Paul A. Colbert
Associate General Counsel
Regulatory Affairs

March 28, 2018

Hon. Kathleen H. Burgess
Secretary to the Commission
New York State Public Service Commission
Agency Building 3
Albany, NY 12223-1350

Re: Matter 17-01276 – *In the Matter of the Value of Distributed Resources Working Group Regarding Value Stack*

Matter 17-01277 – *In the Matter of the Value of Distributed Resources Working Group Regarding Rate Design*

Dear Secretary Burgess:

Please accept for filing in the above-referenced matters Central Hudson Gas & Electric Corporation's responses to SEIA IR-2, PACE IR-JRP-1-4 and UIU IR-1.

Please contact the undersigned at (845)486-5831 or pcolbert@cenhud.com with any questions regarding this matter.

Respectfully submitted,

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Central Hudson Gas & Electric Corporation
Matter Numbers 17-01276 and 17-01277
Response to Interrogatory / Document Request

Request No:	SEIA IR-2
From:	Solar Energy Industries Association
Date of Request:	March 13, 2018
Subject:	Follow Up Questions on March 6 Utility Presentations

Question:

1) Please respond to the following questions, which were issued by SEIA on February 16, 2018 to all utilities:
   a) Please explain how the MCOS studies are used outside the VDER context. Please explain how the MCOS study is linked to the capital investment plan and/or the 15-year transmission and distribution plan.
   b) Does each EDC include all revenue requirement inputs in calculating MCOS (e.g., tax, CapEx depreciation, etc...)?
2) How do CHG&E's current MCOS methodology and assumptions differ from those proposed in the Phase I VDER proceeding?
3) Please provide the variables and statistical fitness of the historical load growth model.
4) For load forecast, how many simulations were run? For the avoided T&D costs, how many simulations were run?
5) Please describe any benefits that DERs provide to the transmission and distribution system that are not reflected in CHG&E's model. Does CHG&E plan to study or has CHG&E studied any of these benefits? If so, please provide related studies, reports, memoranda, and workpapers.
6) Please describe costs and risks of traditional transmission and distribution system investments that are not reflected in CHG&E's model.
   a) For each cost and risk, please describe to what extent and how a) shareholders and b) ratepayers bear the cost or risk.
   b) Does CHG&E plan to study or has CHG&E studied any of these costs or risks? If so, please provide related studies, reports, memoranda, and workpapers.
7) With respect to calculating the LSRV using a ten highest usage hours approach:
   a) How would CHG&E's ten highest usage hours be defined? That is, at what level of granularity?
   b) If the ten highest usage hours would be calculated for CHG&E's entire service territory, rather than for specific to local areas of the service territory, how would the local areas line up with sub-regions designated in the MCOS methodology?
8) At the March 6 conference, Con Edison noted that a NYISO rule prohibits more injections than utility default load.
   a) Please explain how CHG&E currently manages its system to comply with the NYISO rule that prohibits more injections than utility default load.

9) At the March 6 conference, Con Edison stated that its preference is for DERs above a certain size threshold (e.g. 100 kW) to participate in NYISO to get compensation, rather than simply being a load modifier.
   a) Does CHG&E agree? Why or why not?
   b) If so, in CHG&E's opinion, what kind of DERs should be subject to the threshold?
   c) Should all types of DERs be subject to the same threshold?
   d) Please provide current DER installations and capacity, by DER type and by node, on CHG&E's system.
   e) Please provide projected DER installations and capacity, by DER type and by node, on CHG&E's system.
10) Please explain how existing DERs are incorporated into MCOS studies and capital improvement plan projections.
   a) Are existing DERs assumed to remain in service in perpetuity?
   b) What capacity factor assumptions are used for in-service DERs?
   c) Are future deployments of DERs taken into account when forecasting system load?
   d) How is degradation in existing DER generation over time taken into account?
   e) Are DERs modeled separately based on technology, location, or any other factor?
   f) Do existing DERs reduce projected load that is used as an input to MCOS studies and capital improvement plan projections? Are existing DERs included in the baseline when calculating projected changes in load?
11) Do MCOS studies incorporate the potential for vehicle and heating electrification?
   a) If so, how do such studies incorporate projections for electrification?
   b) If not, why not?

Response:

1) Please refer to Central Hudson's response to SEIA's questions regarding the MCOS presentations filed on March 14, 2018 in Matter 17-01276.
2) Please refer to Central Hudson's response to SEIA's questions regarding the MCOS presentations filed on March 14, 2018 in Matter 17-01276.
3) Please refer to Appendix D of Central Hudson's Initial Distributed System Implementation Plan, filed on June 30, 2016 in Case 14-M-0101.
4) Please refer to Appendix D of Central Hudson's Initial Distributed System Implementation Plan, filed on June 30, 2016 in Case 14-M-0101.
5) The Company objects to this question as vague, overbroad and unduly burdensome. Without waiving the foregoing objection, the Company notes that the benefit included in the Avoided T&D study is the potential for DERs to allow the utility to defer or avoid traditional infrastructure investments. However, this benefit has not been thoroughly tested and at this time it is unknown if DERs can provide the same reliability or flexibility as a traditional infrastructure investment. For further

information please refer to Appendix D of Central Hudson's Initial Distributed System Implementation Plan, filed on June 30, 2016 in Case 14-M-0101.

