Grid's IS function on an annual basis. In addition, the National Grid Internal Audit department periodically performs reviews of various aspects of the IS function.

On a collective basis, these efforts are substantial and will assure that the National Grid IS investment plan is implemented with proper project and cost-management controls to protect the interests of National Grid customers, including those in Rhode Island. Given the breadth and depth of the IS function within National Grid's business, it is imperative that the Company be situated to recover the costs incurred to develop and maintain these systems over time. National Grid recognizes this fact and has taken all reasonable steps to assure process integrity and rigorous cost-management oversight. Within this context, it simply does not make sense to introduce an additional third-party that would have no particular insight or familiarity with National Grid's systems, which function to serve stakeholder needs across multiple jurisdictions. In fact, third-party participation could create a distraction within the solid, thoroughly scrutinized and integrally planned IS platform that already exists.

Q. Has National Grid managed its IS investments in the past well?

A. Yes. Although the Division makes claims to the contrary, National Grid has managed IS investments well in the past. The Division's characterization of National Grid's previous investments as a sustained period of "under-investment" is incorrect. National Grid recognizes that customers ultimately bear the cost of IS projects, and therefore, National Grid works to: (1) extract maximum value for customers from IS investments by extending IS infrastructure to the extent of its useful life; and (2) undertake IS investments in a manner designed to achieve successful implementation at a reasonable project cost. With these two objectives in mind, National Grid makes IS investments when necessary and appropriate and did so in each year in the past, referenced by the Division. The reason that National Grid is now contemplating the substantial level of investment planned is because National Grid has reached a point with some of its foundational IS systems where the systems no longer can be maintained in a manner consistent with providing safe and reliable service to customers. Consequently, the IS investment needed to replace those systems is equal to the scale and scope of the foundational systems requiring replacement, which is a circumstance that simply does not occur on an annual basis. Therefore, these circumstances do not support the conclusion that there was previous under-investment.

Rather, these circumstances indicate that there is a set of systems that have been utilized in the service of customers for as long as possible, and now must be replaced so that reliable service to customers is continued and enhanced. In fact, the central flaw in the Division's claim is that, if National Grid had undertaken to replace these foundational systems at an earlier date, it only means that customers would already be bearing the cost of those replacements. Thus, there is no inherent harm that has been visited upon customers because the Company has used the systems for as long as it possibly can without jeopardizing the continuity of business operations. To the contrary, customers have enjoyed lower rates than otherwise would exist due to the avoidance of cost. Consequently, National Grid's previous lower spending is not a reason to penalize it with reduced cost recovery.

IV. <u>Conclusion</u>

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

JOINT REBUTTAL TESTIMONY

OF

ANTHONY H. JOHNSTON

AND

CHRISTOPHER J. CONNOLLY

Dated: May 9, 2018

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I. Introduction and Qualifications

Anthony H. Johnston

Q. Mr. Johnston, please state your name and business address.

A. My name is Anthony H. Johnston. My business address is One MetroTech Center, Brooklyn, New York 11201.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid USA Service Company, Inc. (the Service Company), a subsidiary of National Grid USA (National Grid). Effective April 1, 2016, I was appointed Senior Vice President for National Grid's Gas Business Enablement Program. In this role, I am accountable for the design, development, and delivery of the Gas Business Enablement Program and its anticipated benefits.

Q. Did you previously submit testimony in this matter?

A. Yes. I submitted Joint Pre-Filed Direct Testimony on November 27, 2017 together with Mr. Connolly.

Christopher J. Connolly

Q. Mr. Connolly, please state your name and business address.

A. My name is Christopher J. Connolly. My business address is 404 Wyman Street, Waltham, Massachusetts 02451.

Q. By whom are you employed and in what position?

A. I am employed by the Service Company as Vice President of Process and Business Requirements for the Gas Business Enablement Program. In this role, I am responsible for developing standard business processes across the operating companies and the implementation of capabilities in the new solutions driven from business requirements that will support enhanced customer satisfaction, improved safety and compliance performance, and enhanced employee engagement.

Q. Did you previously submit testimony in this matter?

A. Yes. I submitted Joint Pre-Filed Direct Testimony on November 27, 2017 together with Mr. Johnston.

Q. Mr. Johnston and Mr. Connolly, what is the purpose of your joint rebuttal testimony?

A. The purpose of our rebuttal testimony is to respond to the pre-filed direct testimony submitted by the Division of Public Utilities and Carriers (the Division) and New Energy Rhode Island (NERI) in this proceeding regarding the Company's proposed Gas Business Enablement Program.

Q. How is your testimony organized?

A. Section I is the Introduction. Section II summarizes the issues raised in the testimony of the Division in relation to the Company's proposals on the Gas Business Enablement Program and provides the Company's response to its project concerns. Section III provides the Company's rebuttal on issues relating to the mechanics of cost recovery. Section IV is the conclusion to our testimony.

Q. Would you please explain the naming conventions that you will be using in your testimony to identify the various entities involved in this proceeding?

A. Certainly. This proceeding is a ratemaking proceeding for the electric and gas distribution operations of The Narragansett Electric Company, which constitute the regulated operations that National Grid conducts in Rhode Island. In this case, we will refer to the regulated entity as the "Company," where the reference is to both electric and gas distribution operations on a collective basis. Where there is a need to refer to the "stand-alone" or individual electric or gas operations of The Narragansett Electric Company, we will use the terms "Narragansett Electric" or "Narragansett Gas," respectively, as appropriate. Where we refer to "National Grid USA," we will use the term "National Grid;" where we refer to "National Grid plc," we will use that specific term.

II. Response to Division's Concerns Regarding Ability to Implement Successfully

Q. What is the purpose of the proposed Gas Business Enablement Program?

A. At its core, the Gas Business Enablement Program is a program to replace core utility systems at the end of their useful lives and to standardize gas business processes and capabilities onto three inter-related operating platforms over a five-year period. The capabilities these platforms support are: Work Management, Asset Management, and Customer Enablement. These are indispensable utility operating platforms that are relied on by gas and electric distribution companies across the industry for the safe and reliable delivery of service to utility customers. For National Grid's U.S. gas distribution business, completion of this five-year work effort is critically needed to replace a number of disparate, aged systems at the end of their useful life. The outcome of this important effort will be to enable significant improvements in: (1) the ability of National Grid's employees to perform their job functions effectively; (2) the ability of management to institute effective and efficient work management and data-control processes across the U.S. gas distribution business; (3) the satisfaction of customers, who seek engagement with the Company on a range of interactions that take place during routine and non-routine operations; and (4) the resiliency, reliability and cyber-security protection of systems critical to the safe and effective delivery of gas service to customers.

In addition to the major benefits that gas customers will experience, electric customers will benefit by the fact that the field-mobile solution will be utilized by both gas and electric Customer Meter Services field workers, just as the customer relationship management application will be utilized by customer call center representatives serving both gas and electric customers.

Q. Is there a debate in this case as to whether the Gas Business Enablement Program should go forward in Rhode Island?

A. No. Given the imperative inherent in the undertaking of this initiative, the question in this proceeding is not whether the Gas Business Enablement Program should go forward, but rather how the reasonably and prudently incurred costs of the system will be recovered from customers. The Division's direct testimony makes it clear that the Division concurs, "to a large degree," in the Company's assessment that the Gas Business Enablement Program is needed for Rhode Island [Testimony of Bennett and Neale at 10-11]. The Division cites the following main reasons for its conclusion:

1. A serious failure of one of the legacy systems currently comprising the work management, asset management and customer engagement processes could significantly impact the Company's operating capability and gas safety program in the future [id. at 10-11].[1]
2. Complexity resulting from manual workarounds and security issues caused by a lack of vendor-supported upgrades increases system risk over time [id. at 11].

[1] The Division cites to the fact that a total of 46 percent of the operational systems Narragansett Gas relies on are no longer supported by the vendor and no longer receiving functional or security updates [Testimony of Bennett and Neale at 10-11, citing, DIV 17-9, Tab 4 (b)(i)(ii)(iii)(v)].

3. As systems approach end of life and need replacement, it is the normal course of business for a company to evaluate and upgrade its operational systems taking into consideration changing business requirements [id. at 11].

The Division also considered whether National Grid had sufficiently explored other alternative solutions before deciding upon the Gas Business Enablement approach, and whether a "Rhode Island alternative" rather than an enterprise solution would have been more beneficial to customers [Testimony of Bennett and Neale at 14-15]. The Division states that it accepts National Grid's reasoning for rejecting alternatives to the Gas Business Enablement Program, and that it supports the Company's implementation of the proposed Gas Business Enablement Program for use in Rhode Island [id. at 15].

NERI is the only other intervenor that addresses the Gas Business Enablement Program in direct testimony. Among other claims, NERI contends that it is concerned that the Company is proposing to "gold plate" its gas business operations "in an unjustified effort to grow its rate base without adequately demonstrating the benefits of the spending outweigh the costs" [Testimony of Rábago at 58]. This statement is just completely off-base and is overwhelmingly disproven by the record evidence.[2]

[2] NERI also argues, incorrectly, that the Company "does not offer a Benefit-Cost Analysis to support its proposal specific to Rhode Island or for the GBE program as a whole" [Testimony of Rábago at 60]. The Company has prepared and submitted to the record in this proceeding substantial analysis, including quantification of costs and benefits [see, e.g., Division 12-3].

In fact, in the Company's joint pre-filed direct testimony and responses to data requests in this docket, the Company has presented substantial evidence demonstrating: the purpose and need for Gas Business Enablement; the nature of the evaluation that National Grid has undertaken to scope out possible alternatives and decide upon an enterprise-wide solution; and the exhaustive effort expended to construct a project planning and cost-management framework to implement the program on time and on budget. Consequently, the valid questions that remain at this point are relatively narrow, although important.

Q. What is the status of implementation for the Gas Business Enablement Program in Rhode Island?

A. For Rhode Island, the estimated investment for the Gas Business Enablement Program is $37.9 million for Narragansett Gas and $5.5 million for Narragansett Electric, or a total of $43.4 million. Investment began in Fiscal Year (FY) 2017 and will continue through FY 2023. The annual total revenue requirement for FY 2019 through FY 2021 is $13.4 million for Narragansett Gas and $1.8 million for Narragansett Electric. By the time that the PUC issues a decision in this docket in mid-2018, the Company already will have incurred approximately $13.4 million in total costs associated with non-recurring operating and maintenance (O&M) expense and the Rhode Island portion of Service Company capital expenditures, or approximately one-third of the total estimated cost for the Rhode Island system. By the end of the twelve-month period ended August 31, 2019 (the Rate Year), the Company will have incurred costs in excess of $24.8 million, or more than one-half of the total estimated cost for the Rhode Island system.

In terms of the milestones for Gas Business Enablement, National Grid recently implemented its first release, Portfolio Anchor 1. This release included capabilities to support the work completed by Corrosion, Instrumentation and Regulation, and Collection field workers in Rhode Island. Implementation was postponed by one week to avoid any interference with the financial year-end, and then was phased over two consecutive weekends. The implementation has been very successful so far with work being successfully completed in the new systems on Day 1 and with planned post Go-Live support activities finishing early as a result of positive user adoption and minimal issues identified with the solutions.

As a result, implementation for the first Rhode Island portion of the system is well underway with a successful, smooth launch for the Rhode Island work force.

Q. What is your perspective on the concerns that are voiced by the Division in its direct testimony?

A. The Division voices concerns that fall into two categories: (1) concerns regarding the level of confidence that should be placed in National Grid regarding the implementation of the Gas Business Enablement as an enterprise solution; and (2) the mechanics of the

Company's proposed cost recovery structure. Below, our testimony discusses the Company's response to the claims made in each of these two categories.

Q. What is your understanding of the Division's concerns regarding National Grid's ability to manage the implementation process successfully?

A. The Division indicates that it is "not fully confident the Company can execute the project work in the timeline" suggested in the filing and that, given National Grid's experience with the US Foundation Program (USFP), it is concerned that "the same, or similar issues could affect National Grid's effort to carry out the full scale of its planned Gas Business Enablement [Testimony of Bennett and Neale at 16-17].

The Company fully understands the cautious perspective that the Division has with respect to National Grid's ability to implement the Gas Business Enablement Program successfully, on time and on budget. The total cost of the Gas Business Enablement Program is several hundred million dollars, and the system will cover all three of National Grid's U.S. jurisdictions, i.e., it is a large scale program with far-reaching impact for gas operations. Risks are inherent in any project of this magnitude and the Company understands that National Grid's experience with the USFP implementation would naturally drive a level of skepticism, influencing the Division's perspective [id.].

