BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

Niagara Mohawk Power Corporation d/b/a National Grid.

Cases 24-E-0322 & 24-G-0323

September 26, 2024

Prepared Testimony of:

UIU Rate Panel

Synapse Energy Economics
485 Massachusetts Avenue
Suite 300
Cambridge, MA 02139

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INTRODUCTION AND OVERVIEW

Q. Would the members of the UIU Rate Panel please state your names and business addresses?

A. **(Whited)** My name is Melissa Whited, and my business address is 485 Massachusetts Avenue, Cambridge, MA 02139.

(Palmer) My name is Caroline Palmer, and my business address is 485 Massachusetts Avenue, Cambridge, MA 02139.

(Havumaki) My name is Ben Havumaki, and my business address is 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. By whom are you employed, in what capacity, and what are your professional backgrounds and qualifications?

A. **(Whited)** I am a Vice President at Synapse Energy Economics, Inc. (Synapse). Synapse is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. I have 13 years of experience in economic research and consulting. At Synapse, I have worked extensively on issues related to utility regulatory models and rate design. I have been an invited speaker in numerous industry conferences, including as a panelist for the National Association of Regulatory Utility Commissioners (NARUC) Subcommittee on Rate Design at the 2021 Winter Policy Summit and the 2018 Annual Meeting. I hold a Master of Arts in Agricultural and Applied Economics and a Master of Science in Environment and Resources, both from the University of Wisconsin-Madison. My resume is attached as Exhibit__(URP-2).

(Palmer) I am a Principal Associate at Synapse. I have worked in energy policy and regulation for 8 years. From 2019 to 2024, when I joined Synapse, I worked at Strategen Consulting, where I provided expert witness and consulting services on behalf of public interest clients in regulatory proceedings. Before joining Strategen, I conducted a Fulbright Research Fellowship in Greece and supported clean energy policy consulting at Meister Consultants Group (now Cadmus). I hold a Master of Public Policy from the Goldman School at the University of California Berkeley and a Bachelor of Science from Georgetown University. My resume is attached as Exhibit__(URP-3).

(Havumaki) I am a Principal Associate at Synapse. I have approximately six years of experience working in regulated utility proceedings as an analyst and expert witness. At Synapse, I focus on a range of related regulatory topics, including ratemaking and rate design, performance-based regulation, and grid modernization. I hold a Bachelor of Arts degree in History from McGill University and a Master of Arts degree in Applied Economics from the University of Massachusetts. My resume is attached as Exhibit__(URP-4).

Q. On whose behalf are you testifying in this case?

A. We are testifying on behalf of the Utility Intervention Unit (UIU) of the New York Department of State's Division of Consumer Protection.

Q. Have you previously testified before the New York Public Service Commission (Commission) or any other state utility commission?

A. **(Whited)** Yes. I have sponsored testimony before the Commission in Case 17-E-0238. In addition, I have testified before the Massachusetts Department of Public Utilities, the Illinois Commerce Commission, the New Hampshire Public Utilities Commission, the Georgia Public Service Commission, the Rhode Island Public Utilities Commission, the Maine Public Utilities Commission, the California Public Utilities Commission, the Hawaii Public Utilities Commission, the Public Service Commission of Utah, the Public Utility Commission of Texas, the Virginia State Corporation Commission, the Newfoundland and Labrador Board of Commissioners of Public Utilities, the Nova Scotia Utility and Review Board, and the Federal Energy Regulatory Commission.

(Palmer) I have sponsored testimony before the Maine Public Utilities Commission, the Massachusetts Department of Public Utilities, the Oklahoma Corporation Commission, and the North Carolina Utilities Commission, and have assisted with testimonies and regulatory analyses in numerous additional jurisdictions. The issues covered in these cases include marginal and embedded cost of service studies (ECOSS), revenue allocation, rate design, load management, decoupling, distributed energy resources, interconnection and compensation, electric vehicle infrastructure investments, and pilot frameworks.