6) The Company objects to this question as vague, overbroad and unduly burdensome as it calls for a special study. Without waiving the foregoing objection, please refer to Central Hudson's Initial Distributed System Implementation Plan, filed on June 30, 2016 in Case 14-M-0101.
7)
   a) Please refer to Central Hudson's Value of Distributed Energy Resources Implementation Proposal, filed on May 1, 2017 in Case 15-E-0751 and Case-15-E-0082
   b) Please refer to Central Hudson's Value of Distributed Energy Resources Implementation Proposal, filed on May 1, 2017 in Case 15-E-0751 and Case-15-E-0082. Additionally, it must be noted that aligning the hours of an individual area with the ten highest usage hours for the entire system would defeat the purpose of having an LSRV zone as it would not address the specific system needs for that specific portion of the distribution system. As such this approach would potentially result in the utility providing compensation under the LSRV while receiving little or no relief for local distribution constraints.
8)
   a) Central Hudson has not yet reached a level of injections that is higher than utility default load.
9)
   a) Yes, Central Hudson agrees that injection DER above a certain size threshold should participate and receive its wholesale energy and capacity compensation through the wholesale market.
   b) DERs that provide energy injections.
   c) Yes, for DERs that provide energy injections the threshold should be the same.
   d) Central Hudson does not currently have all of these data points readily available. Please refer Standardized Interconnection Requirements Inventory filed monthly within Matter number 13-00205.
   e) Central Hudson does not currently have all of these data points readily available. Please refer Standardized Interconnection Requirements Inventory filed monthly within Matter number 13-00205.
10) For all subparts to this question, please refer to Appendix D of Central Hudson's Initial Distributed System Implementation Plan, filed on June 30, 2016 in Case 14-M-0101.
11) For all subparts to this question, please refer to Appendix D of Central Hudson's Initial Distributed System Implementation Plan, filed on June 30, 2016 in Case 14-M-0101.

Central Hudson Gas & Electric Corporation
Matter Numbers 17-0126 and 17-01277
Response to Interrogatory / Document Request

Request No:	PACE-1, IR-JRP-1
From:	PACE Energy and Climate Center
Date of Request:	March 13, 2018
Subject:	General

Question:

1. Does the Company assert that economic efficiency is enhanced on a Company or societal basis when fixed costs are recovered using fixed charges? Is yes, please provide citations to any authorities that support this assertion. Please explain how the Company reflects its position in its cost of service approaches.

2. Please provide spreadsheets and data associated with the presentation to the VDER meeting on March 6, 2018.

3. Please provide spreadsheets for all data associated with the cost of service and rate design for all current mass market customer rates.

Response:

1. Economic efficiency is enhanced when utility rates accurately reflect customer-related fixed costs in the customer charge, demand-related costs in the demand charge, and volumetric kWh-related costs in a kWh charge.

   The NARUC DER Rate Design and Compensation Manual recognizes this approach:

   > There are many costs associated with a customer being connected to the grid, as well as benefits to the customer. Particularly to the extent that costs are recovered through volumetric rates, a DER customer may not be paying for all such costs. These costs would then be paid for by other customers, to the benefit of DER customers. (p.82).

   The Department of Public Service Staff also emphasized the need for economic efficiency in utility rates in its White Paper on Ratemaking and Utility Business Models:

   > Efficient price signals and transparency are hallmarks of a successful market. Rate design and compensation mechanisms that accomplish these will help to optimize the investment in and use of DER, thereby reducing total system costs and customer bills, not only for customers with DERs. Conversely, rates that are bundled and mask the underlying costs of service will not facilitate efficient decisions. (Case 14-M-0101, issued July 28, 2015, p.81)

Moreover, Bonbright's Principles of Public Utility Rates (1961) supports the aforementioned assertion of enhanced economic efficiency when rate components accurately reflect the concomitant costs. Bonbright wrote that an objective of reasonable public utility rates should be "[t]he optimum-use or consumer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received." (p.329).

Bonbright further stated, "without doubt the most widely accepted measure of reasonable public utility rates and rate relationships is cost of service." (p. 294). He went on to describe a hypothetical example of the evolution of increased sophistication in rate structures for an electrical utility to better reflect cost of service. Bonbright began with a simplistic rate that only charges a uniform rate per kilowatt-hour. He stated the problem with this rate is that "in treating the total cost of the business as if it varied directly with the changes in the kilowatt-hour output of energy – a grossly false assumption – it violates the most widely accepted canon of fair pricing, the principle of service at cost." (p. 307). His hypothetical evolution of increasing rate sophistication went on to introduce a customer charge because a two-part rate based only upon energy and demand "overlooks the fact that a material part of the operating and capital costs of a utility business is more directly and more closely related to the number of customers than to the energy consumption on the one hand or maximum kilowatt demand on the other hand." (p. 311).

