BEFORE THE NEW YORK STATE
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric and Gas Service	)	**Case 17-E-0238**

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Gas Service	)	**Case 17-G-0239**

DIRECT TESTIMONY OF KARL R. RÁBAGO
ON BEHALF OF PACE ENERGY AND CLIMATE CENTER

August 25, 2017

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Karl R. Rábago. My business address is 78 North Broadway, White Plains, New York 10603.

Q. What is your occupation?

A. I am the Executive Director of the Pace Energy and Climate Center ("Pace") at the Elisabeth Haub School of Law.

Q. What is the Pace?

A. Pace is a project of the Elisabeth Haub School of Law at Pace University. As a non-partisan legal and policy think tank, Pace develops cost-effective solutions to complex energy and climate challenges, seeking to positively transform the way society supplies and consumes energy. For more than twenty-five years, Pace has been providing legal, policy, and stakeholder engagement leadership in New York, the Northeast, and other jurisdictions. Located on the campus of the Elisabeth Haub School of Law, Pace engages and leverages a strong legal faculty and student body in its work, particularly through the internationally recognized Environmental Law Program and the Pace Land Use Law Center. Pace has many years of success in working with and supporting the New York State Energy Research and Development Authority, the New York Public Service Commission ("Commission"), and the New York Department of Environmental Conservation. Pace's work also includes strategic engagement with state legislative and executive officials, as well as in key Commission proceedings. In these capacities, Pace has had the opportunity to form long-lasting partnerships within the community of non-governmental organizations that work in the field of energy.

Q. Please summarize your background and experience.

A. I have more than twenty-five years' experience in electric utility regulation, the electricity business, technology development, and markets. I am an attorney with degrees from Texas A&M University and the University of Texas School of Law, and post-doctorate degrees in military and environmental law from the U.S. Army Judge Advocate General's School and Elizabeth Haub School of Law, respectively. Of note, my previous employment experience includes serving as a Commissioner on the Public Utility Commission of Texas, Deputy Assistant Secretary of Energy with the U.S. Department of Energy, Vice President at Austin Energy, and Director of Regulatory Affairs with the AES Corporation. I am also principal of Rábago Energy LLC, a consulting practice operating in New York. A detailed resume is annexed hereto as Exhibit KRR-1.

Q. Have you previously testified before this or any other regulatory commission?

A. I previously submitted testimony in several rate cases and rule making proceedings before the Commission. In the past four years, I have submitted testimony, comments, or presentations in proceedings in New Hampshire, Virginia, New York, Hawaii, Iowa, Indiana, Ohio, Rhode Island, Georgia, Massachusetts (legislature), Minnesota, Michigan, Missouri, Louisiana, North Carolina, Kentucky, Arizona, Wisconsin, Vermont, California, and the District of Columbia. A listing of my recent previous testimony is annexed hereto as Exhibit KRR-2.

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

A. I am testifying on behalf of Pace in this proceeding.

Q. What is the purpose of your testimony?

A. I offer testimony on selected issues raised by the application of Niagara Mohawk Power Company d/b/a National Grid ("Company" or "NMPC") to change its rates for electric and gas service and for other authority in Cases 17-E-0238 and 17-G-0239.

Q. What issues are addressed by your testimony and that of your Pace colleagues?

A. Pace witness Thomas Bourgeois, who serves as deputy director for Pace, will address the Company's proposals relating to standby rates. Pace witness Sheryl Musgrove will address issues specifically relating to low-income customers. Pace witness Robert Habermann will address issues relating to the Company's recovery of electric and gas utility trade association dues. Along with Mr. Bourgeois, I offer panel testimony on Advanced Metering Infrastructure ("AMI")/Advanced Metering Functionality ("AMF"), addressing metrics relating to infrastructure deployment, services, and program offerings; and the timing and platforms for customer and third-party access to electricity usage data. In this testimony, I will address a number of other issues:

- Cost Classification and the Residential Customer Charge – Issues relating to the classification of customer costs, the "Zero Load" method used by the Company to assign some costs to the customer category, and the way the Company builds the proposed Residential customer charge. In addition, I offer a recommendation on more granular functionalization of costs associated with AMI/AMF investments.
- Earnings Adjustment Mechanisms – Issues relating to the Company's proposals for earning a bonus rate of return based on performance in several areas of operations and services.
- Scorecard Metrics – Issues related to the scorecard metric for conversion of direct combustion fuels (natural gas, propane, fuel oil) to electricity.

- Light-emitting diode ("LED") Lighting Tariff – Issues raised by the Company's proposed program to increase the deployment of LED outdoor lighting through its LED street lighting tariff.
- Electric Transportation – Issues relating to the Company's proposed Electric Transportation Initiative.
- Natural Gas System Expansion – Issues relating to the Company's proposal for gas system load building and infrastructure development, as well as the Company's proposed Electric Heat Initiative.

II. COST CLASSIFICATION AND THE RESIDENTIAL CUSTOMER CHARGE

Q. Please generally describe your concerns with the Company's cost allocation methodology and the way the Company builds its proposed customer charge.

A. First, the Company makes several unreasonable cost assignments to the category of residential customer costs and uses the "Zero Load" method to calculate how Secondary distribution costs are assigned to the customer category. These cost assignments unreasonably inflate residential class revenue requirement base costs and cause residential customers to pay more than their fair share of the revenue requirement and customer charges that are too high. Second, the Company uses an unreasonable method to decide which costs assigned to the residential customer class should be recovered through a fixed monthly customer charge. The costs included in the customer category and the customer charge should be those that vary directly with the number of customers, regardless of power consumption. The Company's proposed customer charge for residential customers does not do this and is too high. For example, the Company includes all line transformer-related costs in the customer charge, even though a significant portion of those costs vary according to the level of demand. Further, the Company includes several expense items in the customer charge calculation that have no place in the customer charge, including energy efficiency program costs described as a customer assistance expense, economic development costs, and a fraction of total labor costs calculated using a labor-to-plant ratio. There are likely to be other costs included in the Company's approach to calculating the customer charge that do not meet the definition of a customer cost. Third, the Company should develop a proposed set of subaccounts and cost categories for tracking grid modernization-related investments, including the three basic cost categories of customer, demand, and commodity energy, as well as specific DER-related functions such as demand response, portal costs, third-party engagement, Electric Vehicle ("EV") interface, and others, as appropriate.

Q. Why does cost classification to the customer, demand, or commodity energy cost categories matter?

A. Assigning a cost to the customer category means that it is more likely to be collected from a residential customer because the number of residential customers is vastly greater than the number of commercial or industrial customers. In addition, costs assigned to the customer category are used as the basis for building class rates, including the customer charge, so the more costs that are classified as customer costs, the bigger the customer charge.

Q. What costs should be classified to the customer function?

A. The customer function, and indirectly, the customer charge, should reflect the costs incurred by the utility to connect the average customer to the electric system for service. In 1961, James C. Bonbright defined the fixed customer charge as follows:

> These are those operating and capital costs found to vary with the number of customers regardless, or almost regardless, of power consumption. Included as a minimum are costs of metering and billing along with whatever other expenses the company must incur in taking on another consumer.[1]

Simply stated, Bonbright's definition ensures that the customer charge should be limited to the cost of connecting the customer to the grid. Adhering to this principle advances other rate making principles such as equity and cost-causation and preserves the power of volumetric charges as a price signal. Residential customers can see a direct correlation, both positive and negative, between their level of usage and their contributions to cost creation when energy- and demand-related costs are recovered through volumetric charges. Allocating demand-related costs to the fixed customer charge eliminates, or at least severely weakens, the price signal impact.

Q. How much cost does a new customer cause?

A. Costs directly related to new customers include a portion of the cost of a meter, billing and metering services, and collection costs—in Bonbright's words, the costs the utility "must incur in taking on another customer."[2] These costs would likely sum to about $5–$10 per customer per month, depending on local costs, billing period used, and other factors.[3] The Company proposes to assign many more costs to the customer category than just those the Company must incur in taking on another customer.

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[1] James C. Bonbright, *Principles of Public Utility Rates*, 347–49 (1961), *available at* http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.
[2] *Id.*
[3] *See* Jim Lazar & Wilson Gonzalez, *Smart Rate Design for a Smart Future*, Appendix D (July 2015), *available at* http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf.

Q. What are the implications of assigning too much of the Company's costs to the customer category and the residential class?

A. Unfairly assigning too much in costs to the customer category leads to unreasonably high and unjust rates for the residential class. Assigning more costs to a customer class will result in a higher customer charge. The Company does not propose increasing the fixed customer charge for residential customers in this proceeding. However, the methods used to assign costs to the residential customer category, and the customer charge, could be used by the Company to argue for fixed charge increases in the future.

Q. Does the Company have high fixed charges compared to other utilities?

A. Yes. The fixed customer charges assessed by large New York utilities are higher than those in neighboring states and in the United States in general.[4] The Company's fixed charge in New York is $17, while National Grid's other subsidiaries in Massachusetts and Rhode Island have customer charges of $5.50 and $5, respectively.[5]

Q. Why are higher fixed customer charges a problem?

A. High fixed customer charges based on fixed costs greater than the cost to connect a customer to the grid weaken price signals to customers associated with their contribution to increased or decreased fixed costs over time. The typically high correlation between energy use and demand means that assignment of transmission and distribution costs (other than the costs to connect) to volumetric rates creates a more efficient price signal than assigning those costs to non-bypassable fixed customer charges. Higher fixed charges are inimical to the goals of the Reforming the Energy Vision ("REV")

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[4] *See* Acadia Center, *Residential Fixed Charges in NY: The Need for Consumer-Friendly Rate Design* (July 2017), http://acadiacenter.org/wp-content/uploads/2017/07/Acadia-Center-Residential-Fixed-Charges-in-NY-July-2017.pdf.
[5] *See id*. at 1.

proceedings as well, because they reduce the cost-effectiveness of distributed energy resources ("DER") and constrain the ability of customers to take action to manage their bills in response to price signals that vary with level of consumption or demand.

Q. What methods do the Company use to assign costs to the customer category?

A. The customer category is used to accumulate costs that will be allocated based on the number of customers served. The Company assigns meter and service costs, capital and operating costs associated with the primary and secondary distribution system, and capital and operating costs for transformers to the customer category.[6] The first way in which costs assigned to the customer category are unreasonably high is the assignment of transformer-related costs. Transformer fixed and operating costs are associated with and sized according to demand serviced by the Company and are more properly categorized as demand-related. Second, in 2011, the Company re-functionalized a wide range of costs as related to either competitive supply or non-competitive ("Billing") service.[7] Those costs, relating to account categories associated with customer service also include several costs that likely vary, at least to some degree, with level of usage and demand, including those associated with customer assistance expenses, supervision of customer assistance, outside services, research and development, and others.[8] The Company assigns all these costs as customer-related.[9] Third, the Company assigned half of all Primary distribution system costs to the customer category, even though these costs are entirely driven by the level of demand that the Company must serve.[10] Finally, the Company also assigned a

[6] Testimony of the Electric Rate Design Panel ("E-RDP") at 16.
[7] *See id.* at 16–17.
[8] *See id.* at 19.
[9] *See id.* at 19–20.
[10] *See id.* at 21.

large fraction of Secondary distribution system costs to the customer category using its Zero Load method and study.[11]

Q. What methods does the Company use to assign distribution system costs other than services and meters to the customer-related category?

A. The Company divides distribution system costs into two main categories. For the Primary distribution system costs, the Company assigns half the costs to the customer category and the remainder to the demand category.[12] The Company does not explain why the 50% assignment factor was used or why any of these demand-related costs are assigned to the customer category. For the Secondary distribution costs, the Company uses a form of a minimum system methodology, which it calls a Zero Load study to allocate a large amount of distribution costs to the customer category.[13] The Zero Load method results in 58.44% of overhead asset costs and 51.75% of underground asset costs being allocated to the customer category.[14]

Q. What is the Zero Load method used by the Company?

A. The Zero Load method is fairly simple to describe and calculate, but deeply flawed as a matter of logic and cost allocation.[15] According to the Company, the Zero Load study first estimates the fraction of total overhead and underground asset capital costs

[11] *See id.*
[12] *See id.*
[13] *See id.*
[14] *See id.*
[15] Minimum system-type methods have been rejected, for example, in Washington State (*Wash. Util. & Transp. Comm'n v. The Washington Water Power Co.*, U-83-26 (5th Supp. Order, Jan. 19, 1984)) and in Iowa (Iowa Admin. Code 199-20.10(426)(2)(g)).

represented by labor costs.[16] The resulting percentage numbers are used to divide the overhead and underground capital costs into two categories—customer and demand.[17]

Q. What effect does the Zero Load method have on the costs assigned to the customer category?

A. The assumption that the sum of labor costs is an indicator of the amount of costs that vary with customer count, as opposed to demand, is at the heart of the Company's approach. Labor costs are driven by both customer count and demand. So using the sum of labor costs to calculate the factor used to determine customer-related costs unreasonably inflates the amount of costs assigned to the customer category. In addition, the method likely results in double recovery of costs by including both costs directly identified as customer costs and an additional fraction of those costs resulting from the application of the labor fraction multiplier.

Q. Why do you assert that the Zero Load method is flawed as a matter of logic and cost allocation?

A. The Company's Zero Load method appears to be a version of a minimum-system or zero-load intercept approach to classification of costs, and suffers from similar flaws. The minimum system method is based on trying to identify the cumulative component costs of a hypothetical smallest system size used to serve customers. Bonbright said that the minimum system method was "clearly indefensible."[18] The notion behind that method is that even with no load at all, a certain basic minimum system would be required. The minimum system abandons the Bonbright principle of defining customer costs as the

[16] *See* Resp.to PACE-1 AD-2 (a copy of which is annexed hereto as Ex. KRR-3).
[17] E-RDP at 21.
[18] Bonbright, *supra* note 1, at 348.

marginal cost to connect a customer to the system. In its place, and in a major step away from cost causation principles, minimum system approaches use average embedded costs as the determinant for customer costs. The zero-intercept method is a version of the minimum system method that is more data-intense but still deeply flawed. That model calculates the total costs at various levels of demand and then uses regression analysis to extend the resulting cost line back to the level of zero demand. The flaw in this approach is that the mathematical result of the regression calculation has nothing to do with the costs that vary almost entirely due to the connection of customers or to customer count. Indeed, the very notion of estimating the cost of a utility that serves no load is preposterous. The Company takes this kind of flawed thinking a step further by using its Zero Load method that asserts that this fantastical hypothetical utility that serves no load would be fully staffed with the Company's current labor force. The Company asserts that since employees cannot serve load without wires and poles and transformers to do the work, the total distribution labor cost should be used as the cost of a distribution system with zero load, and in turn, the fraction of labor to total costs should be used to derive the fraction for assignment of Secondary distribution system costs to the customer category. The Company's Zero Load method also fails to account for differences in customer density. Of course, if the Company had zero load, it would have no labor costs either, and certainly not a phantom cohort of staff and linemen waiting for load to serve. In sum, the fraction of distribution system capital costs related to labor is not at all a reliable measure of the costs that the Company faces when a new customer is connected to the grid and therefore is an unreasonable method for assigning costs to the customer category.