(Havumaki) I have sponsored testimony before the Pennsylvania Public Utilities

Commission, the Minnesota Public Utilities Commission, the Public Utilities Commission of New Hampshire, the Georgia Public Service Commission, the Illinois Commerce Commission, the West Virginia Public Service Commission, the Rhode Island Public Utilities Commission, the Nova Scotia Utility and Review Board, and the New Brunswick Energy and Utilities Board.

Q. What is the scope of your testimony?

A. The purpose of our testimony is to address certain aspects of the ECOSS and revenue allocation proposals submitted by Niagara Mohawk Power Corporation d/b/a National Grid (Niagara Mohawk or the Company) on May 28, 2024, in Cases 24-E-0322 and 24-G-0323. We reserve the right to comment on other issues during rebuttal, in response to proposals offered by other parties, or information that becomes available after this testimony was prepared. The absence of discussion of other topics in this testimony should not be construed as support for, or opposition to, the Company's positions.

Q. How is your testimony organized?

A. This testimony has four sections. First, in this section we introduce our testimony, background, and experience. Second, we summarize our recommendations. Third, we discuss the Company's ECOSS and our recommended modifications. Fourth, we discuss the Company's revenue allocation proposals and our alternative proposals.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Exhibit__(URP-1) contains the Company's responses to Information Requests (IRs) that we relied upon in preparing this testimony. Exhibits__(URP-2), (URP-3), and (URP-4) contain the resumes of Witnesses Whited, Palmer, and Havumaki, respectively. Exhibit__(URP-5) contains the UIU Rate Panel's electric revenue allocation recommendations, Exhibit__(URP-6) contains the UIU Rate Panel's gas revenue allocation recommendations, and Exhibit___(URP-7) contains the Regulatory Assistance Project's cost allocation manual, *Electric Cost Allocation for a New Era.*

I. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please briefly summarize your conclusions.

A. Our conclusions are as follows:

- The ECOSS and revenue allocation methods proposed by the Company contain several critical flaws that undermine the accuracy and fairness of their outcomes.
- The reliance on the minimum system methodology in classifying substantial portions of the electric and gas distribution systems does not accurately reflect the cost-causation principles.
- The evolving nature of the energy grid, driven by increasing renewable energy integration and new policy mandates, necessitates a more nuanced approach to transmission cost allocation, rather than a reliance on 1 CP methods.

- The Company's allocation of costs among customer classes should rely on more transparent principles for developing minimum and maximum revenue increases for each class, and should ensure that all classes bear a sufficient portion of the overall revenue increase.

Q. What are your recommendations?

A. We recommend that the Commission:

1) Reject the minimum system method and adopt the Basic Customer Method for cost classification, which limits customer-related costs to those directly tied to services like metering and billing. This will more accurately reflect cost causation principles and prevent inflated cost allocations to residential and small commercial customers.
2) Direct the Company to revise its transmission cost allocation to better reflect modern power system realities, particularly for projects driven by public policy objectives. Costs associated with these projects should be allocated based on customers' volumetric energy usage.
3) Adopt more transparent minimum and maximum thresholds for class revenue increases. We recommend that:
    a. A cap of 133.3% of the system average revenue increase be applied to limit extreme impacts on customer classes. This would result in a maximum revenue increase of 34.9% for electric customers and 40.8% for gas customers.
    b. A minimum revenue increase should be set at 66.6% of the system

average to ensure all classes contribute equitably to system costs.

II. EMBEDDED COST OF SERVICE STUDIES

A. Overview of Cost of Service Studies

Q. What is the purpose of an ECOSS?

A. An ECOSS is used to assign the utility's revenue requirement to each customer or rate class in proportion to the costs imposed on the system by those customers. Thus, a cost of service study seeks to determine what costs are incurred to serve each class of customers.

Q. How is an ECOSS performed?

A. An embedded cost of service study typically follows three steps: first, costs are functionalized by separating utility plant and expenses according to the primary functions served. Second, the functionalized rate base and operating costs are classified according to the primary cost driver, as related to energy/commodity, demand/capacity, customer, etc. Finally, the costs are either directly assigned to customers or allocated using cost allocation factors based on energy use, demand/capacity maximums, or the number of customers.

