BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

Orange and Rockland Utilities, Inc.

Cases 21-G-0073 and 21-E-0074

May 2021

Prepared Testimony of:
Staff Clean Energy Panel

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Q. Would the members of the Staff Clean Energy Panel, referred to as the Panel, please state your names, employer, and business addresses?

A. Our names are Joel Andruski, Tristan Lowery, Kathryn Mammen, Randy Monica, Jr, and Michael O'Donnell. We are employed by the Department of Public Service, referred to as the Department. Our business address is Three Empire State Plaza, Albany, New York 12223.

Q. Mr. Andruski, what is your position at the Department?

A. I am an Associate Economist in the Office of Market and Regulatory Economics, referred to as OMI.

Q. Please briefly state your educational background and professional experience.

A. I received a Bachelor of Arts Degree in Economics, with honors, and a Bachelor of Arts Degree in Environmental Studies from Hobart College in 2011. From 2010 to 2012, I worked as an energy modeling consultant to Sandia National Laboratories and the National Energy Technology Laboratory. From 2012 to 2014, I worked as an associate energy analyst for Unitil Service

Corporation, an investor-owned electric and gas utility. From 2014 to the present, I have been employed by the Department. In addition to preparing testimony in rate proceedings, my primary assignments at the Department include working on several Reforming the Energy Vision-related issues, including Non-Wires Alternatives, referred to as NWA, and Non-Pipes Alternatives, referred to as NPA, issues related to advancing the goals of the Climate Leadership and Community Protection Act, referred to as the CLCPA, and avoided distribution system cost analysis as part of Case 19-E-0283, the Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies . I have also participated in several retail access proceedings ranging from low-income to energy service company issues.

Q. Have you previously testified before the New York State Public Service Commission, referred to as the Commission?

A. Yes, I testified on management compensation issues in Cases 14-E-0318 and 14-G-0319, Central Hudson Gas & Electric Corporation, referred to as Central Hudson; on marginal cost of service in Cases 16-E-0060 and 16-G-0061, Consolidated Edison Company of New York, Inc., referred to as Con Edison, Case 14-E-0493, Orange and Rockland Utilities, Inc., referred to as O&R or the Company, Cases 17-E-0238, 17-G-0239, 18-E-0067, and 18-G-0068, Niagara Mohawk Power Corporation, d/b/a National Grid, referred to as National Grid, in Cases 15-E-0283, 15-G-0284, 15-E-0285, and 15-G-0286, New York State Electric & Gas Corporation, referred to as NYSEG, and Rochester Gas and Electric Corporation, referred to as RG&E, and Cases 17-E-0459 and 17-E-0460, Central Hudson; on Reforming the Energy Vision issues in Cases 14-E-0493 and 14-G-0494, O&R, and Cases 15-E-0283, 15-G-0284, 15-E-0285, and 15-G-0286, NYSEG and RG&E; and on the competitiveness of retail access markets in Cases 15-M-0127, 12-M-0476 and 98-M-1343.

Q. Mr. Lowery, please state your position at the Department.

A. I am a Utility Analyst 1 assigned to the Distributed Generation and Demand Response section of OMI.

Q. Please describe your academic credentials.

A. I earned a Bachelor of Arts in Media Studies from Queens College, City University of New York in 2002 and a Master of Regional Planning with a specialization in environmental and land-use planning from the State University of New York at Albany in 2015.

Q. Please describe your professional experience and your duties at the Department.

A. I joined the Department in 2017 as a Utility Analyst Trainee 2. My previous experience in New York State government includes a position with the New York State Department of Transportation Highway Data Services Bureau and a graduate internship in regional planning with the Hudson River Valley Greenway. My principal areas of responsibility since joining OMI include analysis of utility-administered energy efficiency, referred to as EE, demand response, and other energy conservation programs.

Q. Have you previously testified before the Commission?

A. Yes. I testified in Cases 17-E-0459 and 17-G-0460, Central Hudson, as part of the Staff

Incentives and Customer Engagement Panel and the Staff Markets and Innovation Energy Efficiency Panel; in Cases 19-E-0378, 19-G-0379, 19-E-0380, and 19-G-0381, NYSEG and RG&E, as part of the Staff Efficiency and Distributed Energy Resources Panel; and in Cases 20-E-0428 and 20-G-0429, Central Hudson, as part of the Staff Clean Energy and Earnings Adjustment Mechanism Panel. I testified as part of the Staff Conservation and Efficiency Panel in Case 19-W-0168, SUEZ Water New York, SUEZ Westchester, and SUEZ Owego-Nichols Forest Park.

Q. Ms. Mammen, what is your position at the Department?

A. I am a Utility Supervisor in the Clean Energy Section of OMI.

Q. Please describe your educational background.

A. I received a Bachelor of Arts Degree in sociology from Fordham University in 2006. I also received a Master of Public Administration from Rockefeller College of Public Affairs & Policy at the University at Albany, State University of New York in 2010.

Q. Please describe your professional experience and responsibilities at the Department.

A. I joined the Department in 2009, first as an intern for the Secretary to the Commission, and later as a Utility Analyst in the Office of Energy Efficiency and the Environment where I was responsible for overseeing the implementation and evaluation of EE programs offered under the Energy Efficiency Portfolio Standard, referred to as EEPS. Currently, my relevant responsibilities include reviewing and monitoring utility EE programs and developing policy recommendations for Commission consideration related to EE and other clean energy activities.

Q. Have you previously testified before the Commission?

A. Yes. I testified in Cases 19-E-0378, 19-G-0379, 19-E-0380 and 19-G-0381, NYSEG and RG&E; Cases 19-E-0065 and 19-G-0066, Con Edison; Cases 15-G-0058 and 15-G-0059, KeySpan Gas East Corp. d/b/a National Grid and The Brooklyn Union Gas Company d/b/a National Grid NY on EE issues. I also testified in Case 16-W-0130, Suez Water New York Inc., on the issue of the water conservation program.

Q. Mr. Monica, what is your position at the Department?

A. I am a Utility Analyst Trainee 2 in the Clean Energy and Markets section of OMI.

Q. Please describe your educational experience and professional background.

A. I received a Bachelor of Arts in Environmental Studies with minors in Environmental Science and Political Science from the State University of New York College at Potsdam in May 2019. I began my career at the Department in December 2019 as a Utility Analyst Trainee 1.

Q. Please briefly describe your responsibilities at the Department.

A. My responsibilities include participating in stakeholder meetings at the New York Independent System Operator, advising on issues within the wholesale market, and helping coordinate the Department's responses to wholesale market rule changes and complaints to the Federal Energy Regulatory Commission.