Q. Is the Zero Load method commonly used?

A. No. In the Company's answers to interrogatories seeking authorities for the Zero Load method, the Company provided only a citation to the NARUC Cost Allocation Manual discussion of the Zero Intercept method, and the 2d edition of Bonbright's Principles of Public Utility Rates.[19] The NARUC Manual describes the minimum system method and the minimum/zero intercept method, but not a Zero Load method. The second edition of the Bonbright text reprises the problems with the minimum system method expressed in the first edition and does not reference the Zero Load method. The Company did not point to any other jurisdictions where the Zero Load method is used, and I have not encountered the concept anywhere else in my 27 years of utility regulatory practice.[20]

Q. What are the current and proposed customer charges for residential customers in Service Classification 1 ("SC-1") class in the Company's filing?

A. The Company currently charges $17 per customer per month for the residential SC-1 class, and proposes to maintain that level of charge.[21] However, the Company assigns costs to the customer function that, if fully collected, would increase the customer charge even further. According to the Company, the total costs assigned to the customer category could result in a customer charge of $20.52 per customer per month.[22]

Q. What is the Company's method for building its residential customer charge?

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[19] Ex. KRR-3 (Resp. to Pace-1 AD-2). Pace asked the Company to provide "copies of or links to all authorities relied on to answer this question. If one or more of the authorities are books, please provide the citations." The only references the Company provides in response relate to the Zero Intercept method: "Zero intercept (or Minimum intercept) studies are discussed in the National Association of Regulatory Utility Commission ("NARUC") *Electric Utility Cost Allocation Manual*, January 1992 ("NARUC Manual"), pp. 92–96. Zero intercept studies are also discussed in *Principles of Public Utility Rates*, Professor Bonbright et al, p. 491."

[20] Ex. KRR-3 (Resp. to Pace-1 AD-2).

[21] Leaf 349, Initial Effective Date: Jun. 1, 2017, pending.

[22] Ex. __ (E-RDP-3CU), Sched. 4.

A. The Company builds its residential customer charge from two primary sources of costs.[23] First, it calculates a "customer-charge return component" that is based on rate base items associated with "service cost" (service lines and associated equipment), "meter cost," and "[distribution] transformer cost." Transformer cost represents about 57% of these costs.[24] The Company uses a rate of return value of 6.93% to derive a return on these rate base items and grosses the amount up for income taxes.[25] This calculation amounts to about $50 million of the total $365 million that the Company seeks to recover through the fixed customer charge, or about $2.76 per customer per month.[26]

Q. What accounts for the remaining $17.76 per customer per month that the Company includes in the customer charge category?[27]

A. The second major group of costs is the "expense component," which accounts for $316 million of the total for the customer charge calculation.[28] In this group are a wide range of expenses relating to general expenses, maintenance expenses, and depreciation expenses for meters, transformers, and service assets, as well as property taxes applicable to transformers.[29] In this subgroup, which accounts for about $61 million in expenses, the largest items are the $19 million in depreciation expense on transformers and a $17 million expense for transformer property taxes.[30] I estimate that the costs and expenses

[23] *See id.*
[24] *See id.*
[25] *See id.*
[26] *See id.*
[27] Calculated as $20.52 – $2.76 = $17.76.
[28] Ex. __ (E-RDP-3CU), Sched. 4, at 1 of 2.
[29] *See id.*
[30] *See id.*

related to line transformers amount to about $3.69 per customer per month.[31] As I previously stated, the transformer-related cost items do not represent costs incurred to connect customers to the grid and that vary with the number of customers regardless, or almost regardless, of power consumption.

Q. What costs does the Company include in the remaining $255 million[32] assigned to the customer charge?

A. The remaining expense items included in the Company's customer charge calculation include a wide range of expenses that largely fail to meet the test for classification as customer costs and should be recovered through volumetric charges associated with demand or commodity energy. These include $136 million in customer assistance expenses[33] which, in turn, includes $83 million in energy efficiency program costs that the Company labels as customer assistance expenses,[34] and another $6.5 million in expenses related to economic development.[35]

The expenses subgroup also includes $57 million in labor related costs that the Company calculates using a labor ratio like the one used in its Zero Load method.[36] In this calculation, the Company calculates a labor fraction for its entire utility plant in service (which yields a 22.95% factor) and then multiplies this factor times $248 million in total labor expenses to yield a "labor related costs" item of $57 million that it includes in the customer-charge. As discussed above, there is no rational basis for presuming that

[31] Calculated as ((57% * $49,116,000) + $1,313,000 + $19,004,000 + $17,000,000) / 17,779,729 = $3.69
[32] Calculated as $364,905 – ($49,115 + ($8,298 + $274 + $1,313 + $9,027 + $6,290 + $19,004 + $17,000) = $254,584. (000s)
[33] Ex. __ (E-RDP-3CU), Sched. 2, at 4 of 7.
[34] *See id.*
[35] *See id.*
[36] *See id.*, Sched. 4, at 2 of 2.

the labor fraction of total plant in service is indicative of costs that are customer related; nor does it justify a conclusion that this fraction of total labor belongs in the customer charge. Removing the energy efficiency "customer service," the economic development expenses, and the labor related costs from the customer charge calculation would reduce the customer charge component by $8.22 per customer per month.[37]

Q. Are you taking the position that no labor costs should be included in the customer charge calculation?

A. No. There is labor expense associated with connecting customers to the grid. Some reasonable fraction of the customer service expenses can be properly included in the customer charge. But the Company has overreached in its approach, and should be directed to review its expenses from the bottom up to include in the customer charge only those costs that meet the definition cited above.

Q. What about the remaining expense items included in the customer charge?

A. The remaining items include customer records and collection ($42 million), all of which likely do not vary directly with customer count, and delivery uncollectable expenses ($20 million).

Q. What do you conclude about the way the Company calculates the customer charge for residential customers?

A. The Company unreasonably assigns costs to the customer category and uses an unreasonable Zero Load method to calculate Secondary distribution system costs assigned to the customer category, and as a result, the residential customer charge is too high. Further analysis will likely reveal other ways in which the resulting customer

[37] Calculated as ($82,811,000 + $6,497,000 + $56,938) / 17,779,729 = $8.22

charge is too high. On the whole, the Company's proposed customer charge for residential customers is unjust and unreasonable.

Q. What changes should the Company make to the way it assigns costs to the customer category?

A. A more reasonable approach to cost assignment would involve four major changes by the Company. (1) The Company must remove most, if not all costs associated with line transformers from the customer category. (2) The Company must review each of the service related costs that it re-functionalized in 2011, and only include as customer costs those costs that the Company must incur in taking on another customer (the cost to connect). (3) The Company must remove all Primary distribution costs from the customer category. (4) The Company must abandon the Zero Load method for assigning Secondary distribution system costs and instead assign to the customer category only those costs that the Company must incur in taking on another customer (the cost to connect). A more reasonable approach to cost assignment would result in significant rate reductions, and a reduction in customer charges, for residential customers.

Q. What is your recommendation for the Commission?

A. The Commission should reject the Company's proposed customer costs and customer charge calculation. The Commission should direct the Company to prepare an entirely new model for classifying customer costs and calculating the customer charge that conforms with the requirement that only the cost to connect a customer is included in the charge, as I just described.

Q. What level of residential customer charge do you believe is reasonable?

A. I did not conduct a complete review of all of the Company's proposed customer costs and customer charge calculation. Based only on the quantification that I described above, the Company's residential customer charge should be much lower than it is and lower than the Company proposes. The Company should provide detailed documentation of its revised classification and calculations in order to facilitate a thorough review.

Q. Earlier you stated that the customer cost category should include *some* of the costs associated with the meter, the line drop, and services. How should these costs be classified and assigned in the future?

A. In our era of utility transformation, especially as modern AMI and AMF—a broader category term that encompasses not just meter-related investments—is deployed, cost assignment and allocation methods should recognize that the range of products and services provided and available to customers is rapidly expanding. In the past, the assignment of the cost of a meter entirely to the customer category was appropriate because meters could really only do one thing—measure cumulative consumption over time. Today's advanced meters and associated distribution system infrastructure, customer service support and offerings, billing and data management systems, and other investments and expenses associated with a richer, more complex service environment can be used to help the utility and customers manage demand, offer and participate in new versions of time-varying rates, enable integration of distribution generation and electric vehicles, participate in demand response programs, and other perform other functions. The new AMI meter can do more and costs more than what is required to simply measure consumption, and the functionalization of meter and associated infrastructure and other costs should be subject to much more granularity in order to accurately track cost causation and ultimately send efficient price signals. In sum, the cost of advanced meters and associated services and infrastructure is related to customer count, energy use, and demand, and as well to a wide range of other more granular functions associated with the modern electric grid.

Q. Is this increased diversity of function limited to meters?

A. No. Customer billing systems, distribution automation and distribution management systems, mesh networks, and many other distribution-level investments associated with grid modernization similarly involve costs that can be classified in the customer, demand, and commodity energy categories. In addition, the investments and associated expenses support many more functions than just "serving load."

Q. What do you recommend based on this changing reality associated with the functions performed by investments and infrastructure at the distribution edge?

A. Now is the time for the Company to develop a more granular cost tracking system to enable more accurate characterization and classification of costs associated with AMI/AMF deployment, with grid modernizations, and with implementation of REV. This data will be essential for improved cost of service analysis, for tracking performance against Earnings Adjustment Mechanism ("EAM") targets, and for inclusion in value of DER calculations, among other uses. The Commission should direct the utility to develop a proposed set of subaccounts and cost categories for tracking grid modernization-related investments that includes the three basic cost categories of customer, demand, and commodity energy, as well as the many kinds of specific functions--such as demand response, portal costs, third-party engagement, and EV interface, among others—performed by the modern and future distribution platform utility.

III. EARNINGS ADJUSTMENT MECHANISMS

Q. What are your concerns with the Company's proposed EAMs?

A. The Company is proposing four electric and one gas EAM.[38] Based on a review of the Company proposals, I find that the Company has offered some reasonable EAM categories in its proposal to tie incentives to electric system efficiency, electric energy efficiency, distributed generation interconnection, customer engagement, and gas efficiency. I have three concerns with the Company's proposals: the Company's baseline budget for energy efficiency investments to achieve savings beyond those targeted in the Company's Energy Efficiency Transition Implementation Plan ("ETIP"), the aggressiveness of the EAM targets, and the treatment of lost sales resulting from activities that earn EAM incentives.

Q. What is the policy background for your review of the Company's proposals?

A. As the Commission has acknowledged, "energy efficiency is the cheapest and most effective manner to reduce carbon emissions in the energy sector."[39] Substantially greater levels of energy efficiency investments will reduce customers' bills and facilitate more cost-effective achievement of the state's clean energy goals.

Based on Commission proceedings related to energy efficiency, it has become clear that energy efficiency budgets and targets proposed in the rate case context and included in each utility's rate base must be an integral and significant component of the

[38] Testimony of the Electric Customer Panel ("ECP") at 41–73.
[39] *Order Adopting a Clean Energy Standard* ("CES Order") 81–82, Case 15-E-0302 (Aug. 1, 2016).

state's energy efficiency strategy.[40] The Order urged utilities to integrate "cost-effective energy efficiency" into their "basic business operations."[41]

Following this model, the Joint Proposal approved by the Commission in the Con Edison rate case set forth a structure whereby Con Edison will ramp up its energy efficiency investments each year from 2017 through 2019, roughly doubling its total savings levels by 2019.[42] The Con Edison 2017 Rate Order also allows Con Edison to recover the costs of these investments through its delivery charges and permits the utility to earn a return on those investments as it would traditional distribution investments, thereby integrating energy efficiency into its basic business operations.[43] In ramping up cost effective investments each year, the order supports more cost-effective achievement of the state's clean energy goals.

In approving energy efficiency portfolios for each of the state's investor owned utilities' ETIPs, the Commission explained that it expected significant increases in energy efficiency through EAMs:

> [T]he Commission anticipates developing an Earnings Incentive Mechanism in track two of the REV Proceeding, [for which] the Commission expects significant utility investment in energy

[40] *See Order Adopting a Ratemaking and Utility Revenue Model Policy Framework*, Case 14-M-0101 (May 19, 2016) ("Track Two Order").
[41] *Id.* at 23.
[42] Order Approving Electric and Gas Rate Plans 71, *Proceeding on Motion of the Comm'n as to the Rates, Charges, Rules and Regulations of Consolidated Edison Co. of New York, Inc. for Elec. & Gas Serv.*, Case Nos. 16-E-0060 & 16-G-0061 (PSC Jan. 25, 2017) ("Con Edison 2017 Rate Order"); Joint Proposal 76–77, *Proceeding on Motion of the Comm'n as to the Rates, Charges, Rules and Regulations of Consolidated Edison Co. of New York, Inc. for Elec. & Gas Serv.*, Case Nos. 16-E-0060, 16-G-0601, 15-E-0050 & 16-E-0196 (PSC Sept. 19, 2016) ("Con Edison Joint Proposal") (PSC Sept. 2016).
[43] Con Edison Joint Proposal at 81.

> efficiency in a manner that best supports the local needs of their systems and advances energy efficiency as an operational resource rather than a regulatory mandate.[44]

Subsequently, the Track Two Order established a structure whereby EAMs for energy efficiency would be established to go above and beyond the amount of energy efficiency achieved through the ETIPs.[45]

Q. What is your first concern about the proposed EAMs?

A. First, the baseline for the Company's proposed efficiency-related EAMs is the savings produced by the programs and activities in the Company's ETIP. As reported by the Electric Customer Panel, the Company submitted a revised ETIP for 2017–2020 that reflected level budgets for electric and gas efficiency programs.[46] In my view, the funding provided in the ETIP is inadequate both in itself and as a foundation for extraordinary earnings under an EAM. The first step the Company should have taken was to develop aggressive budgets for energy efficiency investments to be recovered through delivery rates, along with aggregate efficiency goals for these investments, together with its ETIP funding budgets. Even in the absence of any EAM proposal, it would have been reasonable and appropriate for the Company to increase its energy efficiency budgets and performance targets significantly above and beyond those included in the ETIP. Added incentives through the EAMs should be reserved for performance above and beyond

[44] Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2016 – 2018, at 28, *In the Matter of Utility Energy Efficiency Programs*, Case No. 15-M-0252 (Jan. 22, 2016).
[45] Track Two Order at 82.
[46] ECP at 37–38; *see* Niagara Mohawk Power Corporation d/b/a National Grid 2017–2020 Electric and Gas Energy Efficiency Portfolios Budget and Metrics Plan, *In the Matter of Utility Energy Efficiency Programs*, Case No. 15-M-0252 (Jun. 1, 2017).

business-as-usual improvements in program results. The Company's proposal fails to build upon the successful model first established in the Con Edison rate case discussed above. Rather than providing for significant year-on-year increases in energy efficiency investments recovered through the delivery charge, the Company proposes to leave investments flat each year after 2017. This will effectively freeze energy efficiency at levels significantly below the amounts needed to cost effectively achieve the state's goals, and at levels vastly below energy efficiency levels achieved by the Company's affiliates in neighboring states. Should the state continue on its current trajectory without a significant ramp up in energy efficiency from its investor owned utilities, the state will fail to achieve even the savings levels assumed for purposes of setting targets in the CES Order, and the cost of achieving the Order's 50 percent renewables supply by 2030 goal will become significantly more expensive.

Q. Is a substantial improvement in the Company's energy efficiency performance reasonable to expect?

A. Yes. National Grid's own Massachusetts affiliate ramped up annual incremental savings levels from 1.34% of total load to 3.03% of total load across a period of 5 years (for an annual increase of .34%).[47] A simple graphic depicts the dramatic difference in the improvement rate in historical energy savings as a percent of sales for National Grid Massachusetts as compared to growth rate that the Company proposes for NMPC.