Q. How do analysts determine the appropriate approaches to cost classification and allocation?

A. When selecting classification factors or allocators, the goal is to fairly allocate costs among different customer classes based on cost causation. Cost causation reflects the notion that the customer or set of customers that caused a cost should pay for the cost. To determine cost causation, analysts often rely on economic theory and power system engineering considerations.

Q. In your view, has the Company selected appropriate classification and allocation approaches?

A. No. In the sections that follow, we describe our concerns and recommend revisions to the Company's ECOSS approaches. In particular, the Company classifies portions of the electric and gas distribution system as partially "customer-related" based on a flawed minimum system methodology. Our testimony recommends alternative approaches that are better supported by economic theory and power system engineering. While we acknowledge that no cost of service study is perfect, we explain why our recommended approach is more reasonable and should therefore be used when determining revenue allocation and rate design.

Q. How should an ECOSS be used in a rate case?

A. Parties and the Commission should exercise judgement when using an ECOSS to inform revenue allocation or rate design, as it is an inherently imprecise tool. Every cost analyst makes numerous subjective determinations which may dramatically impact the results of the study. As such, utility cost of service studies should serve as one of several tools to inform decision-makers in revenue allocation and rate design, rather than being viewed as the sole determinant or final authority.

B. Classification of Distribution System Costs Using a Minimum System Study

Q. Did the Company classify certain distribution system costs as both customer-related and demand-related?

A. Yes. The Company classified electric FERC accounts 364-367 (poles, conductors, and conduits) and gas FERC account 376 (mains) as partly customer-related. The Company also mistakenly classified gas FERC account 378 (measuring and regulating station equipment) as partly customer-related, which it intends to correct in its forthcoming rebuttal filing. (See the Company's response to IR No. UIU-081(a)). To assess the share of each of these accounts to classify as customer-related versus demand-related, the Company used a minimum system study.

Q. What is a minimum system study?

A. The minimum system approach aims to determine the smallest capacity distribution system that the utility would install, reasoning that such system would fulfill the purpose of connecting customers to the distribution system. The Company calculates the ratio of the minimum system's cost to the cost of the entire distribution system to determine the share of the relevant accounts that should be classified as customer-related, while the remainder is considered demand-related. (See Direct Testimony of the Electric Rate Design Panel

("Electric Panel"), at 31; Direct Testimony of the Gas Rate Design Panel ("Gas Panel"), at 24).

Q. Do the minimum system studies deem significant portions of plant to be customer-related?

A. Yes. For electricity, the minimum system study classifies the vast majority of primary and secondary overhead distribution costs as customer-related, as well as sizeable portions of the underground distribution system. Specifically, according to the Company's electric minimum system study, the customer-related portions are:

- Primary Overhead, 86.57%
- Secondary Overhead, 92.46%
- Primary Underground, 46.41%
- Secondary Underground, 11.70%

For gas, the minimum system study indicates that 47.88% of distribution mains are customer-related.

Q. What are your concerns with the minimum system methodology?

A. The minimum system methodology does not align with the Company's definition of customer costs; it is unsound to use as the basis for determining cost causation; and it inflates the costs classified as customer-related. We discuss each concern below. In certain instances, we limit our discussion to just the electric system.

However, the concerns that we articulate about the application of the minimum system method to electric distribution costs generally apply to the gas system, too.

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Q. Why doesn't the minimum system methodology align with the Company's definition of customer costs?

A. As defined by the Company, electric "customer-related costs are incurred for assets that attach a customer to the distribution system and…are primarily a function of the number of customers served, incurred by the Company regardless of whether a particular customer uses any electricity, and typically do not vary with usage or load profile" (See Direct Testimony of the Electric Panel, at 26). Similarly, the Company explains that gas customer-related costs "are incurred by the Company regardless of whether an individual customer uses any gas" (See Direct Testimony of the Gas Panel, at 22).