Q. Have you previously testified in a proceeding before the Commission?

A. No, I have not.

Q. Mr. O’Donnell, what is your position at the Department?

A. I am employed as a Utility Analyst Trainee 2 assigned to the Efficiency & Innovation section in OMI.

Q. Please describe your educational experience and professional background.

A. I received a Bachelor of Arts degree in International Relations from SUNY Geneseo in 2019.

Q. Please describe your professional experience and responsibilities with the Department.

A. I began employment with the Department in January 2020. Prior to joining the Department, I worked at the Department of Environmental Conservation analyzing efficiency of e-waste recycling programs and auditing e-waste databases. Currently, my responsibilities include continuous evaluation and management of the Community Choice Aggregation program and its functions, as well as the development of policy related to data use and distribution.

Q. Have you previously testified in a proceeding before the Commission?

A. No, I have not previously testified in a proceeding before the Commission.

Q. Panel, what is the purpose of your testimony in these proceedings?

A. The Panel will address a number of O&R's proposals discussed in the initial testimony of the Customer Service Panel, and offer recommendations regarding proposals related to the Company's electric and gas EE portfolios, including O&R's proposals to amortize EE expenses over 10 years. The Panel will also discuss the NWA proposals as presented in the Company's Electric Infrastructure and Operations Panel, referred to as the EIOP. Lastly, the Panel will discuss the NPA incentive cost recovery mechanism as presented in the Company's Gas Rate Panel and Accounting Panel.

Q. What is the Rate Year in these proceedings?

A. The Rate Year is the 12-month period ending December 31, 2022. The Company has referred to Calendar Years 2023 and 2024, the two years following the Rate Year, as Rate Year 2 and Rate Year 3, respectively. For ease of reference, the Panel will use the same references as O&R in its initial testimony.

Q. Has the Panel referred to, or otherwise relied upon, any information obtained during the discovery phase of these proceedings?

A. Yes, we have referred to and relied upon several responses to Information Requests, referred to as IRs, provided by O&R. These responses are contained within Exhibit__(SCEP-1).

Q. Is the Panel sponsoring any other exhibits?

A. Yes, we are sponsoring 2 other exhibits.

Q. Please briefly describe these exhibits.

A. Exhibit__(SCEP-2) provides the Panel's proposed allocation of unspent EE funds.

Exhibit__(SCEP-3) demonstrates the math error found in the Company's testimony on EE amortization.

ENERGY EFFICIENCY PROGRAMS

Energy Efficiency Portfolio Background

Q. Please describe the Company's EE portfolio.

A. The Company has been offering EE programs to its customers since 2008 when EEPS was initiated in Case 07-M-0548, Proceeding on Motion of the Commission Regarding an Energy Efficiency

Portfolio Standard, the EEPS Proceeding. Initially, the Company’s EE portfolio included electric and natural gas efficiency programs in the residential and commercial and industrial sectors.

Q. Provide a brief background of the events that occurred after EEPS was initiated that led to the Company’s current EE programs.

A. Through a series of Orders issued in the EEPS Proceeding, Case 09-G-0363, EEPS Gas Energy Efficiency Programs Proceeding, Case 14-M-0101, the Reforming the Energy Vision Proceeding, and Case 15-M-0252, Utility Energy Efficiency Programs Proceeding, the Commission progressed from approving budgets and targets for the Company’s gas and electric EE programs on a per-program basis to approving an EE portfolio. The EE portfolio provides for a greater degree of flexibility in designing and implementing the Company’s respective electric and gas EE programs to meet portfolio-level megawatt hour, or MWh, and million British Thermal Units, or MMBtu, savings targets within Commission-authorized portfolio-level budgets.

Q. What was the funding mechanism for the portfolio-level budgets?

A. From the start of EEPS in 2008 until the beginning of the Company’s current rate plan beginning on January 1, 2019, the Company collected costs through the System Benefits Charge, or SBC, which was a separate surcharge on customers’ bills. The SBC consisted of two components: (1) the Clean Energy Fund, or CEF, Surcharge, which was designed to collect the Company’s proportional shares of the statewide New York State Energy Research and Development Authority, referred to as NYSERDA, electric and gas EE and clean energy programs; and (2) the EE Tracker surcharge, which was designed to collect the authorized funding for the Company’s electric and gas Energy Efficiency Transition Implementation Plan, or ETIP, programs.

Q. How does the Company currently collect the funds for its gas and electric EE programs?

A. Pursuant to the March 14, 2019 Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans in Cases 18-E-0067 and 18-G-0068, referred to as the 2019 Rate

Order, the Company began collecting the electric and gas EE program budgets through base rates like other components of the revenue requirement.

Q. What is the amount collected in rates for the Company's electric and gas EE portfolio?

A. The annual amount currently collected through rates is approximately $9.9 million for the electric EE portfolio and approximately $0.703 million for the gas EE portfolio.

Q. Did any other Commission actions outside the rate case proceedings occur that affected the Company's EE portfolios?

A. Yes, additional Commission action was taken in Case 18-M-0084, the Utility Energy Efficiency Proceeding, which increased the Company's EE portfolio targets and budgets for the 2021-2025 period.

Q. Please describe the Commission's additional actions in the Utility Energy Efficiency Proceeding that affected the Company's electric and gas EE portfolios.

A. On January 16, 2020, the Commission issued its Order Authorizing Utility Energy Efficiency and

Building Electrification Portfolios Through 2025 in Case 18-M-0084, referred to as the January 2020 Efficiency Order, which increased the Company's electric and gas targets and budgets for the 2021-2025 period; established electric and gas targets and budgets specific to the Company's EE program activity within its low to moderate income, referred to as LMI, market segment for the same period; established building electrification targets and budgets, also known as heat pump program targets and budgets, for the same period; directed the Company to reflect these targets and budgets in an updated System Energy Efficiency Plan, or SEEP; and directed the Company and the other large investor-owned utilities and NYSERDA to jointly file a single Statewide LMI Portfolio Implementation Plan and a Statewide Heat Pump Program Implementation Plan.

Q. What is the SEEP?

A. The SEEP describes the entirety of the utility's expanded reliance on, and use of, cost-effective EE to support its distribution system and customer needs.

Q. Was the Statewide Heat Pump Program Implementation Plan filed by the Company and the other large investor-owned utilities and NYSERDA?

A. Yes, the Clean Heat: Statewide Heat Pump Program Implementation Plan was filed jointly in Case 18-M-0084 on March 16, 2020, and most recently updated in a June 1, 2020 filing.

Q. Was the Statewide LMI Portfolio Implementation Plan filed by the Company, the other large investor-owned utilities, and NYSERDA?

A. Yes, the Statewide LMI Portfolio Implementation Plan was filed jointly on July 24, 2020, in Case 18-M-0084.

Q. Did the Company file its SEEP to reflect the targets and budgets for 2019 through 2025?

A. Yes, the Company filed its SEEP in the Utility Energy Efficiency Proceeding on September 15, 2020, and a revised SEEP on April 1, 2021.