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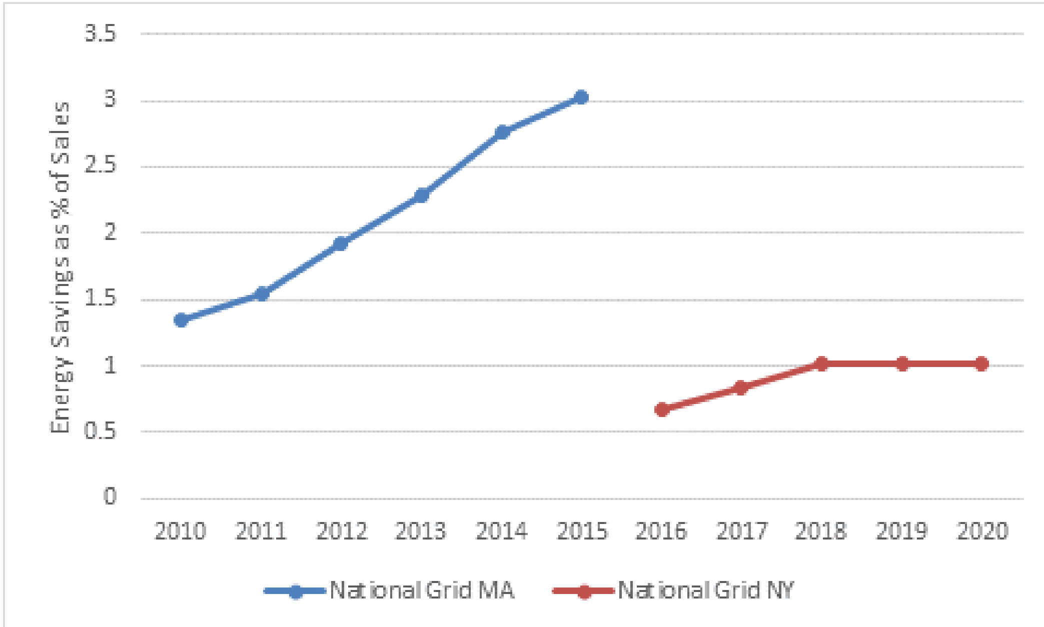
[47] Clean Energy Advisory Council, *Energy Efficiency Metrics and Targets Options Report* 50 (Nov. 2016) ("*CEAC Report*").

Figure KRR-1 – Energy Savings as % of Sales, NG Mass vs. NMPC[48]



Q. What is your second concern about the proposed EAMs?

A. The most fundamental problem with the Company's proposed EAMs is that the Company is not being as aggressive as it should be in the structure of its EAM proposals and energy efficiency targets. For New York to lead on energy efficiency, its utilities should be expected to ramp up energy efficiency investments at an annual rate demonstrated to be achievable by leading utilities across the country, until savings rates are comparable to that of national leaders. Because energy efficiency is the most cost-effective manner to

[48] The sources of data for Figure KRR-1 are the following: National Grid Massachusetts energy savings and load data are derived from the *CEAC Report*, *supra* note 47, at 50; Company sales data are derived from the U.S. Energy Information Administration, *Electric Power Sales, Revenue, and Energy Efficiency Form EIA-861 Detailed Data Files*, https://www.eia.gov/electricity/data/eia861/, using 2015 as index year for sales; 2016 New York Company electricity savings targets are from National Grid Scorecard Reports – 1st Quarter 2016, *In the matter of Utility Energy Efficiency Programs*, Case no. 15-M-0252 (PSC Jun. 30 2016); and the 2017–2020 electricity savings targets are from the Company's testimony and exhibits in this proceeding, *see* ECP at 53, Table 6 (Annual Incremental Energy Efficiency Reduction Targets (MWh) and Basis Points (bps)).

reduce carbon emissions, setting EAMs in this aggressive manner would follow through on the Track Two Order's requirement for EAMs to work "toward reducing the cost of achieving [the state's clean energy] goals through cost-effective and market-initiated efficiency."[49] As the Efficiency Ramp Up Advocates explain in the *CEAC Report*, other utilities across the country have ramped up energy efficiency levels by roughly 0.4% of total load each year.[50] In other words, utilities have demonstrated that with regulatory and institutional support, they can *increase* savings levels by roughly 0.4% each year. In the 2016 White Paper, *Aiming Higher: Realizing the Full Potential of Cost-Effective Energy Efficiency in New York*, Synapse Energy Economics Inc. modeled a scenario in which each of the state's investor owned utilities would ramp up their savings levels at this rate beginning in 2017, until 3% annual incremental savings were achieved.[51] The analysts found that, under such a scenario, New York customers would save "roughly $3 billion in electricity costs between now and 2030."[52]

Q. Do the Company's proposals graphically depict the modest nature of the EAM goals?

A. Yes. The Company's proposed minimum, target, and maximum performance levels are much less aggressive then the Company's record of performance over the past three years as relates to residential energy intensity, commercial energy intensity, and low-income energy intensity.[53] When accounting for the more recent three-year trend line for those

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[49] Track Two Order at 81–82.
[50] *CEAC Report*, *supra* note 47, at 50 (citing EPA, Demand-Side Energy Efficiency Technical Support Document 81(Aug. 2015)).
[51] Synapse Energy Economics, Inc., *Aiming Higher: Realizing the Full Potential of Cost-Effective Energy Efficiency in New York* 1–15 (April 2016).
[52] *Id.* at ii (emphasis added).
[53] Ex. __ (ECP-5), Scheds. 5–7.

measures, which coincides with the launch of the REV initiative, the proposed maximum performance level appears to be more appropriately the minimum performance level. The EAM targets are not adequately aggressive.

Q. What is your third area of concern about the proposed EAMs?

A. I am concerned that under the structure proposed by the Company, some activities that qualify to earn incentives under the EAMs could also result in decreased sales revenue due to reductions in energy sales or demand charges, and would then recover lost sales revenues under the Revenue Decoupling Mechanism ("RDM"). I propose that the Company explicitly commit that the RDM will not be used to compensate for lost sales revenues created by activities that also earn EAM incentives.

Q. Why do you take the position that the Company should not be able to make an RDM adjustment for lost revenues for results that also lead to incentive awards under an EAM?

A. I share the Commission's view that EAMs are "best thought of as a bridge"[54] between the kinds of earnings streams enjoyed under the status quo and those that characterize a fully functioning platform utility under REV. Decoupling adjustments are a sound and reasonable mechanism for removing disincentives associated with lost revenues under the status quo, but should be supplanted by performance-based revenues in a world of animated DER markets. EAMs should be designed to provide sufficient revenues to encourage aggressive pursuit of efficiency and demand reduction without reliance on a decoupling adjustment mechanism designed to work in yesterday's business model environment.

[54] Track Two Order at 60.

Q. Doesn't your proposal mean that EAMs will have to be set higher than if lost revenues were also recovered through an RDM that operated in conjunction with the EAMs?

A. Only in the relatively short term. The concept of providing performance incentives through EAMs is that EAMs must "both encourage achievement of new policy objectives and counter the implicit negative incentives that the current ratemaking model provides against REV objectives."[55] So, until business model transformation is complete, serving these dual functions may mean that the EAM has to do the "work" of both addressing the negative incentives from the old system and creating incentives to transition to the new.

Q. How do you expect EAMs to evolve over the longer term?

A. I share the Commission's judgement that properly structured EAMs can support the accomplishment of several goals, including: (1) integrating the activities of markets into an optimized distribution system that costs less to operate, (2) increasing innovation by the utilities, (3) encouraging an enterprise-wide approach to achieving results, (4) encouraging outcomes that simulate competitive market behavior, and (5) creating an incentive for economic development by the utilities, that unlike the old model is based on efficiency improvements rather than just increases in sales.[56]

Q. Based on your review of the proposed EAMs, what do you recommend?

A. The Company should go back to the drawing board and assemble an aggressive energy efficiency portfolio more in line with the state's clean energy ambition. I recommend that the Company be required to propose energy efficiency targets that are more aggressive, both in the ETIP and in the energy intensity EAMs, and, if necessary, to make any

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[55] *Id.*
[56] *Id.* at 62–65.

adjustments in its proposed EAM levels to account for not using the RDM to adjust for lost revenues associated with performance that earns EAM incentives.

Q. Do you recommend that the Company adopt any additional EAMs?

A. Yes. I recommend that the Company be required to propose the use of a low-income household multiplier for their energy efficiency and other DER-related EAMs. The multiplier should be designed to encompass all low-income housing, including master-metered affordable multifamily housing. The multiplier should be sufficient enough to induce the Company to focus its attention and efforts on increasing energy efficiency and access to DERs for low-income households, but should not be so great that the Company will focus its attention and efforts exclusively on low-income households and ignore its other customers. The appropriate level of low-income multiplier needed to reach that balance would need to be determined, but would likely range between a 1.1 multiplier to a 2.0 multiplier. For example, the Clean Energy Incentive Program, which is part of the Clean Power Plan, uses a multiplier of 2.0.[57]

I also recommend that the Company be required to propose an environmental justice community multiplier for their energy efficiency and DER EAMs. Again, this multiplier should be sufficient enough to induce the Company to focus its attention and efforts on increasing energy efficiency and access to DERs for households located in environmental justice communities, but should not be so great that the Company will

[57] *See* U.S. Envtl. Prot. Agency ("EPA"), *The Clean Energy Incentive Program* (undated), *available at* https://archive.epa.gov/epa/sites/production/files/2015-08/documents/fs-cpp-ceip.pdf; Energy Efficiency for All, *Summary of EPA's Proposed Regulations for the Clean Energy Incentive Program* (undated). http://energyefficiencyforall.org/sites/default/files/eefa-ceip-fact-sheet.pdf.

focus all of its attention and efforts exclusively on environmental justice communities. This multiplier should be designed to complement the low-income multiplier.

IV. SCORECARD METRICS

Q. What is your position on the Company's proposed scorecard metrics?

A. In addition to its three proposed AMI metrics, the Company proposes a set of scorecard metrics to track progress relative to several activities and initiatives, including carbon reduction, interconnection, and time-of-use rate participation by electric vehicle drivers.[58] I find that the Company approach on these scorecard metrics is generally consistent with the guidance set out by the Commission in the REV Track Two order and am confident that the scorecard data will be useful in improving the associated programs, and for other purposes. My primary area of concern relates to the scorecard metric for carbon reduction, and to the proposed reporting schedule.

Q. What are your concerns about the scorecard metric for carbon reduction?

A. My concerns with the carbon scorecard metric are two. First, to the extent that the Company seeks to track carbon dioxide ("CO_2") impacts associated with system conversions, such as oil-to-electric heat conversions, it should broaden the scope of its efforts to track all "fuel switching" conversions, including propane-to-electric, oil-to-gas, gas-to-solar, etc. Second, the Company should take great care and seek advice on how to develop tracking mechanisms that account for overlaps in the causes for tracked behaviors and investments, and in the extent to which the same customers account for reductions through more than one action or program. Attention to causes and results will

[58] ECP at 74–76.

enable efforts to prevent double counting and accurately capture synergistic program efforts.

Q. What is your concern regarding the Company's proposed reporting schedule?

A. The Company proposes to report its scorecard metric findings as part of its annual EAM compliance filing on March 31 of each year.[59] I recommend that the Company report its metrics once they are established and invite comments from interested stakeholders as part of the process of initiating tracking. In addition, even if it reports only once a year, the data should be collected and tracked on a monthly basis.

V. LED LIGHTING TARIFF PROPOSAL

Q. Please describe the Company's LED street light tariff proposal.

A. The Company proposes an LED street light tariff for the conversion of existing high-intensity discharge ("HID") roadway luminaires to LED technology within its service territory.[60] A municipal customer converting from HID to LED lighting must commit to convert at least 15% of the installed Company-owned roadway luminaires that serve that particular customer, or 100 units, whichever is greater.[61] There is also a charge to cover the "permanent discontinuance assessment" for the removed HID facilities.[62] The Company's annual conversion rate across its service territory is capped at 20% of the total in-service "cobra head" roadway luminaires, or 39,107 fixtures per year.[63]

Q. Is the LED street light tariff voluntary or mandatory?

[59] ECP at 72.
[60] Testimony of Outdoor Lighting Panel ("OLP") at 10.
[61] *Id.* at 11–12.
[62] *Id.* at 12.
[63] Response to PACE-5 AD-1 (a copy of which is annexed hereto as Ex. KRR-4).

A. Municipal customers may opt out of the program, and the Company plans to defer implementation of the program until at least April 1, 2019, to afford municipalities the time and resources to decide whether they will participate.[64] Even after opting out of the tariff, a customer may change its opt-out designation to allow for the replacement of failed HID light fixtures with LEDs.[65]

Q. How many street lights does the Company anticipate it will convert under the tariff?

A. The Company's proposed capital plan includes capital investment for converting approximately 10% of HID luminaires in the Rate Year.[66] This conversion would cost $6.97 million for the new LED fixtures, plus $0.775 million for cost of removing the existing HID luminaires.[67] Hundreds of thousands of light fixtures are eligible for conversion. Service classification 2, for example, has approximately 193,448 roadway fixtures that are eligible to be converted.[68] The Company responded to 79 inquiries regarding the program as of April 13, 2017.[69] Of those requests, the Company has converted 432 street lights across eight municipalities.[70]

Q. Does the Company have a plan in the event demand exceeds the 10 percent target?

A. Yes. The Company is proposing a two-way LED capital investment tracker to allow the Company to convert up to 20 percent of street lights per year and to defer costs incurred either in excess of or below the amount reflected in rates.[71]

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[64] OLP at 14.
[65] Ex. KRR-4 (Resp. to PACE-5 AD-1).
[66] OLP at 20.
[67] *See id.* at 20.
[68] Testimony of Electric Rate Design Panel ("ERDP") at 57.
[69] OLP at 12.
[70] *See id.*
[71] Resp. to PACE-5 AD-3 (a copy of which is annexed hereto as Ex. KRR-5).

Q. How did the Company estimate the LED conversion cost of $6.97 million for the capital investment, plus $0.775 million for cost of removal?