These definitions align with the 1992 National Association of Regulatory Utility Commissioners (NARUC) *Electric Utility Cost Allocation Manual* (hereinafter NARUC Electric Manual). The NARUC Electric Manual defines customer costs as "costs that are directly related to the number of customers served." See NARUC Electric Manual, at 20)

Despite classifying large portions of the system as customer-related, the equipment the minimum system studies classify as customer-related does not vary directly with the number of customers. For example, increasing the number of customers in an area without increasing demand can be accomplished with no additional poles or conductors. It is particularly inappropriate to classify the primary electric system, which is designed to move power from the transmission system to the secondary distribution system, as customer-related. (See Direct Testimony of the Electric Panel, at 25) It is unreasonable to suggest that the purpose of primary equipment (with voltage levels commonly at 15,000 volts), is to simply attach a residential customer to the distribution system.

Q. Has the Company itself argued that any of these distribution system costs should be classified as demand-related rather than customer-related?

A. Yes. In its 2010 rate cases, assigned docket number 10-E-0050, the Company proposed to classify primary electric distribution costs as 100% demand-related, arguing that primary system cost does not depend on the number of customers the utility serves, because the primary system does not connect customers to the system. (Rebuttal Testimony of the Rate Design, Customer and Markets Panel, at 9-10).

Further, the Company currently proposes to recover costs classified as Primary Customer, and most of the costs classified as Secondary Customer, in the on-peak rate of its Residential Optional Time of Use Delivery and Commodity Rate because they are "used to meet peak demand." (See Direct Testimony of the Electric Panel, at 49) The fact that the Company offers customers a financial incentive to avoid those costs during peak hours certainly suggests that the costs vary with customer usage.

Q. Why is the minimum system method unsound to use as the basis for determining cost causation?

A. The method requires distinguishing a hypothetical system that serves only customers, not their electricity or gas demand. To create this imaginary system, the Company makes numerous subjective assumptions that oversimplify system engineering and impact the study results in unquantifiable ways.

Q. Did the Company calculate a minimum system that serves only to connect customers, rather than meet customer demands?

A. No. Any size of the distribution system will necessarily serve a portion of customers' demand. Not only does the Company's minimum system construct fail to produce a system that serves only to connect customers, but it is also so extensive that it satisfies multiple customer classes' entire electric peak demands. Specifically, the electric minimum system meets the peak demands of all, or almost-all, Service Classification (SC)-1, SC-1C, and SC-2-Non demand customers. (See Direct Testimony of the Electric Panel, at.33).

Q. Is it reasonable to classify such a large portion of the system as "customer-related" if it meets these customers' maximum demands?

A. No. A system that is large enough to accommodate entire classes of customers' peak demands goes well beyond a theoretical "minimum." It is unreasonable to assign customers hefty distribution system costs based on such a flawed representation of the "customer-portion" of the distribution system.

Q. Does the Company also allocate demand-related costs to the customer classes whose peak demands are being met through the "customer-related" portion of the system?

A. No. The Company appears to recognize this logical inconsistency and potential to double count cost responsibility. To address this problem, the Company allocates these customer classes $0 of the supposed demand-related portion of the electric system. (See Direct Testimony of the Electric Panel, 33-34).

Q. Does the Company's proposed allocation approach address your concerns with the minimum system?

A. No. Allocating $0 of demand costs is an important way to compensate for the oversized nature of the minimum system but is an imprecise workaround to address a problem that need not exist under alternate classification methods. The identified minimum system clearly exceeds its intended theoretical scope, inflating the costs classified as customer-related.

Q. Does the Company account for the load-carrying capacity of its minimum-sized gas system?

A. No, the Company does not account for the load-carrying capacity of the minimum gas system. However, the Zero Load approach utilized by the Company in past cases did account for this capacity. The fact that the Company does not correct for the load-carrying capacity of its gas minimum system, though it did in prior cases and does within its electric ECOSS in the instant proceeding, illustrates that methods for determining the customer-related classification of distribution mains are somewhat arbitrary.