Central Hudson has reflected these positions in its cost of service approach by classifying as customer-related any costs associated with the presence of customers on the electric delivery system and moving customer charges closer to such customer-related costs.

2. Please refer to Consolidated Edison's response to IR JRP-1.2.

3. The Company asserts that this request is unduly burdensome and irrelevant because it does not contribute to the Commission's goal of developing a mass market NEM successor tariff by December 31, 2018.

Central Hudson Gas & Electric Corporation
Matter Numbers 17-01276 and 17-01277
Response to Interrogatory / Document Request

Request No:	PACE-1, IR-JRP-2
From:	PACE Energy and Climate Center
Date of Request:	March 13, 2018
Subject:	Marginal Cost Recovery

Question:

1. Does the Company assert that its current mass market rates do or do not collect marginal costs for serving customers in the mass market classes? Please explain and provide documentation, including the marginal costs for each rate component of service and for each mass market rate classification.

2. Please provide an explanation of the sources of marginal costs recovered in mass market rates.

Response:

1. The Company's current delivery rates applicable to all service classifications, including mass market service classifications, are not designed to collect the marginal costs for serving customers in each service classification. Rather, the Company's current delivery rates applicable to all service classifications, including mass market service classifications, recover the revenue requirement for each service classification. Concerning the request for documentation, this request is unduly burdensome, and not relevant to the determination of a mass market NEM successor tariff by December 31, 2018.

2. As explained in the response to JRP-2.1, the Company's current delivery rates are not designed to recover marginal cost for any service classifications, including mass market service classifications.

Central Hudson Gas & Electric Corporation
Matter Numbers 17-01276 and 17-01277
Response to Interrogatory / Document Request

Request No: PACE-1, IR-JRP-3
From: PACE Energy and Climate Center
Date of Request: March 13, 2018
Subject: Cost of Service Methodology

Question:

1. Please provide a detailed explanation of the cost of service methodology used by the Company in establishing mass market rates.

2. Please describe and numerically display the methodologies used for determining the classification and functionalization of costs in the cost of service study.

3. Please explain why the Company is using the methodology or methodologies that it is currently uses for each aspect of the ECOSS that the Company uses.

4. If the Company uses any form of minimum system, zero-intercept, zero-load, or other similar methodology, please provide a detailed description of the method. Please provide any citations or authorities supporting the selected method, and the reason for rejecting alternative methods.

5. Please provide a detailed list of the types and levels of costs that are: (1) included in costs that are classified as customer costs, (2) included in demand-related costs, and (3) included in energy-related costs in the cost of service study.

6. Please describe the Company's preferred cost of service methodologies. Please explain how the methods currently in use differ from the preferred approach. Please detail the cost and rate consequences of any deviation between the preferred method and the currently used methods. Please detail the Company's plans to change the methodologies that it currently uses in future rate proceedings.

7. Please detail the actual incremental costs the Company incurs to connect a new customer or initiate new customer service in each mass market rate class.

8. Please detail the costs that the Company would allocate to the customer cost category if the Company used a "Basic Customer Cost" methodology.

Response:

1. Please refer to the March 6th Joint Utility presentation and the Company's last rate order issued June 17, 2015 in Case 14-E-0318.

2. Please refer to the March 6th Joint Utility presentation.

3. The request is not relevant to the determination of the mass market NEM successor tariff by December 31, 2018. Notwithstanding the above, in overall response to this IR, the companies developed their most-recent ECOSs in accordance with prior practice and commission precedent. Please refer to the March 6th Joint Utility presentation.

4. Please refer the Company's response to UIU-1.4 for detailed descriptions of the methodology utilized by the Company in classifying investment in FERC Accounts 364-368. The Company utilized the "Electric Utility Cost Allocation Manual" dated January 1992 by the National Association of Regulatory Utility Commissioners as the basic reference on cost of service methodology in developing and applying the aforementioned methodology.

5. The requested information is provided in the March 6th Joint Utility presentation (Slide 19 for Central Hudson). This information has also been provided in Excel format in response to JRP-1.2 (please refer to Consolidated Edison's response to IR JRP-1.2).

6. The approach proposed by the Company in its most recent rate case is its preferred cost of service approach. Please refer to the testimony of the Company's Cost of Service Panel for a description of that approach.

7. The Company asserts that this Information Request is not relevant to the determination of the mass market NEM successor tariff by December 31, 2018. Specifically, "the actual incremental costs the Company incurs to … initiate new customer service in each mass market rate class" has no relevance in the determination of customer charges to mass market service classes which reflect the Commission's cost causation rate design principle.

8. The Company does not understand the meaning of the methodology characterized as "Basic Customer Cost".

Central Hudson Gas & Electric Corporation
Matter Numbers 17-01276 and 17-01277
Response to Interrogatory / Document Request

Request No: PACE-1, IR-JRP-4
From: PACE Energy and Climate Center
Date of Request: March 13, 2018
Subject: Cost of Service Methodology

Question:

1. Please explain what cost allocation methods (i.e., coincident or non-coincident peak, and number of peak hours, months per year) the Company uses for each of the cost components of mass market rates. Please explain how these allocation methods operate to determine the revenue requirement associated with each component of each mass market rate. For example, if Cost "A" is allocated according to class NCP, please show the basis for calculating the class NCP, the costs to be allocated and their source, the calculations applying the allocator to the costs, and the resulting addition to the class revenue requirement.) Please provide electronic (Excel) tables with formulas intact for this information.