<u>Energy Efficiency Gas and Electric Portfolio</u>

Q. What are the Company's electric EE budgets and targets as authorized in the January 2020 Efficiency Order?

A. The Company's electric EE budgets for calendar years 2021 through 2025 are approximately $11.42 million, $12.18 million, $12.59 million, $12.96 million, and $13.11 million, respectively. The associated EE electric targets for the corresponding years are 60,770 MWh; 64,606 MWh; 66,574 MWh; 68,357 MWh; and 69,005 MWh; respectively.

Q. What are the Company's gas EE budgets and targets as authorized in the January 2020 Efficiency Order?

A. The Company's gas EE budgets for calendar years 2021 through 2025 are approximately $1.91 million, $2.41 million, $3.11 million, $3.85 million, and $4.49 million, respectively. The associated EE gas targets for the corresponding years are 50,484 MMBtu, 61,604 MMBtu; 79,075 MMBtu, 97,514 MMBtu, and 114,075 MMBtu, respectively.

Q. Are these annual electric and gas budgets and targets inclusive of the budgets and targets associated with the Company's EE program activity within its LMI market segment?

A. Yes, these annual electric and gas budgets and targets are inclusive of the LMI budgets and targets.

Q. Are these annual electric budgets and targets inclusive of the budgets and targets associated with the Company’s heat pump program?

A. No, the annual electric budgets and targets are not inclusive of the heat pump program.

Q. At what level did the January 2020 Efficiency Order establish the budgets and targets for the heat pump initiative?

A. The January 2020 Efficiency Order authorized heat pump budgets for Calendar Years 2020 through 2025 of $1.24 million, $1.97 million, $2.40 million, $2.83 million, $3.16 million, and $3.40 million, respectively. The January 2020 Efficiency Order also established targets for that same period of 6,440 MMBtu, 10,421 MMBtu, 13,027 MMBtu, 16,109 MMBtu, 18,912 MMBtu, and 21,748 MMBtu, respectively.

Q. Does the January 2020 Efficiency Order direct the Company to collect the additional EE and heat pump budgets in a specific manner?

A. Yes, on pages 65 and 66 of the January 2020 Efficiency Order, the Commission directed the Company to address the increased incremental costs of the electric and gas EE programs and heat pump initiative in the Company's next rate proceedings and authorized cost recovery through base rates.

Q. Did the January 2020 Efficiency Order direct the Company to manage the cost recovery mechanism in a particular manner prior to its next rate proceedings?

A. Yes, on page 68 of the January 2020 Efficiency Order, the Commission authorized the Company to defer the additional spending up to the incremental budget amount set forth in the Order.

Q. Was the Company expected to use any other sources of funds to offset the incremental budgets authorized in the January 2020 Efficiency Order?

A. Yes, on page 66 of the January 2020 Efficiency Order, the Commission stated its expectation that all available uncommitted and unspent utility EE funds will be used to mitigate the impacts of the portfolio budgets authorized in the Order.

Q. Is the Company proposing any modifications to its electric and gas EE budgets?

A. On page 65 of the Customer Service Panel's initial testimony, the Company proposes to allocate the additional budgets authorized in the January 2020 Efficiency Order for the years 2020 and 2021 to Calendar Years 2022 and 2023. Specifically, the Company is proposing to allocate the total 2020 and 2021 incremental electric and gas EE budgets of $1.36 million for electric and $0.82 million for gas, such that the amount of EE funds to be amortized for the Rate Year consists of the total authorized budget for 2022 plus approximately one half of the incremental authorization for 2020 and 2021, with the other half to be collected in 2023.

Q. Will the Panel address the Company's proposed targets?

A. No, the Staff Earnings Adjustment Mechanism Panel will address the Company's proposed targets in relation to the EE Share-the-Savings earnings adjustment mechanisms.

Q. Does the Panel agree with the Company's proposed modifications to the budgets?

A. Yes, these modifications are consistent with the

Commission's January 2020 Efficiency Order, which allowed the Company to defer the collection of the incremental budget until its next rate filing. However, the Commission also required the use of unspent funds to offset the incremental budgets.

Q. Does the Company have any unspent funds available?

A. Yes. In the first and second supplemental responses to IR DPS-33-582, included in Exhibit__(SCEP-1), the Company outlines its unspent funds from Calendar Years 2016 through 2018. These funds total $7,033,620 for electric and $534,330 for gas. The Company also has $4,351,942 in NYSERDA Bill As You Go interest. In addition to this, the Company has received, or will receive, from NYSERDA a total of $4,450,365 in unspent EEPS gas funds.

Q. How does the Company propose to use these unspent funds?

A. In the supplemental response to IR DPS-33-582, included in Exhibit__(SCEP-1), the Company states that it has not yet proposed a method to use unspent EE funds or NYSERDA Bill As You Go funds.

Q. Does the Panel have a recommendation for how these funds should be used?

A. Yes, as previously stated, the Commission ordered unspent funds be used to offset incremental budgets. As such, we recommend that the Company use $11,385,562 and $2,451,034 of unspent EE funds and Bill As you Go interest for electric and gas, respectively, to reduce the Rate Year unamortized EE deferrals. For gas operations, the use of $2,451,034 of the funds will reduce the deferral balance to $0. The remaining $2,533,661 of gas funds should be set aside for future rate years. The Panel's specific proposal is provided in Exhibit__(SCEP-2).

<u>Customer Engagement Marketplace Platform</u>

Q. Please describe the Customer Engagement Marketplace Platform, or the CEMP?

A. On page 12 of the Customer Service Panel's initial testimony, the Company describes the CEMP, also called My ORU Store, as an online marketplace offering a suite of distributed energy resource, or DER, and EE products, programs, and home services to O&R customers through a user-friendly e-commerce platform. O&R states that the platform helps achieve goals outlined in New Efficiency: New York, referred to as NE:NY, by offering rebates for products that help meet MWh and MMbtu reduction goals.

Q. Is the Company proposing changes to the CEMP?

A. On pages 16 through 17 of the Customer Service Panel's initial testimony, the Company proposes to expand the CEMP marketplace existing platform to target LMI and small to medium business, or SMB, customers.

Q. How will the Company determine if a customer qualifies as LMI?

A. In its response to IR DPS-6-289, included in Exhibit__(SCEP-1), the Company states that the enhancement of the CEMP platform will include eligibility checks and provide added validation fields.

Q. Please describe how the CEMP enhancement will serve LMI customers.

A. On pages 16 and 17 of the Customer Service Panel's initial testimony, the Company states that LMI customers may be underserved by the

Company's current program offering. In the Company's response to IR DPS-6-289, included in Exhibit__(SCEP-1), the Company states that LMI customers will be better served with rebates and products tailored specifically to this sector. With this enhancement, the Company states that it would include low or no cost offerings, such as LED light bulbs, faucet aerators, low flow showerheads, and advanced power strips, to promote EE regardless of whether participants own or rent their home.