Q. What are the specific factors that appear to be driving the Division's perspective

that there is a basis for concern?

A. As the basis for its concerns, the Division relies to a certain extent on the "comprehensive technical review" of the Gas Business Enablement Program conducted by the staff of the New York Department of Public Service (NYDPS), as well as other information in the record [Testimony of Bennett and Neale at 17]. The factors identified by the Division as a basis for concern are as follows:

1. That the internal controls built into the program functionality may not fully solve National Grid's internal control issues, similar to what happened with USFP [id. at 18].

2. That the identified benefits "have not been reflected in the proposed revenue requirement" and it is not clear how or when these benefits will flow through the customers [id. at 19].

3. That National Grid is implementing Gas Business Enablement first in Rhode Island; that it is "likely" to experience greater issues than in other jurisdictions; or that implementation may not work in a larger jurisdiction, causing a significant program redesign that could result in cost overruns and delays in the implementation schedule; or that National Grid may turn its attention to other jurisdictions rather than maintaining focus on Rhode Island [id. at 21].

4. That National Grid's training may not adequately prepare its employees to implement the Gas Business Enablement Program [id. at 22].

5. That the focus of National Grid's senior management emphasis on financial performance results in a "variance" management focus, rather than attention to root cause [id. at 23].

As a conclusion, the Division states that "it all comes down to execution and the Company has yet to show that it is capable of fully implementing this level of IS investment on time and on schedule" and further that National Grid's deployment of Gas Business Enablement in Rhode Island first, "puts a higher degree of project risk on Rhode Island customers" [Testimony of Bennett and Neale at 24].

Q. What is your response to these concerns?

A. Although understandable, neither of the Division's primary concerns – execution risk or "going first" – should cause the PUC to effectively sanction the Company *in advance of* project implementation, which is what a decision to truncate recovery on the front end would do. The underlying implication of each of these concerns is cost. As we discuss below, the PUC has the ultimate authority to assure that customers do not pay any more than the reasonable and prudently incurred costs associated with the implementation of Gas Business Enablement. The Company is committed to making sure that the PUC has the information and opportunity to exercise this authority in the interests of Rhode Island customers and is proposing a process below to achieve this objective.

Q. Are there any other perspectives that the PUC should consider?

A. Yes. First, the Company recognizes that the Division has worked hard through the discovery process to assess the Company's Gas Business Enablement Program carefully to gain an understanding of the costs and benefits of the program and the nature of the program drivers. The Company appreciates the thorough review of its proposal because the program is eminently important to the Company and its customers. The Gas Business Enablement Program is necessary to continue to provide safe and reliable service to customers and to position the Company to improve that service over time. There is no understating this point. The program is a necessity and the Company's request in this case is simply to recover the costs associated with taking eminently reasonable and appropriate steps to secure service to customers.

Second, as to the question of whether National Grid is appropriately situated to execute successfully on the implementation of Gas Business Enablement Program, it is necessary to move ahead through the implementation plan to find the answer given the extensive preparation undertaken by National Grid. In fact, National Grid has taken all reasonable steps to assure the success of this implementation. National Grid has established a structure with multiple layers of outside expertise by independent expert consultants and system developers, which are integrated in such a way as to provide genuine, dependable checks and balances. National Grid has participated in deep-reaching internal examinations and external audits regarding the flaws in the UFSP implementation and researched external expertise and experience of other utilities in relation to successful implementations. National Grid has entered into fixed price vendor contracts with rigorous performance requirements. National Grid has established an over-arching internal project-management and oversight process that has clear lines of responsibility and decision-making responsibility, with a single senior executive ultimately responsible for project delivery. For many reasons, it is important for National Grid to deliver on this program as planned. Not the least of these reasons is the Company's commitment to maintaining credibility with its customers and regulators in Rhode Island.

In this regard, the Division states that it concurs with the NYDPS Staff GBE Panel that, "only real world experience can definitively answer" the question as to whether National Grid's implementation approach will sufficiently address problems encountered in the past [Testimony of Bennett and Neale at 20]. This is correct. National Grid cannot remain in a state of paralysis because of circumstances that have unfortunately occurred in the past. There is no course of action that National Grid can reasonably take to eliminate all execution risk associated with the implementation of a new system. At this point, National Grid has commenced implementation in Rhode Island and is on track to execute its roadmap for all three jurisdictions. Thus, the best course of action is to establish a process and timeline for the PUC to have a line of sight into project implementation so that it can exercise appropriate authority, if there is a need to exercise that authority.

It should also be noted that National Grid's operating affiliates in New York will account for the majority of project costs, equaling almost 65 percent of the total project implementation cost of $458 million. After substantial review and investigation, the NYDPS Staff is supporting National Grid's movement forward on Gas Business Enablement, approving a rate settlement that will allow Niagara Mohawk Power Corporation (Niagara Mohawk) to recover the full amount of Gas Business Enablement Program costs requested, including non-recurring expense, capital cost and future "Run the Business" operating expenses for each of three future rate years FY 2019, FY 2020, and FY 2021 [Response to Division 32-51]. Thus, Niagara Mohawk has obtained full recovery of its allocated share of total implementation costs of $458 million, subject to certain customer protections. Through the rate settlement, the New York Public Service Commission and DPS Staff will have a line of sight into Gas Business Enablement implementation, as well as controls over the ultimate cost paid for by customers, and the PUC and the Division should have the same for Rhode Island customers.

Q. Is the Division's criticism that Gas Business Enablement may not fully solve National Grid's internal control issues, similar to what happened with the USFP financial internal controls reasonable?

A. Changing operational systems for any utility is a challenge. Unless the utility can stop the operation that will be conducted by the new system, which is very rarely an option, system changes must occur in parallel with efforts to run the business. The Gas Business Enablement Program is designed to encompass lessons learned in the past and so the implementation has been disaggregated into manageable pieces rather than being attempted all at once in a "big bang" fashion. Also, the enterprise-solution approach will allow the standardization of processes across the enterprise as part of the implementation design, simplifying the task and reducing the complexity and risk. This approach also allows for the implementation of not just more standard operational controls but more automation of controls, moving away from some of the manual controls used today, this is very different to the challenges on financial controls experienced in USFP. Lastly, the "agile approach" that is being used during the implementation requires far more significant business engagement throughout the development lifecycle, ensuring that users of the system are getting visibility to the solution with the ability to give feedback far earlier than would be traditionally possible. National Grid's early findings from the first release, Portfolio Anchor 1, that was placed in service in early April 2018 in Rhode Island have demonstrated the value of this approach, given that business users were able to complete work successfully in the new systems from Day 1 of implementation.

Q. The Division expressed "continued reservations" that National Grid employees are adequately trained to be able to implement the Gas Business Enablement Program's new processes. Are the Division's continued reservations justified?

A. No. As part of the Gas Business Enablement Program, there is a senior leader, Reihaneh Irani-Famili, who is the Vice President of Business Design and Readiness. Ms. Irani-Famili has full oversight over the design, development, and delivery of training for Gas Business Enablement prior to go-live. Training for Gas Business Enablement is starting early through awareness and visibility sessions. The team is organizing road shows to demonstrate the solution to front line employees and get them familiar prior to formal training. In addition, rigorous testing of the solutions will be performed in preparation for each release and User Acceptance Testing will be performed by business users. This testing supports the development of training materials. Testing also validates that that systems are fit for purpose.

In addition, there is a "Gas Business Enablement App" that will enable all National Grid employees to receive additional information including training videos of the new solution. All employees working with the systems will have formal training to complete with a test to pass at the end to demonstrate appropriate knowledge retention and understanding. As part of the robust business readiness process and governance, operational vice presidents accountable for operations in Rhode Island will have to give approval prior to the implementation of the new systems. One of the readiness criteria will be whether appropriate training of their employees has been completed.

Q. What about the Division's concern that the "Rhode Island first" approach creates greater risk for Rhode Island customers?

A. Although the Company appreciates that the concern over the "Rhode Island first" approach is founded on the desire to protect Rhode Island customers, the fact is that execution risk exists in *any sequence that might be undertaken*. For example, the Division first states that, because Rhode Island is going first, it is "likely" to experience greater issues in other jurisdictions [Testimony of Bennett and Neale at 21]. However, there is no evidence in the record that substantiates or even indicates such a conclusion. The Division does not cite to any evidence to support this claim. This is simply an assumption that "first" is riskier than "next."

Conversely, the Division states that, even if the system is implemented in Rhode Island, implementation may not work in one of the "larger, more complex" jurisdictions, requiring a "significant program redesign" that could cause cost overruns and delays in implementation [id.]. The Division further posits that problems in "larger, more complex jurisdictions," could cause National Grid to turn its attention to those deployments, depriving Rhode Island of needed attention [id.].

However, the possibility that National Grid may encounter difficulties in implementation in "larger, more complex jurisdictions" exists whether implementation is undertaken *first or last*. There is no possibility of National Grid seeing into the future and picking a sequence that will avoid any and all problems. There is risk inherent in systems replacement; the risk cannot be eliminated. Because risk cannot be wholly avoided, system replacements have to go forward with feasible, reasonable steps taken to *mitigate and manage* risk.

In that regard, the Division does not identify any steps or any actions that could have been taken by National Grid in planning for Gas Business Enablement, but were not. There is no evidence or indication as to the existence of a gap or omission in the planning process. The concerns around internal costs controls, training and management focus are valid and appropriate, but – as recognized by the NYDPS Staff and the Division – National Grid has attempted to address these concerns within the framework put in place to conduct the Gas Business Enablement Program. The dialogue is really around the unknowns and the degree to which these concerns will be addressed by National Grid's framework.

Q. Are there any specific protections that are encompassed in the design of Gas Business Enablement that will mitigate the "risk" of being first for Rhode Island customers?

A. Yes. The phased implementation approach that will proceed by jurisdiction and by similar work types will have the effect of mitigating the operational risk that would have been experienced if the program were implemented using a "big bang" method. In addition, there are a number of other elements of Gas Business Enablement that further mitigate risk of a major operational impact including: the "agile" development method that ensures that there is far greater and earlier business involvement in the development and testing of the solution before it reaches implementation; and a robust business readiness process and governance process, which requires sign-off from the operational Vice Presidents accountable for operations in Rhode Island. Operational vice presidents must approve the implementation of the new systems only when these individuals are comfortable that the solution is ready and that their employees are trained and prepared to use the system. In addition, the Operations vice presidents and Functional vice presidents are engaged regularly throughout the phases of the Gas Business Enablement Program through the Gas Business Enablement Design Authority. Multiple sessions are held monthly to engage, provide status updates and ask for support and decisions during planning, development, testing and release preparations. Lastly, dedicated program resources will be located in each of the Rhode Island field locations to provide post go-live support to help users with any issues they experience post-implementation.

Q. What is the Company's suggestion to address any remaining concerns regarding execution risk and the "Rhode Island first" approach?

A. The best possible next step is for National Grid to provide quarterly reports to the PUC and the Division on the status and process of implementation so that the PUC and the Division are enabled fully to review the impacts of project implementation on Rhode Island customers. With full information on the status of project implementation, including reports on issues that arise and how those issues are resolved, the PUC or the Division will be positioned to take action, *if action is warranted*. The Company is not suggesting that the PUC grant recovery of project costs in this proceeding without a plan to revisit those costs to review *what actually happened* and to make adjustments, as warranted and appropriate. "Shorting" the Company on the front side is not an effective tool to protect the interests of customers. This type of action will simply act as a penalty, creating a disincentive for the Company to prioritize Rhode Island implementation on this and other projects.

Instead, the PUC should align cost recovery with cost incurrence so that customers get the systems and processes needed to assure safe and reliable service to customers -- while the Company obtains recovery of the reasonable and prudent costs it has expended to achieve that outcome for customers. Detailed, periodic information and briefing on the project status across all three jurisdictions will give the PUC and the Division the information and access it needs to evaluate impacts for Rhode Island customers, and to take actions that achieve the proper alignment of project costs and project recovery on behalf of customers. Gas Business Enablement Program costs that are not reasonably or prudently incurred will be absorbed by shareholders.

III. Response to Division's Concerns Regarding Mechanics of Cost Recovery

Q. What criticisms does the Division raise with respect to the Company's proposal for recovery of costs to implement Gas Business Enablement in Rhode Island?