A. The Company estimated this cost by assuming a five-year, 20 percent annual LED conversion program, taking into account the number of existing roadway fixtures across the Company's service territory; the cost of the LEDs; and the estimated number of necessary labor hours to convert the fixtures and to complete design, project management, and field supervision work.[72] Since the capital investment plan assumes that only 10 percent of HID luminaires will be converted in the Rate Year, this estimated cost was then divided in half.[73]

Q. Have municipalities expressed any concerns as to the cost or implementation of the LED street light tariff?

A. Yes, municipalities have expressed some concerns about the costs. While there has been strong municipal interest, the adoption rate has been low, due to low acceptance and concern from municipalities about the initial cost.[74] The Company notes that some municipalities are concerned about that up-front cost, which includes a "required payment for the undepreciated investment of the existing luminaire assets to be removed."[75]

Q. What solutions has the Company proposed to overcome these barriers?

A. The Company proposes to offer an outdoor lighting energy efficiency program to incentivize municipalities to adopt the tariff.[76] The Company will offer municipalities

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[72] *See id.*
[73] *See id.*
[74] OLP at 11.
[75] *See id.*
[76] *See id.* at 15–16.

incentives to transition to LED lights based on the net energy savings per fixture attributable to customer- or Company-owned LED conversions. The Company proposes to include program costs in base rates, rather than in the ETIP.[77]

This LED street light energy efficiency program would use incremental energy efficiency funds, with an annual cost of approximately $1.6 million per year.[78] If the municipality converts more than 10 percent of street lights annually, and the demand for energy efficiency funds exceeds $1.6 million, the Company proposes to defer for future recovery any additional costs up to $3.2 million.[79] Conversely, if the Company underspends the annual base rate allowance, the Company would defer that amount for future return to customers.[80]

Q. Does the Company propose other initiatives that may impact municipal adoption of the LED tariff?

A. The Company intends to reduce the depreciable lives for the existing, in-service street lights to 20 years from 50 years (for overhead-sourced outdoor lighting HID luminaires) and 70 years (for underground-sourced outdoor lighting HID luminaires).[81]

Q. How was this new depreciable life developed?

A. The Company believes that the assumed 50–70 year service life of HID lighting systems is inaccurate, because it does not reflect the actual operational experience.[82] Accounting for depreciation expenses at the 50–70-year rate appears to have increased the net accounting value of the lighting assets in question. Therefore, the Company proposes to

[77] Testimony of Electric Customer Panel (“ECP”) at 39.
[78] OLP at 16.
[79] ECP at 39.
[80] *See id.*
[81] OLP at 17–18.
[82] *See id.*

reduce the service life of the assets, which will accelerate the collection of depreciation expenses over a shorter time horizon. To do so, the non-LED luminaires will be segregated from the total "street lighting plant accounts," and their operational life will be reduced to 20 years.[83] With the accelerated collection of depreciation expenses, the net accounting value will decline, but a larger share of the depreciation reserve will be allocated specifically to luminaires.[84]

Q. What effect, if any, would reducing the depreciable life have on the LED street light tariff program?

A. Reducing depreciable life would increase annual expenses associated with existing HID equipment, improving the cost effectiveness of replacement with LED equipment. Accelerating the depreciation of existing equipment also accelerates the reduction in any stranded costs associated with early retirement of the equipment.[85] These effects could improve the attractiveness of the LED tariff for municipalities.

Q. Does the reduction in depreciable life apply to all HID luminaires in the Company's service territory, including those in the pilot projects discussed below?

A. The change to the service life of HID luminaires would affect all HID luminaires in the Company's service territory except those involved in the pilot projects.[86] For pilot project participants the permanent discontinuance assessment addresses costs associated with removal of existing equipment.

Q. Should the Company consider additional mechanisms for lowering the up-front cost barrier to municipal adoptions of the LED street light tariff?

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[83] *See id.* at 18.
[84] *See id.* at 19.
[85] Resp. to PACE-5 AD-2 (a copy of which is annexed hereto as Ex. KRR-6).
[86] *Id.*

A. Yes. The Company has implemented the LED street light tariff as a mechanism to support the State's clean energy goals. The energy efficiency program and the reduction in HID luminaires' depreciable life may provide some relief from the up-front cost barriers. These efforts alone, however, may be insufficient to increase municipal adoption of the tariff. Additional cost reduction mechanisms that the Company should consider include:

- Allocating the recovery of the up-front payment for the undepreciated HID luminaires across a broader range of ratepayers. LED lights provide customer and system benefits to ratepayers beyond the municipal customers, who directly provide the service, and it would be appropriate to encourage LED adoption by spreading some, or all, of the undepreciated costs among a wider range of customers.
- Spread the permanent discontinuance assessment over 20 years (the new operational life of HID luminaires). This would allow municipal customers to "pay as they save" with new street lights.

VI. ELECTRIC TRANSPORTATION INITIATIVE

Q. Have you reviewed the programs proposed by the Company under its Electric Transportation Initiative?

A. The Company's Electric Transportation Initiative ("Initiative") is described as a future offering that the Company is willing to "further explore" in collaboration with Commission staff and other parties.[87] The Benefit-Cost Analysis ("BCA") prepared for the Initiative is based on $37.25 million in costs over the period FY 2018-2030, of which $23 million would be spent over the next three years. The three programs include an

[87] ECP at 29-31; Ex. __ (ECP-1), Sched. 8.

Electric Vehicle ("EV") Charging Host program, a Consumer EV Education program, and an EV Grid Integration program, all focused on "increase[ing] the adoption" of electric vehicles and "support[ing] New York State's zero emission vehicles and greenhouse gas emissions policy goals."[88]

Q. What is your assessment of the Company's proposal to develop and launch its Initiative?

A. Based on the information provided by the Company and conversations with Company staff, I find that the proposed Electric Transportation Initiative is soundly conceived and well worth further development and implementation. The Initiative can contribute to expansion in EV adoption and use, and is focused on major issues facing growth of the EV market.

Q. Why is growth in the EV market and electric transportation a good thing?

A. Increased use of electricity in the transportation sector reduces the environmental and economic costs of transportation, especially if targeted in environmentally and economically challenged communities. EVs can provide significant benefits to the grid as a form of DER. With today's technology, time varying rate schemes can optimize the value of increased load to charge vehicles. In the future, EVs will be able to both charge from and discharge to the grid, creating a mobile storage resource that can follow customers to their job site.

Q. How do you think the Company should proceed with its Initiative?

A. The Company should develop a standing working group to provide input and feedback on program design and implementation. The Company should develop budgets for the

[88] *Id.* at 29–30.

programs and time-tables for program implementation. And the Company should follow through on its plans to manage and learn from its programs in an interactive and coordinated manner. In addition, the Company should devote resources to and engage stakeholders in the development of an Electric Transportation Strategic Plan or blueprint.

Q. Why do you think development of an Electric Transportation Strategic Plan is important?

A. I was privileged to lead a utility team at Austin Energy that crafted such a plan for its electric transportation initiatives. In my experience, the process of developing a strategic business plan for electric transportation initiatives is the best way to ensure that disparate programs are effectively coordinated and that lessons learned are quickly internalized. A strategic plan will reveal complementary approaches and competing alternatives, and will allow for the development of metrics appropriate for the future program modifications and initiatives. A strategic plan will reveal the areas in which pilot and demonstration projects are appropriate, and ultimately inform tariff and incentive program development.

VII. NATURAL GAS ISSUES

Q. What concerns do you have about the Company's proposed gas investments, rates, and programs?

A. My major concerns are that the Company is proposing several initiatives that will expand its natural gas system and that it is proposing to spread the costs for those efforts, net of contributions in aid of construction ("CIAC"), to all gas customers.[89]

Q. What gas program initiatives does the Company propose?

[89] *See* Testimony of Gas Customer Panel ("GCP") at 4.

A. The Company is proposing two non-pipeline alternative projects that are appropriate and consistent with the spirit of the Commission's REV initiative. These demonstration projects will deploy and evaluate (1) a geothermal heat system in combination with solar hot water, and (2) a voluntary demand response program for commercial firm gas customers.[90] In addition, the Company now operates gas efficiency programs under an ETIP.[91] The Company is proposing to move $3.5 million in platform-related gas efficiency costs into base rates over the course of the next three years and is seeking a concomitant increase in the ETIP budget to maintain level funding in the ETIP.[92] I support the proposed gas ETIP budget proposal. I also support, in concept, the Company's proposal to create a gas efficiency EAM, though I offer no opinion on the specifics of the EAM incentive levels and thresholds. My concern lies with program efforts to expand natural gas service and use.

Q. Why are you concerned about programs to expand natural gas service and use?

A. Natural gas is today a very affordable fuel. However, infrastructure to extend service is expensive and requires considerable capital investment. In addition, natural gas combustion produces less carbon dioxide and other atmospheric pollutants than does burning other fossil fuels like oil and coal. When natural gas leaks, as it does during production and transportation, its carbon equivalent impacts are much more significant than those of CO_2, so much so that they can obviate any benefits from the lower CO_2 emissions from combustion of natural gas in lieu of higher-carbon fuels. In contrast, distributed energy technologies like ground-source heat pumps ("GHP") and solar hot

[90] *See id.* at 5.
[91] *See id.* at 9–10.
[92] *See id.* at 11–15.

water systems are clean and increasingly cost-effective alternatives to combustion technologies, requiring little or no infrastructure investment beyond the systems themselves. When these factors are considered together with New York's greenhouse gas reduction goals and the potential for significant improvements in the energy efficiency of buildings, there is an increasing risk that natural gas distribution infrastructure will become stranded as it ages. Gas infrastructure investment costs are typically shared with all gas customers, meaning that savings enjoyed by some customers come at a financial as well as environmental cost to other customers.

Q. Did the Company evaluate these costs and other impacts associated with natural gas system expansion?

A. No.[93]

Q. How much money does the Company propose to spend on gas growth-related capital investments?

A. According to data provided by the Company's Gas Infrastructure and Operations Panel, the Company proposes to invest more than $150 million in gas growth-related capital investments in fiscal years 2018–2021. The chart below summarizes the Company's proposal.

[93] Resp. to KRR-7 PACE-15 CO-1 (a copy of which is annexed hereto as Ex. KRR-7).

Niagara Mohawk
Gas Capital and Cost of Removal

Classification	Rate Case Category	Historic Test Year ($000's)	FY'18 Business Plan ($000's)	FY'19 Rate Year ($000's)	FY'20 Data Year 1 ($000's)	FY'21 Data Year 2 ($000's)
Growth	Base Growth - Install Main	$ 8,117	$ 6,176	$ 7,208	$ 7,626	$ 8,043
	Base Growth - Install Services	$ 12,701	$ 11,855	$ 13,696	$ 14,491	$ 15,284
	Base Growth - Neighborhood Expansion Program - Main	$ 4	$ 623	$ 679	$ 698	$ 715
	Base Growth - Neighborhood Expansion Program - Services	$ -	$ 375	$ 489	$ 502	$ 514
	Base Growth - Customer Contributions	$ (1,182)	$ (2,048)	$ (1,241)	$ (1,275)	$ (1,305)
	Base Growth - Fitting	$ 6,613	$ 4,614	$ 5,719	$ 5,874	$ 6,015
	Base Growth - Install Meter/Regulator	$ 3,694	$ 2,302	$ 3,877	$ 3,983	$ 4,078
	Base Growth - Meter Purchases	$ 1,986	$ 1,145	$ 2,197	$ 2,302	$ 2,404
	Gas System Reinforcement	$ 787	$ 3,322	$ 6,560	$ 7,857	$ 12,201
	Marcy NanoTech Center (MV Edge)	$ 1,022	$ 9,559	$ 500	$ -	$ -
	Marcy NanoTech Center (MV Edge) CIAC	$ (1,527)	$ (9,559)	$ (500)	$ -	$ -
	Global Foundries	$ (69)	$ -	$ -	$ -	$ -
	Global Foundries CIAC	$ (69)	$ -	$ -	$ -	$ -
Subtotal Growth		**$ 32,077**	**$ 28,364**	**$ 39,184**	**$ 42,058**	**$ 47,949**

Source: Exhibit __ (GIOP-1)

Q. What does the Company propose regarding its Neighborhood Expansion gas growth program?

A. Within the gas capital spending proposal is the Neighborhood Expansion Program, which now reflects about $1 million of capital investment each year and is proposed to grow to an overall cost of $1.168 million in the Rate Year, $1.2 million in the Data Year 1, and $1.229 million in Data Year 2. The Company's Neighborhood Expansion Program currently includes an annual target of 14,000 feet of new gas main and 100 new customers. [94] The Company proposes to increase those goals to 16,000 feet of gas main and 120 new customers. Over three years, the Company is therefore proposing to spend about $10,000 per new customer added. To support the new targets, the Company proposes (1) to reduce the customer density threshold used as a screen for qualifying neighborhoods, and (2) to decrease the secured customer commitment required for project start from 60 percent to 50 percent.[95] In all, the Company is planning to expand

[94] GCP at 18.
[95] *See id.*

gas service into locations with fewer customers per foot of gas main and to take a risk that half of them never become gas customers at all.

Q. Does the Company propose expenses relating to gas growth?

A. Yes. The Company proposes to spend $1 million per year on rebates for the Oil-to-Gas Conversion Rebate program, all of which is to be included in the revenue requirement, as opposed to deferring 50 percent of annual actual costs for future recovery from customers, as it has been doing under the terms of its 2012 ratemaking.[96]

Q. Does the Company propose gas growth spending targeted at low income customers?

A. The Company proposes to extend CIAC relief to Energy Affordability program participants by providing longer additional main and service line connections at no cost to the customer.[97]

Q. Does the Company fund gas growth through economic development rates and economic development grants?

A. Yes. The Company awards gas discounts to customers through its Empire Zone Rider and Excelsior Jobs Program rates.[98] In addition, the Company proposes to spend up to $1 million each year on various grants to customers adding gas load to the system. [99]

Q. Does the Company propose any other major capital investment projects that relate to gas system expansion?

A. At some level, many of the proposed projects, even those relating to reliability, repair, and system life extension all support increased gas sales. However, the reliability, safety, and leak reduction benefits of these programs suggest that they need not be the first

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[96] *See id.* at 19–20.
[97] *See id.* at 21.
[98] *See id.* at 22–23.
[99] *See id.* at 24.

priority for addressing the problems associated with system expansion. There is one major project, named the "Albany Loop Closure," that does merit additional detailed review due to its large budget.[100]

Q. What does the Albany Loop Closure project involve?

A. The Albany Loop Closure project involves nearly $70 million in proposed project capital expenditures in FY 2019-2021.[101] This project serves the dual purposes of improving system reliability to existing customers and allows for continued system growth in the Albany area. This project would connect existing pipelines with 38,000 feet of new transmission main, and increase the amount of gas that can be moved into the system from 60 Mdt to 100 Mdt.[102]

Q. Did the Company consider alternatives to the Albany Loop Closure project?

A. According to the Company's project description, the Company considered a new pipeline lateral approach in lieu of the looping proposal, and a "Do Nothing" alternative.[103]

Q. What is your recommendation regarding the Albany Loop Closure project?

A. It is difficult to determine how much (if any) of the Albany Loop Closure project is related to system reliability improvements, and how much of it is related to system expansion objectives. This is because the description of project alternatives is not particularly robust in the Company filing. Moreover, the "Do Nothing" alternative described by the Company does not evaluate demand-side options that could increase the reliability of the existing system through other means. I recommend that the Company be directed to provide a more comprehensive assessment of alternatives, including

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[100] Testimony of Gas Infrastructure and Operations Panel ("GIOP") at 31–32.
[101] Ex. __ (GIOP-1) at 1.
[102] GIOP at 32 & Ex. __ (GIOP-4) at 50–51.
[103] Ex. __ (GIOP-4) at 51.

alternatives to the scope of the project. Most importantly, the Company should perform a comprehensive assessment of non-pipeline alternatives.

Q. What is your assessment of the Company's gas growth investment and spending?

A. In my opinion, the Company should not be spending on gas load building, just as it should not be spending on electric load building, unless it can demonstrate net societal benefits over the life of the program or measure.

Q. What do you recommend that the Commission do in regard to these programs?

A. I recommend that the Commission declare a moratorium on gas load building programs and spending until it can establish and implement a protocol for evaluation of the program from a long-term societal perspective. Such a tool will inform EAM design and guide the development and implementation of more cost-effective alternatives to natural gas system expansion.

Q. Why should the Commission and the Company suspend gas expansion programs until comprehensive BCA tools based on a societal perspective can be developed?