2. Please provide a detailed explanation and citations to authorities for each cost allocation method used in the Company's mass market rates. Please explain how these authorities support the use of the particular allocation method for that cost or category of costs.

Response:

1. The requested information concerning allocation methods is provided in the Joint Utility's March 6th presentation (Slide 19 for Central Hudson). This information has also been provided by Consolidated Edison in Excel format in response to JRP-1.2. Please see the testimony of the Company's Cost of Service Panel in its most recent rate case, Case 17-E-0459, for detailed information on the allocation approaches and results from the Company's most recently filed ECOS.

2. The Company asserts that this request is unduly burdensome and irrelevant because it does not contribute to the Commission's goal of developing a mass market successor tariff by December 31, 2018.

Central Hudson Gas & Electric Corporation
Matter Numbers 17-01276 and 17-01277
Response to Interrogatory / Document Request

Request No:	PACE-1, IR-JRP-5
From:	PACE Energy and Climate Center
Date of Request:	March 13, 2018
Subject:	Cost of Service Methodology

Question:

1. Does the Company agree with the content of the Brattle Group presentation that was discussed in the March 6, 2018 meeting? If there are any aspects of the presentation that the Company does not agree with, please identify them.

2. Does the Company agree with the statement of Dr. Faruqui that all policy matters (such as low income customer support or incentives for DG systems) should be excluded from rate design considerations? Would the Company support policy changes such as an increased and permanent ITC for solar and "e-stamps" to help reduce the energy burden on low income customers if these aspects were removed from rate design?

3. If the Company proposes a rate design that generally conforms with the Brattle Group recommendations (i.e. a three-part rate for mass-market customers), please describe the following aspects of the rate design:
    a. What costs (e.g. primary distribution, secondary distribution, transformers, etc) will be recovered through the demand charge?
    b. Will demand be measured based on NCP or CP? If based on CP, will it be based on the system (ISO) CP, the utility-specific CP, the zonal CP, the class CP, or some other measure?
    c. What is the duration of the demand interval that would be used (i.e. 15 minute, 60 minute, etc)?
    d. Will there be any time of use demand charges? If so, what will be the methodology for determining the peak seasons/days/hours?
    e. For customers served by the Company under a standard offer service tariff, will any of the supply costs be recovered through demand charges? If so, please describe the demand rate structure for supply costs and whether it differs from the demand rate structure for T&D costs.

4. If a customer whose previous highest individual peak demand was 10 kW hits a new highest individual monthly peak demand of 12 kW at a time when neither the system nor the class is peaking, what equipment must be added to serve this incremental peak demand? If no equipment must be added, what are the incremental costs associated with serving the additional 2 kW of customer peak demand?

5. What steps would the Company take to educate mass-market customers that would be subject to the three-part rate?

6. Does the Company believe that pilots or actions described on page 45 of the Brattle presentation should be performed before implementing mass-market three-part rates for NEM customers on January 1, 2020? Does the Company believe that there is sufficient time to design, implement, and learn from these pilots by January 1, 2020?

7. Slide 42 of the Brattle presentation shows that energy usage for medium and large customers increased by 0.8% and 2.1%, respectively, under the residential demand charge tariff compared to the flat rate. Does this increase in energy usage from this rate design concern the Company?

8. Will each of the Companies have metering infrastructure and billing systems in place that will:
   a. Allow NEM customers to see the date and time of their peak usage in their monthly bill by January 1, 2020?
   b. Allow all mass-market customers to see this value by January 1, 2020?
   c. If the answer to either part (a) or part (b) is no, please indicate when the necessary metering and billing infrastructure will be operational for NEM and all mass-market customers to be able to receive this value on their monthly bill.

Response:

1. The Company generally agrees with the content of the Brattle Group March 6, 2018 presentation, "Rate Design for DER Customers in New York." The Company particularly agrees with the overall focus of the March 6th Brattle presentation, which is summarized on slide 8 in the following quote from Principles of Public Utility Rates, James Bonbright, "One standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and public opinion alike – the standard of cost of service."

2. The Company asserts that this Information Request is not relevant to the determination of a mass market NEM successor tariff by December 31, 2018. Notwithstanding the Company's assertion that this Information Request is not relevant, the Company believes that it is Dr. Faruqui's position that electric rates should be determined in a manner that reflects the costs to provide service.

3. The Company cannot respond to the question at this time as it is premature. Rate design proposals will be submitted May 14, 2018 and the Company will provide a presentation on its rate design proposal on May 24, 2018.

4. This question does not include sufficient information to determine if any equipment must be added to serve the hypothetical incremental peak demand.

The Company also asserts that this Information Request is not relevant to the determination of a mass market NEM successor tariff by December 31, 2018. Specifically, the cost of additional equipment that may or may not be required if one mass market customer increases peak demand by 2 kW is not relevant to cost-based ratemaking. Rather, cost-based ratemaking for a service classification should be informed by the combined effect of all customers in the service classification on the utilization of the Company's transmission and distribution systems.