Q. Please describe how the CEMP will serve SMB customers.

A. SMB customers will similarly see tailored offerings and rebates, as well as targeted marketing for EE measures based on their individual unique needs.

Q. What are the associated costs for these changes?

A. On pages 18 and 19 of the Customer Service Panel's initial testimony, the Company explained that the costs of these marketplace upgrades for the Rate Year is $200,000. The cost will cover software licensing fees, technical platform changes, data integration, product sourcing, targeted marketing, customer support services, and contract and labor increases.

Q. Is the cost separated out by both the LMI and SMB sectors?

A. Yes. In response to IR DPS-13-387, included in Exhibit__(SCEP-1), the Company stated that the cost for the expansion to target the LMI sector is $45,000 annually with a one-time setup fee of $40,000, and the SMB sector expansion cost is $55,000 annually with a one-time setup fee of $60,000 for the Rate Year.

Q. How does the Company propose to fund the CEMP upgrades?

A. The Company is proposing that the additional funds be added to base rates.

Q. Did the Company explain why it did not include these costs in its already authorized EE portfolio funding?

A. In its response to IR DPS-13-387, included in Exhibit__(SCEP-1), the Company stated that these costs are outside of its current authorized EE portfolio budget because platform upgrades do not reduce MWh. Furthermore, the Company states that, because this software is focused on customer engagement efforts, which are not guaranteed to result in EE savings, the Company is requesting additional funding.

Q. Does the Panel agree with the Company's proposal to add the CEMP expansion costs to base rates?

A. No. The Panel does not support providing additional funding outside of that provided to the Company by the Commission in the January 2020 Efficiency Order. Since the CEMP is used as a tool for the Company's EE programs, the Panel recommends that the Company use the funding already authorized through its EE portfolio budgets as outlined in the January 2020 Efficiency Order.

<u>Cost Recovery Mechanism - Energy Efficiency Amortization</u>

Q. How are the Company's EE programs currently funded?

A. The Company currently funds its EE programs through base rates. In the Company's last rate proceedings, the costs associated with EE, including labor, were shifted into base rates as directed by the Commission.

Q. Does the Company propose to modify its collection of EE costs in these rate proceedings?

A. Yes, on page 66 of the Customer Service Panel's initial testimony, the Company proposes to treat the entirety of its EE funding as a regulatory asset to be amortized over a 10-year period still collected in base rates.

Q. Why does the Company propose to treat these funds as a regulatory asset?

A. On pages 68 and 69 of the Customer Service Panel's initial testimony, the Company asserts that EE investments should be recovered over the same period of time during which customers receive the benefit of the investments. Further, the Company maintains that, if EE investments are meant to replace traditional infrastructure investments, they must be treated comparably in terms of cost recovery. Thus, according to O&R, recovering the costs over a 10-year period would both properly value EE investments over their expected lifespan and would treat them similarly to the traditional asset investments they are meant to replace.

Q. What amount of the EE portfolio program costs does the Company propose to collect in the Rate Year?

a. In the Rate Year, the Company is proposing to collect $15,164,331 and $2,723,371 for the electric and gas EE portfolios, respectively. In Rate Year 2, the Company is proposing to collect $16,093,635 and $3,580,680 for the electric and gas EE portfolios, respectively. In Rate Year 3, the Company is proposing to collect $16,057,800 and $3,820,738 for the electric and gas EE portfolios, respectively.

Q. How would amortization change EE investment costs for the Rate Year?

A. On page 70 of the Customer Service Panel's initial testimony, the Company explains that, if expensed, the revenue requirement impact of the total EE investment cost for the Rate Year would be $18.4 million. If amortized over 10 years, the Rate Year revenue requirement would be reduced to $2.4 million.

Q. Does the Panel agree with the Company's proposal to amortize EE costs over a 10-year period?

A. Yes, in the limited context of these proceedings, we do agree with the Company's proposal to amortize its EE costs over a 10-year period. In the December 13, 2018 Order Adopting Accelerated Energy Efficiency Targets in Case 18-M-0084, the Commission stated that individual rate plans may permit for the amortization of EE program costs where the overall context of the rate plan establishes a benefit to doing so, such as moderation of overall customer bill impacts. In these rate proceedings, the overall bill impacts are significant enough that amortization of EE costs is appropriate; however, the Panel does not intend for its recommendation in this specific instance to indicate its support for the amortization of EE costs in future rate proceedings for O&R or any other utility.

Q. Does the Panel propose any other modifications to the EE amortization schedule?

A. Yes, the Panel noticed a clerical error in the Company's calculation of EE funding. On page 68 of the Customer Service Panel's initial testimony, the Company outlines the electric and gas funds to be amortized in a chart. In this chart, the calculation for electric funds adds the value of each calendar year to the amount as if it were a dollar amount. For example, the electric EE funding for the year 2022 is overstated by $2,022. Similarly, the calculations for 2023 and 2024 are off by $2,023 and $2,024, respectively. This error and the corrected calculation are demonstrated in Exhibit__(SCEP-3), which also provides the Panel’s proposed amortization schedule.

Non-Wires Alternatives

Q. Does the Company propose any changes to its NWA project portfolio?

A. Yes. As explained on page 140 of the initial testimony of the EIOP, the Company proposes changes to two of its four NWA projects, the Monsey NWA project and the Pomona DER project. The Panel will address these two projects separately.

Q. Describe the Monsey NWA project.

A. On pages 66 and 67 of 2019 Rate Order, the Commission authorized the Company to recover the costs of an NWA project to address overloaded circuits and substation transformer banks around Monsey, in the Town of Ramapo in Rockland

County, due to residential and commercial growth. As explained on page 141 of the initial testimony of the EIOP, the Company’s original proposal for a Monsey NWA required the installation of a battery energy storage system to defer development of conventional infrastructure. However, during project development, the Company was unable to secure approval for a battery installation from local authorities, which prevented continued implementation of the original NWA project and forced the Company to identify a new solution.

Q. When did the Company learn that its original proposal would no longer be possible?

A. According to the Company’s response to IR DPS-12-370, included in Exhibit__(SCEP-1), the Company was informed by the Community Design Review Committee of the Town of Ramapo of public opposition to the project siting during a regularly scheduled meeting of the committee in January 2020. The Town of Ramapo officially withdrew support for the original project site in February 2020.

Q. How did the Company proceed to address electrical infrastructure needs in the Monsey area following the preclusion of the original NWA solution?