A. The low current prices for natural gas have created an understandable enthusiasm for increased natural gas utilization as a power plant fuel and for direct combustion in homes and businesses. However, capital investment in gas infrastructure—whether for production, transmission, distribution, or conversion—cannot be evaluated for cost-effectiveness in a vacuum or only in the short term. Alternatives to natural gas exist and are increasingly cost-effective.[104] These options include large-scale renewable energy generation, distributed renewable generation, energy efficiency, beneficial electrification

[104] *See* Lazard, Lazard's Levelized Cost of Energy Analysis—Version 10.0 (2016), *available at* https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf (describing cost of electrical power only).

equipment like GHPs, electric vehicles, and others.[105] In the absence of up-to-date and comprehensive BCA tools that address the tradeoffs associated with natural gas system expansion investments from a long-term societal perspective and drive Company proposals and Commission decisions regarding those investments, there is an increasing risk of creating an asset class that will become a stranded investment in the future.[106] Money spent on and committed to natural gas system expansion creates an opportunity cost by shifting resources away from clean, no-fuel technology options like renewable energy and energy efficiency, which frustrates New York's policies aimed at significant greenhouse gas emissions reductions.[107] In the face of these important tradeoffs, the Company should have developed and submitted a comprehensive BCA that evaluates natural gas system expansion against a range of non-gas alternatives.

Q. How do natural gas system expansion investments impact customers?

A. Natural gas system expansions can appear to provide new gas customers with lower energy bills because of the currently lower prices of natural gas, but those potential savings can easily evaporate if gas prices increase. When natural gas prices do rise, customers can be locked into a higher-cost fuel or stranded cost payments for years.

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[105] *See, e.g.*, Neil Veilleux et al., Meister Consultants Grp., prepared for Int'l Energy Agency, Renewable Energy Technology Deployment, Waking the Sleeping Giant 8 (2015), *available at* http://iea-retd.org/wp-content/uploads/2015/02/RES-H-NEXT.pdf (depicting renewable alternatives to gas heating).

[106] For its Carbon Reduction Program, Central Hudson Gas & Electric Corporation has prepared a BCA, which includes alternatives to gas heating. *See* Direct Test. of the Earnings Adjustment Mechanism ("EAM") Panel 11–12, *Proceedings on Motions of the Comm'n as to the Rates, Charges, Rules and Regulations of Cent. Hudson Gas & Elec. Corp. for Elec. and Gas Serv.*, Case Nos. 17-E-0459 & 17-G-0460 (PSC July 28, 2017). I have not seen the Central Hudson BCA, and therefore do not endorse it here. I do note National Grid's failure to prepare such an analysis for its gas expansion proposals and the conflicting results of Central Hudson's analysis and that prepared for National Grid's Electric Heat Initiative.

[107] *See* Direct Testimony of Thomas G. ("Jerry") Acton on behalf of Alliance for a Green Economy, submitted in connection with this proceeding.

These expansion investments can also raise rates for existing customers when the costs of system expansion are rate-based and not charged directly to the newly connected customers.[108] Economic development programs encouraging greater gas use can likewise create benefits for funding recipients while raising rates for customers at large.

Q. What are the mid- to long-term issues that could potentially strand natural gas system expansion investments?

A. These issues include not only the improving economics of the alternatives to natural gas, but also a range of problems associated with natural gas as a fuel.

- First, today's lower natural gas prices are a favorable condition, but when viewed over the longer term, natural gas prices have been quite volatile. This volatility can translate into rate shock when passed through to customers.[109]
- Second, natural gas is a finite fossil fuel. There are well known problems with the very optimistic estimates of gas reserves developed by the U.S. Energy Information Administration ("EIA"), and a series University of Texas studies predict that gas from the four largest shale plays in the U.S. will peak in 2020.[110] The useful life and straight-line depreciation life of many gas infrastructure investments may actually be

[108] A recent decision of the Ontario Energy Board, in Canada, addressed the issue of subsidized gas system expansion. The Board decided that subsidies from existing customers to support gas expansion to new customers were not appropriate. *See* Decision With Reasons 4, *Generic Proceeding on Cmty. Expansion*, Case No. EB-2016-0004 (Ont. Energy Bd. Nov. 17, 2016), *available at* http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=EB-2016-0004&sortd1=rs_dateregistered&rows=200.

[109] *See* EIA, *New York Price of Natural Gas Delivered to Residential Consumers*, https://www.eia.gov/dnav/ng/hist/n3010ny3A.htm (data released July 31, 2017) (showing price of natural gas delivered to residential customers in New York State from 1967 to 2016).

[110] *See* J. David Hughes, Post Carbon Inst., 2016 Shale Gas Reality Check 1 (2016) (citing Texas studies), http://www.postcarbon.org/publications/2016-shale-gas-reality-check/; Mason Inman, *Natural Gas: The Fracking Fallacy*, 516 Nature 28, 29 (Dec. 2014) (citing Texas studies) (citing Texas studies).

longer than the period during which natural gas will be readily available at affordable prices.[111] Long before the physical resource is exhausted, supply constraints due to resource distribution could cause price increases and volatility. Increasing natural gas end-use puts direct consumer reliance on natural gas in direct competition with gas use for electricity production in times of fuel constraint that are certain to increase over the coming decades.

- Third, natural gas is, in New York, an imported fuel. This means that increasing reliance on gas shifts risk of transport congestion and supply constraint to an increasing portion of New York customers. Even now, the Company claims that natural gas transport constraints can be a reliability issue.[112] Moreover, as an imported fuel, the trade balance for natural gas tilts heavily toward exports of capital. With efficiency and in-state renewable energy generation, a higher fraction of the costs remains in New York.
- Fourth, when burned for power, natural gas offers reduced emissions of CO_2 as compared with those of coal, oil, and propane. These benefits are partially, and potentially entirely, offset by the greenhouse gas impacts of methane leaks that occur in every part of the natural gas life cycle, from production to final use.[113] Methane is a dramatically more potent greenhouse gas than CO_2, so much so that life cycle

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[111] *See* EIA, Annual Energy Outlook 2017 with Projections to 2050 at 55 (Jan. 5, 2017), https://www.eia.gov/outlooks/aeo/pdf/0383%282017%29.pdf (showing possible quadrupling of Henry Hub spot prices by 2040).
[112] GIOP at 31–32; Ex. __ (GIOP-4) at 50–51 (discussing Albany Loop Closure project).
[113] *See* David R. Lyon, *Methane Emissions from the Natural Gas Supply Chain*, Chapter 3, in Environmental and Health Issues in Unconventional Oil and Gas Development 33–48 (Debra Kaden & Tracie L. Rose eds., 2016), *available at* http://www.sciencedirect.com/science/article/pii/B9780128041116000030.

leakage could offset all combustion-related CO_2 reduction benefits.[114] Moreover, as the equipment that uses natural gas as a fuel ages, the efficiency of fuel use degrades, reducing the carbon reduction benefits of the fuel.

- Finally, it is important to remember that New York has already moved substantially to reduce its dependence on fossil fuels for electricity production. Approximately 40% of the New York electric production sector's greenhouse emissions are related to natural gas use.[115] Meeting the objectives of the New York State Energy Plan and CES requires a fundamental shift away from use of natural gas, not an increase in natural gas end uses.[116]

Q. What role would a moratorium on gas expansion and the development of a comprehensive benefit-cost analysis procedure play in a strategy to reduce natural gas use?

A. The first step in getting out of a hole is to stop digging. New York has taken a critical first step in rejecting the production of natural gas through hydraulic fracturing. The next step is a moratorium on any gas expansion investments, including incentives for end-use conversion, pending development of a benefit-cost analysis procedure. The next step after that is for New York to develop a comprehensive strategy for managed de-capitalization of the natural gas system. This strategy would focus on idling and then abandoning

[114] *See* Sarah Zielinski, *Natural Gas Really Is Better than Coal*, Smithsonian.com, Feb. 13, 2014, (citing Adam R. Brandt et al., *Methane Leaks from North American Natural Gas Systems*, 343 Science 733, 733–735 (2014)).

[115] *See* EPA, Emissions & Generation Resource Integrated Database ("eGRID"), eGRID2014 Summary Tables, Table 11 (State Resource Mix) (rev. Feb. 27, 2017); NYSERDA, New York State Greenhouse Gas Inventory, https://www.nyserda.ny.gov/-/media/Files/EDPPP/Energy-Prices/Energy-Statistics/greenhouse-gas-inventory.pdf.

[116] *See* NYSERDA, *Clean Energy Standard*, https://www.nyserda.ny.gov/All-Programs/Programs/Clean-Energy-Standard.

natural gas infrastructure in a measured and deliberate fashion by aiming electrification and efficiency initiatives at portions of the grid that are experiencing declining sales. In addition, alternative uses of gas infrastructure should be explored. The long term objective should be the significant reduction and eventual elimination of end-use natural gas consumption.

Q. What recommendations do you have for the design of a BCA framework for gas expansion and its alternatives?

A. The BCA used to evaluate gas expansions, and ultimately inform a managed de-capitalization strategy, must encompass the broadest scope of analysis, from natural gas production to the burner tip. The BCA must take a long-term perspective, examining the decades over which infrastructure would be in place. The procedure must take a full societal perspective of costs and benefits, including assessment of the health and environmental justice impacts of natural gas production, transmission, distribution, and use. The procedure must also take into account the projected future commodity price of natural gas and the impact of price instability and increases on ratepayers. The BCA should provide points of comparison for all of those parameters as applied to non-fossil-fuel alternatives to natural gas.

Q. Are you concerned that a moratorium on gas system expansion investments could adversely impact low- and moderate-income customers who would benefit from today's lower prices for natural gas?

A. Low- and moderate-income ("LMI") customers face high energy burdens, and taking the opportunity to cost-effectively reduce those burdens in both the near and long term is properly the policy of the Commission and the State of New York. It is important that near-term cost savings do not come at the expense of a long-term mortgage that is unaffordable. That is another major reason that the Commission should establish, and the Company should energetically participate in, a process to develop a comprehensive analytical procedure that accounts for cost and benefits over the long term, and to society as a whole.

Q. What do you recommend that the Company do to provide opportunities to reduce energy burdens for LMI customers in the near term?

A. LMI customers that otherwise would have qualified for gas expansion and conversion programs should be aggressively targeted for energy efficiency improvements. The Company should also consider providing other support to these customers. In addition to energy efficiency programs aimed at reducing levels of use, the Company should move ahead with its proposal to develop its Electric Heat Initiative[117] aimed at accelerating the deployment of highly efficient GHP systems for residential customers.

Q. What is your opinion of the Company's proposed Electric Heat Initiative?

A. The Electric Heat Initiative is an excellent concept as it relates to increasing deployment of high-efficiency GHP systems and should be pursued aggressively by the Company. GHP systems represent a beneficial electrification option that avoids the problems and risks of gas expansion and delivers cost savings benefits to customers. Coupled with strong efforts to improve the efficiency of home energy uses, GHP systems can create a win-win-win solution that provides electricity sales revenues to the utility, cost savings and energy service security to customers, and reduced environmental harms. Moreover, as the New York grid gets progressively cleaner under the CES, the carbon footprint of

[117] ECP at 31–32 & Ex. __ (ECP-1), Sched. 7.

GHP system operation progressively improves. In the near term, the Electric Heat Initiative offers an important opportunity to mitigate near-term problems created by a moratorium on gas.

Q. Is the Company's Electric Heat Initiative ready to launch?

A. Not yet. Pace appreciates the Company's willingness to propose the Initiative for further discussion in settlement and beyond. The Company should convene a working group to ensure the best possible design and operation of the Electric Heat Initiative. Pace commits to participating in such a process.

Q. What steps should the Company take in designing and launching the Electric Heat Initiative?

A. After convening a working group of interested stakeholders, including Commission staff, the Company's first priority should be to establish a sound data foundation for the Initiative. The Company constructed a BCA for heat pumps that, while basically structurally sound, contains some significant errors in assumptions.[118]

Q. What kinds of errors did you find in the Company's Heat Pump BCA?

A. I have discovered a few issues that should be aired and resolved as a first step in launching the Electric Heat Initiative. These examples are meant to point out the need to convene stakeholders early in the Initiative process:

- The Heat Pump BCA appears to understate the costs of fuel oil and propane. It relies on wholesale, rather than retail, prices for these fuels.
- The costs to install heat pumps may be overstated, and, at the same time, the avoided costs associated with heat pump operation may be understated.

[118] Resp. to DPS-21 MZS-2, Attach. 1 (a copy of which, without the attachment, is annexed hereto as Ex. KRR-8).

- The relative benefits of air source and GHPs may be incorrectly characterized in the Heat Pump BCA, which does not include a location-based climate adjustment for air source systems.
- The Heat Pump BCA seems to compare air source heat pumps and GHPs directly. This approach ignores the likelihood that many GHPs will be installed as a whole-house solution, while many air source systems will be installed as a replacement for window air conditioners or to serve a limited portion of the home.
- As a replacement for direct combustion, heat pumps displace particulate air pollutants that are not reflected in the Heat Pump BCA. These avoided costs, which can be even more significant in communities with significant environmental justice concerns (often low-income communities), should be characterized.
- The Heat Pump BCA appears to use environmental emissions factors from the Energy Information Administration's "Frequently Asked Questions" reference. Methane emissions information also should be included, and it is available from the US EPA's Greenhouse Gas Inventory Guidance.[119]
- The Heat Pump BCA appears to include erroneous information regarding the Baseline Heating COP, in that it assumes that both new and existing Oil systems have the same Base Heating COP value.[120]

Q. Do these concerns diminish your enthusiasm for the Electric Heat Initiative put forward by the Company?

[119] U.S. EPA, Greenhouse Gas Inventory Guidance: Direct Emissions from Stationary Combustion Sources (2016), *available at* https://www.epa.gov/sites/production/files/2016-03/documents/stationaryemissions_3_2016.pdf.
[120] Ex. KRR-8 (Resp. to DPS-21 MZS-2), Attach. 1 (Measure Input Data, Column R).

A. Not at all. At Pace, we are eager to get to work on programs to increase the use of clean, efficient GHP systems.

Q. Does this conclude your testimony?

A. Yes.

Testimony of Karl R. Rábago

Exhibit KRR-1

Resume

Karl R. Rábago

Executive Director, Pace Energy and Climate Center
Elisabeth Haub School of Law
78 North Broadway, White Plains, NY 10603

c: +1.512.968.7543 e: krabago@law.pace.edu

Summary

Nationally recognized leader and innovator in electricity and energy law, policy, and regulation. Experienced as a public utility regulatory commissioner, educator, research and development program manager, utility executive, business builder, federal executive, corporate sustainability leader, consultant, and advocate. Highly proficient in advising, managing, and interacting with government agencies and committees, the media, citizen groups, and business associations. Successful track record of working with US Congress, state legislatures, governors, regulators, city councils, business leaders, researchers, academia, and community groups. National and international contacts through experience with Pace Energy and Climate Center, Austin Energy, AES Corporation, US Department of Energy, Texas Public Utility Commission, Jicarilla Apache Tribal Utility Authority, Cargill Dow LLC (now NatureWorks, LLC), Rocky Mountain Institute, CH2M HILL, Houston Advanced Research Center, Environmental Defense Fund, and others. Skilled attorney, negotiator, and advisor with more than twenty-five years of experience working with diverse stakeholder communities in electricity policy and regulation, emerging energy markets development, clean energy technology development, electric utility restructuring, smart grid development, and the implementation of sustainability principles. Extensive regulatory practice experience. Nationally recognized speaker on energy, environment and sustainable development matters. Managed staff as large as 250; responsible for operations of research facilities with staff in excess of 600. Developed and managed budgets in excess of $300 million. Law teaching experience at Pace University School of Law, University of Houston Law Center, and U.S. Military Academy at West Point. Post-doctorate degrees in environmental and military law. Military veteran.

Employment

PACE ENERGY AND CLIMATE CENTER, PACE UNIVERSITY SCHOOL OF LAW

Executive Director: May 2014—Present.