Q. Were there any other issues with the gas minimum system study?

A. Yes. The Company's gas ECOSS utilized an incorrect minimum-system ratio (See the Company's response to IR No. DPS-826), and the ECOSS incorrectly classified measuring and regulating station equipment, FERC Account 378, using the minimum-system results rather than as 100% demand-related (See the Company's response to IR No. UIU-081). We corrected these errors and present updated ECOSS results further below.

Q. Are the Company's minimum system studies based purely on actual system data?

A. No. The Company made many subjective judgements and assumptions in the development of its minimum system studies. For example, in the electric study, conductor types with no purchase history since 2019 were assigned the cost per foot of "an equivalent conductor" (See Direct Testimony of the Electric Panel, at 32; Company's response to IR No. UIU-069). As a result, over 1/3 of the primary overhead costs, the largest cost category in the supposed minimum system, are based on costs for other conductors rather than on precise values.

In another example of arbitrary methodological choices, the Company did not conduct a minimum system study for electric Account 364, Poles, Towers and Fixtures. Instead, it used the same minimum system ratio from Account 365, Overhead Conductors and Devices. Although the results could be similar, there is no guarantee that they would be.

In addition, for both the electric and gas studies, the Company arrived at its minimum-system ratio by averaging the results of two separate studies covering different historical periods. These differences in results do not necessarily correspond to any changes in the architecture of the hypothetical minimum system. Rather, changes in the resulting ratios reflect seemingly arbitrary methodological choices and variations in relative component costs over time.

Q. What is the result of these judgements and assumptions?

A. The accumulation of these falsely precise approximations forms an unreliable basis on which the Company has assigned substantial costs among classes with significant impacts in revenue allocation and rate design.

Q. Has the Company always used the minimum system method?

A. No. As described above, in 2010, the Company proposed to classify primary electric distribution costs as 100% demand-related, rather than apply the minimum system method to the primary distribution system.

The Company has also used different methods for classifying gas mains in the past. In the Company's 2017 and 2012 rate case proceedings, it used a "Zero Load" approach to determine the customer share (See the Company's response to

IR No. UIU-076), which dispenses entirely with the minimum-sized system construct and instead simply classifies distribution mains labor costs as customer-related on the grounds that labor does not have load-serving capacity. (See the Company's response to IR No. UIU-076.)

In addition, the Company's subsidiary, National Grid in Massachusetts, does not use a minimum system study for classification (See Exhibit NG-PP-1 in D.P.U. 23-150, at 18, stating "the Company has not performed a minimum system study in its last four distribution rate cases, or more, and…did not perform a minimum system study for this ACOSS").

Q. What method do you recommend instead of the minimum system method?

A. We recommend the basic customer method. As shown in the Regulatory Assistance Project's manual *Electric Cost Allocation for a New Era*, Exhibit___(URP-7), this method is used by multiple states across the country and is intuitive and data-based, as it includes only costs that are directly customer-related. Specifically, the basic customer method generally classifies only costs associated with meters, meter reading, services, and billing as customer-related. Not only has the basic customer method been used by utilities in numerous states, in some cases public utility commissions have explicitly rejected the minimum system method or otherwise required that utilities classify primary and secondary distribution costs as 100% demand related. For example:

- The Arkansas Public Service Commission found that accounts 364-368 should be classified as 100% demand related. (See Exhibit___(URP-7), p. 145).

- The Illinois Commerce Commission has repeatedly rejected the minimum distribution or zero intercept approach. (See Exhibit___(URP-7), p. 145).
- The Iowa Administrative Code requires customer cost allocations to only include costs of the distribution system related to transformers, meters, and associated customer service expenses. (See Exhibit___(URP-7), p. 145).
- The Washington Utilities and Transportation Commission in 1993 directed the parties not to propose the Minimum System approach in the future unless technological changes in the industry emerge, justifying revised proposals. (See Exhibit___(URP-7), p. 145).
- Alaska administrative code requires that customer related costs may not include "any portion of the distribution system costs, which will be considered and classified as demand-related costs." (3 Alaska Admin. Code § 48.540)

Q. If the Commission chooses not to approve the basic customer method, would a hybrid classification method be more appropriate than the minimum system approach?