A. There are three specific concerns regarding the Company's cost recovery proposal that we would like to address. These concerns center around the following issues: (1) Type II savings and whether these savings should be deducted from amounts eligible for recovery [Testimony of Bennett and Neale at 32-33]; (2) allocation of costs and savings between jurisdictions [Testimony of Bennett and Neale at 26]; and (3) the recovery of pre-Rate Year non-recurring O&M expense and whether recovery of these amounts would constitute "retroactive ratemaking" [Testimony of Bennett and Neale at 28].

Q. The Division argues that benefits of Gas Business Enablement designated as "Type II" benefits should have been deducted from the costs included in the proposed revenue requirement. How do you respond?

A. As demonstrated on the record, National Grid identified two categories of cost savings that would be expected to result from the implementation of Gas Business Enablement. Type I savings represent actual expected reductions in operating costs. The Company has included these savings in the proposed revenue requirement as the Division acknowledges (approximately $58,000 for the Rate Year) [Testimony of Bennett and Neale at 32]. The "run rate" of annual savings for Rhode Island customers is estimated at approximately $900,000 annually, following full program implementation in FY 2023 [Schedule MAL-36 (REV. 2) at 6].

Type II savings are not actual cost savings, but rather are estimated ***avoided cost*** increases. The Division suggests that Type II savings should somehow be deducted from the revenue requirement; however, these are costs that will not occur. If costs do not actually occur, then reducing the Company's operating revenue requirement by that amount will *double count* those savings and improperly short the Company on cost recovery. For example, the Division states that "even if some or all of the [Type II] cost savings are delivered, there is currently no mechanism to return these savings to ratepayers until the Company decides to file its next rate case" [Testimony of Bennett and Neale at 33]. However, because an outcome of implementing Gas Business Enablement is expected to be the ***prevention*** of costs, then customers are receiving that benefit so long as the ***cost is avoided.*** Where the cost is avoided, the computation of the revenue requirement in the next rate case will *not include* that cost, and therefore, there is no need to offset the cost with a deduction in the revenue requirement. The revenue requirement would be *higher* if the cost exists, and without the cost, the revenue requirement computed for the rate case is lower than it otherwise would be.

A more specific way of illustrating this effect is that one of the types of savings encompassed in the Type II savings calculation is avoided penalties for pipeline safety. If the benefit is achieved and there are no penalties that occur before the next rate case, then the cost is avoided. Deducting the estimated amount of avoided penalties from the revenue requirement would make no sense, particularly given that customers do not pay for avoided penalties in any event. As a result, any deduction from the cost of service would effectively be a penalty, simply eliminating actual operating cost from the revenue requirement, rather than accounting for any savings.

Customers will benefit from Type II savings – even the avoidance of penalties because the incurrence of a pipeline safety penalty means that there is a safety infraction. Customers are better off with no safety infractions. Even if the avoided cost is one that would normally be included in the revenue requirement, customers benefit because the revenue requirement is lower than it otherwise would be where costs are avoided in the test year.

Consequently, there is no basis upon which to "account for" these avoided cost increases by adjusting the amount of recovery of costs actually incurred through the revenue requirement. It would not be appropriate under any construct to reduce cost recovery by the amount of avoided costs, i.e., *by the amount of costs not ever incurred.* Moreover, to the extent there are expectations regarding reduced operating expense, it does not occur until a point *after* the system is implemented. Thus, the Company will incur the cost of implementing the system before any savings can be achieved, which means that cost recovery naturally and unavoidably would precede the achievement of actual operating cost reductions, as well as the avoidance of future costs. For this reason, it is not appropriate to reduce cost recovery by an amount for Type II savings, which is what the Division is recommending [Testimony of Bennett and Neale at 33].

Q. Please summarize the Division's concerns regarding National Grid's proposed method of allocating the costs and benefits of the Gas Business Enablement Program across jurisdictions.

A. There are a couple of issues tied up in the consideration of the allocation of costs and benefits. First, the Division generally agrees that National Grid's allocation methodology for project cost is fundamentally consistent with the generally accepted cost allocation principles used by National Grid to allocate prudently incurred costs to its operating companies [Testimony of Bennett and Neale at 25]. In that regard, National Grid is allocating Gas Business Enablement Program costs among the three jurisdictions sharing in the use of the system using the C-210 Allocator. The SAP C-210 allocator is the All US Gas Distribution Companies – number of retail customers. The cost of system implementation is driven by the development of the system to provide the service capability that each jurisdiction requires for its customer base. Therefore, the number of customers in the customer base is the proper allocator of cost.

Q. What is the Division's concern then, with respect to the allocation of costs?

A. The Division argues that, if the PUC accepts a different method of cost allocation for other multi-jurisdictional investments, like the GIS system that is proposed for Power Sector Transformation (PST), then the PUC should review the cost allocators for the Gas Business Enablement Program in the similar manner and require the Company to revise its revenue requirement to reflect an allocation of cost on the basis of "how benefits are expected to be realized" [Testimony of Bennett and Neale at 26].

Q. Do you agree with this suggestion regarding the allocation of program costs among the three jurisdictions?

A. No, we do not. First, it is entirely unclear why the cost allocation for the Gas Business Enablement Program would or should be the same for PST investments. As discussed throughout this proceeding (and at the outset of this testimony), the Gas Business Enablement Program is a systems *replacement* project at its core. The systems it is replacing are largely traditional utility operating systems and any operating savings that are achieved are tangential benefits of the systems replacement. PST investments are unique investments not necessarily undertaken in the past that may be cost justified on a different basis. There is no innate reason why the cost allocations would be the same for PST investments and Gas Business Enablement.

Q. What about the argument that savings should be allocated on the exact same basis as costs?

A. It is not clear what the Division is trying to get at with tying the cost allocation for Gas Business Enablement to PST investments. However, this approach may be aimed at trying to address the Division's claim that costs and benefits for the Gas Business Enablement Program are not being allocated on the same basis. On this point, the Division is arguing that, because a greater proportion of Type II savings are allocated to New York, a greater share of Gas Business Enablement costs should be allocated to New York [Testimony of Bennett and Neale at 26]. Thus, fundamentally, the Division is arguing that the *costs* should be allocated not on the basis of cost causation principles, but rather on the basis of how defined financial *benefits* are expected to be realized [id. at 26].

Q. Does the Company agree with the Division's suggestion that the savings should be allocated on the basis of the C-210 Allocator also?

A. No. First, with respect to cost: As the Division acknowledges, the Company's cost allocation proposal is consistent with generally accepted principles used by National Grid and previously approved by the PUC. The systems that will be implemented through the

Gas Business Enablement Program are core operating systems for a gas distribution company, touching on virtually every aspect of the Company's day-to-day service delivery capabilities. This is because the primary purposes of these systems are to: (a) support field operations functions and track and manage assets; (b) add functionality and enable routine business operations; and (c) support service interactions with customers. These systems are not designed to eliminate business processes or displace functionalities in order to reduce operating costs to the magnitude that would be necessary for these systems to pay for themselves.

In that regard, the costs of the Gas Business Enablement Program should (and will) align with the level of usage by each jurisdiction; hence the use of the C-210 Allocator. The costs that the Company will incur are necessary to build a system to provide service to customers, including a range of operational functionality, i.e., the principal objective of implementing the system is not to reduce operating costs. Therefore, it is not reasonable or correct to expect that the savings would occur in ratable proportion to cost. The cost is properly expected to be proportional to customer value (i.e., usage of the resulting work stream capabilities).

Customers in all jurisdictions will be receiving the benefits that include increased and improved customer service, including self-service tools and reduction in operational risk of using aging information systems and tools to coordinate and perform gas operations.

This reflects the belief and understanding that the new systems are being deployed for operational "reliability" and customer service reasons primarily, with cost savings being a corollary (good) benefit, but not the primary driver for undertaking the project. Second, with respect to savings: The Type I savings that National Grid has quantified are derived for each individual company on the basis of expected operational savings. Type II savings are quantified and derived through a combination of direct assignment and allocation, using appropriate allocators that reflect the specific type of cost savings expected to be achieved. This is a proper and reasonable approach, i.e., each type of savings arises from a distinct origin, and therefore, should be allocated on the basis of its origin. This is a separate exercise in form and content from the exercise of attributing cost where the cost is caused by the development of the system to provide the service capability that each jurisdiction requires for its customer base.

Consequently, the Division is recommending a method of cost allocation that is unwarranted and inappropriate. The implementation of a work-management system, asset-management system, or customer enablement system is a business decision that must be undertaken to support operations, and utilities often have to move ahead to maintain the reliability and functionality of systems without pre-identifying operating cost reductions of a magnitude that is equal to or greater than the cost of those systems. Therefore, the Division's recommendation that cost should be allocated on the basis of how benefits are to be realized is unreasonable and unworkable.

Q. What about the claim that Type II benefits are weighted toward other jurisdictions?

A. Type II savings include the value of avoided pipeline safety penalties, which have occurred to a greater degree in jurisdictions outside of Rhode Island. As an initial matter, it is a positive fact that the Company has not had the same level of pipeline safety infractions in Rhode Island – this is a benefit for customers *today* on an "avoided cost" basis.

In addition, the Company's answer to PUC 8-5 provided important analysis of the Type II savings computation. The Gas Business Enablement Program will facilitate improved compliance performance as one of a range of outcomes, driving avoidance of penalty costs. When compliance penalties are removed from the benefits for each operating company, the benefits align more closely with the cost allocation percentage for each operating company.

Accordingly, National Grid has appropriately allocated the costs and benefits of the Gas Business Enablement Program and the Division's recommendations are not reasonable or warranted modifications to National Grid's methodology.

Q. Is the Division correct that the share of costs attributable to National Grid's gas operating affiliates, Keyspan Energy Delivery New York[3] and KeySpan Energy Delivery Long Island[4], will not be recovered and that this changes the cost benefit ratio for customers?

A. No, the Division is not correct, and there is no basis for this assertion. The Division claims that, because there is no rate case planned for the KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island affiliates, the $24 million share of program costs allocated to those operating affiliates will not be recovered [Testimony of Ballaban and Effron at 62]. Specifically, the Division claims that, by the time these other affiliates presumably file rate cases again, "the costs will be in the distant past, well beyond any 12-month historical test year period" [id.]. The Division claims that this is a "significant" consideration given that the ratio of benefits to costs is higher for New York customers than for Rhode Island customers.

This claim is incorrect for two reasons. First, it is not correct to assume that National Grid will not seek or obtain recovery of the $24 million share allocated to other affiliates, and there is no evidence of this fact in the record. Moreover, National Grid's recovery or non-recovery of this allocated share of $24 million has no impact whatsoever on the "ratio of benefits" associated with the Gas Business Enablement Program. Rhode Island

[3] The Brooklyn Union Gas Company d/b/a National Grid NY (formerly d/b/a KeySpan Energy Delivery New York) (KeySpan Energy Delivery New York).

[4] KeySpan Gas East Corporation d/b/a National Grid (formerly d/b/a KeySpan Energy Delivery Long Island) (KeySpan Energy Delivery Long Island).

customers are paying only for their share, and their share is smaller than it otherwise would be with the inclusion of the operating affiliates in the computation. Conversely, the Type I and Type II savings identified are allocated appropriately to each jurisdiction and are not unbalanced, as suggested by the Division.

Q. Would you please describe the Division's last concern with respect to the recovery of pre-Rate Year non-recurring O&M expense?

A. The Division is challenging the Company's proposal to recover non-recurring pre-Rate Year implementation costs on the basis that recovery of these amounts would be inconsistent with Rhode Island's rule against retroactive ratemaking. Additionally, the Division does not support recovery of annual expenses for Gas Business Enablement implementation beyond the rate year unless a multi-year rate plan is put in place.

Q. How do you respond to the claim that recovery of the pre-Rate Year non-recurring O&M expense would be "retroactive ratemaking"?

A. First, we are not attorneys and, fundamentally, this is a legal question. Therefore, the Company is prepared to provide a substantive legal analysis through its final briefs in this proceeding, or at such time that it is requested by the PUC.