A. As further discussed in the Company's response to IR DPS-12-370, included in Exhibit__(SCEP-1), after the Town of Ramapo withdrew its support for the original project site, the Company identified a new NWA need and subsequently designed a new NWA solution for the area. As explained on page 141 of the initial testimony of the EIOP, the new Monsey NWA project is a hybrid solution comprising DER technologies and conventional capital investment. This hybrid solution will combine three battery installations with a new transformer installation at the Burns substation. According to the Company's response to IR DPS-26-530, included in Exhibit__(SCEP-1), the new Monsey NWA is a direct continuation of the original proposal as it will provide system relief through a different circuit to circumvent the siting constraints identified in the original proposal.

Q. How does the scale of the new Monsey NWA project compare to the original proposal?

A. As explained by the Company on pages 141 and 142 of the initial testimony of the EIOP, the new $43 million Monsey NWA project will defer a much larger capital investment that would be required to construct a new substation in the hamlet of Viola in Ramapo.

Q. How much of the $16 million budget for the original Monsey NWA project did the Company spend before abandoning the program following the withdrawal of support for the original battery site by the Town of Ramapo?

A. According to the Company's response to IR DPS-12-370, included in Exhibit__(SCEP-1), the Company spent a total of $274,241 on the original Monsey NWA prior to the abandonment of the original project site. In its response to DPS IR-26-530, included in Exhibit__(SCEP-1), the Company noted that this amount was calculated on November 11, 2020, and that no further funds were spent on the original Monsey NWA in that year. Of the total $274,241, the Company spent $12,510 during calendar year 2020.

Q. What does the Company propose in terms of cost recovery for the new Monsey NWA proposal?

A. According to the Company's response to IR DPS-12-370, Exhibit__(SCEP-1), the Company intends to continue to reconcile actual costs of the new Monsey NWA proposal with the level provided in current rates for the remainder of its current electric rate plan. The Company anticipates that, at the end of this reconciliation period, it will have accrued a $654,000 credit for the benefit of customers, which it intends to net with future project spending. In its response to IR DPS-26-530, included in Exhibit__(SCEP-1), the Company explains that this $654,000 credit was subtracted from the projected Rate Year costs of the new Monsey NWA proposal of $19,281,000, resulting in projected Rate Year expenditures of $18,627,000.

Q. Has the Company described any assurances from third-party vendor, municipal, or other partners that the new Monsey NWA will avoid the site approval problems that terminated the original NWA proposal?

A. In its response to IR DPS-26-530, included in Exhibit__(SCEP-1), the Company notes that the new Monsey NWA site is zoned for commercial use, in contrast to the residential designation of the previous location. Additionally, the Company cites a secured lease between the vendor and the property owner, as well as extensive outreach efforts with the local fire department and the subsequent development of an emergency response plan and plans for onsite training as declarations of project support.

Q. When would the Company need to begin to implement a conventional infrastructure solution instead of the Monsey NWA if the Company cannot secure all necessary approvals for the latter?

A. According to its response to IR DPS-26-530, included in Exhibit__(SCEP-1), the Company would begin planning for a conventional infrastructure solution instead of the NWA if it does not anticipate securing approvals with reasonable certainty by the fourth quarter of 2021. This conventional solution would require additional transformer bank reinforcements, associated circuits, and construction of a new substation in order to maintain reliable service.

Q. Would the Company be required to obtain authorization for this conventional infrastructure solution outside of the pending rate case if the Monsey NWA were not approved?

A. Yes. According to its response to IR DPS-34-589, included in Exhibit__(SCEP-1), the Company would be required to obtain authorization for a conventional infrastructure project in a separate proceeding.

Q. Is the Company seeking cost recovery of the new Monsey NWA in this proceeding?

A. Yes. As explained on page 143 of the initial testimony of the EIOP, the Company requests approximately $19,281,000 in 2022, $1,621,000 in 2023, and $1,626,000 in 2024.

Q. How does the Company propose to use this funding during the rate term?

A. According to the Company's response to IR DPS-26-530, included in Exhibit__(SCEP-1) these funds are necessary to cover the costs of battery installation and conventional small capital investment costs, program costs, internal portfolio administration costs, and interconnection costs. Additionally, the costs of charging the battery storage system through the end of the estimated deferral period of 2022 through 2031 are included in this total, as the Company would relinquish ownership at the end of the project.

Q. How does the Company propose to recover these additional Monsey NWA costs?

A. As explained on page 143 of the initial testimony of the EIOP, the Company proposes to recover these additional costs through the existing Monsey NWA reconciliation mechanism, in which forecasted program costs incurred during the rate period are amortized over 10 years. The Company would continue to reconcile the revenue requirement effect of its actual costs for this item with the level provided in rates.

Q. Does the Panel agree with the additional funds and cost recovery proposed by the Company for the implementation of the new Monsey NWA proposal?

A. In part. The Panel agrees with the additional funding request necessitated by the new Monsey NWA proposal. The new proposal has a positive benefit-cost analysis ratio and, if implemented successfully, will defer a much larger capital investment than the original Monsey NWA. Therefore, we agree that these costs are necessary and reasonable. However, we disagree with the proposal by the Company to continue the current cost recovery mechanism established for the Monsey NWA in 2019 Rate Order.

Q. What does the Panel recommend?

A. We recommend against forecasting costs of the new Monsey NWA and recovering those costs through base rates. The Monsey NWA should be subject to the same cost recovery treatment as other NWA projects; that is, costs should be deferred as they are spent, amortized over a ten-year period and recovered through a surcharge until they can be recovered through base rates in the subsequent rate case once the costs are fully known.

Q. Describe the Pomona DER Program.

A. The Pomona DER Program was approved by the Commission in the October 16, 2015 Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans, issued in Cases 14-E-0493 and 14-G-0494, referred to as the 2015 Rate Order. The Pomona DER Program is intended to defer the construction of a new Pomona substation and associated facilities in the Village of Pomona in Rockland County by implementing a combination of DER and demand-side management. The program currently consists of EE and demand response programs complementing a 3 megawatt/12 megawatt-hour-battery energy storage system.

Q. Describe the Pomona DER Program budget and costs incurred at the time of the Company's filing.

A. According to page 145 of the initial testimony of the EIOP, the program budget was limited to a total of $9.5 million in 2014 dollars, which equates to $11.5 million in future escalated dollars. The Company has spent $3.679 million on the Pomona DER Program as of July 31, 2020.

Q. Has the Commission authorized any incentives associated with the execution of the Pomona DER Program?

A. Yes. In the 2015 Rate Order, the Commission authorized the Company to earn an incentive if it achieves load reduction over 3.0 MW or achieves per-MW cost savings compared to the cost of the proposed Pomona substation.

Q. Is the Company requesting additional cost recovery for the Pomona DER Program that is not included under the $9.5 million cap established in the 2015 Rate Order in the instant proceeding?

A. Yes. As stated on pages 146 and 147 of the initial testimony of the EIOP, the Company is requesting an additional $200,000 annually from 2022 through 2024 for ongoing operation costs of the Pomona DER Program, all allocated to operation and maintenance, or O&M, budgets.