The Company asserts that cost-based rates should provide proper price signals related to the use of a utility's current transmission and distribution assets. A customer who increases demand from 10 kW to 12 kW is using the capacity-related components of the system, and should pay their fair share, according to the Commission's rate making principle of cost causation.

5. The Company cannot respond to the question at this time as it is premature. The approach to outreach must be coordinated with the recommended rate design approach which will not be submitted until May 14, 2018.

6. Should the Company propose a mass-market three-part rate for NEM customers, the Company does not believe that it is necessary to perform pilots before implementing such rates for NEM customers on January 1, 2020. The Company will be guided by the experience and learnings from other jurisdictions and utilities that have implemented demand charges for mass market customers.

7. No, the increase in energy usage that is shown on Slide 42 of the Brattle presentation is not concerning. The information presented by Brattle on Slide 42 is hypothetical, based on the assumed load profiles (shown on Slide 41) for Customers A (small but peaky), B (average customer) and C (large and less peaky) and the hypothetical "current," "TOU," and "Residential Demand" rate. The customer responses to the Brattle hypothetical TOU and demand rates that are summarized on Slide 42 are specific to the hypothetical load profiles and rates that were used in Brattle's example and are not indicative of the way that any group of actual customers would respond to any set of actual rate designs. In addition, based on rate design principles, rate designs should empower economic decisions; it is an appropriate customer response to the introduction of properly-designed price signals with a demand charge that at least some customers would increase total usage. For example, a residential customer that could switch from the "Current" to "Residential Demand" rates on Slide 41 may respond by acquiring an electric vehicle that they charged at home during off-peak hours, when the EV charging would not affect the (on peak) demand charge. This customer's total usage would likely increase due to the EV charging that is deemed to be beneficial to society; this customer's on peak demand would likely decrease, in response to the on-peak demand charge.

8. Although discussion of a mass market NEM successor tariff is premature, such tariff will initially be targeted at new customers interconnected on and after January 1, 2020.
    a. It is anticipated that these customers will be able to see the date and time of their peak usage.
    b. It is anticipated that meter infrastructure and billing system capabilities will be in place to support these targeted customers by January 1, 2020.
    c. The implementation of rate design for all mass market customers will, as noted in Staff's January 30, 2018 rate design instructions (pp. 3,6), be dependent on the results of a bill impact analysis and reflect the principle of gradualism. All customers under the new rate design will have the necessary meters to provide this information.

Central Hudson Gas & Electric Corporation
Matter Numbers 17-01276 and 17-01277
Response to Interrogatory / Document Request

Request No: UIU IR-1
From: Utility Intervention Unit
Date of Request: March 12, 2018
Subject: Joint Utility Presentations March 6, 2018

Question:

1. Since 2002 to present (which for most utilities will be approximately 5 rate cases), please indicate if the Company uses a historic embedded costs of service (ECOS), pro-forma (forecasted) ECOS, marginal cost of service (MCOS), or any other combination as a guide to allocate costs to service classes during an electric rate case. In addition, please describe how each study or multiple studies are used to develop customer charges and costs in each electric rate case.

Case	Type of Cost of Service Used	Explanation
18-E-xxxx	Combination of Pro-Forma ECOS, Historic ECOS, MCOS	
17-E-xxxx		
16-E-xxxx		
15-E-xxxx		
14-E-xxxx		
Etc.		

2. Please explain in detail any changes in methodology used in each of the Company's electric ECOS studies conducted since 2002. If methodology and/or allocators have changed throughout the various steps of each rate case, please indicate the change in methodology:
   - as filed in Direct Testimony
   - as per MOU, Stipulation Agreement, etc.
   - as modified per Joint Proposal
   - as modified per Commission Order

   The table below can be used as a template for a response

Case	Methodology Change [as proposed in Utility Direct	Methodology Change [as per Joint Proposal]	Methodology Change [as per Commission	Methodology Change [as per MOU,

	Testimony]		Order]	Stipulation Agreement, etc.]
18-E-xxxx				
17-E-xxxx				
16-E-xxxx				
15-E-xxxx				
14-E-xxxx				
Etc.				

3. Please identify, in table format as illustrated below, the degree to which the Company classified costs associated with the specified FERC accounts as “demand-related” or “customer-related” or “other-related” (at both primary and secondary voltage facilities) in each electric embedded cost of service (ECOS) study it filed from 2002 to present. For example, a cell might read, “100% demand/0% customer.” If any electric ECOS study employed a different demand/customer/other (please specify “other” in your answer) classification between primary and secondary voltage facilities within the same FERC account, please include such separate demand/customer classifications for each voltage facility.

PRIMARY FERC ACCOUNTS – Demand/Customer/Other Breakdown

Case	FERC Account 364	FERC Account 365	FERC Account 366	FERC Account 367	FERC Account 368
18-E-xxxx	50% demand				
	50% customer				
17-E-xxxx					
16-E-xxxx					
15-E-xxxx					
14-E-xxxx					
Etc.					