Leader of a team of professional and technical experts in energy and climate law, policy, and regulation. Secure funding for and manage execution of research, market development support, and advisory services for a wide range of funders, clients, and stakeholders with the overall goal of advancing clean energy deployment, climate responsibility, and market efficiency. Supervise a team of employees, consultants, and adjunct researchers. Provide learning and development opportunities for law students. Coordinate efforts of the Center with and support the environmental law faculty. Additional activities:

- Co-Director and Principal Investigator, Northeast Solar Energy Market Coalition (2015-present). The NESEMC is a US Department of Energy's SunShot Initiative Solar Market Pathways project. Funded under a cooperative agreement between the US DOE and Pace University, the NESEMC seeks to harmonize solar market policy and advance best policy and regulatory practices in the northeast United States.
- Chairman of the Board, Center for Resource Solutions (1997-present). CRS is a not-for-profit organization based at the Presidio in California. CRS developed and manages the Green-e Renewable Electricity Brand, a nationally and internationally recognized branding program

for green power and green pricing products and programs. Past chair of the Green-e Governance Board (formerly the Green Power Board).

- Director, Interstate Renewable Energy Council (IREC) (2012-present). IREC focuses on issues impacting expanded renewable energy use such as rules that support renewable energy and distributed resources in a restructured market, connecting small-scale renewables to the utility grid, developing quality credentials that indicate a level of knowledge and skills competency for renewable energy professionals.

RÁBAGO ENERGY LLC

Principal: July 2012—Present. Consulting practice dedicated to providing expert witness and policy formulation advice and services to organizations in the clean and advanced energy sectors. Recognized national leader in development and implementation of award-winning "Value of Solar" alternative to traditional net metering. Additional information at www.rabagoenergy.com.

AUSTIN ENERGY – THE CITY OF AUSTIN, TEXAS

Vice President, Distributed Energy Services: April 2009—June 2012. Executive in 8th largest public power electric utility serving more than one million people in central Texas. Responsible for management and oversight of energy efficiency, demand response, and conservation programs; low-income weatherization; distributed solar and other renewable energy technologies; green buildings program; key accounts relationships; electric vehicle infrastructure; and market research and product development. Executive sponsor of Austin Energy's participation in an innovative federally-funded smart grid demonstration project led by the Pecan Street Project. Led teams that successfully secured over $39 million in federal stimulus funds for energy efficiency, smart grid, and advanced electric transportation initiatives. Additional activities included:

- Director, Renewable Energy Markets Association. REMA is a trade association dedicated to maintaining and strengthening renewable energy markets in the United States.
- Membership on Pedernales Electric Cooperative Member Advisory Board. Invited by the Board of Directors to sit on first-ever board to provide formal input and guidance on energy efficiency and renewable energy issues for the nation's largest electric cooperative.

THE AES CORPORATION

Director, Government & Regulatory Affairs: June 2006—December 2008. Government and regulatory affairs manager for AES Wind Generation, one of the largest wind companies in the country. Manage a portfolio of regulatory and legislative initiatives to support wind energy market development in Texas, across the United States, and in many international markets. Active in national policy and the wind industry through work with the American Wind Energy Association as a participant on the organization's leadership council. Also served as Managing Director, Standards and Practices, for Greenhouse Gas Services, LLC, a GE and AES venture committed to generating and marketing greenhouse gas credits to the U.S. voluntary market. Authored and implemented a standard of practice based on ISO 14064 and industry best practices. Commissioned the development of a suite of methodologies and tools for various greenhouse gas credit-producing technologies. Also served as Director, Global Regulatory Affairs, providing regulatory support and group management to AES's international electric utility operations on five continents. Additional activities:

- Director and past Chair, Jicarilla Apache Nation Utility Authority (1998 to 2008). Located in New Mexico, the JAUA is an independent utility developing profitable and autonomous utility services that provides natural gas, water utility services, low income housing, and energy planning for the Nation. Authored "First Steps" renewable energy and energy efficiency strategic plan.

HOUSTON ADVANCED RESEARCH CENTER

Group Director, Energy and Buildings Solutions: December 2003—May 2006. Leader of energy and building science staff at a mission-driven not-for-profit contract research organization based in The Woodlands, Texas. Responsible for developing, maintaining and expanding upon technology development, application, and commercialization support programmatic activities, including the Center for Fuel Cell Research and Applications, an industry-driven testing and evaluation center for near-commercial fuel cell generators; the Gulf Coast Combined Heat and Power Application Center, a state and federally funded initiative; and the High Performance Green Buildings Practice, a consulting and outreach initiative. Secured funding for major new initiative in carbon nanotechnology applications in the energy sector. Developed and launched new and integrated program activities relating to hydrogen energy technologies, combined heat and power, distributed energy resources, renewable energy, energy efficiency, green buildings, and regional clean energy development. Active participant in policy development and regulatory implementation in Texas, the Southwest, and national venues. Frequently engaged with policy, regulatory, and market leaders in the region and internationally. Additional activities:

- President, Texas Renewable Energy Industries Association. As elected president of the statewide business association, leader and manager of successful efforts to secure and implement significant expansion of the state's renewable portfolio standard as well as other policy, regulatory, and market development activities.
- Director, Southwest Biofuels Initiative. Established the Initiative acts as an umbrella structure for a number of biofuels related projects, including emissions evaluation for a stationary biodiesel pilot project, feedstock development, and others.
- Member, Committee to Study the Environmental Impacts of Windpower, National Academies of Science National Research Council. The Committee was chartered by Congress and the Council on Environmental Quality to assess the impacts of wind power on the environment.
- Advisory Board Member, Environmental & Energy Law & Policy Journal, University of Houston Law Center.

CARGILL DOW LLC (NOW NATUREWORKS, LLC)

Sustainability Alliances Leader: April 2002—December 2003. Founded in 1997, NatureWorks, LLC is based in Minnetonka, Minnesota. Integrated sustainability principles into all aspects of a ground-breaking biobased polymer manufacturing venture. Responsible for maintaining, enhancing and building relationships with stakeholders in the worldwide sustainability community, as well as managing corporate and external sustainability initiatives. NatureWorks is the first company to offer its customers a family of polymers (polylactide – "PLA") derived entirely from annually renewable resources with the cost and performance necessary to compete with packaging materials and traditional fibers; now marketed under the brand name "Ingeo."

- Successfully completed Minnesota Management Institute at University of Minnesota Carlson School of Management, an alternative to an executive MBA program that surveyed fundamentals and new developments in finance, accounting, operations management, strategic planning, and human resource management.

ROCKY MOUNTAIN INSTITUTE

Managing Director/Principal: October 1999–April 2002. In two years, co-led the team and grew annual revenues from approximately $300,000 to more than $2 million in annual grant and consulting income. Co-authored "Small Is Profitable," a comprehensive analysis of the benefits of distributed energy resources. Worked to increase market opportunities for clean and distributed energy resources through consulting, research, and publication activities. Provided consulting and advisory services to help business and government clients achieve sustainability through application and incorporation of Natural Capitalism principles. Frequent appearance in media at international, national, regional and local levels.

- President of the Board, Texas Ratepayers Organization to Save Energy. Texas R.O.S.E. is a non-profit organization advocating low-income consumer issues and energy efficiency programs.
- Co-Founder and Chair of the Advisory Board, Renewable Energy Policy Project-Center for Renewable Energy and Sustainable Technology. REPP-CREST was a national non-profit research and internet services organization.

CH2M HILL

Vice President, Energy, Environment and Systems Group: July 1998–August 1999. Responsible for providing consulting services to a wide range of energy-related businesses and organizations, and for creating new business opportunities in the energy industry for an established engineering and consulting firm. Completed comprehensive electric utility restructuring studies for the states of Colorado and Alaska.

PLANERGY

Vice President, New Energy Markets: January 1998–July 1998. Responsible for developing and managing new business opportunities for the energy services market. Provided consulting and advisory services to utility and energy service companies.

ENVIRONMENTAL DEFENSE FUND

Energy Program Manager: March 1996–January 1998. Managed renewable energy, energy efficiency, and electric utility restructuring programs for a not-for-profit environmental group with a staff of 160 and over 300,000 members. Led regulatory intervention activities in Texas and California. In Texas, played a key role in crafting Deliberative Polling processes. Initiated and managed nationwide collaborative activities aimed at increasing use of renewable energy and energy efficiency technologies in the electric utility industry, including the Green-e Certification Program, Power Scorecard, and others. Participated in national environmental and energy advocacy networks, including the Energy Advocates Network, the National Wind Coordinating Committee, the NCSL Advisory Committee on Energy, and the PV-COMPACT Coordinating Council. Frequently appeared before the Texas Legislature, Austin City Council, and regulatory commissions on electric restructuring issues.

UNITED STATES DEPARTMENT OF ENERGY

Deputy Assistant Secretary, Utility Technologies: January 1995–March 1996. Manager of the Department's programs in renewable energy technologies and systems, electric energy systems, energy efficiency, and integrated resource planning. Supervised technology research, development and deployment activities in photovoltaics, wind energy, geothermal energy, solar thermal energy, biomass energy, high-temperature superconductivity, transmission and distribution, hydrogen, and electric and magnetic fields. Developed, coordinated, and advised on legislation, policy, and renewable energy technology development within the Department, among other agencies, and with Congress. Managed, coordinated, and developed international agreements for cooperative activities in renewable energy and utility sector policy, regulation, and market development between the Department and counterpart foreign national entities. Established and enhanced partnerships with stakeholder groups, including technology firms, electric utility companies, state and local governments, and associations. Supervised development and deployment support activities at national laboratories. Developed, advocated and managed a Congressional budget appropriation of approximately $300 million.

STATE OF TEXAS

Commissioner, Public Utility Commission of Texas. May 1992–December 1994. Appointed by Governor Ann W. Richards. Regulated electric and telephone utilities in Texas. Laid the groundwork for legislative and regulatory adoption of integrated resource planning, electric utility restructuring, and significantly increased use of renewable energy and energy efficiency resources. Co-chair and organizer of the Texas Sustainable Energy Development Council. Vice-Chair of the National Association of Regulatory Utility Commissioners (NARUC) Committee on Energy Conservation. Member and co-creator of the Photovoltaic Collaborative Market Project to Accelerate Commercial Technology (PV-COMPACT). Member, Southern States Energy Board Integrated Resource Planning Task Force. Member of the University of Houston Environmental Institute Board of Advisors.

LAW TEACHING

Professor for a Designated Service: Pace University Law School, 2014-present. Non-tenured member of faculty. Courses taught: Energy Law. Supervise a student clinical effort that engages in a wide range of advocacy, analysis, and research activities in support of the mission of the Pace Energy and Climate Center.

Associate Professor of Law: University of Houston Law Center, 1990–1992. Full time, tenure track member of faculty. Courses taught: Criminal Law, Environmental Law, Criminal Procedure, Environmental Crimes Seminar, Wildlife Protection Law. Provided *pro bono* legal services in administrative proceedings and filings at the Texas Public Utility Commission.

Assistant Professor: United States Military Academy, West Point, New York, 1988–1990. Member of the faculty in the Department of Law. Honorably discharged in August 1990, as Major in the Regular Army. Courses taught: Constitutional Law, Military Law, and Environmental Law Seminar. Greatly expanded the environmental law curriculum and laid foundation for the concentration program in law. While carrying a full time teaching load, earned a Master of Laws degree in Environmental Law. Established a program for subsequent environmental law professors to obtain an LL.M. prior to joining the faculty.

LITIGATION

Trial Defense Attorney and Prosecutor, U.S. Army Judge Advocate General's Corps, Fort Polk, Louisiana, January 1985–July 1987. Assigned to Trial Defense Service and Office of the Staff Judge Advocate. Prosecuted and defended more than 150 felony-level courts-martial. As prosecutor, served as legal officer for two brigade-sized units (approximately 5,000 soldiers), advising commanders on appropriate judicial, non-judicial, separation, and other actions. Pioneered use of some forms of psychiatric and scientific testimony in administrative and judicial proceedings.

NON-LEGAL MILITARY SERVICE

Armored Cavalry Officer, 2d Squadron 9th Armored Cavalry, Fort Stewart, Georgia, May 1978–August 1981. Served as Logistics Staff Officer (S-4). Managed budget, supplies, fuel, ammunition, and other support for an Armored Cavalry Squadron. Served as Support Platoon Leader for the Squadron (logistical support), and as line Platoon Leader in an Armored Cavalry Troop. Graduate of Airborne and Ranger Schools. Special training in Air Mobilization Planning and Nuclear, Biological and Chemical Warfare.

Formal Education

LL.M., Environmental Law, Pace University School of Law, 1990: Curriculum designed to provide breadth and depth in study of theoretical and practical aspects of environmental law. Courses included: International and Comparative Environmental Law, Conservation Law, Land Use Law, Seminar in Electric Utility Regulation, Scientific and Technical Issues Affecting Environmental Law, Environmental Regulation of Real Estate, Hazardous Wastes Law. Individual research with Hudson Riverkeeper Fund, Garrison, New York.

LL.M., Military Law, U.S. Army Judge Advocate General's School, 1988: Curriculum designed to prepare Judge Advocates for senior level staff service. Courses included: Administrative Law, Defensive Federal Litigation, Government Information Practices, Advanced Federal Litigation, Federal Tort Claims Act Seminar, Legal Writing and Communications, Comparative International Law.

J.D. with Honors, University of Texas School of Law, 1984: Attended law school under the U.S. Army Funded Legal Education Program, a fully funded scholarship awarded to 25 or fewer officers each year. Served as Editor-in-Chief (1983–84); Articles Editor (1982–83); Member (1982) of the Review of Litigation. Moot Court, Mock Trial, Board of Advocates. Summer internship at Staff Judge Advocate's offices. Prosecuted first cases prior to entering law school.

B.B.A., Business Management, Texas A&M University, 1977: ROTC Scholarship (3–yr). Member: Corps of Cadets, Parson's Mounted Cavalry, Wings & Sabers Scholarship Society, Rudder's Rangers, Town Hall Society, Freshman Honor Society, Alpha Phi Omega service fraternity.