Q. How does the Company propose to spend this $200,000 O&M annual budget request during the rate term?

A. The Company notes, on page 146 of the initial testimony of the EIOP, that this additional annual funding is required for ongoing O&M of the Pomona DER Project battery, water infrastructure maintenance services, and communications network fees. In response to IR DPS-12-369, included in Exhibit__(SCEP-1), the Company further explains that it has an agreement with Key Capture Energy, the battery vendor, to manage O&M of the storage system for a period of five years at a fixed annual cost of $180,000. Additionally, the Company is negotiating a contract with SUEZ Water to perform maintenance on the dedicated five hydrant and water line at the battery site at an estimated cost of $5,000 per year. The Company is also negotiating the costs of communications network fees with Verizon, which it estimates at $15,000 per year.

Q. Will the $600,000 requested by the Company in additional O&M funding from 2022 through 2024 affect the earning and recovery of incentives by the Company for performance of the Pomona DER Program, as established in the 2015 Rate Order?

A. No. As the Company explains in its response to IR DPS-26-531, included in Exhibit__(SCEP-1), the Company was authorized to earn incentives based on the performance of the Pomona DER Program according to cost savings and load reduction achieved. O&M costs were not included in the incentive structure.

Q. Does the Panel agree with the additional $200,000 annual O&M funding requested by the Company for the continued operation of the

Pomona DER Program?

A. Yes. As the Company explains in its response to IR DPS-36-602, included in Exhibit__(SCEP-1), the battery vendor services, maintenance on a dedicated fire hydrant and water line at the battery site, and communications network fees required by the implementation of the 3-megawatt utility-scale battery storage system could not have been anticipated at the time the Company, Staff and other parties entered into the Joint Proposal that was adopted in the 2015 Rate Order, as this storage component was not part of the project at the time and a detailed site plan did not yet exist. According to the Company's most recent quarterly expenditures and program report for the Pomona DER Program, submitted for filing on March 25, 2021, in Case 14-E-0493, the Company issued a request for proposals for the energy storage system on December 6, 2017, and the unit did not become operational until December 22, 2020. The utility-scale battery is a valuable component of the overall Pomona DER Program and the contract with Key Capture Energy for battery O&M and the future contracts for necessary fire suppression and communications network services are reasonable and prudently incurred costs of this project. Moreover, the contracted services to be provided by SUEZ for hydrant and water line maintenance and by Verizon for communications network security are required by Town of Ramapo regulations and the Company's own cybersecurity standards, respectively, as explained by the Company in its response to IR DPS-36-602, included in Exhibit___(SCEP-1). Additionally, according to the Joint Proposal adopted by the 2015 Rate Order, the $9.5 million expenditure cap on the Pomona DER Program does not apply to maintenance associated with capital investments of the project.

Non-Pipes Alternatives Cost Recovery

Q. Has the Company proposed any NPAs in this case?

A. No; however, the Company states that it is open to exploring NPAs where feasible. As described by the Company on page 21 of the initial testimony of the GIOP, the Company will continue to evaluate NPAs where infrastructure investment may be necessary to maintain the safety and reliability of the gas distribution system.

Q. If the Company has no planned NPAs in this rate filing, but is otherwise pursuing NPAs as part of its planning process, has it proposed a cost recovery mechanism for NPA costs not included in base rates but later identified and implemented within the Rate Year?

A. Yes, as noted on page 37 of the initial testimony of the Gas Rate Panel, and further explained by the Accounting Panel on pages 72 and 73 of its initial testimony, the Company is proposing a surcharge that will be a component of the Monthly Gas Adjustment for the recovery of the revenue requirement associated with the costs for NPA projects that the Company may propose in the future.

Q. Does the Panel agree with the proposed cost recovery mechanism as described by the Accounting Panel?

A. Yes. As described, the proposed cost recovery mechanism for NPAs would mirror the cost recovery structure of NWAs, including the treatment of Average Plant in Service Balances and carrying charges. Furthermore, the proposed

10-year amortization period, which is the amortization period used for NWAs, aligns with the useful lives of possible NPA solutions, which include both third party investments and EE programs. Treating cost recovery mechanisms for these types of similar costs maintains consistency among NPA, NWA, and EE portfolios.

Q. Is it advisable to maintain consistency between programs that address different types of load growth concerns?

A. Yes. Utility portfolios for NWAs could include a gas component, and portfolios for NPAs could have an electric component. Many NWA and NPA portfolios have an EE component. Therefore, amortizing these types of costs over 10 years maintains consistency among complementary programs and reduces a utility's incentive to pursue one program over another simply due to different cost treatment.

<u>Managed Charging Program</u>

Q. Please describe the Managed Charging Program proposed by the Company.

A. As explained on pages 163 and 164 of the initial testimony of the EIOP, the Company proposes a five-year Managed Charging Program designed to encourage electric vehicle, or EV, operators to charge vehicles during off-peak times to maintain system reliability, beginning in 2022 and continuing through 2026. The Company proposes to collaborate with a to-be-determined third-party vendor or vendors to manage the program, which may rely on various technological solutions, including vehicle-connected hardware, telematic software, smart charging applications, application programming interfaces, and advanced metering infrastructure. The Company proposes an enrollment bonus of up to $150 per participating EV to incentivize participation and startup costs. Other incentives include a $5 per month credit for active program participation, a $0.10/kilowatt-hour rate for off-peak charging time, and a $20 credit for avoidance of peak-time charging from June through September. The Company proposes a maximum three-year participation term per participant with an annual incentive cap of $500 per participant per year.

Q. What are the costs of the Managed Charging

Program as proposed by the Company?

A. As stated on page 166 of the initial testimony of the EIOP, the Company estimates that the total cost of the five-year program is $800,000, which is based on program costs developed assuming a full enrollment of 100 EVs per year, maximum available incentives per EV, and third-party vendor costs estimated on a per-EV basis.

Q. Does the Panel support the Company's Managed Charging Program proposal?

A. Yes. The Company's proposal is in accordance with the requirements of the July 16, 2020 Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs in Case 18-E-0138, referred to as the July 2020 EV Make-Ready Order, wherein the Commission directed utilities to file proposals for active or managed charging programs for mass-market customers within 120 days of the issuance of the Order. The Company submitted for filing its proposed Managed Charging Program for Mass Market Customers on December 4, 2020 in Case 18-E-0138.

Q. How does the Company propose to recover the costs of the Managed Charging Program?

A. As explained on page 166 of the initial testimony of the EIOP, the Company is requesting cost recovery for the program in Case 18-E-0138, the Electric Vehicle Supply Equipment and Infrastructure proceeding, outside of the electric revenue requirement to be established in the instant rate proceedings. In view of this request, the Panel will not opine further on aspects of this program, but it does note that the Company's proposal appears reasonable, and it should continue development of its Managed Charging Program for appropriate review within Case 18-E-0138, the generic EV proceeding.