A. Yes. If the Commission does not approve the basic customer method, there are still ways to better align the minimum system study with system costs. For electric, we recommend that the Company classify primary distribution costs as 100% demand-related and only apply the minimum system methodology to secondary distribution costs, which are the lower-voltage lines that connect most customers to the grid.

For gas, we recommend that the Company classify distribution main costs as 75% demand-related and 25% customer-related. This position is consistent with UIU's recommendation in National Grid's 2017 rate case, reflects an approximate compromise between the basic customer approach that would classify mains as entirely demand related and the Company's minimum-system approach, and is consistent with the understanding that classification of mains costs is not an exact science. (See Case 17-G-0239, Direct Testimony of UIU Rate Panel, at 30)

C. Electric Transmission Allocation

Q. Does the evolving power system impact traditional cost of service study methods?

A. Yes. The evolving power system – one that must integrate higher levels of renewable resources – has increased the importance of cost allocation approaches that reflect a modern resource mix.

Q. Does the Company's transmission classification and allocation approach reflect the modern resource mix?

A. No. The Company must modernize its treatment of transmission costs to reflect modern cost causation.

Q. How does the Company treat transmission in its ECOSS?

A. The Company classifies all transmission costs as demand-related and allocates them based on class contributions to system peak ("1CP").

Q. Does this reflect the way in which the Company incurs transmission costs?

A. No, not entirely. The Company incurs transmission costs when transmission projects are approved by FERC for regional (statewide) cost allocation and billed to Niagara Mohawk by the New York Independent System Operator (NYISO) using allocations that vary project-to-project.

More recently, some projects are driven by statewide public policy, selected to meet the statewide carbon emission goals of the Climate Leadership and Community Protection Act and Accelerated Renewable Energy Growth and Community Benefit Act legislation, such as the Smart Path Connect Priority Transmission Project. NYISO allocates these projects' costs based on a statewide load-ratio share methodology, calculated volumetrically based on Actual Energy Withdrawals by Load Serving Entity (See the Company's response to IR No. UIU-071).

Q. How should the Company treat transmission costs related to public policy in its ECOSS, specifically the costs of transmission projects that NYISO allocates to Niagara Mohawk based on a statewide load-ratio share methodology or other energy-related allocator?

A. Given that these public policy costs have been allocated to the Company based on its volumetric energy delivery, the Company should in turn allocate them to customer classes based on their volumetric (MWh) contribution to the specific load ratio share that NYISO uses. Doing so would better reflect cost causation for those projects, given that NYISO allocates the project costs based on energy. The

Company confirmed that the appropriate volumetric allocator would by the "MWh-Gen" allocator (See the Company's response to IR No. UIU-118).

Q. Did you modify the Company's ECOSS to reflect this volumetric allocation?

A. No. When requested in discovery, the Company did not provide the data necessary to confidently make the modification, such as clear transmission project cost for energy-allocated projects (See response to IR No. UIU-071 and UIU-118). We recommend that the Commission direct the Company to make this modification and file a revised ECOSS.

Q. What are the likely impacts of your recommended volumetric allocation?

A. Because larger usage users (in customer classes such as Large General TOU-Transmission) require relatively more of the Company's MWh delivery than their requirement on its coincident peak demand, their cost allocation from the "MWh-Gen" allocator would increase relative to the "1CP_Trans" allocator, reflecting the higher volumetric load they impose on the public policy transmission projects described above. Allocation to most residential and small general classes would in turn decrease proportionally to their relatively lower volumetric load. (See Exhibit__(E-RDP-3CU Sch. 8D).

III. REVENUE ALLOCATION

A. Summary of the Company's Proposed Revenue Allocation

Q. How does the Company determine how much of a revenue increase to apportion to each of the customer classes?

A. Although the Company's electric and gas cost of service studies produce estimates of class revenue requirements that would recover its requested embedded costs , the Company deviates from these results in consideration of gradualism (See Direct Testimony of the Gas Panel, at 33; Direct Testimony of the Electric Panel, at 42).