Selected Publications

"Achieving very high PV penetration – The need for an effective electricity remuneration framework and a central role for grid operators," Richard Perez (corresponding author), Energy Policy, Vol. 96, pp. 27-35 (2016)

"The Net Metering Riddle," Electricity Policy.com, (April 2016)

"The Clean Power Plan," Power Engineering Magazine (invited editorial), Vol. 119, Issue 12 (Dec. 2, 2015)

"The 'Sharing Utility:' Enabling & Rewarding Utility Performance, Service & Value in a Distributed Energy Age," co-author, 51st State Initiative, Solar Electric Power Association (Feb. 27, 2015)

"Rethinking the Grid: Encouraging Distributed Generation," Building Energy Magazine, Vol. 33, No. 1 Northeast Sustainable Energy Association (Spring 2015)

"The Value of Solar Tariff: Net Metering 2.0," The ICER Chronicle, Ed. 1, p. 46 [International Confederation of Energy Regulators] (December 2013)

"A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation," co-author, Interstate Renewable Energy Council (October 2013)

"The 'Value of Solar' Rate: Designing an Improved Residential Solar Tariff," Solar Industry, Vol. 6, No. 1 (Feb. 2013)

"A Review of Barriers to Biofuels Market Development in the United States," 2 Environmental & Energy Law & Policy Journal 179 (2008)

"A Strategy for Developing Stationary Biodiesel Generation," Cumberland Law Review, Vol. 36, p.461 (2006)

"Evaluating Fuel Cell Performance through Industry Collaboration," co-author, Fuel Cell Magazine (2005)

"Applications of Life Cycle Assessment to NatureWorks™ Polylactide (PLA) Production," co-author, Polymer Degradation and Stability 80, 403-19 (2003)

"An Energy Resource Investment Strategy for the City of San Francisco: Scenario Analysis of Alternative Electric Resource Options," contributing author, Prepared for the San Francisco Public Utilities Commission, Rocky Mountain Institute (2002)

"Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size," co-author, Rocky Mountain Institute (2002)

"Socio-Economic and Legal Issues Related to an Evaluation of the Regulatory Structure of the Retail Electric Industry in the State of Colorado," with Thomas E. Feiler, Colorado Public Utilities Commission and Colorado Electricity Advisory Panel (April 1, 1999)

"Study of Electric Utility Restructuring in Alaska," with Thomas E. Feiler, Legislative Joint Committee on electric Restructuring and the Alaska Public Utilities Commission (April 1, 1999)

"New Markets and New Opportunities: Competition in the Electric Industry Opens the Way for Renewables and Empowers Customers," EEBA Excellence (Journal of the Energy Efficient Building Association) (Summer 1998)

"Building a Better Future: Why Public Support for Renewable Energy Makes Sense," Spectrum: The Journal of State Government (Spring 1998)

"The Green-e Program: An Opportunity for Customers," with Ryan Wiser and Jan Hamrin, Electricity Journal, Vol. 11, No. 1 (January/February 1998)

"Being Virtual: Beyond Restructuring and How We Get There," Proceedings of the First Symposium on the Virtual Utility, Klewer Press (1997)

"Information Technology," Public Utilities Fortnightly (March 15, 1996)

"Better Decisions with Better Information: The Promise of GIS," with James P. Spiers, Public Utilities Fortnightly (November 1, 1993)

"The Regulatory Environment for Utility Energy Efficiency Programs," Proceedings of the Meeting on the Efficient Use of Electric Energy, Inter-American Development Bank (May 1993)

"An Alternative Framework for Low-Income Electric Ratepayer Services," with Danielle Jaussaud and Stephen Benenson, Proceedings of the Fourth National Conference on Integrated Resource Planning, National Association of Regulatory Utility Commissioners (September 1992)

"What Comes Out Must Go In: The Federal Non-Regulation of Cooling Water Intakes Under Section 316 of the Clean Water Act," Harvard Environmental Law Review, Vol. 16, p. 429 (1992)

"Least Cost Electricity for Texas," State Bar of Texas Environmental Law Journal, Vol. 22, p. 93 (1992)

"Environmental Costs of Electricity," Pace University School of Law, Contributor–Impingement and Entrainment Impacts, Oceana Publications, Inc. (1990)

Testimony of Karl R. Rábago

Exhibit KRR-2

List of Prior Testimony

Table of Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, or through Rábago Energy LLC

(as of 28 July 2017)

Date	Proceeding	Case/Docket #	On Behalf Of:
Dec. 21, 2012	VA Electric & Power Special Solar Power Tariff	Virginia SCC Case # PUE-2012-00064	Southern Environmental Law Center
May 10, 2013	Georgia Power Company 2013 IRP	Georgia PSC Docket # 36498	Georgia Solar Energy Industries Association
Jun. 23, 1203	Louisiana Public Service Commission Re-examination of Net Metering Rules	Louisiana PSC Docket # R-31417	Gulf States Solar Energy Industries Association
Aug. 29, 2013	DTE (Detroit Edison) 2013 Renewable Energy Plan Review (Michigan)	Michigan PUC Case # U-17302	Environmental Law and Policy Center
Sep. 5, 2013	CE (Consumers Energy) 2013 Renewable Energy Plan Review (Michigan)	Michigan PUC Case # U-17301	Environmental Law and Policy Center
Sep. 27, 2013	North Carolina Utilities Commission 2012 Avoided Cost Case	North Carolina Utilities Commission Docket # E-100, Sub. 136	North Carolina Sustainable Energy Association
Oct. 18, 2013	Georgia Power Company 2013 Rate Case	Georgia PSC Docket # 36989	Georgia Solar Energy Industries Association
Nov. 4, 2013	PEPCO Rate Case (District of Columbia)	District of Columbia PSC Formal Case # 1103	Grid 2.0 Working Group & Sierra Club of Washington, D.C.
Apr. 24, 2014	Dominion Virginia Electric Power 2013 IRP	Virginia SCC Case # PUE-2013-00088	Environmental Respondents
May 7, 2014	Arizona Corporation Commission Investigation on the Value and Cost of Distributed Generation	Arizona Corporation Commission Docket # E-00000J-14-0023	Rábago Energy LLC (invited presentation and workshop participation)
Jul. 10, 2014	North Carolina Utilities Commission 2014 Avoided Cost Case	North Carolina Utilities Commission Docket # E-100, Sub. 140	Southern Alliance for Clean Energy
Jul. 23, 2014	Florida Energy Efficiency and Conservation Act, Goal Setting – FPL, Duke, TECO, Gulf	Florida PSC Docket # 130199-EI, 130200-EI, 130201-EI, 130202-EI	Southern Alliance for Clean Energy
Sep. 19, 2014	Ameren Missouri's Application for Authorization to Suspend Payment of Solar Rebates	Missouri PSC File No. ET-2014-0350, Tariff # YE-2014-0494	Missouri Solar Energy Industries Association
Aug. 6, 2014	Appalachian Power Company 2014 Biennial Rate Review	Virginia SCC Case # PUE-2014-00026	Southern Environmental Law Center (Environmental Respondents)

Aug. 13, 2014	Wisconsin Public Service Corp. 2014 Rate Application	Wisconsin PSC Docket # 6690-UR-123	RENEW Wisconsin and Environmental Law & Policy Center
Aug. 28, 2014	WE Energies 2014 Rate Application	Wisconsin PSC Docket # 05-UR-107	RENEW Wisconsin and Environmental Law & Policy Center
Sep. 18, 2014	Madison Gas & Electric Company 2014 Rate Application	Wisconsin PSC Docket # 3720-UR-120	RENEW Wisconsin and Environmental Law & Policy Center
Sep. 29, 2014	SOLAR, LLC v. Missouri Public Service Commission	Missouri District Court Case # 14AC-CC00316	SOLAR, LLC
Jan. 28, 2016 (date of CPUC order)	Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs, etc.	California PUC Rulemaking 14-07-002	The Utility Reform Network (TURN)
Mar. 20, 2015	Orange and Rockland Utilities 2015 Rate Application	New York PSC Case # 14-E-0493	Pace Energy and Climate Center
May 22, 2015	DTE Electric Company Rate Application	Michigan PSC Case # U-17767	Michigan Environmental Council, NRDC, Sierra Club, and ELPC
Jul. 20, 2015	Hawaiian Electric Company and NextEra Application for Change of Control	Hawai'i PUC Docket # 2015-0022	Hawai'i Department of Business, Economic Development, and Tourism
Sep. 2, 2015	Wisc. PSCo Rate Application	Wisconsin PSC Case # 6690-UR-124	ELPC
Sep. 15, 2015	Dominion Virginia Electric Power 2015 IRP	VA SCC Case # PUE-2015-00035	Environmental Respondents
Sep. 16, 2015	NYSEG & RGE Rate Cases	New York PSC Cases 15-E-0283, -0285	Pace Energy and Climate Center
Oct. 14, 2015	Florida Power & Light Application for CCPN for Lake Okeechobee Plant	Florida PSC Case 150196-EI	Environmental Confederation of Southwest Florida
Oct. 27, 2015	Appalachian Power Company 2015 IRP	VA SCC Case # PUE-2015-00036	Environmental Respondents
Nov. 23, 2015	Narragansett Electric Power/National Grid Rate Design Application	Rhode Island PUC Docket No. 4568	Wind Energy Development, LLC
Dec. 8, 2015	State of West Virginia, et al., v. U.S. EPA, et al.	U.S. Court of Appeals for the District of Columbia Circuit Case No. 15-1363 and Consolidated Cases	Declaration in Support of Environmental and Public Health Intervenors in Support of Movant Respondent-Intervenors' Responses in Opposition to Motions for Stay

Dec. 28, 2015	Ohio Power/AEP Affiliate PPA Application	PUC of Ohio Case No. 14-1693-EL-RDR	Environmental Law and Policy Center
Jan. 19, 2016	Ohio Edison Company, Cleveland Electric Illuminating Company, and Toledo Edison Company Application for Electric Security Plan (FirstEnergy Affiliate PPA)	PUC of Ohio Case No. 14-1297-EL-SSO	Environmental Law and Policy Center
Jan. 22, 2016	Northern Indiana Public Service Company (NIPSCO) Rate Case	Indiana Utility Regulatory Commission Cause No. 44688	Citizens Action Coalition and Environmental Law and Policy Center
Mar. 18, 2016	Northern Indiana Public Service Company (NIPSCO) Rate Case – Settlement Testimony	Indiana Utility Regulatory Commission Cause No. 44688	Joint Intervenors - Citizens Action Coalition and Environmental Law and Policy Center
Mar. 18, 2016	Comments on Pilot Rate Proposals by MidAmerican and Alliant	Iowa Utility Board NOI-2014-0001	Environmental Law and Policy Center
May 27, 2016	Consolidated Edison of New York Rate Case	New York PSC Case No. 16-E-0060	Pace Energy and Climate Center
June 21, 2016	Federal Trade Commission: Workshop on Competition and Consumer Protection Issues in Solar Energy	Invited workshop presentation	Pace Energy and Climate Center
Aug. 17, 2016	Dominion Virginia Electric Power 2016 IRP	VA SCC Case # PUE-2016-00049	Environmental Respondents
Sep. 13, 2016	Appalachian Power Company 2016 IRP	VA SCC Case # PUE-2016-00050	Environmental Respondents
Oct. 27, 2016	Consumers Energy PURPA Compliance Filing	Michigan PSC Case No. U-18090	Environmental Law & Policy Center, "Joint Intervenors"
Oct. 28, 2016	Delmarva, PEPCO (PHI) Utility Transformation Filing – Review of Filing & Utilities of the Future Whitepaper	Maryland PSC Case PC 44	Public Interest Advocates
Dec. 1, 2016	DTE Electric Company PURPA Compliance Filing	Michigan PSC Case No. U-18091	Environmental Law & Policy Center, "Joint Intervenors"
Dec. 16, 2016	Rebuttal of Unitil Testimony in Net Energy Metering Docket	New Hampshire Docket No. DE 16-576	New Hampshire Sustainable Energy Association ("NHSEA")
Jan. 13, 2017	Gulf Power Company Rate Case	Florida Docket No. 160186-EI	Earthjustice, Southern Alliance for Clean Energy, League of Women Voters-Florida

Table of Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, or through Rábago Energy LLC

(as of 28 July 2017)

Jan. 13, 2017	Alpena Power Company PURPA Compliance Filing	Michigan PSC Case No. U-18089	Environmental Law & Policy Center, "Joint Intervenors"
Jan. 13, 2017	Indiana Michigan Power Company PURPA Compliance Filing	Michigan PSC Case No. U-18092	Environmental Law & Policy Center, "Joint Intervenors"
Jan. 13, 2017	Northern States Power Company PURPA Compliance Filing	Michigan PSC Case No. U-18093	Environmental Law & Policy Center, "Joint Intervenors"
Jan. 13, 2017	Upper Peninsula Power Company PURPA Compliance Filing	Michigan PSC Case No. U-18094	Environmental Law & Policy Center, "Joint Intervenors"
Mar. 10, 2017	Eversource Energy Grid Modernization Plan	Massachusetts DPU Case No. 15-122/15-123	Cape Light Compact
Apr. 27, 2017	Eversource Rate Case & Grid Modernization Investments	Massachusetts DPU Case No. 17-05	Cape Light Compact
May 2, 2017	AEP Ohio Power Electric Security Plan	PUC of Ohio Case No. 16-1852-EL-SSO	Environmental Law & Policy Center
Jun. 2, 2017	Vectren Energy TDSIC Plan	Indiana URC Cause No. 44910	Citizens Action Coalition & Valley Watch
Jul. 28, 2017	Vectren Energy 2016-2017 Energy Efficiency Plan	Indiana URC Cause No. 44645	Citizens Action Coalition
Jul. 28, 2017	Vectren Energy 2018-2020 Energy Efficiency Plan	Indiana URC Cause No. 44927	Citizens Action Coalition
Aug. 11, 2017	Dominion Virginia Electric Power 2017 IRP	VA SCC Case # PUR-2017-00051	Environmental Respondents
Aug. 18, 2017	Appalachian Power Company 2017 IRP	VA SCC Case # PUR-2017-00045	Environmental Respondents

Testimony of Karl R. Rábago

Exhibit KRR-3

Response to Pace-1 AD-2

Date of Request: July 19, 2017 | Request No. PACE-1 AD-2
Due Date: July 31, 2017 | NMPC Req. No. NM-1211

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: PACE Energy and Climate Center, Alok Disa

TO: National Grid, Electric Rate Design Panel

SUBJECT: **ELECTRIC RATE DESIGN PANEL**

Request:

1. Reference Exhibit_(E-RDP-3) Schedule 9C.
   a. Please provide Exhibit_(E-RDP-3) Schedule 9C, or the "Zero Load Study," in full and in excel format with formulas and links intact.
   b. What is a zero load study? Please provide copies of or links to all authorities relied on to answer this question. If one or more of the authorities are books, please provide the citations.
   c. How is a zero load study different from the zero intercept approach?
   d. How is a zero load study different from the minimum system method or minimum size approach?
   e. Is allocation between customer and demand inherent in a zero load study?
   f. Is allocation between "Labor" and "Materials and Other" inherent in a zero load study?
   g. What is the date of NMPC's Zero Load Study in Exhibit_(E-RDP-3)?
   h. When was this study commissioned?
   i. Who performed the study? If performance of the study was by contract, please provide the name of the firm and relevant contacts within the firm.
   j. How was this study used for NMPC's current electric rate proposal?
   k. Has NMPC used the Zero Load Study in Schedule 9C in other proposed rate plans filed either at the New York Public Service Commission (NYPSC) or other public service commissions? Please provide the docket numbers of those cases and explain how the study was used in each of those cases.
   l. How does this zero load study support NMPC's proposed cost allocation of the Wires Accounts?
   m. Has NMPC performed special zero load studies for previous rate plans in New York State? Please provide the docket number(s) where such plans were filed.

2. Reference p. 21, lines 1–21 of the Electric Rate Design Panel testimony in which the Electric Rate Design Panel describes the process for determining the portions of the Wires Accounts that are classified as customer-related versus demand-related.

   a. Is the Company proposing changes to how the Wires Accounts have been assigned in the past (demand vs. customer)?

   b. Reference the May 19, 2017 technical presentation at 34, which states that this "classification is the same as prior cases." Please specify the prior case(s) where the Company has identified the capital costs of or investments in labor of Overhead Assets and Underground Assets accounts as customer-related. Please provide the accompanying NYPSC order that approved, denied, or otherwise does not include such classifications.

   c. Is this the first time NMPC has included in its rate plan a proposal to classify the labor portion of the capital cost of Overhead Assets and Underground Assets as customer-related? If not, please identify prior dockets where such proposals were filed with the Commission and identify prior NYPSC orders from approving NMPC's classification of the labor portions of the Wires Accounts as customer-related.

   d. Please identify prior orders of the NYPSC that, if applicable, approved NMPC's classification of capital labor investments from Wires Accounts as customer-related based on a "zero load study." If there are such orders, provide copies of the zero load studies NMPC performed in those dockets.

