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November 25, 2020

Honorable Michelle Phillips
Secretary to the Commission
New York State Public Service Commission
Three Empire State Plaza
Albany, NY 12223-1350

Re: Case 15-E-0751 – In the Matter of the Value of Distributed Energy Resources.

Dear Secretary Phillips,

Attached for filing in the above captioned proceeding please find the Whitepaper on Allocated Cost of Service Methods Used to Develop Standby and Buyback Service Rates jointly developed by the Department of Public Service Staff and the New York State Energy Research and Development Authority. This whitepaper describes findings and recommendations regarding the September 23, 2019, investor-owned electric utility filings directed by the Public Service Commission's May 16, 2019, Order on Standby and Buyback Service Rate Design and Establishing Optional Demand-Based Rates issued in this case. Specifically, this whitepaper considers application of the Allocated Cost of Service methodology, as well as the appropriateness of imposing certain of the resulting Standby and Buyback Service Charges to stand-alone energy storage systems.

Sincerely,

Bridget M. Woebbe
Assistant Counsel

Whitepaper on Allocated Cost of Service Methods Used to Develop Standby and Buyback Service Rates

Case 15-E-0751

November 25, 2020

Contents

Introduction and Background

Procedural History of ACOS and Standby/Buyback Rate Filings

On December 12, 2018, Department of Public Service Staff (DPS Staff) filed the Whitepaper on Standby and Buyback Service Rate Design and Residential Voluntary Demand Rates (2018 Staff Whitepaper) in Case 15-E-0751. In the relevant part, the 2018 Staff Whitepaper recommended using an Allocated Cost of Service (ACOS) methodology, originally proposed by Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), to develop more granular and cost-based Standby Service and Buyback Service rates, along with a number of other proposals related to options for participation under Standby and Buyback Service[1] and requirements for the design of specific rate elements. The 2018 Staff Whitepaper described the ACOS methodology as one that builds upon existing Embedded Cost of Service (ECOS) studies by further classifying all identified costs as either Customer, Shared, or Local, thereby determining the revenue requirements that would be recovered through the Customer Charge, Daily As-Used Demand Charge, and Contract Demand Charge, respectively, for Standby Service rates, as well the Customer Charge and Contract Demand Charge for Buyback Service rates. The 2018 Staff Whitepaper recommended that the Public Service Commission (Commission) require that each of New York State's investor-owned electric utilities (collectively, the Joint Utilities)[2] file updated Standby Service and Buyback Service rates using the ACOS methodology, including various changes to specific Standby Service charge components.

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1 Standby Service was initially designed for customers that self-supply some or all of their electricity needs from on-site generation sources. Standby Service is required for customers with on-site generation, although there are numerous technology and customer size-based exemptions. Buyback Service was initially designed for customers that use their on-site generation to export power back to a utility-owned electric grid, and is required for customers wishing to inject power, except for numerous technology- or customer size-based exemptions. Most of the exemptions to Standby Service and Buyback Service are directed by Public Service Law §66(j). The 2018 Staff Whitepaper includes a more complete description of Standby and Buyback Service history, exemptions, and other requirements.

2 The Joint Utilities, or utilities, are comprised of Central Hudson Gas & Electric Corporation (Central Hudson); Consolidated Edison Company of New York, Inc. (Con Edison); National Grid; New York State Electric & Gas Corporation (NYSEG); Orange and Rockland Utilities, Inc. (O&R); and Rochester Gas & Electric Corporation (RG&E).

In its May 16, 2019 Order on Standby and Buyback Service Rate Design and Establishing Optional Demand-Based Rates (2019 Standby Rate Order),[3] the Commission adopted many of the proposals included in the 2018 Staff Whitepaper, and directed each of the Joint Utility members to file updated Standby Service and Buyback Service rates developed using the ACOS methodology. The Joint Utilities made their respective filings on September 23, 2019, with Con Edison and O&R filing together, NYSEG and RG&E filing together, and Central Hudson and National Grid each filing separately. In addition to the information contained in the filings themselves, Staff convened two technical conferences prior to the deadline for public comments related to the Joint Utilities' filings. The first technical conference and stakeholder feedback session was held on November 15, 2019, and focused on providing time for the Joint Utilities to explain their filings and for Stakeholders to ask questions about such filings. The second technical conference was held on February 7, 2020, and focused on providing time for Stakeholders to present their views on the Joint Utilities' filings, as well as additional time for discussion on the filings themselves.

This Whitepaper is being jointly filed by DPS Staff and New York State Energy Research and Development Authority (NYSERDA) staff[4] (collectively referred to as Staff) and presents findings and recommendations regarding topics within the utility filings. Staff recommends that the Commission direct additional process and consideration of the utility filings prior to a final Commission determination. Specifically, in this Whitepaper Staff reports findings and recommendations regarding the utilities' application of the ACOS methodology, as well as the appropriateness of imposing certain of the resulting Standby and Buyback Service Charges to stand-alone energy storage systems.