To develop the revenue increases for each class, the Company first determines a "tolerance band" for the overall system return at current rates. The tolerance band ranges from 75% to 125% of the overall system return for electric and 80% to 120% of the overall system return for gas. (See Direct Testimony of the Gas Panel, at 33; Direct Testimony of the Electric Panel, at 42). Then the Company categorizes each rate class according to whether its current rate of return falls under the tolerance band, within the tolerance band, above the tolerance band, or well above the band. (See Direct Testimony of the Electric Panel, at 42). Finally, the Company assigns a percentage revenue increase to each group of customers, based on whether their relative return falls below, within, above, or well above the tolerance band. However, the percentage increase in revenues that is recommended for each category is ultimately a product of judgement.

Q. Please summarize the Company's proposed revenue increases for each group of customers based on whether their relative return is below, within, above, or well above the tolerance band.

A. For electric, the Company requested a system average revenue increase of 26.2%. The Company recommends class revenue increases ranging from 2.9% to 29.7%. This represents a maximum revenue increase for any class of 113% of the system average. The specific revenue increases the Company recommends for each class are as follows:

- 2.9% for classes that are "high" above the tolerance band (greater than 200% of the system average return)
- 23% for classes that are "over" the tolerance band (between 125% and 200% of the system average return)
- 26.9% for classes that are "within" the tolerance band (between 75% and 125% of the system average return)
- 29.7% for classes that are "under" the tolerance band (below 75% of the system average return)

For gas, the Company requested a system average revenue increase of 30.6%. This represents a maximum revenue increase for any class of 134% of the system average. The specific revenue increases the Company recommends for each class are as follows:

- 2.1% for classes that are "very high" above the tolerance band (greater than 200% of the system average return)

- 27.96% for classes that are “over” the tolerance band (between 120% and 200% of the system average return)
- 32.16% for classes that are “within” the tolerance band (between 80% and 120% of the system average return)
- 34.52% for classes that are “under” the tolerance band (below 80% of the system average return)
- 41.07% for classes that are negative (below 0% of the tolerance band)

Q. How did the Company determine its specific recommendations for electric and gas sector revenue allocation for each group of customer classes?

A. The Company states that it applied the concept of gradualism to mitigate any extreme impacts on service classes (See Direct Testimony of the Electric Panel, at 42), and that its proposed revenue increases “represent what the Company believes are fair and reasonable increases to the classes based on their returns at present rates while also supporting the effort to achieve the Company’s goal of moving classes closer to cost of service.” (See the Company’s responses to IR No. UIU-074(b)). However, the Company is otherwise silent regarding how it developed its specific revenue increase recommendations for each group of customer classes. Instead, the Company simply states that it assigned greater revenue increases to classes with returns below the system average and lower increases to classes with returns above the system average. (See the Company's responses to IR No. UIU-074(b) and IR No. UIU-085(b)).

Q. How did the Company determine that a maximum revenue increase of 113% for electric customer classes and 134% for gas customer classes was appropriate?

A. Other than referring to the concept of gradualism, the Company did not provide any specific information regarding how it determined the maximum revenue increase for any class.

Q. Do you have concerns regarding the Company's proposed revenue allocation approach?

A. Yes. As discussed above, the Company's use of the minimum system method is flawed and significantly impacts the ECOSS results on which the Company's revenue recommendations are predicated. In addition, the Company's recommendations for gas revenue allocation are predicated on a gas ECOSS that includes at least two key errors affecting the calculations of relative return and revenue increases.

B. Electric Revenue Allocation Recommendations

Q. What is your recommendation regarding electric revenue allocation?

A. Our electric revenue allocation recommendation is based on our ECOSS recommendation to use the basic customer method for electric distribution cost classification and is presented in Exhibit__ (URP-5).

Q. Did you consider an alternative outcome for electric revenue allocation?

A. Yes. In the event the Commission does not accept our primary ECOSS recommendation to rely on the basic customer method, we considered an electric revenue allocation outcome based on our secondary ECOSS recommendation to classify primary distribution costs as 100% demand-related and only apply the minimum system methodology to secondary distribution costs as shown in Exhibit__(URP-5). In this scenario, our proposed class revenue increase remains the same, while the relative return under that proposed increase differs, given the new starting point of the updated ECOSS results.