3. Page 21, lines 10–14 states "[t]he labor-only portion of these costs has zero load carrying capacity, is largely independent of the capacity installed, varies with the length of the distribution system installed and is incurred primarily to connect customers to the system; therefor this portion of cost was classified as customer-related."

   a. Please provide copies of or links to all authorities relied on to reach this conclusion apart from Exhibit__ (E-RDP-3) Schedule 9C.

4. Reference p. 59, lines 1–10 of the Electric –Rate Design Panel testimony.

   a. Are disconnection charges the same for all rate classes and all customers?

   b. Are there special, lower disconnection charges for low-income customers?

<u>Response</u>:

1.

   a. A working copy of the "Zero Load Study" is provided as Attachment 1.

   b. The end result of a Zero Load Study is the same as the end result of a zero intercept study - to estimate the cost of a distribution system that has zero-load carrying capability, and to compare this to the actual cost of the distribution system. In a Zero Load Study, this cost is estimated to be equal to labor-only costs, because without materials there is no load-carrying capacity. In a zero-intercept study, this cost is estimated by statistically regressing the costs for different load capacities to determine the cost at the zero-intercept. Zero intercept (or Minimum intercept) studies are discussed in the National

Association of Regulatory Utility Commission ("NARUC") *Electric Utility Cost Allocation Manual*, January 1992 ("NARUC Manual"), pp. 92-96. Zero intercept studies are also discussed in *Principles of Public Utility Rates*, Professor Bonbright et al, p. 491.

c. See the response to b. above.

d. The end result of a Zero Load Study is discussed in the response to b. above. The end result of a minimum system study is to estimate the cost of a hypothetical minimum system, and to compare this to the actual cost of the distribution system. The term "minimum system" can be applied in several ways, as discussed in the NARUC Manual, p. 95. However, the minimum system has some load carrying capacity, and in using the results of the minimum system study for cost allocation, the demand allocators should be adjusted to reflect this capacity. No such adjustment is required for a Zero Load Study.

e. The purpose of the Zero Load Study is to estimate the customer / demand split for the assets in the study.

f. In a Zero Load Study, the cost of a distribution system that has zero-load carrying capability is estimated to be equal to labor-only costs, because without materials there is no load-carrying capacity.

g. The study was performed in 2017, using data from 2008-2015.

h. The study was initiated in 2017 in preparation for the Company's rate filing.

i. The study was performed by the Electric Rate Design Panel whose qualifications are included in the testimony.

j. The results of the study were used to determine the customer / demand classification split for certain distribution assets. The demand-related portions were allocated among the rate classes using demand allocators; the customer-related portions were allocated based on number of customers.

k. NMPC used a Zero Load Study to determine the customer / demand classification split for certain distribution assets in Case 10-E-0050 before the NYPSC.

l. See response to j. above.

m. See response to k. above.

2.

a. No.

b. See response to 1k. above.

c. No. See response to 1k. above.

d. See response to 1k. above. The Zero Load Study performed for Case 10-E-0050 is provided as Attachment 2.

3.

a. The NARUC Manual, p. 95, states “the customer cost derived from the minimum-intercept method is based on the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.”

4.

a. Disconnection fees are the same for all rate classes and customers.

b. Customers are not charged a disconnection fee when the Company disconnects the customer for non-payment. The Company will waive the re-establishment fee for customers who receive a HEAP grant and have had their service disconnected for non-payment.

Name of Respondent:	Date of Reply:
Howard Gorman Carol Teixeira	July 27, 2017

Classify
E-RDP-2 (S), Sch. 4

Niagara Mohawk Power Corporation d/b/a National Grid
Class Cost of Service Study ($000s)- Rate Year Ended December 31, 2014

Classification of Secondary Distribution Function

Line			Labor	Non-Labor	Total	Customer Labor %	Demand Non-Labor %
1	Total 2008-2011						
2	364_365	Overhead	177,592,308	100,999,204	278,591,512	**63.75%**	**36.25%**
3	366_367	Underground	50,575,474	42,480,039	93,055,513	**54.35%**	**45.65%**
4			228,167,781	143,479,243	371,647,024	**61.39%**	**38.61%**
5			*228,167,781*	*143,479,243*			
6							
7	Summary 2008-2011		Labor	Non-Labor	Total	Labor %	Non-Labor %
8		364 Poles, Towers and Fixtures	85,277,429	41,615,227	126,892,657	67.20%	32.80%
9		365 Overhead Conductors & D	92,314,878	59,383,977	151,698,855	60.85%	39.15%
10		366 Underground Conduit	7,920,800	5,115,588	13,036,388	60.76%	39.24%
11		367 Underground Cond & Dev	42,654,674	37,364,451	80,019,125	53.31%	46.69%
12	Total		228,167,781	143,479,243	371,647,024	61.39%	38.61%
13							
14	Summary 2011		Labor	Non-Labor	Total	Labor %	Non-Labor %
15		364 Poles, Towers and Fixtures	18,902,137	8,730,232	27,632,369	68.41%	31.59%
16		365 Overhead Conductors & D	21,724,980	11,469,865	33,194,845	65.45%	34.55%
17		366 Underground Conduit	2,280,443	1,323,355	3,603,798	63.28%	36.72%
18		367 Underground Cond & Dev	12,505,758	10,401,917	22,907,675	54.59%	45.41%
19	Total		55,413,318	31,925,369	87,338,688	63.45%	36.55%
20							
21	Summary 2010		Labor	Non-Labor	Total	Labor %	Non-Labor %
22		364 Poles, Towers and Fixtures	26,918,289	12,250,563	39,168,853	68.72%	31.28%
23		365 Overhead Conductors & D	24,276,882	14,165,229	38,442,111	63.15%	36.85%
24		366 Underground Conduit	2,609,565	1,473,337	4,082,901	63.91%	36.09%
25		367 Underground Cond & Dev	9,927,278	7,609,341	17,536,618	56.61%	43.39%
26	Total		63,732,014	35,498,470	99,230,483	64.23%	35.77%
27							
28	Summary 2009		Labor	Non-Labor	Total	Labor %	Non-Labor %
29		364 Poles, Towers and Fixtures	24,999,619	11,488,390	36,488,008	68.51%	31.49%
30		365 Overhead Conductors & D	24,607,153	16,017,336	40,624,489	60.57%	39.43%
31		366 Underground Conduit	724,316	511,972	1,236,289	58.59%	41.41%
32		367 Underground Cond & Dev	10,199,132	8,155,458	18,354,590	55.57%	44.43%
33	Total		60,530,221	36,173,156	96,703,377	62.59%	37.41%
34							
35	Summary 2008		Labor	Non-Labor	Total	Labor %	Non-Labor %
36		364 Poles, Towers and Fixtures	14,457,384	9,146,042	23,603,426	61.25%	38.75%
37		365 Overhead Conductors & D	21,705,863	17,731,547	39,437,409	55.04%	44.96%
38		366 Underground Conduit	2,306,476	1,806,924	4,113,400	56.07%	43.93%
39		367 Underground Cond & Dev	10,022,506	11,197,735	21,220,241	47.23%	52.77%
40	Total		48,492,229	39,882,248	88,374,477	54.87%	45.13%

Testimony of Karl R. Rábago

Exhibit KRR-4

Response to Pace-5 AD-1

Date of Request: July 26, 2017 | Request No. PACE-5 AD-1
Due Date: August 7, 2017 | NMPC Req. No. NM-1338

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: PACE Energy and Climate Center, Alok Disa

TO: National Grid, Outdoor Lighting Panel

SUBJECT: **TESTIMONY OF OUTDOOR LIGHTING PANEL**

Request:

1. Reference p. 11, line 18 through p. 15, line 12 of the Outdoor Lighting Panel's testimony.

a. Can a customer convert more than 20 percent of the existing outdoor luminaires from HID technology to LED technology within a given year?

b. Once a municipality has opted out from having LED replacements for failed HID luminaire facilities, may they opt back in at a later date?

Response:

1.a Yes. Under the Company's P.S.C. No. 214 – Outdoor Lighting Tariff ("Tariff"), Leaf 47, and consistent with the New York Public Service Commission's "Order Adopting the Addition of LED Street Lighting Options" in Case 15-E-0645 issued on May 23, 2016 ("LED Conversion Order"), municipal customers "must commit to a conversion of no less than 15% of their currently installed Company Owned Roadway luminaires, or a minimum of 100 of their currently installed Company Owned Roadway luminaires, whichever is greater, per bill account in an annual period." As provided in the Tariff and on page 2 of the LED Conversion Order, the Company's annual conversion rate across all roadway luminaires in its service territory is capped at "20% of the total in-service cobra head roadway luminaires, or 39,107 fixtures per year, if requested by customers."

1.b Yes, a customer may change its opt-out designation, allowing the replacement of failed HID luminaires with LEDs. However, the Company does not allow the customer to change its decision more than once regarding this program, as the administration and field operations will become difficult to manage and maintain accurate records.

Name of Respondent:	Date of Reply:
John Walter	August 6, 2017

Testimony of Karl R. Rábago

Exhibit KRR-5

Response to Pace-5 AD-3

Date of Request: July 26, 2017 | Request No. PACE-5 AD-3
Due Date: August 7, 2017 | NMPC Req. No. NM-1340

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: PACE Energy and Climate Center, Alok Disa

TO: National Grid, Outdoor Lighting Panel

SUBJECT: **TESTIMONY OF OUTDOOR LIGHTING PANEL**

Request:

3. Reference p. 20, line 1 through line 23 of the Outdoor Lighting Panel's testimony.

a. If the estimated cost of annual LED conversions accounts for converting only approximately 10 percent of HID luminaires in the Rate Year, as the capital plan proposes, what is the Company's plan in the event that demand for conversions exceeds 10 percent?

b. How did the Company estimate the LED conversion cost of $6.97 million for the capital investment, plus $0.775 million for cost of removal?

Response:

a. As discussed in the Outdoor Lighting Panel's direct testimony on pages 21 and 22, the Company is proposing a two-way LED capital investment tracker to enable the Company to convert up to 20 percent per year of its installed roadway luminaires to LED luminaires. The Company's proposed rates are based on the 10 percent conversion level, with a two-way tracker to defer costs incurred either in excess of, or below, the amount reflected in rates. The tracker will include a return on investment and associated depreciation as reflected in Exhibit___(RRP-9), Schedule 2.

b. The Company developed its estimate for LED conversion costs assuming a five-year (20 percent annual) LED conversion program using the number of roadway fixtures across the Company's service territory, the estimated cost of the LED replacements, the estimated labor hours necessary to perform the LED conversion work, as well as design, project management, and field supervision work. The Company then divided this number in half to reflect the 10 percent of LED conversions assumed in the Company's capital investment plan.

Name of Respondent:
John Walter

Date of Reply:
August 6, 2017

Testimony of Karl R. Rábago

Exhibit KRR-6

Response to Pace-5 AD-2

Date of Request: July 26, 2017 Request No. PACE-5 AD-2
Due Date: August 7, 2017 NMPC Req. No. NM-1339

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: PACE Energy and Climate Center, Alok Disa

TO: National Grid, Outdoor Lighting Panel

SUBJECT: **TESTIMONY OF OUTDOOR LIGHTING PANEL**

Request:

2. Reference p. 17, line 11 through p. 19, line 22 of the Outdoor Lighting Panel's testimony.

a. What effect does reducing the depreciable life of the existing HID luminaires have on the required payment for the undepreciated investment of the existing luminaire assets to be removed?

b. Does this proposed reduction apply to all HID luminaires in the service territory, including those in the pilot projects, or just to the luminaires as part of the Lighting Tariff?

Response:

2.a As discussed in the Outdoor Lighting Panel's direct testimony on page 19, by segregating the street light accounts between luminaires and all other equipment, and using a 20-year life for luminaires versus 50-year life for the other equipment, a larger percentage of the existing book depreciation reserve will be allocated to luminaires. This proposal will reduce the net book value (*i.e.*, undepreciated investment) of the existing luminaires. Additionally, the shorter proposed service life for luminaires will accelerate the reduction of the net book value. As a result, the reduction in the depreciable life of existing HID luminaires will promote a reduction in the net book value of the luminaires that is to be recovered from the customer as part of the LED conversion program.

2.b If approved by the Commission, the proposed change to the average service life would impact all HID luminaires in the Company's service territory. With regard to the pilot projects (*i.e.*, Colonie and Schenectady), which are both in progress, the depreciable life proposal would not apply to either project.

Name of Respondent: John Walter

Date of Reply: August 6, 2017

Testimony of Karl R. Rábago

Exhibit KRR-7

Response to Pace-15 CO-1

Date of Request: August 15, 2017 Request No. PACE-15 CO-1
Due Date: August 25, 2017 NMPC Req. No. NM-1634

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: PACE Energy and Climate Center, Chinyere Osuala

TO: National Grid, Gas Customer Panel

SUBJECT: **GAS CUSTOMER PANEL**

Request:

1. Reference pp. 19-21 of the Gas Customer Panel referring to the Oil-to-Gas conversion rebate program.

a. Are customers affected by NMPC's planned gas expansion included in the Oil-to-Gas conversion rebate program?

b. Has the company done a benefit cost analysis ("BCA") for all customers converting from oil to gas service? If so, please provide the analysis in executable excel format with all formulas and substitutions in tact.

c. If NMPC has not done a BCA for the conversion from oil to gas service, has NMPC done any other analysis of the environmental or economic impacts of conversion from oil to gas service? If so, please provide a copy of the analysis, in executable excel format with all formulas and substitutions in tact if possible.

d. Has NMPC done a BCA for all customers in its service territory converting from propane to gas? If so, please provide the analysis in executable excel format with all formulas and substitutions in tact.

e. If NMPC has not done a BCA for the conversion from propane to gas service, has NMPC done any other analysis of the environmental or economic impacts of conversion from oil to gas service? If so, please provide a copy of the analysis, in executable excel format with all formulas and substitutions in tact if possible.

Response:

1.

a. Customers benefit from gas expansion in many ways. Expansion spreads the fixed costs over additional customers thereby reducing the per customer costs. As shown in Attachment 1, customers that convert to natural gas see commodity costs savings and the State as a whole benefits from the environment benefits of natural gas over fuel oil.

b. The Company has not performed a benefit costs analysis for all customers converting from oil to gas service.

c. See Attachment 1 for an analysis that was done for residential customers who convert from fuel oil to natural gas. The analysis does not include new construction or commercial conversions.

d. The Company has not performed a benefit costs analysis for all customers converting from propane to gas service.

e. Please see the response to part c of this question.

Name of Respondent:	Date of Reply:
Glynn Matthews	August 23, 2017

Testimony of Karl R. Rábago

Exhibit KRR-8

Response to DPS-21 MZS-2

Date of Request: May 8, 2017 Request No. DPS-021 MZS-2
Due Date: May 18, 2017 NMPC Req. No. NM-408

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: DPS Staff, Mary Ann Sorrentino

TO: National Grid, Electric Customer Panel

SUBJECT: ***ELECTRIC HEAT INITIATIVE***

Request:

With reference to the Panel's Pre-Filed Direct Testimony and the accompanying Exhibit ECP-1, Schedule 7, Page 1 of 1, provide the workpapers used to develop the increased utility revenue and program administration costs contained in the bottom two charts shown on the referenced document. Any Excel file(s) provided in response to this request should have all formulas unlocked and functions enabled.

Response:

Please see Attachment 1 for the Electric Heat BCA work book and refer to the "Costs" tab for the calculations for increased utility revenue and program administration costs.

Name of Respondent:
Mackay Miller
Courtney Eichhorst

Date of Reply:
May 16, 2017