However, from our non-legal perspective, the recovery of the pre-Rate Year expenses would not constitute "retroactive ratemaking" due primarily to the fact that the costs were

(1) incurred in the test year; and (2) are non-periodic, “extraordinary” or atypical costs that are not present in the cost of service that was used to set base distribution rates in the past. In our understanding, retroactive ratemaking is a possibility when a utility requests to adjust the amount of a normally recurring operating expense collected through existing base rates. National Grid is not making that type of proposal. For the Division’s theory to be correct, the rule would have to be that no cost that might be reasonably and prudently incurred outside of the Rate Year may be recovered through customer rates without triggering retroactive ratemaking. This would appear to be an entirely unreasonable and unworkable standard given that there are times that utilities have a need to make a major expenditure in the course of providing service to customers, which may come along at a point that is not a Rate Year, and yet has to be incurred nevertheless to serve customers. Under the Division’s theory, if that cost does not *happen* to arise in a rate year, there is no path to recovery. This is not a reasonable or workable approach given that the business will encounter these types of situations across time. Moreover, in the Company’s response to data request Division 32-51, the Company provided three examples of cases where the PUC allowed the recovery of systems implementation costs that arose prior to the Rate Year, and yet were amortized into rates. The Company is simply asking for the same treatment here.

Q. What recommendations has the Division made to modify the Company's cost recovery proposal?

A. The Division has offered five recommendations that it suggests will enhance customer protections: (1) limit cost recovery of and on capital in the Rate Year to 85 percent of the Rate Year allocated revenue requirement to Narragansett Gas and Narragansett Electric as filed by the Company in Docket No. 4770; (2) limit the cost recovery of and for non-recurring operating expenses in the Rate Year to 85 percent of the Rate Year non-recurring operating expenses as provided by the Company in its response to data request Division 3-58; (3) in the event that actual Gas Business Enablement costs are greater than 85 percent, but do not exceed filed amounts, allow the Company to create a regulatory asset to defer the balance of charges for future recovery subject to National Grid's demonstration of cost and implementation results; (4) cap recovery of the Gas Business Enablement Program at the Company's allocated cost of $37.1 million less pre-Rate Year expenses; and (5) in the event that actual Gas Business Enablement costs related to these investments are less than 85 percent, require the Company to create a regulatory liability to defer the balance of charges for the benefit of customers [Testimony of Ballaban and Effron at 40-41]. The Division also asks for the PUC to require the hiring of an independent outside consultant to review the Company's Gas Business Enablement implementation [id. at 39].

The Division estimates that its recommendations will result in a Rate Year revenue requirement reduction of $977,286 and $83,599 for Narragansett Gas and Narragansett Electric, respectively [id. at 41].

Q. Are the Division's recommendations necessary or appropriate to protect customers?

A. No. As an initial matter, the recovery of costs will occur over time, not all at once. Therefore, the PUC will have the information and opportunity to make adjustments, if there is a basis for doing so. Second, the Division's recommended modifications to the Company's proposal are not appropriate in that the provisions effectively sanction the Company up front before there is any determination that something has gone wrong. The PUC has plenary authority to assure that the total cost ultimately charged to customers is only the cost that the PUC ultimately deems to be reasonable and prudently incurred. Lastly, the Division has offered no indication as to how it derived the level of 85 percent as the appropriate cost allowance. There is no record evidence supporting this deduction from the Company's proposed recovery. Accordingly, these modifications should be rejected.

Q. Does the Company agree with the recommendation to layer on another independent consultant to review the Company's progress on the Gas Business Enablement Program?

A. No, the Company does not agree with this recommendation – only because it is simply unnecessary. As noted above, National Grid has established a structure with multiple layers of outside expertise by independent expert consultants and system developers, which are integrated in such a way as to provide genuine, dependable checks and balances. National Grid also has participated in deep-reaching internal examinations and external audits regarding the flaws in the UFSP implementation and researched external expertise and experience of other utilities in relation to successful implementations. There is no incremental value that another independent consultant will bring to the program for customers, particularly at this late stage. The involvement of another outside expert will simply distract from the important task at hand and draw resources and management attention away from the crux of the project, which is the implementation of the Gas Business Enablement Program on budget and on time so that the significant benefits of implementation can be achieved for customers.

Q. Is the Company willing to incorporate the work product of its Value Assurance consulting partner into the quarterly progress reports provided to the PUC and the Division to provide oversight access for the Gas Business Enablement Program?

A. National Grid already has incorporated the role of an independent consultant into the Gas Business Enablement Program, as the "Value Assurance" role. National Grid retained PA Consulting as the Value Assurance partner, and PA Consulting is charged with reviewing and evaluating progress on the implementation plan. PA Consulting is providing important "checks and balances" in the Value Assurance role and is conducting periodic "mini reviews" to document status and progress. The Company is willing to incorporate information and findings set forth in the PA Consulting evaluations as part of the quarterly reports to the PUC and the Division.

IV. Conclusion

Q. Does this conclude your testimony?

A. Yes.

JOINT REBUTTAL TESTIMONY

OF

RAYMOND J. ROSARIO, JR.,

ALFRED AMARAL III,

AND

RYAN M. CONSTABLE

Dated: May 9, 2018

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I. Introduction

Q. Messers. Rosario, Amaral, and Constable, have you previously filed testimony in this case?

A. Yes. We previously submitted joint direct testimony on November 27, 2017 in support of the Company's proposal to add new electrical and gas worker positions. Specifically, the Company has proposed to add 32 full-time equivalent (FTE) employees (29 union and 3 management) to the electrical workforce and 30 FTE employee (24 union and 6 management) to the gas work force during the Rate Year (i.e., September 1, 2018 to August 31, 2018). In addition, in light of the explosive growth in Distributive Generation interconnection requests, the Company has also proposed to add 19 new FTE employees to the National Grid USA Service Company, Inc. workforce during the Rate Year.[1]

II. Purpose of Testimony

Q. What is the purpose of your joint rebuttal testimony?

A. The purpose of this testimony is to rebut and address the recommendations in the pre-filed Joint Direct Testimony of Division of Public Utilities and Carriers' (Division) Witnesses Michael R. Ballaban and David J. Effron on the number and need for incremental electric and gas positions, and the pre-filed Direct Testimony of Division Witness Gregory L. Booth on the number and need for incremental distributed generation (DG) positions on behalf of the Division.

[1] Testimony and Schedules of Raymond J. Rosario, Jr., Alfred Amaral III, and Ryan M. Constable, Book 4 of 17, Bates Pages 11-12, and Response to Division Data Request 20-5.

III. Incremental Electric and Gas Positions

Q. Please summarize the Division's recommendations with respect to incremental electric and gas positions.

A. While the Division agrees that the Company's request for incremental full-time equivalent (FTE) employees to address gas maintenance and construction-related workload increases are reasonable, the Division concluded that the timing of head count additions related to retirements may be driven more by the timing of this case, rather than good business practice. Accordingly, they recommended a downward adjustment in labor costs of about $935,548 to reflect a smooth hiring pattern for incremental hires requested, but not filled. (Ballaban and Effron, p. 46-52). However, as described in the rebuttal testimony of Company Witness Melissa A. Little, the Division's adjustment of $935,548 includes two errors: (1) this adjustment double-counts the impact of three DG-related incremental hires, for which the Division has proposed a separate downward adjustment to the Company's cost of service discussed later in this testimony; (2) the Division's number of incremental hires to date (through February 2018) is incorrect. If the Company were to recalculate this adjustment using the Division's methodology, the resulting adjustment would be a reduction to the cost of service of $742,361, not $935,948.

Q. Does the Company agree with the Division's findings and recommendation regarding labor increases?

A. No. The Division's statements regarding the timing of head count additions are unsupported and ignore traditional standards of prudency. Partially underlying the Company's need for incremental electric and gas employees is the fact that the Company has an aging workforce with the potential for significant retirements in the near future. In addition, in order to maintain an adequate workforce to continue to meet its obligation to provide a high level of service to its customers, the Company recognized challenges in being able to hire a sufficient number of trained workers. Because the qualification process for electric and gas workers requires a minimum of between one and four years, the Company completed a future retirement study to identify its potential future needs.[2] Properly identifying, planning, and hiring of additional electric and gas employees to ensure that an adequate workforce is available to meet the needs of customers is prudent and a good business practice.

In addition, Division Witnesses Ballaban and Effron specifically find that "the Company's retirement model is reasonable" (Ballaban and Effron, p. 51), yet they paradoxically conclude that the age trend has not changed significantly for workers over 50 years of age. They also conclude that the Company's ability to attract qualified, capable employees in the current competitive marketplace was unclear; therefore,

[2] Testimony and Schedules of Raymond J. Rosario, Jr. Alfred Amaral III, and Ryan M. Constable, Book 4 of 17, Bates Pages 12-16, 19-28, Schedule OPEX-1.

customers should not have to cover expenses related to incremental FTEs until the Company is able to successfully hire and retain these post-Test Year new hires. (Ballaban and Effron, p. 52). These statements also are unsubstantiated. The Company's retirement model supports all the Company's requests for incremental electric and gas FTE employees. Yet, having found the Company's retirement model analysis reasonable, Witnesses Ballaban and Effron offer no explanation why only selective incremental FTE employee gas positions related to gas maintenance and construction should be accepted. Moreover, Witnesses Ballaban and Effron simply ignore the fact that an extended period of training (one to four years) is necessary for the incremental electric and gas FTE employees to be adequately qualified for the positions, and thus must be hired in advance of any retirements (Ballaban and Effron, p. 52).

Q. How does the Company respond to the Division's claim that age trend has not changed significantly for workers over 50 years of age?

A. The Division highlighted the age trend for workers over 50 years of age, whereas the Company's focus and concern is with workers over 55 years of age.[3] The numbers of workers in the age group 50-54 is trending downward as the population ages into the 55+ age range and, thus, distorts the risk analysis detailed in the testimony, which targets workers greater than 55 years of age, approaching retirement. Excluding consideration of the age group 50-54; the age groups of 55+ or 60+ continue to grow from 25% to 29%

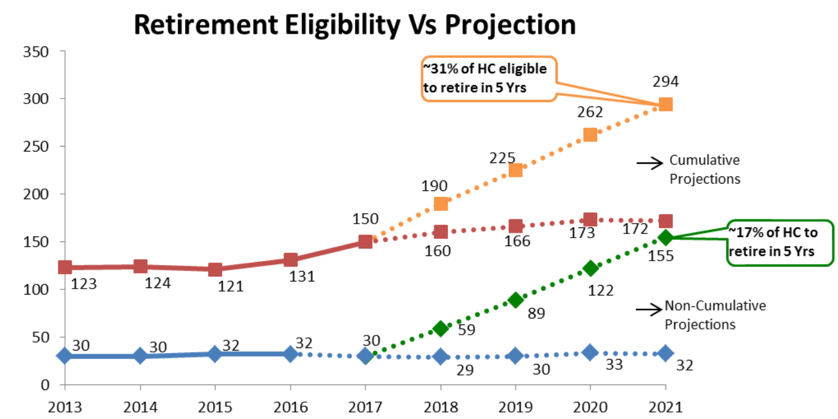
[3] Testimony and Schedules of Raymond J. Rosario, Jr. Alfred Amaral III, and Ryan M. Constable, Book 4 of 17, Bates Pages 10, 28; Schedule OPEX-1.

and 5% to 8% respectively, as detailed in Schedule OPEX-1 of the Company's initial filing. As detailed in the Company's direct testimony, the Company's operating workforce currently encompasses a disproportionate ratio of employees over the age of 55. These employees will retire as they reach the age of 60-65. This cannot be avoided.

Q. What other basis does the Company have to support that the age and impending retirement trends are increasing?

A. The Company's modeling analysis of retirement eligibility, which was previewed with the Division during an "in camera review" shows that there will be a steady increase in the number of employees eligible to retire through the Rate Years. From 2016 through 2017, the number of Rhode Island workers eligible to retire increased from 131 to 150 and will further increase to 294 by 2021, as detailed in the chart below, representing 31% or the workforce becoming retirement-ready.[4] This upward eligibility trend is consistent with the aging workforce trends detailed in the Company's testimony.

[4] Retirement eligibility is when an employee meets the retirement requisites set out in the Company's traditional pension plans.