Q. How did you arrive at your recommendations for electric revenue allocation?

A. We began by establishing guardrails for the maximum and minimum increase to be applied to any class, in the interest of gradualism. We limited the total increase applied to any class to 133.3% of the system average revenue increase, which corresponds to a maximum class revenue increase of 34.9% for the *Under* category. We then established the minimum increase for any class at 66.6% (two-thirds) of the system average increase to ensure that all classes are contributing substantially to the overall system revenue increase. The minimum increase for any class under this scenario is 17.5%, for the *High* category. We finally adjusted the revenue increase upward for the remaining customer classes, all within the

Over category, to make up the difference in the overall revenue requirement, resulting in a 23.2% increase. Note that the UIU Rate Panel is not endorsing the Company's proposed revenue requirement increase, but rather is including it for comparison purposes only. However, the estimated combined impact to the electric and gas requirement proposed by UIU's other witnesses in these cases and for consideration by the Commission is summarized on page 54 of the Direct Testimony of Dustin M. J. Madsen.

A. Gas Revenue Allocation

Q. What is your recommendation regarding gas revenue allocation?

A. Our primary recommendation for gas revenue allocation is based on our proposed gas ECOSS methodology which classifies distribution mains as 100% demand-related, rather than using the minimum system method. Our revenue allocation recommendations associated with this classification method are presented in Exhibit__(URP-6).

Q. How did you arrive at your primary recommendations for gas revenue allocation?

A. As with our proposal for the electric side, we established the maximum and minimum increase to be applied to any class to avoid extreme outcomes. We limited the total increase applied to any class to 133.3% of the system average revenue increase, which corresponds to a maximum class revenue increase of 40.80%. We then established the minimum increase for any class at 66.6% (two-thirds) of the system average increase. The minimum increase for any class under this scenario is 20.40%.

Next, we increased all classes with relative returns below the tolerance band (i.e., within the "Under" or "Negative" categories) by the maximum increase of 40.80%, and increased any classes in the "Very High" category by the minimum amount of 20.40%. Finally, we reduced the Company's proposed increase to be applied to the Residential class very modestly so that total revenues would equal the Company's distribution revenue requirement.

Q. Did you develop a secondary recommendation for gas revenue allocation?

A. Yes. In the event the Commission does not accept our primary recommendation to classify distribution mains as 100% demand-related, we developed a secondary revenue allocation recommendation.

Q. Please provide your secondary recommendations for gas revenue allocation.

A. Our secondary recommendations is presented in Exhibit__(URP-6).

Q. How did you arrive at your secondary recommendations for gas revenue allocation?

A. In formulating these recommendations, we began by applying the same guardrails for the maximum and minimum increase to be applied to any class that were introduced in the discussion relating to our primary revenue allocation recommendations. Next, we increased all classes with yields below the tolerance band (within either the "Under" or "Negative" categories) by the maximum increase of 40.80%, and increased any classes in the "Very High" category by the minimum amount of 20.40%. After making these adjustments, total system revenues were below the Company's proposed revenue requirement. To address this, we first raised the revenue increase to be applied to Small General until this class achieved a relative return of 1.0. Finally, we raised the revenue increase to be applied to the Residential class by the necessary additional margin to achieve the overall system revenue requirement.

Q. How did the relative returns change after making the gas ECOSS corrections?

A. The Small Firm (SC-7) class went from being within the tolerance band to under the tolerance band, while the Standby class (SC-8) went from being below the tolerance band to being negative. Exhibit__(URP-6)**Error! Reference source not found.** presents the return for each class relative to the system average under the uncorrected and corrected ECOSS, as well as the class categorizations relative to the tolerance band. Class categorizations that changed with the correction of the ECOSS errors are noted in bold italicized text.

Q. Does this conclude your direct testimony, which was prefiled with the Commission on September 26, 2024?

A. Yes.