*Note: The total customer/demand/other split for each FERC Account should equal 100%

SECONDARY FERC ACCOUNTS – Demand/Customer/Other Breakdown

Case	FERC Account 364	FERC Account 365	FERC Account 366	FERC Account 367	FERC Account 368
18-E-xxxx	100% demand				
17-E-xxxx					

16-E-xxxx					
15-E-xxxx					
14-E-xxxx					
Etc.					

*Note: The total customer/demand/other split for each FERC Account should equal 100%

4. In each of the Company's electric ECOS models filed from 2002 to present, please explain how the demand/customer/other split was derived for primary and secondary distribution FERC accounts 364-368. Was there a special study performed by the Company to obtain the demand/customer/other split for primary and secondary distribution accounts 364-368? If yes, please provide a copy of the special study and the workpapers with formulas unlocked. If no special study was performed to derive the split, indicate how the answer was derived (i.e., previous rate case Joint Proposal, Rate Design Stipulation Agreement, MOU). Please explain in detail and provide all documents to support your answer.

5. Compared to the electric ECOS study the Company filed in the most recent rate case, did any electric ECOS study the Company filed in previous rate cases since 2002 employ a different cost classification (customer, demand, energy, etc.) for any electric FERC account other than accounts 364, 365, 366, 367, and 368? If so, please illustrate such demand/customer classifications for each such FERC account in table format as illustrated below.

Proceeding	FERC Account [X]	FERC Account [Y]	Etc.
18-E-xxxx			
17-E-xxxx			
16-E-xxxx			
15-E-xxxx			
14-E-xxxx			

6. As a follow-up to the Joint Utilities presentation on March 6, 2018, please provide the following detailed information for each utility from the Company's latest ECOS model:

   Functionalization Step:

   During the Functionalization step in the Company's most recent electric ECOS model, please list ALL FERC Accounts and respective costs. If the FERC Accounts are further broken down by primary and secondary accounts, please indicate the costs for each. See below for a template example.

FERC Accounts	Costs [$M]
364 - Primary	
364 - Secondary	
365 – Primary	

365 - Secondary	
Etc.	

Classification Step:

During the Classification step in the Company's most recent electric ECOS model, please provide the percent classification of costs for each FERC Account (i.e., customer related, demand related, energy related, labor related, etc.). See below for a template example.

FERC Account	% of Customer Related Costs	% of Demand Related Costs	% of Energy Related Costs	Etc.	Total Costs [%]
364 Primary	50%	50%	0%	0%	100%
364 Secondary	20%	80%	0%	0%	100%
Etc.					

Allocation Step

During the Allocation step in the Company's most recent electric ECOS model, please provide the allocation of costs for each FERC Account broken down by each Service Class and subclass defined in the Company's ECOS model. Please also list the type of allocator used (i.e., customer allocator, primary demand allocator, secondary demand allocator …). See below for a template example.

FERC Account	Type of Costs	Type of Allocator	SC-1 Non-heating Cost Allocation [%]	SC-1 Heating Cost Allocation [%]	SC-2 Cost Allocation [%]	SC-3 Cost Allocation [%]	Etc.	Total Cost Allocation [%]
364 - Primary	Demand	NCP - Primary	10%	30%	20%	35%		100%
	Customer	Customer - Primary	3%	85%	5%	2%		100%
364 - Secondary	Demand	NCP - Secondary						
	Customer	Customer - Primary						
Etc.								

Please provide the resulting customer charges for each service class from the Company's ECOS model. If the Company used multiple ECOS models, please provide the answer from each model.

	SC-1 Cost	SC-2 Cost	SC-3 Cost	Etc.
Customer Charge				
Number of Customers				

7. Please list all the components that constitute the monthly residential electric customer charges (i.e., administrative costs, postage, building rent costs, etc.). If the utility has multiple residential service classes (or subclasses), please provide the customer component breakdown for each service class or subclass.

8. Are there service classes (or subclasses) that are analyzed separately (i.e., in the allocation step) in the utility's ECOS study and then combined with another service class prior to the revenue allocation step? If so, please identify the service classes this applies to, the variation in the rate of returns before and after combining service classes or subclasses, and explain why the Company follows this practice.

9. Please explain if each utility tracks the load profiles for net metered residential customers? If the answer is no, when does the utility plan on obtaining this information?

10. Please explain how many residential customers are currently and historically enrolled in Time of Use (TOU) rates? What percentage does this represent out of the entire electric residential customer population? How many of these customers have Plug-In Electric Vehicles? Please breakdown the number of customers by service class and/or sub classes.

11. Please explain if current and historical TOU rates are a) derived revenue neutral to the entire electric residential service class (generally known as SC1 in a utility ECOS model) or b) based on a separate service class from the electric ECOS cost profile. Please explain your answer in detail and include data such as the resulting rate of returns of the residential TOU class vs. SC1 class if applicable.

12. Please explain the different usage profile and cost profile of residential customers under (a) the standard residential service class (generally known as SC1) and (b) residential customers under Time of Use Service Classes (i.e., Niagara Mohawk's SC-1C, Central Hudson's SC-6, etc.).