Legend:

Retirement Actuals

Retirement Projection for next 5 years

Retirement Projection (Cumulating exits in 5 years)

Employees Eligible to retire with benefits at beginning of year

Employees Eligible to retire with benefits in next 5 years

Employees Eligible to retire at end of 5 years (Cumulative)

Q. How does the Company respond to the Division's claim that the Company's ability to attract qualified, capable employees in the current competitive marketplace is unclear. (Ballaban and Effron, p. 52)

A. The Company's ability to attract qualified, capable employees in the current marketplace is clearly addressed in its direct testimony in this case.[5] The issue is not with attracting qualified, capable electric and gas employees, but rather with attracting fully trained

[5] Testimony and Schedules of Raymond J. Rosario, Jr. Alfred Amaral III, and Ryan M. Constable, Book 4 of 17, Bates Pages 12-16, 19-28.

employees. The Division's claim ignores that most capable and fully qualified electric and gas employees are not available to be hired off the street. Rather, new electric and gas employees, depending on the job, require multiple years of training (one to four years) before they are capable of performing the full range of work to maintain the electric system on a safe and reliable basis. This means that the Company must hire in advance to ensure no degradation of service or safety to its customers. Moreover, it is important to recognize that hiring new employees prior to existing retirements allows for valuable "on-the job" type training, which includes actual knowledge transfer when working in the field with experienced employees.

Q. What other facts support the Company's request for incremental electric and gas FTE employees in this case?

A. The Division refers to Attachment DIV 20-5 in support of its $935,548 downward adjustment to the number of electric and gas FTE employees (Ballaban and Effron, p. 52). However, the Division's analysis ignores that Attachment DIV 20-5 demonstrates that the Company has posted and filled 21 of the 22 new incremental electric FTE employees positions requested in this case. In addition, the Company currently plans to post and hire an additional ten Electrical Customer Meter positions in the September/October timeframe to implement "on-the-job" training and facilitate knowledge transfer for these positions.

Q. How does the Company respond to the Division's recommendation to use a three-year average of wage increases for non-union employees, similar to that used for unions?

A. The Division's recommendation is unwarranted and should be rejected. Company Witness Maureen Heaphy addresses the flaws in the Division's rationale for its proposed downward adjustment for non-union employee wage increases in her rebuttal testimony.

IV. Incremental Distributed Generation Positions

Q. Please summarize the Division's recommendations with respect to the hiring of incremental DG employees.

A. The Division concludes that the request for additional staffing for DG interconnections is premature and not prudent at this time (Booth, p. 32). Division Witnesses Ballaban and Effron recommend a significant reduction in the number of staff to support increased DG applications from 19 to 3 incremental FTEs in the Rate Year, resulting in a downward adjustment to labor costs of $765,268 (Ballaban and Effron, p. 48). However, as described in the testimony of Company Witness Melissa A. Little, the Division incorrectly calculated its recommended downward adjustment in incremental DG labor costs of $765,268 because the Division failed to take into account that the FTEs at issue would be employees of the Service Company, not direct employees of the Company. If the Company were to make this adjustment to its cost of service based on the Division's methodology, the resulting decrease should be $261,475, not $765,268.

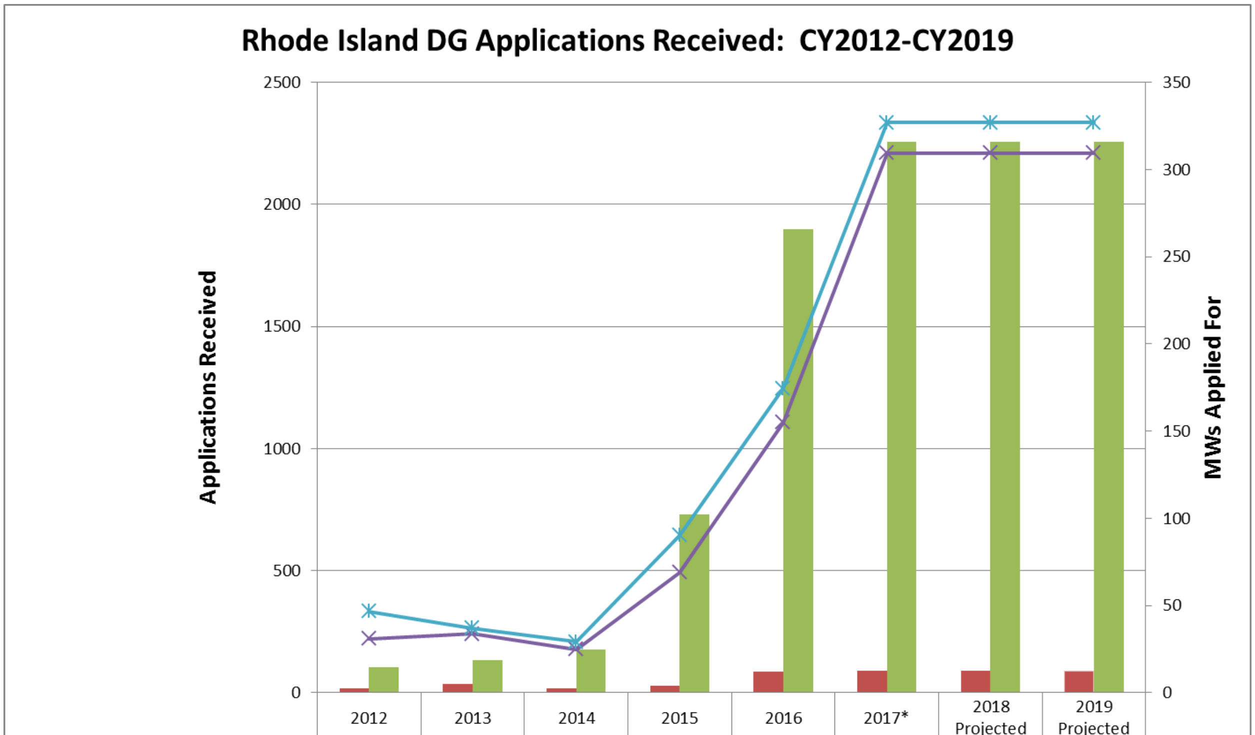
Q. Does the Company agree with Division Witness Booth's claim that the Company's request for 19 incremental DG positions is not a prudent investment at this time (Booth, p. 32-34)?

A. No. In support of his recommendation to reduce the incremental DG positions from 19 to three, Division Witness Booth asserts the Company should manage any increase in future DG interconnections by leveraging existing staff and using external engineering consultants to augment internal staff and manage variable work load. In addition, he argues that the proposed positions, such as those related to GIS, maps and records should be part of the Company's normal course of business and not added solely due to DG integration (Booth, p. 32-34). Witness Booth's conclusions do not consider current staffing levels, the current use of external engineering consultants, or the Company's past efforts to leverage resources. Rather, Division Witness Booth's suggestions are common steps any utility would employ for work variability, which the Company already has done, as discussed below. Furthermore, Mr. Booth's recommendation to reduce incremental DG positions from 19 to three is arbitrary and without any support.

Rhode Island's current engineering, design, and mapping resources were largely determined prior to the 2012 Rate Case to address ongoing system and new business issues. The Company prudently maintained resource levels and used external resources as necessary for work variability into 2015. From 2015 into 2016, during the significant DG application increase, the Company did shift or leverage Service Company resources to Rhode Island for DG interconnection work. However, the distributed energy resource effort in all three of National Grid's jurisdictions has significantly increased or remained at a high level, as shown in Figures 1, 2 and 3, below, making further leveraging of resources impossible. Furthermore, the shifting of internal resources was not enough to keep up with the significantly increasing work load, despite the Company's external contracting efforts in 2016. In 2017, the Company experienced yet another a significant increase in DG applications, and the internal and external resources remained strained to an unsustainable level. As described in the Company's initial filing, from calendar year 2012 through the majority of calendar year 2017, the Company experienced dramatic increases in the number of total and complex DG interconnection applications received, both in volume of applications received and in the size (megawatt or MW) of the applications, as shown in Figure 1 of the Company's initial filing and reproduced below.[6] The Division's recommendations address variability or temporary conditions, but are not prudent business practices for significant and sustained work volume increases.

[6] *See* Direct Testimony of Raymond J. Rosario, Jr., Alfred Amaral III, Ryan M. Constable, Book 4 of 17, Bates Pages 61-66, Figure 1.

FIGURE 1



	2012	2013	2014	2015	2016	2017*	2018 Projected	2019 Projected
Complex Applications Received	17	36	17	30	87	89	89	89
Total Applications Received	105	133	178	729	1898	2258	2258	2258
Complex MW Applied For	31	34	25	69	155	309	309	309
Total MW Applied For	47	37	29	90	175	327	327	327

(*the last two months of 2017 data are projected)

FIGURE 2

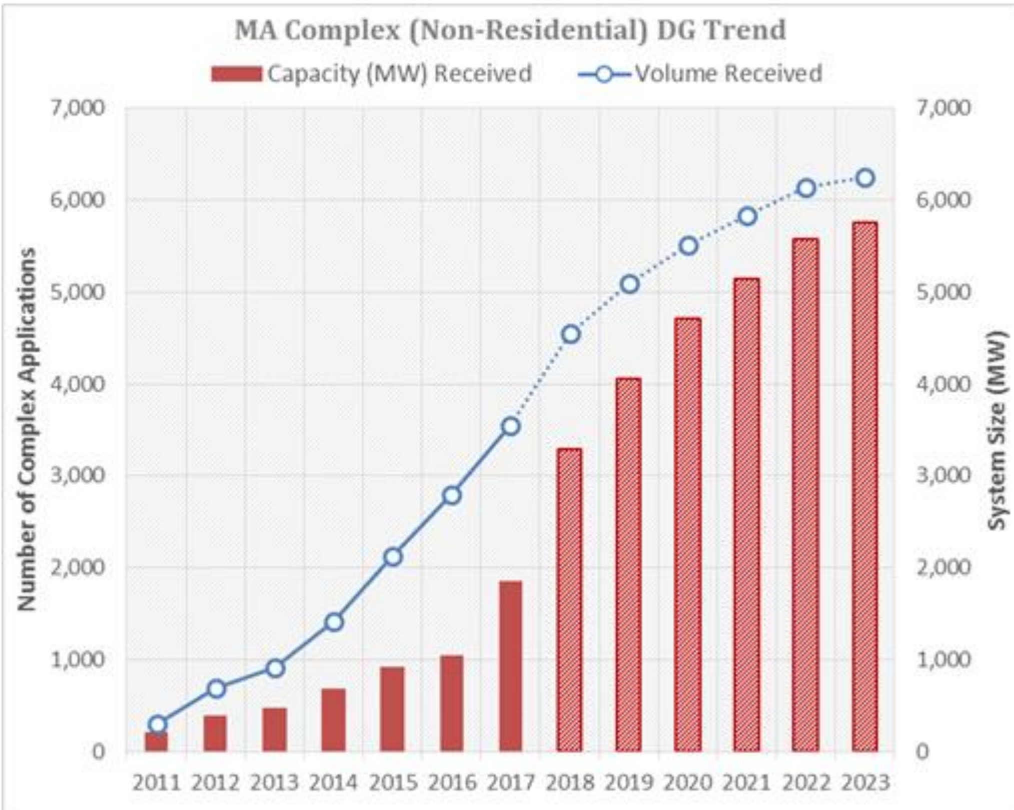
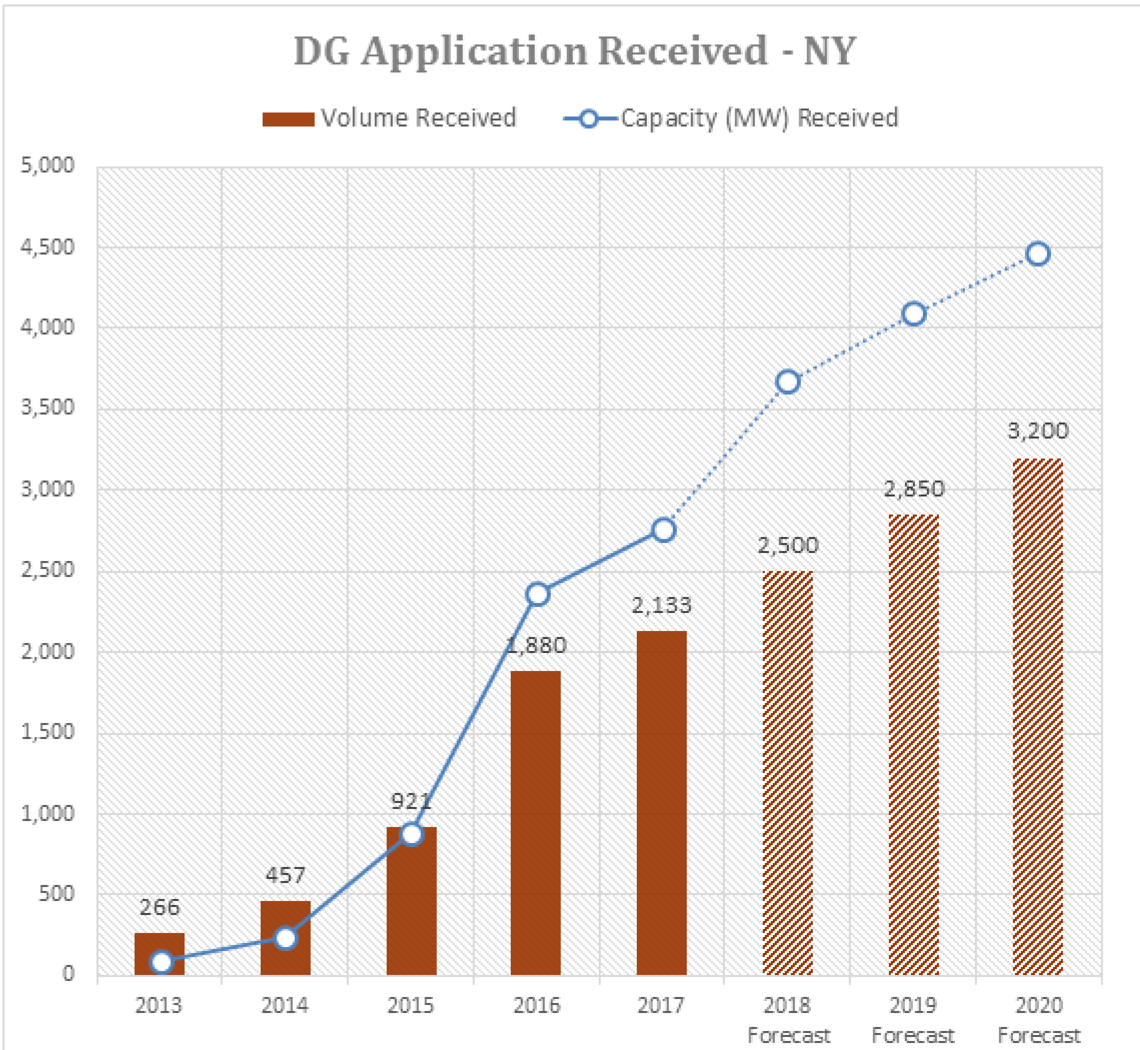