<u>Major Account Engineer Positions</u>

Q. Please describe the Company's request for two additional New Business Services, or NBS, engineers.

A. As explained on pages 79 through 80 of the initial testimony of the Customer Service Panel, the Company proposes funding for two additional full-time equivalent, or FTE, NBS engineers. These positions would be responsible for supporting various Company clean energy initiatives, with functions to include interconnection and energization of DERs and EV charging stations.

Q. Please describe the Company’s justification for these two NBS engineer positions.

A. On pages 80 and 81 of its initial testimony, the Customer Service Panel explains that DER and EV charging infrastructure installations have increased steadily in the last three years in O&R’s service territory, and it expects this increase to continue as the Company implements its EV Make-Ready Program and as DER interconnections increase to meet the solar photovoltaic, referred to as PV, generation, and battery storage capacity mandates of the Climate Leadership and Community Protection Act, or CLCPA. The Company also cites the anticipated addition of over 100 megawatts, or MW, of solar PV and 60 MW of energy storage from 2022 to 2024 as increases in expected engineering workloads.

Q. How many engineers does the Company currently employ in its NBS department?

A. On page 80 of its initial testimony, the

Customer Service Panel states that the Company currently has four engineers in its NBS department who manage between 40 to 60 projects. However, on page 70 of Exhibit__(CSP-1), the Company states that there are currently five engineers in the NBS department. In response to IR DPS-20-475, included in Exhibit__(SCEP-1), the Company confirmed that it currently employs five engineers in its NBS department.

Q. Has this contingent remained constant over the last decade?

A. For the most part. According to the Company's response to IR DPS-20-475, included in Exhibit__(SCEP-1), the Company has employed a maximum of four engineers per year from 2010 through 2020, except in 2017 and 2020, when it employed three and five engineers in its NBS department, respectively.

Q. What schedule does the Company propose for the employment of these two NBS engineer positions?

A. The Company proposes to hire one NBS engineer to begin employment in January 2022, with a second NBS engineer to begin employment in January 2023.

Q. What is the revenue requirement effect of employing these two NBS engineers according to the schedule proposed by the Company?

A. The annual cost of each position is $130,000, with a total cost of $130,000 in RY1, $260,000 in RY2, and $260,000 in RY3, with a proposed 100 percent allocation to O&M.

Q. Does the Panel agree with the Company's proposal to employ two NBS engineer FTEs at the schedule and costs described above?

A. Yes. In addition to the approximately 2,900 EV charging plugs required to be installed in the Company's service territory in accordance with the July 2020 EV Make-Ready Order, the Company is also expected to meet CLCPA objectives requiring the Company to install 90 MW of energy storage capacity and 180 MW of solar PV generation capacity by 2025. According to the Company's response to IR DPS-28-547, included in Exhibit__(SCEP-1), the Company currently has approximately 6.17 MW of energy storage capacity and approximately 131.1 MW of solar PV generation capacity installed as of April 2021. While the Company only needs to increase its existing solar capacity by approximately 37 percent to meet its share of the 2025 statewide CLCPA objective, the requisite increase in energy storage will necessitate an increase of more than 1,300 percent over the Company's installed capacity by 2025. Furthermore, these 2025 CLCPA objectives are interim targets intended to pave the way for much larger targets in 2030 and beyond. In view of anticipated increases to the Company's workload in the proposed rate term and the relatively static total labor available in its NBS department over the last decade, it is reasonable to allow these additional FTEs. Importantly, these new FTEs would be employed by the Company to advance the ambitious State energy policy objectives.

Electrification Portfolio Management

Q. Please describe the Company's proposal to expand its Utility of the Future organization.

A. As described on pages 136 and 137 of its initial testimony, the EIOP requests funding for an Electrification Portfolio Management, or EPM, group to expand its Utility of the Future organization, which currently comprises a

Markets and Regulatory Team and a Distributed Energy Resource Integration Team.

Q. According to the Company, what functions would the EPM group perform?

A. On pages 136 through 139 of its initial testimony, the EIOP states that the EPM group would develop initiatives to increase decarbonization through transportation electrification, building and heating electrification, and the development of NPAs to defer or avoid natural gas infrastructure construction.

Q. For what activities will the EPM group be responsible?

A. According to the initial testimony of the EIOP at pages 136 through 139, the EPM group will help implement new business models, demonstration projects, online marketplace development, customer resources, and lead implementation of Company electrification programs. According to the Company, the EPM group will administer Company efforts in transportation electrification, building and heating electrification, and NPA projects.

Additionally, the EPM group would lead project management in these activities across various Company organizations and third-party partners, with a particular emphasis on maintaining system reliability, resiliency, and safety as electrical load increases due to the beneficial electrification measures of these sectors.

Q. Does the Company provide any justifications for the proposed addition of the EPM group to its Utility of the Future organization?

A. Yes. On pages 137 and 138 of its initial testimony, the EIOP cites ambitious State decarbonization goals, including the 85 percent reduction of 1990 emissions levels by 2050 mandated by the CLCPA, and the 2014 Zero-Emissions Vehicle Memorandum of Understanding in which New York State committed to achieve registration of approximately 850,000 electric vehicles statewide by 2025. The Company states that the EPM group is necessary to help accelerate growth of the electrification industry, coordinate with utility customers and third parties in new business models and develop internal operations to allow for continued and sustainable service as electrification of the heating, building, and transportation sectors increases.

Q. Is the Company requesting any additional resources to perform this work?

A. Yes. As stated on page 140 of the initial testimony of the EIOP, the Company requests funding for two FTEs in the EPM group. Specifically, O&R requests funding for a Section Manager at $140,000 per year and a Project Specialist at $120,000 per year, both of which are completely allocated to the O&M budget.

Q. Does the Panel support the Company's proposal to expand its Utility of the Future organization with the addition of the EPM group?

A. In part. The Panel recognizes the ambitious state policy objectives that the Company's proposed EPM group would be assigned to help achieve and the increased workloads associated with these goals. The Panel also notes that the Company anticipates that its current labor resources will likely be inadequate to accomplish work in several task areas as explained in the Company's response to IR DPS-

39-615, included in Exhibit__(SCEP-1), specifically electrification of heating, electrification of transportation, developer/contractor customer outreach and education, and demonstration projects. However, the Company anticipates that work will also remain constant in the task areas of the Direct Current Fast Charger program, distributed system implementation plan development, and long-range plan development. Furthermore, the Company does not currently have an NPA program in place, nor has it proposed any NPA projects in the present rate filing. Lastly, as indicated in the Company's response to IR DPS-39-615, the Company's Utility of the Future staffing has more than doubled in the last five years, increasing from six employees in 2016 to 13 in 2020. Therefore, it is reasonable for the Panel to recommend one of the proposed FTEs, but not two.