13. Please explain how many residential customers are currently net metered residential customers in the utility service territory from 2006 to present? What percentage does the present number of net metering residential customers represent out of the entire electric residential population? Please breakdown the number of customers by service class and/or sub classes.

14. How many customers does the Company forecast to:
    a. Install solar on customer premise in the next 3 years?

b. Install geothermal unit on customer premise in the next 3 years?
c. Buy an electric vehicle in the next 3 years?

15. Please explain if the Company has billing indicators that distinguish between electric heating and non-heating residential customers.

16. Please explain if the Company has load profiles of various electric residential customers (i.e., heating, non-heating, low income, customer with solar, customers with electric vehicles, customers with geothermal technology, etc.). If the Company currently has this information, please provide the range of current and historic load factor values for the various types of residential customers.

17. Please provide the monthly bill usages ranging from 0 to the maximum usage experience in <u>each</u> residential and small commercial (non-demand) service class and subclass for January and July 2017. Please also provide the number of customers and number of low-income customers (residential only) in each billing usage range. If this information is not available during the requested time period, provide the latest year that the data is available. Please note, most utilities have provided this information in utility rate cases and it did not seem to be an issue for them to obtain the information.

18. Approximately how many residential heating and non-heating customers are currently in the Company's service territory that are (1) multifamily and (2) single family? Does the Company currently have the ability to extrapolate this information from its CIS system?

Response:

1. The provision of the historical data requested by UIU is unduly burdensome and not directly related to the goal of establishing a mass market NEM successor tariff by December 31, 2018. As such Central Hudson will provide only the latest available information based on UIU's request.

   In its most recent filing in Case 17-E-0459, Central Hudson prepared both historical year and pro-forma rate year ECOS studies which allow for a comparison of estimated realized to estimated expected rates of return based on the effective rate structure. The pro-forma rate year ECOS study provides a frame of reference and guidance for the design of cost-based delivery service rates that will produce relative rate of return uniformity among the various rate classes.

2. The Company asserts that this request is unduly burdensome and irrelevant because it does not contribute to the Commission's goal of developing a Mass Market NEM successor tariff by the end of 2018.

3. The provision of the historical data requested in IR UIU-3 is unduly burdensome and not directly related to the goal of establishing a mass market NEM successor tariff by December 31, 2018. Therefore, this response to IR UIU-3 will provide only the requested information from the Company's ECOS study from its most recently completed proceeding (Case 14-E-0318), which is provided in the March 6th Joint Utility presentation (Slide 19 for Central Hudson). This information has also been provided in Excel format in response to JRP-1.2 (please refer to Consolidated Edison's response to IR JRP-1.2).

4. The provision of the historical data requested by UIU is unduly burdensome and not directly related to the goal of establishing a mass market NEM successor tariff by December 31, 2018. As such Central Hudson will provide only the latest available information based on UIU's request. Please also refer to the March 6th Joint Utility presentation for this information.

   An explanation of the derivation of the demand/customer split for FERC Accounts 364-368 based on the Company's historical year ECOS filed in Case 17-E-0459 is provided in the table below:

Account	Demand/Customer	Primary/Secondary
364.00 - Poles	Customer-related cost determined as estimated average age-adjusted installed book cost of 45 ft pole applied to estimated number of 45 ft poles installed. Remaining balance deemed demand-related.	Determined based on the balances in Accounts 365.10 (Overhead Primary) and 365.20 (Overhead Secondary).
365.10 – Overhead Primary	Demand-related portion determined as current material cost related to minimum size wire/cable installed divided by age-adjusted average investment per foot. Remainder of age-adjusted average unit cost installed deemed customer-related. Unit costs so determined applied to actual footage installed. Resulting proportions applied to plant balance to determine demand related and customer related portions.	Primary
365.20 – Overhead Secondary	Demand-related portion determined as current material cost related to minimum size cable installed divided by age-adjusted average investment per foot. Remainder of age-adjusted average unit cost installed deemed customer-related. Unit costs so determined applied to actual footage installed. Resulting proportions applied to plant balance to determine	Secondary

	demand related and customer related portions.	
366.11 – Underground Conduit System	Demand-related portion follows conductor determination.	Determined for each sub-account (primary or secondary)
366.22 – Underground Direct Burial System	Demand-related portion follows conductor determination.	Determined for each sub-account (primary or secondary)
367.11 – Underground Primary in Conduit	Demand-related portion determined as current material cost for minimum size cable installed divided by age-adjusted average investment per foot. Remainder of age-adjusted average unit cost installed deemed customer-related. Unit costs so determined applied to actual footage installed. Resulting proportions applied to plant balance to determine demand related and customer related portions.	Primary
367.12 – Underground Primary Directly Buried	Demand-related portion determined as current material cost for minimum size cable installed divided by age-adjusted average investment per foot. Remainder of age-adjusted average unit cost installed deemed customer-related. Unit costs so determined applied to actual footage installed. Resulting proportions applied to plant balance to determine demand related and customer related portions.	Primary
367.21 – Underground Secondary in Conduit	Demand-related portion determined as current material cost for minimum size cable installed divided by age-adjusted average investment per foot. Remainder of age-adjusted average unit cost installed deemed customer-related. Unit costs so determined applied to actual footage installed. Resulting proportions applied to plant balance to determine demand related and customer related portions.	Secondary
367.22 – Underground Secondary Directly Buried	Demand-related portion determined as current material cost for minimum size cable installed divided by age-adjusted average investment per foot. Remainder of age-adjusted average unit cost installed deemed customer-related. Unit costs so determined applied to actual footage installed. Resulting proportions applied to plant balance to determine demand related and customer related portions.	Secondary
368.11 – Overhead Transformers	Age-adjusted average material cost for minimum size installed is multiplied	Not specifically identified.