MA Complex (Non-Residential) DG Trend
Capacity (MW) Received
Volume Received
Number of Complex Applications
System Size (MW)
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023

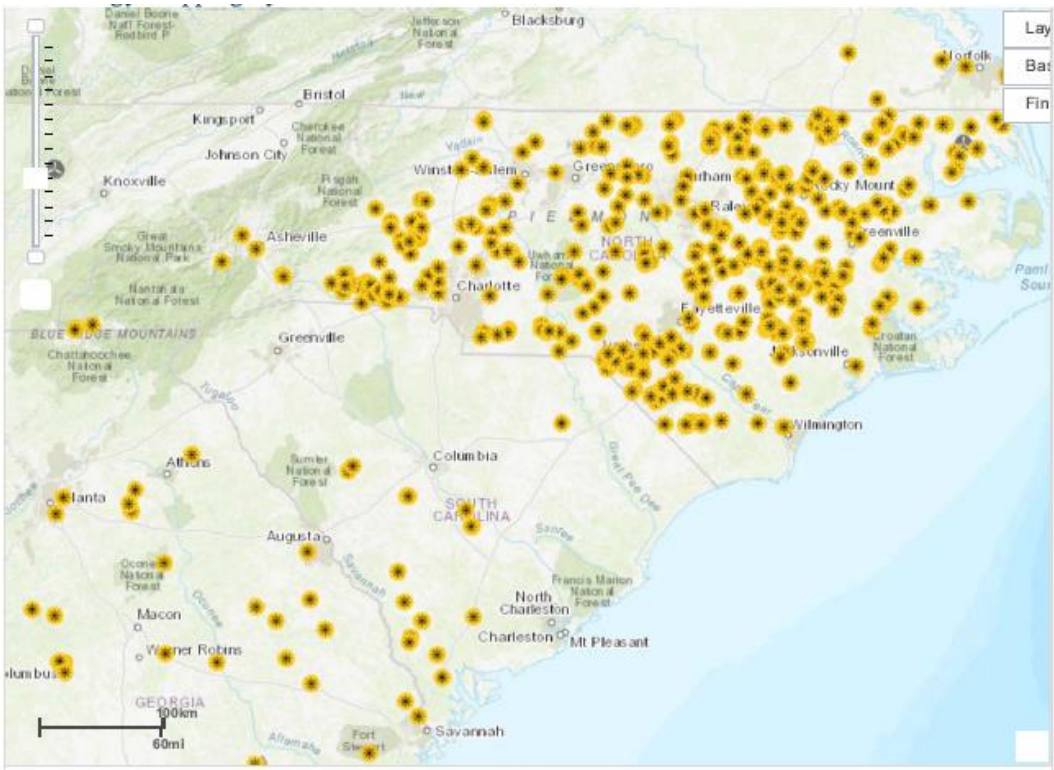
FIGURE 3



Q. Please address Division Witness Booth's suggestion that the Company look to other utilities, such as Duke Energy Progress, as an example of an appropriate "ramping up" strategy by using outside engineering firms to address increases in workload.

A. Witness Booth's suggestion that the Company look to other utilities, such as Duke Energy Partners for an appropriate "ramping up" strategy is unfounded. The Company has extensive experience, as do most utilities, on the appropriate use of external resources. Internal resources should be used for a base load of work and supplemented with external resources for work variability. In practice, this concept fluctuates and is never perfectly balanced.

The Division's comparison with Duke Energy Partners also is unfounded. The Division provides no evidence comparing existing resources within Duke Energy Partners to the Company's resources in Rhode Island, or actual DG workload. While North Carolina has a robust DG industry, South Carolina does not at this time (see Figure 1 from US Energy Mapping System with solar and wind power plant layers, https://www.eia.gov/state/maps.php).



Q. Please address Witness Booth's statement that proposed positions such as GIS, maps and records should be part of the Company's normal course of business.

A. The DG interconnection work in Rhode Island impacts all engineering, design, and mapping departments within National Grid. The requested FTEs are incremental to current staffing levels to handle the increase in DG interconnection work, and should not be considered normal course of business.

Q. Is there anything else from Witness Booth's testimony that you would like to address?

A. Yes, Witness Booth claims that National Grid's request for FTE employees is "purely a premature attempt to ramp up in anticipation of interconnection workload." However, this claim fails to recognize that the anticipated interconnection work load is aligned with State energy policies in all National Grid's service territories.

V. <u>Conclusion</u>

Q. Does this conclude your joint testimony?

A. Yes, it does.

REBUTTAL TESTIMONY

OF

MAUREEN P. HEAPHY

Dated: May 9, 2018

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I. Introduction

Q. Would you please state your full name, occupation, and business address.

A. My name is Maureen P. Heaphy. I am Vice President of U.S. Compensation, Benefits, and Pensions for National Grid USA Service Company, Inc. My business address is One Metrotech Center, Brooklyn, New York 11201.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes. On November 27, 2017, I submitted direct testimony in this proceeding in support of The Narragansett Electric Company d/b/a National Grid (the Company) demonstrating the reasonableness of employee compensation and benefit costs included in the Company's revenue requirement.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the joint direct testimony submitted to the Rhode Island Public Utilities Commission (PUC) in this proceeding by Michael R. Ballaban and David J. Effron on behalf of the Rhode Island Division of Public Utilities and Carriers (the Division) proposing that the PUC set non-union employee wage increases based on the general wage increases granted to the Company's *union* employees. In particular, my rebuttal testimony substantiates the Company's use of market data to set non-union wages and responds to certain assertions made by Mr. Ballaban and Mr. Effron in their testimony. My rebuttal testimony, in turn, supports the use of market data to set the payroll increase for non-union employees during the rate year.

II. Use of Market Data to Support Non-Union Employee Compensation

Q. Do Mr. Ballaban and Mr. Effron agree with the Company's use of market data to set non-union employee compensation?

A, No. Mssrs. Ballaban and Effron propose that the PUC should adopt a new method for setting non-union employee compensation by using an average of *union* employee wage increases. I am not aware of any other proceeding in Rhode Island in which such a proposal was made.

Q. Would you briefly summarize the reasons given by Mr. Ballaban and Mr. Effron for adopting a new standard with respect to non-union employee wage increases?

A. Yes. In their testimony, Mssrs. Ballaban and Effron state that the non-union employee increases "appear to be too high" and that use of a three-year average of union increases "better reflects the expectations of non-union employees."[1]

Q. Would you also briefly describe how Mr. Ballaban and Mr. Effron propose to set non-union employee wages?

A. My understanding of their testimony is that they propose to replace the increase included in the rate year for non-union employees with a percentage increase calculated for *union* employees.[2]

[1] Testimony of Ballaban and Effron at 52, 54.
[2] The union increase percentages used by Mr. Ballaban and Mr. Effron are noticeably lower than the actual contracted increases found in Workpaper MAL-4, Pages 14 and 15.

Q. Do you agree with their proposal?

A. No. The use of arms-length negotiated union increases are not applicable to non-union wage increases as indicated in the study included in my direct testimony. Non-union wages are set based on market data. Use of market data allows the Company to compete for similarly skilled management employees in order to obtain the necessary talent to provide safe and reliable service to the Company's customers. Use of market data has been approved by the PUC in setting a reasonable level of non-union salaries including annual wage increases.[3] The Division's witnesses have presented no evidence that rebuts the reasonableness of the non-union wage increases proposed by the Company. Moreover, there is no reliable evidence presented by Mr. Ballaban and Mr. Effron for the PUC to consider a new method to set non-union wages and disregard precedent.

Q. Would you describe what evidence the Company provided to support the non-union wage increases?

A. Yes. As I stated in my direct testimony, non-union wage increases generally are based on market data, which ensures that compensation for the Company's non-union employees is competitive. The Company, as in past rate proceedings, submitted a study by its consultant that analyzed the overall level of the compensation package offered to the Company's non-union employees.[4] The study included an analysis of the total cash compensation (fixed and variable) and concluded that the value of non-union or

[3] See RI PUC Docket Nos. 4323 Order at 24-26 (Heaphy Testimony at 9-11); 4065 (Dowd Testimony at 3, 10-11).
[4] Schedules MPH-2 through MPH-5.

management salary and target total compensation was slightly below the competitive market but within a reasonable range of the market and that target variable pay was equal to the market average.[5]

Q. Why is market data provided by Willis Towers Watson important to the Company and to setting non-union employee wages?

A. The Company must compete with other similarly situated companies to obtain and retain high-caliber talent. To do so, the Company has to know what the market data indicates are to align its compensation package with the market. The costs of base salary, performance-based variable pay, and various benefits is not only important but necessary and must be incurred for the Company to meet its obligations to provide safe and reliable utility service to its customers.

Q. What are the reasons that the PUC should reject the Division's recommendation?

A. The recommendation put forth by the Division's witnesses to use union increases conflicts with PUC precedent and ignores that the non-union employee wage increase for July 1, 2017 was implemented and that the July 1, 2018 wage increase has been approved by Company management. Moreover, the Division's witnesses provide no evidentiary support that a change to precedent is necessary or desirable. In addition, adoption of the Division's recommendation would place the Company at a competitive disadvantage with

[5] Schedules MPH-4 and MPH-5.

respect to hiring and retaining qualified employees to provide, safe, reliable, and efficient service to its customers.

III. Conclusion

Q. Does this conclude your testimony?

A. Yes, it does.

REBUTTAL TESTIMONY

OF

MELISSA A. LITTLE

Dated: May 9, 2018

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I. <u>Introduction and Qualifications</u>

Q. Please state your full name and business address.

A. My name is Melissa A. Little, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. By whom are you employed and in what capacity?

A. I am Director, New England Revenue Requirements for National Grid USA Service Company, Inc. (the Service Company). The Service Company provides engineering, financial, administrative, corporate, management, and other technical support to direct and indirect subsidiary companies of National Grid USA (National Grid). My current duties include revenue requirement responsibilities for National Grid's electric and gas distribution activities in New England, including the electric and gas operations of The Narragansett Electric Company d/b/a National Grid (the Company).