Q. What recommendations does the Panel make regarding the Company's proposed EPM group labor request?

A. The Panel recommends allowing the requested project specialist at $120,000 per year but disallowing the requested section manager at $140,000 per year. The Panel has adjusted the $140,000 requested by the Company for the section manager in the Rate Year to $0.

Behavioral Demand Response Pilot Program

Q. Please describe the Behavioral Demand Response Pilot Program proposed by the Company.

A. As explained on pages 23 through 25 of the initial testimony of the Customer Service Panel, the Company proposes a Behavioral Demand Response Pilot Program, referred to as the BDR Pilot Program, to achieve reductions in both electricity and natural gas usage on peak days through voluntary adjustments to customer energy consumption, generally referred to as demand response. The Company proposes that the BDR Pilot Program investigate the use of residential demand response enabled through the Oracle Corporation's Opower BDR software. According to its BDR Pilot Project proposal, the Company would signal demand response requests to residential customers one day before a forecast peak day on its electricity or gas systems, along with information on how customers can avoid energy usage during the peak period. The Company anticipates no more than 10 demand response events during each summer and winter season.

Q. Please describe how the Company proposes to implement the BDR Pilot Program.

A. As explained on page 26 of the initial testimony of the Customer Service Panel, the Company intends to enroll a select group of residential customers who have the ability to opt out without penalty. According to the Company's response to IR DPS-16-433, included in Exhibit__(SCEP-1), the Company intends to enroll approximately 115,000 electricity customers and 65,000 natural gas customers into two treatment groups, with an additional 38,000 electricity customers and 21,000 natural gas customers remaining unenrolled as control groups. The first phase of the BDR Pilot Program would begin in the Rate Year with unincentivized behavioral demand response messaging. A second phase, beginning in Rate Year 2, would include up to $400,000 in participation incentives for natural gas customers and $700,000 in incentives for electric customers.

Q. Why does the Company propose one year of unincentivized behavioral demand response followed by one year of customer incentives?

A. As the Company explains on page 28 of the Customer Service Panel’s initial testimony, O&R intends to determine the level of behavioral demand response that can be induced without monetary awards in the first program year by relying only on customer messaging. In the second phase, the Company will evaluate the BDR Pilot Program effectiveness and determine the level of financial incentives necessary to provide peak demand reduction.

Q. Did the Company identify any anticipated benefits of the BDR Pilot Program?

A. On pages 26 and 27 of its initial testimony, the Customer Service Panel provides high-level estimates of winter and summer peak demand reductions and customer participation. The Company estimates 3,600 kilowatts of summer peak demand reduction with 115,000 electricity customers participating and 455 dekatherms of winter peak demand reduction from 65,000 gas customers. On page 24 of its initial testimony, the Customer Service Panel also notes that a residential behavioral demand response program can rely on prompting altruistic actions by customers at a large scale without necessitating additional infrastructure or services.

Q. Has the Company developed a benefit-cost analysis of its proposed BDR Pilot Program?

A. No. As stated in the Company’s response to IR DPS-10-332, included in Exhibit__(SCEP-1), the Company has not performed a benefit-cost analysis.

Q. What is the estimated total cost of the BDR Pilot Program?

A. According to Company estimates provided on pages 27 and 28 of the initial testimony of the Customer Service Panel, the BDR Pilot Program would cost $1.72 million during the proposed rate term for the electric program and $1.00 million for the natural gas program. The Company proposes to recover the electric and natural gas program costs through the Energy Cost Adjustment and Monthly Gas Adjustment, respectively.

Q. Does the Panel support the Company's proposed BDR Pilot Program?

A. The Company's BDR Pilot Program appears reasonable; however, without a positive benefit-cost analysis to justify the estimated expense, we cannot support this proposal as a utility pilot program.

Q. Is a completed benefit-cost analysis important for demand response programs?

A. Yes. Benefit-cost analyses are critical for pilot programs, and especially for demand response programs in general, as incentives provided to participants are typically designed to achieve societal benefits. The primary reason to implement demand response programs is to rely on load reductions provided by voluntary customer actions, rather than the construction of conventional infrastructure. Without a benefit-cost analysis, it is impossible to determine whether a demand response program will fulfill its primary purpose.

<u>Customer Enablement Initiative</u>

Q. Please describe the Company's Customer

Enablement Initiative proposal.

A. As described on pages 158 and 159 of the initial testimony of the EIOP, O&R proposes to establish a Customer Enablement Initiative designed to facilitate customer adoption of emerging clean energy technologies, primarily EVs and heat pumps. The Company describes a flexible program with elements that may include outreach and education efforts, rebate programs with a focus on LMI customers, in-person customer engagement events at retail sites, including EV test drive events, and the development of online calculators to provide total cost of ownership to prospective clean energy technology customers. The Company proposes a focus on customer engagement and coordination between various Company organizations to improve the customer experience, maintain third-party relationships, and encourage customer adoption of EVs and heat pumps in support of the State energy policies advanced by the Commission’s Reforming the Energy Vision initiative and the CLCPA.

Q. What is the revenue requirement effect of the

Company's proposed Customer Enablement Initiative?

A. According to page 163 of the initial testimony of the EIOP, O&R is requesting $500,000 in the Rate Year, $870,000 in Rate Year 2, and $874,000 in Rate Year 3. These requests include the annual salary for one full-time equivalent Project Specialist in Rate Years 2 and 3 at $120,000 and $124,000 annually, respectively. These costs are allocated entirely to O&M.

Q. Does the Panel agree with the Company's proposed Customer Enablement Initiative?

A. No. While the Panel recognizes the importance of increased customer adoption of heat pumps, EVs, and other clean energy technologies to meet State policy objectives, the Customer Enablement Initiative as proposed by the Company in testimony is too vague and imprecise to provide unequivocal and compelling justifications for its recommendation.

Q. Does the Company demonstrate a convincing need for this program?

A. No. In its responses to IR DPS-13-388 and DPS-20-474, included in Exhibit__(SCEP-1), the

Company does not adequately explain how the Customer Enablement Initiative will provide functions not already performed by existing Company organizations, nor has it cited any convincing deficiencies in its current performance related to customer adoption of EVs, heat pumps, or other clean energy technologies to warrant such an initiative. The Company also has not cited any compelling evidence of adverse effects of failing to implement this proposal. Absent more persuasive evidence demonstrating a need for this program, the Panel cannot recommend implementation of the Customer Enablement Initiative and adoption of its associated labor and budget proposals.

Q. Does the Panel have any recommendations regarding the Company's proposed Customer Enablement Initiative and its associated labor request and proposed annual budgets?

A. Yes. The Panel recommends disallowing these proposed costs for both the program and labor. The Panel has adjusted the $500,000 requested by the Company for these expenses in the Rate Year to $0.

Q. Does this conclude the Panel’s testimony?
A. Yes.