	by number installed to determine customer-related portion. Remainder of investment is deemed demand-related.	
368.12 – Padmount Transformers	Age-adjusted average material cost for minimum size installed is multiplied by number installed to determine customer-related portion (performed for both single phase and three phase). Remainder of investment is deemed demand-related.	Not specifically identified.
368.13 – Overhead Capacitors 368.14 – Underground Capacitors 368.15 – Overhead Regulators	Demand-related.	Not specifically identified.
368.17 – Overhead Protection	Customer-related.	Not specifically identified.

5. The Company asserts that this request is unduly burdensome and irrelevant because it does not contribute to the Commission's goal of developing a mass market NEM successor tariff by the end of 2018.

6. The Company asserts that this request is irrelevant because it does not contribute to the Commission's goal of developing a mass market NEM successor tariff by the end of 2018.

7. To clarify, the Company's monthly residential electric customer charge is not "constituted" of components of the Company's customer-related costs; Slide 25 of the Joint Utility's March 6th presentation demonstrates that the current Service Class 1 (residential) customer charge does not fully recover all customer-related costs that are allocated to Service Class 1. The customer charge developed within the ECOS study is designed to recover the customer portion of primary lines, line transformers, secondary lines and services, as well as the costs of meter installations, installations on customer premises, meter ownership, meter services and maintenance, meter reading, bill printing, mailing and receipt services, customer services, customer account services and low income program costs, less the customer portion of other revenue.

8. Central Hudson asserts that this request is unduly burdensome and irrelevant because it does not contribute to the Commission's goal of developing a mass market NEM successor tariff by the end of 2018.

9. During 2017 Central Hudson actively expanded its electric load research program, selecting a sample of net metered accounts, installing load research meters and

initiating collection of data. However, sufficient data will not be available from these meters for use in the determination of NEM successor rates by December 31, 2018.

10. Central Hudson asserts that the provision of the requested historical data is unduly burdensome because it does not contribute to the Commission's goal of developing a mass market NEM successor tariff by the end of 2018. As such Central Hudson will provide only the latest available information based on UIU's request. For the twelve months ended December 31, 2017, an average of 971 customers, or 0.38% of total residential customers, were billed under the Company's residential time-of-use rates. The Company does not track Plug-In Electric Vehicle ownership by account.

11. (a) Central Hudson's alternative TOU delivery rates, effective December 1, 2017 pursuant to the Commission's November 17, 2017 order in Cases 17-E-0369, et al., were designed to be revenue neutral to the Service Class 1 (residential) rates, and will be adjusted to maintain such revenue neutrality in the event of a rate change.

    (b) Central Hudson's pre-existing TOU delivery rates, which are closed to new customers effective December 1, 2017 pursuant to the aforementioned order, are designed based on a separate service class designation within the ECOS study. Data related to this presentation within the ECOS study can be found under Case 17-E-0459.

12. The Company cannot respond because it is not clear what UIU means by "usage profile" or "cost profile".

13. The Company asserts that the provision of the requested historical data is unduly burdensome because it does not contribute to the Commission's goal of developing a mass market NEM successor tariff by the end of 2018. As such Central Hudson will provide only the latest available information based on UIU's request. As of December 31, 2017, 7,350 residential accounts were net metered as follows:

	Net Metered Installations	**Average Number of SC Customers**	**% Net Metered**
SC 1	7,296	257,115	2.8%
SC 6	54	971	5.6%
Total Residential	7,350	258,086	2.8%

14. a. As of February 28, 2018 there were 306 photovoltaic systems proposed for interconnection to the Company's system.
    b. The Company has not performed a study to estimate geothermal installations.
    c. The Company has not performed a study to estimate the electric vehicle purchase rate within the Company's service territory.

15. While there is no difference in electric rates, the Company does have account indicators that distinguish between residential electric heating and non-heating customers. It should be noted that this account information is generally self-reported by the customer.

16. Please refer to the Company's September 20, 2017 presentation on Data Availability for the Rate Design Working Group wherein Central Hudson discussed the availability of average hourly load in kW for each hour of 2 day types [weekday (M-F) and weekend (Sat, Sun, holiday)] for each month. This profile data is available on the Company's web site.

17. Please see attached file titled "UIU-017 Attachment.xlsx."

18. Central Hudson does not track this information nor does it have the ability to extrapolate this information from its CIS system.