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes. On November 27, 2017, I submitted direct testimony in this proceeding in support of The Narragansett Electric Company d/b/a National Grid's revenue requirements for Narragansett Electric and Narragansett Gas.

Q. Would you please explain the naming conventions that you will be using in your testimony and associated schedules to identify the various entities involved in this proceeding?

A. Certainly. This proceeding is a ratemaking proceeding for the electric and gas distribution operations of The Narragansett Electric Company, which together constitute the regulated operations that National Grid conducts in Rhode Island. In this case, I will refer to the regulated entity as the "Company," where the reference is to both electric and gas distribution operations on a collective basis. Where there is a need to refer to the "stand-alone" or individual electric or gas operations of The Narragansett Electric Company, I will use the terms "Narragansett Electric" or "Narragansett Gas," respectively, as appropriate. Where I refer to "National Grid USA", I will use the term "National Grid"; where I refer to "National Grid plc," I will use that specific term.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony is designed to serve two purposes: First, my rebuttal testimony provides the second revision to the revenue requirement calculation and existing revenue deficiency for Narragansett Electric, and separately for Narragansett Gas, for the twelve-month period ending August 31, 2019 (the Rate Year). In addition, as stated in its response to data request PUC 3-39, although the Company filed a one-year rate case, the Company is including revised forecast data for the two twelve-month periods ending August 31, 2020 (Data Year 1) and August 31, 2021 (Data Year 2) (Data Year 1 and Data Year 2 are referred to collectively herein as the Data Years) to aid in potential settlement discussions among the parties to this proceeding.

Second, my rebuttal testimony responds to the pre-filed direct testimony submitted by the Division of Public Utilities and Carriers (the Division) in this proceeding regarding the Company's revenue requirement calculations and existing revenue deficiencies for Narragansett Electric and Narragansett Gas.

Q. How is your testimony organized?

A. Section I is the Introduction. Section II presents the second revision to the revenue requirements and revenue deficiencies for Narragansett Electric and Narragansett Gas. Section III describes the corrections to the cost of service that were identified during discovery and in finalizing the second revision to the cost of service that are presented in two new schedules: Schedule MAL-1a-ELEC (REV-2) and Schedule MAL-1a-GAS (REV-2). Section IV summarizes the issues raised in the testimony of the Division and provides the Company's response to those issues. Section V is the conclusion to my testimony.

Q. Please describe the schedules accompanying your rebuttal testimony.

A. The schedules that I have prepared for the second revision to the cost of service are labeled with the designation "REV-2" to distinguish them from the initial cost of service schedules provided in the Company's initial filing on November 27, 2017 and from the first revision to the cost of service filed with the PUC on March 2, 2018, which were labeled with the designation "REV-1". I have prepared separate schedules for Narragansett Electric and Narragansett Gas, with the schedules labeled with the designations “ELEC” and “GAS,” respectively, as appropriate. For ease of reference, I have maintained the same naming convention for the presentation of similar information for Narragansett Electric and Narragansett Gas. For example, Schedule MAL-1-ELEC (REV-2) represents the summary revenue requirement and resulting revenue deficiency for Narragansett Electric. Schedule MAL-1-GAS (REV-2) contains the same information for Narragansett Gas. For schedules that provide common support for both electric and gas, no “ELEC” or “GAS” designation is used. In addition, as noted above, I have prepared two new schedules – Schedule MAL-1a-ELEC (REV-2) and Schedule MAL-1a-GAS (REV-2)– that summarize all corrections identified during discovery and in finalizing the second revision to the cost of service.

Using these designations, the revenue requirements schedules accompanying my testimony are as follows:

Schedule MAL-1-ELEC (REV-2)	Revenue Requirement – Electric
Schedule MAL-1-GAS (REV-2)	Revenue Requirement – Gas
Schedule MAL-2-ELEC (REV-2)	Revenue – Electric
Schedule MAL-2-GAS (REV-2)	Revenue – Gas
Schedule MAL-3 (REV-2)	Operation & Maintenance Expense Summary
Schedule MAL-4-ELEC (REV-2)	Amortization of Regulatory Deferrals – Electric
Schedule MAL-4-GAS (REV-2)	Amortization of Regulatory Deferrals – Gas
Schedule MAL-5-ELEC (REV-2)	Amortization of Intangibles – Electric
Schedule MAL-5-GAS (REV-2)	Amortization of Intangibles – Gas

Schedule MAL-6-ELEC (REV-2)	Depreciation – Electric
Schedule MAL-6-GAS (REV-2)	Depreciation – Gas
Schedule MAL-7-ELEC (REV-2)	Municipal Taxes – Electric
Schedule MAL-7-GAS (REV-2)	Municipal Taxes – Gas
Schedule MAL-8 (REV-2)	Payroll Taxes
Schedule MAL-9 (REV-2)	Other Tax and Gross Receipts Tax
Schedule MAL-10-ELEC (REV-2)	Income Taxes – Electric
Schedule MAL-10-GAS (REV-2)	Income Taxes – Gas
Schedule MAL-11-ELEC (REV-2)	Rate Base – Electric
Schedule MAL-11-GAS (REV-2)	Rate Base – Gas
Schedule MAL-12 (REV-2)	Labor
Schedule MAL-13 (REV-2)	Health Care
Schedule MAL-14 (REV-2)	Group Life Insurance
Schedule MAL-15 (REV-2)	Thrift Plan
Schedule MAL-16 (REV-2)	FAS112 / ASC 712
Schedule MAL-17 (REV-2)	Service Company Rents
Schedule MAL-18 (REV-2)	Joint Facilities
Schedule MAL-19 (REV-2)	Uninsured Claims
Schedule MAL-20 (REV-2)	Insurance Premium
Schedule MAL-21 (REV-2)	Regulatory Assessments
Schedule MAL-22 (REV-2)	Uncollectible Accounts
Schedule MAL-23 (REV-2)	Postage
Schedule MAL-24 (REV-2)	Strike Contingency
Schedule MAL-25 (REV-2)	Environmental Response Fund
Schedule MAL-26 (REV-2)	Paperless Bill Credit

Schedule MAL-27 (REV-2)	Post-Retirement Benefits Other than Pension
Schedule MAL-28 (REV-2)	Pension
Schedule MAL-29 (REV-2)	Energy Efficiency Program

II. Second Revision to the Company's Cost of Service

Q. Please summarize the revisions to the Company's cost of service for Narragansett Electric and Narragansett Gas that are reflected in the schedules accompanying your rebuttal testimony.

A. The revised schedules reflect changes to the proposed cost of service since the Company filed its first revision to the cost of service with the PUC in this docket on March 2, 2018. The Company's proposed cost of service is $297,969,704 for Narragansett Electric reflecting a weighted cost of capital of 7.43 percent on rate base of $730,084,338, as reflected in Schedule MAL-1-ELEC (REV-2). The Company's proposed cost of service is $228,214,528 for Narragansett Gas reflecting a weighted cost of capital of 7.67 percent on rate base of $765,221,251, as reflected in Schedule MAL-1-GAS (REV-2).

The revenue requirement for Narragansett Electric, including other operating revenue, before reflecting the required increase, is $279,091,943, as shown on Schedule MAL-1-ELEC (REV-2). As also shown, the base distribution revenue increase required for Narragansett Electric is $18,877,761. Thus, Narragansett Electric's total revenue requirement is $297,969,704. The revenue requirement for Narragansett Gas, including other operating revenue, before reflecting the required increase, is $212,763,488, as shown on Schedule MAL-1-GAS (REV-2). As also shown, the base distribution revenue increase required for Narragansett Gas is $15,451,041. Thus, Narragansett Gas's total revenue requirement is $228,214,528.

Q. How does the Company's second revision to the proposed cost of service for Narragansett Electric and Narragansett Gas compare to the Company's original proposed cost of service presented in its initial filing submitted to the PUC on November 27, 2017 and its first revision to the proposed cost of service submitted to the PUC on March 2, 2018?

A. As discussed above, compared to its original proposed cost of service in its initial filing submitted to the PUC on November 27, 2017, the Company has reduced its proposed increases in base distribution revenues as summarized on Schedule MAL-1-ELEC (REV-2) and Schedule MAL-1-GAS (REV-2) from $320,487,337 to $297,969,704 for Narragansett Electric and from $244,846,133 to $228,214,528 for Narragansett Gas for a total reduction of $39,149,238. Compared to its first revision to the cost of service filed with the PUC on March 2, 2018, the Company has reduced its proposed increases in base distribution revenues as summarized on Schedule MAL-1-ELEC (REV-2) and Schedule MAL-1-GAS (REV-2) from $41,294,907 to $18,877,761 for Narragansett Electric and from $30,322,543 to $15,451,041 from Narragansett Gas for a total reduction of $37,288,648.

III. <u>Corrections Identified During Discovery and in Finalizing the Second Revision to the Cost of Service</u>

Q. You stated earlier in your testimony that you have prepared two new schedules, Schedule MAL-1a-ELEC (REV-2) and Schedule MAL-1a-GAS (REV-2), that reflect the corrections to the cost of service that were identified during discovery and while the Company was finalizing its second revision to the cost of service. Please describe how you have organized the information presented in those schedules.

A. Certainly. The purpose of Schedule MAL-1a-ELEC (REV-2) and Schedule MAL-1a-GAS (REV-2) is to provide an itemized list of the revisions made to the Company's revenue requirement calculation since its initial submission on November 27, 2017 and its submission of the first revised revenue requirement on March 2, 2018. The first column marked "Description" provides a brief commentary on the purpose of adjustment. The next column marked "Category" reflects the area of the cost of service being impacted by the adjustment (Revenue, Rate Base, Income Tax, etc.). Column (a) reflects the dollar increase or decrease to that category resulting from the adjustment. Columns (b) through (d) reflect any flow-through impacts to income tax, uncollectible expense, and operating income due to the adjustment in Column (a), to arrive at the total revenue requirement impact of the adjustment in Column (e). Columns (g) through (j) illustrate the impact of any adjustments to rate base, with the total rate base impact summarized in Column (j). Any flow-through impacts to income tax, uncollectible expense, and operating income related to the rate base adjustments in Column (j) are also included in Columns (b) through (d). Column (k) lists the revenue requirement schedule to which the adjustment was applied. Column (l) references the Company's response to data requests in which the adjustment was addressed, if applicable. Therefore, the Rate Year total in Column (f) reflects the total revenue requirement as shown in Schedule MAL-1-ELEC (REV-2) and Schedule MAL-1-GAS (REV-2) in the Rate Year of $297,969,702 for Narragansett Electric and $228,214,530 for Narragansett Gas, respectively. Identical schedules are also presented in Schedule MAL-1a-ELEC (REV-2) and Schedule MAL-1a-GAS (REV-2) for Data Year 1 and Data Year 2.

IV. <u>Response to Division's Adjustments to the Revenue Requirement Calculation and Revenue Deficiency</u>

Plant Additions Related to Gas Growth

Q. What is the Company's forecast of gas plant additions related to gas growth for the Rate Year?

A. As shown on Schedule MAL-11-GAS, Page 4 and on Attachment DIV 20-3 to the Company's response to Division 20-3, the Company's forecast of gas plant additions related to gas growth for the Rate Year is $24,014,376.

Q. How does the Company's forecast of gas plant additions for the Rate Year compare to actual plant additions related to gas growth in prior years?

A. The forecast for the Rate Year is higher than the actual plant additions related to gas growth for Fiscal Year 2016, which was $20,990,000, and Fiscal Year 2017, which was $18,914,000, as noted in the Company's response to data request Division 20-3.

Q. What is the Division's recommendation regarding the Company's forecast of plant additions for the twelve-month period ended August 31, 2018 and for the Rate Year?

A. The Division proposes to modify the forecast of plant additions for the twelve-month period ended August 31, 2018 and the Rate Year by using the average of actual gas growth plant additions for Fiscal Years 2016 and 2017, which the Division calculates to be approximately $20 million. The Division claims that the Company's forecast for these periods is "significantly higher than the actual rate of plant additions [for gas growth]" [Testimony of Ballaban & Effron at 22] and that "[a]bsent further explanation and justification from the Company for the increase in the rate year" [id. at 23], the Division believes using the approximately $20 million average for Fiscal Years 2016 and 2017 is a "reasonable estimate" to use as a forecast for the twelve-month period ended August 31, 2018 and the Rate Year [id.].

Q. Does the Company agree with the Division's recommendation?

A. The Company appreciates the concerns that the Division has raised with respect to the Company's projection of growth plant additions; however , it does not agree with the Division's recommendation. The Division had raised concerns about the Company's growth-related projections in its last base rate case in Docket No. 4323; however, in that case, the Division challenged the Company's projection of revenue growth in the rate year in that case. In Docket No. 4323, the Company, the Division, and other parties entered into a settlement agreement (Settlement Agreement) to resolve certain of the disputed issues in that case. Among the settled items was a resolution of the Division's challenge to the Company's revenue growth projections by agreeing to a reconciliation of the forecasted growth-capital revenue requirement and the actual gas growth capital revenue requirement in the rate year.[1] The Company recommends that this approach be adopted in this proceeding, which will ensure that customers will be credited with an accurate level of gas growth revenue and address the Division's concern regarding the Company's growth capital forecast.

Rate Year Labor to Support Increased Distributed Generation (DG) Applications and Other Proposed Adjustments to Rate Year Labor

Q. Please summarize the Division's proposed adjustments to Rate Year labor expenses.

A. As discussed in the joint direct testimony of Michael R. Ballaban and David J. Effron and the direct testimony of Gregory L. Booth on behalf of the Division, the Division recommends the following downward adjustments to labor expense:

1. A significant reduction in the Company's proposal to add 19 additional full time equivalent (FTE) employees needed to support increased DG applications in large part due to state policy initiatives that strongly encourage the development of more renewable and distributed energy, resources resulting in a downward adjustment to labor expense of $765,268 [Testimony of Ballaban & Effron at 48; Testimony of Booth at 32-34];

[1] See Amended Settlement Agreement by and among the Company, the Division, and the U.S. Department of the Navy dated November 13, 2012, at Bates Page 23, approved by the PUC in its Report and Order No. 21011 (April 11, 2013) in Docket No. 4323.

2. An overall reduction to the Rate Year labor expense of $935,548 to reflect a smooth hiring pattern over the course of the Rate Year for all Narragansett Gas and Narragansett Electric incremental FTEs requested by the Company [Testimony of Ballaban & Effron at 52]; and

3. A reduction to the Company's proposed wage increase for non-union employees reflecting the Division's application of the average of the wage increases for union employees during the periods July 1, 2017 to June 30, 2018, July 1, 2018 to June 30, 2019, and July 1, 2019 to June 30, 2020, to each of those periods for non-union employees, resulting in a downward adjustment to labor expense of $976,005 [id. at 52-54].

Q. How does the Company respond to the Division's recommendations?

A. The Division's downward adjustments noted above are unwarranted and should be rejected. In their joint rebuttal testimony, Company Witnesses Alfred Amaral III, Raymond J. Rosario, Jr., and Ryan M. Constable discuss the reasons why the Division's first two labor expense adjustments noted above are without merit. Company Witness Maureen Heaphy addresses the flaws in the Division's rationale for its proposed downward adjustment for non-union employee wage increases in her rebuttal testimony.

Q. Are there any incorrect mathematical calculations or other methodological flaws in the Division's downward adjustments to Rate Year labor expense?

A. Yes. First, the Division incorrectly calculated its recommended downward adjustment in labor costs of $765,268 because the Division failed to take into account that the FTEs at issue would be Service Company employees, not direct employees of the Company. Second, the Division's downward adjustment in labor costs of $935,548 is flawed because the Division included the same three Narragansett Electric DG-related FTEs in this adjustment that already were used to calculate the $765,268 adjustment, thereby doubling this adjustment.

Q. Please describe the first mathematical error with respect to the Division's adjustment for incremental FTEs to support increased DG applications.

A. The Division developed its $765,268 downward adjustment by starting with the total incremental Rate Year labor and related overheads for Narragansett Electric and dividing that sum by the total number of incremental FTEs the Company proposed to add to support increased DG applications (<u>i.e.</u>, 19 incremental FTEs). The Division's calculation, however, fails to capture the costs of these incremental FTEs accurately.

Q. Please explain.

A. Only three of the 19 incremental FTEs proposed in the Company's filing in this docket were proposed to be hired by the Company as Narragansett Electric employees. The remaining 16 incremental FTEs were to be hired as Service Company employees. The Company is responsible for the full cost of employees hired as Narragansett Electric employees; however, the Company is responsible for only its allocated share of the cost of employees hired as Service Company employees. The average Rate Year salary of a Narragansett Electric employee with related overheads charged to operating and maintenance (O&M) expense is $47,829 [<u>see</u> Division Workpaper Attachment 1-27-3_RRP_DIV_29-6, tab "Summary"]. The average allocated Rate Year salary of a Service Company employee with related overheads charged to O&M expense is $9,076 [<u>see</u> Division Workpaper Attachment 1-27-3_RRP_DIV_29-6, tab "Summary"].

Two incremental FTEs to support increased DG applications already have been hired as Service Company employees. The Company anticipates that the next position to be filled will be a Customer Energy Integration Consultant, which is also a Service Company position. Therefore, if the Company were to make an adjustment to its cost of service based on the Division's methodology, that adjustment would be to remove three Narragansett Electric FTEs at $47,829 each, and 13 Service Company FTEs at $9,076 each, for a total of $261,475, not $765,268.

Q. Please describe the second mathematical error pertaining to the Division's $935,948 downward adjustment.

A. The Division claims that labor expense should be reduced by approximately $935,948 "to reflect a smooth hiring pattern over the course of the [Rate Year] for all Narragansett Gas [and] Narragansett Electric incremental FTEs requested, but not filled" (footnote omitted) by the Company [Testimony of Ballaban & Effron at 52]. The main flaw in the calculation of this adjustment is that the Division double-counted its reduction for the three incremental DG-related FTEs by using these FTEs in the development of its $765,268 downward adjustment discussed above and using these same FTEs in the development of its $935,948 downward adjustment. The Division developed this adjustment using the numbers set forth in Table 1 below; these numbers are slightly different from the Company's figures, which are set forth in Table 2 below.

<u>TABLE 1</u>

	Division - Rate Year (9/1/18 - 8/31/19)					
	Number of Employees	**Estimated Hires to Date**	**Remaining Hires**	**Adjusted to Remaining Hires (50%)**	**Average Rate Year Narragansett Electric Incremental FTE**	**Labor Costs (O&M)**
New Hires						
Electric	32	19	13	7	$ 47,829	$ 334,805
Gas	30	6	24	12	$ 50,095	$ 601,144
Total	62	25	37	19		$ 935,948

TABLE 2

	Company - Rate Year (9/1/18 - 8/31/19)					
	Number of Employees	**Actual Hires to Date DIV 20-5**	**Remaining Hires**	**Adjusted to Remaining Hires (50%)**	**Average Rate Year Narragansett Electric Incremental FTE**	**Labor Costs (O&M)**
New Hires						
Electric	29	21	8	4	$ 47,829	$ 191,316
Gas	30	7	23	12	$ 50,095	$ 551,045
Total	59	28	31	16		$ 742,361

Q. Please explain the errors in the Division's methodology used to calculate its $935,948 downward adjustment.

A. The first error in the Division's methodology is that the Division used 32 incremental FTEs, instead of 29 incremental FTEs, for Narragansett Electric in the "Number of Employees" column. Three of the incremental FTEs included in the Division's total of

32 FTEs for Narragansett Electric in the "Number of Employees" column are the same three incremental FTEs that the Division already adjusted for in its downward adjustment for labor expense associated with incremental FTEs to support increased DG applications. Therefore, the Division erroneously double-counted its reduction for these three proposed incremental FTEs.

The next error in the Division's methodology is that the Division estimated that, to date, the Company has hired 19 incremental Narragansett Electric FTEs and six incremental Narragansett Gas FTEs as reflected in the "Estimated Hires to Date" column in Table 1. The Division derived these estimated hires using information provided by the Company in Attachment DIV 20-5 provided in response to data request Division 20-5. In Attachment DIV 20-5, the Company quantified the number of incremental positions that had been filled as of February 2018, which at that time were 21 Narragansett Electric FTEs and seven incremental Narragansett Gas FTEs for a total of 28 incremental FTEs. The Division attempted to use these numbers to correlate to the number of employees listed in the "Number of Employees" column. The Company, however, can confirm that each of the 28 incremental FTEs who were hired are related directly to the number of FTEs listed in the "Number of Employees" column that the Company proposed to hire to address workload issues other than the increased workload associated with DG applications.

Because of the Division's errors set forth in the columns labeled "Number of Employees" and "Estimated Hires to Date" in Table 1 above, there is a resulting error in the column labeled "Remaining Hires" in Table 1: The Division's total number of "Remaining Hires" is 37; however, the correct number is 31, as shown in Table 2.

The third flaw in the Division's methodology pertains to the Division's suggestion that the Company move 50 percent of the remaining hires from the Rate Year to the Data Years, yielding a difference of three FTEs between the Division's total of 19 FTEs in Table 1 as compared to 16 FTEs in Table 2.

The Company does not agree with the Division's proposed reduction to labor expense. If, however, the Company were to use the Division's average Rate Year salaries with related overheads as calculated on the Division's Workpaper "Attachment 1-27-3_RRP_DIV_29-6, tab "Summary", the resulting mathematical calculations would derive a total downward adjustment of $742,361, not $935,948, as follows:

1. Applying the $47,829 to the four Narragansett Electric FTEs moved to the Data Years results in a reduction of $191,316; and

2. Applying the $50,095 to the 11 Narragansett Gas FTEs moved to the Data Years results in a reduction of $551,045.

Operation and Maintenance Costs Assigned to the Gas Cost Recovery Mechanism

Q. Please summarize the recommendation of the Division's witness, Bruce R. Oliver, with respect to operation and maintenance (O&M) expense designated for recovery through Narragansett Gas's Gas Cost Recovery (GCR) mechanism.

A. In his direct testimony, Mr. Oliver does not appear to recommend any adjustment with respect to the current amount of O&M costs designated for recovery through Narragansett Gas's GCR mechanism. In his direct testimony, Mr. Oliver claims that the Company's "Rate Year GCR-Related O&M expense shown in Schedule MAL-32 represents an increase of $725,698 or 127.3% over the level currently included in [Narragansett Gas's] GCR charges" (emphasis omitted) [Testimony of Oliver at 67]. He derived the increase of $725,698 (and the resulting 127.3 percent increase) by comparing the Company's $1,308,279 of Rate Year GCR-Related O&M expense to the fixed component of the Company's annual Supply Related LNG O&M costs recovered through the GCR mechanism of $575,581. Mr. Oliver also claims that the "Test Year costs alone represent an 89% increase over the levels presented in Docket No. 4323 and currently included in [Narragansett Gas's] GCR charges" without explanation, and that Narragansett Gas's "Rate Year cost claim includes an unexplained 25% increase in Labor Costs" (emphasis omitted) [id.]. Mr. Oliver's 89 percent increase was similarly derived based on the $575,581 figure.

Q. Is Mr. Oliver's analysis accurate?

A. No, it is not. The Company's annual Supply Related LNG O&M cost that it recovers through the GCR mechanism is $1,148,275, comprised of the fixed cost component of

$575,581 and a variable cost component of $572,694.[2] Mr. Oliver's analysis erroneously reflected the fixed cost component being recovered through the GCR and not the variable cost component. This total is actually more than the test year level of GCR-related O&M expense on Schedule MAL-32, Page 6, Line 14 of $1,088,655.

Q. Has the Company addressed Mr. Oliver's comment concerning the "unexplained 25% increase in Labor Costs"?

A. Yes. The Division issued data request Division 40-1 on March 29, 2018 seeking support for the Company's $207,639 pro forma adjustment to the labor portion of the GCR-related O&M expense on Schedule MAL-32 and resulting 25 percent increase. This request was received nine days prior to the Division's testimony, which it filed with the PUC on April 6, 2018. The Company filed its response to data request Division 40-1 and supporting Attachment DIV 40-1 with the PUC on April 11, 2018, which was subsequent to the Division filing its testimony.

V. Conclusion

Q. Does this conclude your rebuttal testimony?

A. Yes.

[2] See Supplemental 2017 Gas Cost Recovery filing (Docket No. 4719), Attachment AEL-1S Page 2, Line 8 and Attachment AEL-1S Page 3, Line 7 for the fixed cost and variable cost components of the Supply Related LNG O&M costs.