Summary of Recommendations

Following review of the Joint Utilities' 2019 ACOS filings, Staff concludes that the filed ACOS studies do not sufficiently meet the Commission's directive for consistency in approaches among the Joint Utilities expressed in the 2019 Standby Rate Order, and result in inconsistent allocations of cost categories between customer classes. Therefore, Staff suggests

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[3] Case 15-E-0751, Value of Distributed Energy Resources, Order on Standby and Buyback Service Rate Design and Optional Demand-Based Rates (issued May 16, 2019).

[4] Guidehouse, a consultant contracted by NYSERDA, also contributed to this Whitepaper.

that the Commission require each of the Joint Utilities to file new ACOS studies and resulting rates based on a consistent standardized methodology, discussed further below.

In addition to a consistent ACOS methodology, Staff recommends that the Commission implement an exemption from Buyback Service Contract Demand Charges for stand-alone energy storage systems[5] that export electricity to the electric grid. Staff finds that the existing charges imposed under Standby Service, consisting of a Customer Charge, a Contract Demand Charge, and a Daily As-Used Demand Charge when electricity is withdrawn from the grid are appropriate for stand-alone energy storage systems. However, given the impact of both Standby and Buyback Service rates on stand-alone storage project economics, Staff recommends providing relief in the near-term to enable these stand-alone storage systems to gain greater penetration in the market while providing benefits to the distribution system. Therefore, Staff recommends that stand-alone energy storage systems be exempted from Contract Demand Charges for injections under Buyback Service.

Review of the Joint Utilities 2019 ACOS Filings

The Commission's 2019 Standby Rate Order required each of the Joint Utilities to apply the ACOS methodology to allocate embedded costs and use such allocated costs to develop rates for Standby Service and Buyback Service. When applying the ACOS methodology, the Joint Utilities allocated costs to three defined categories:

1) **Shared** – embedded costs associated with load-related assets (expenses and return on rate base) that are caused by the combined electric usage of many customers.
2) **Local** – embedded costs associated with load-related assets (expenses and return on rate base) that are caused exclusively by electric usage of individual customers or small groups of customers.
3) **Customer** – embedded costs associated with expenses related to serving customers, regardless of such customer's usage of electricity.

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[5] Stand-alone energy storage systems refer to energy storage systems which are not connected to other customer load beyond equipment necessary for operation and control of the energy storage system itself. Stand-alone energy storage systems typically draw power directly from the electric system for charging purposes, and discharge or export power directly back to the electric system. These systems are also colloquially referred to as "front of the meter" or "grid-connected" energy storage systems.

The intent of the 2019 Standby Rate Order requiring the ACOS filings was for each of the Joint Utilities to put forward a consistent methodology for further allocating the costs of service identified in their ECOS studies among these three categories, applying the Commission's guidance regarding the definitions of Shared, Local and Customer costs. In so doing, each of the Joint Utilities started with their ECOS study, which tracks costs consistent with the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts, which are accounting rules and reported as part of the required FERC Form 1.[6] Generally, the Joint Utilities' embedded cost filings either provided costs at a FERC account level or grossed up several FERC accounts by asset class or type.[7] The Joint Utilities then allocated costs by function: Production, Transmission, Primary Demand, Primary Customer, Secondary Demand, Secondary Customer and Customer Other. Finally, each of the Joint Utilities allocated costs to customer classes. The resulting allocation of costs to service classifications by function is the typical output of the ECOS study.

To perform the ACOS methodology, the Joint Utilities took the additional step to then allocate the costs by customer class and function identified in the ECOS study into Shared, Local and Customer costs. The Joint Utilities applied different approaches to allocation to the above categories, as shown in Table 1, below. The first approach was assigning aggregated FERC cost items into cost categories as either entirely Shared or Local, such as aggregating all Transmission demand costs and allocating them 100% to Shared. The second approach was allocating aggregated FERC cost items to both Shared and Local using a factor (designated as "Ratio" in Table 1),[8] such as the ratio of coincident peak demand to non-coincident peak demand, to allocate a percentage of all Primary Distribution costs to Local and the remaining to Shared. The third approach was directly assigning or allocating unaggregated FERC cost items (designated as "Mix" in Table 1), such as assigning all secondary overhead lines to Local or allocating all primary overhead lines to both Local and Shared based on the ratio of coincident peak demand to

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6 FERC form 1 is an annual regulatory requirement for Major electric utilities, licensees, and others.

7 National Grid, NYSEG, and RG&E provided ECOS results by FERC Account, whereas Con Edison, O&R, and Central Hudson grossed up several FERC Accounts in their ECOS studies.

8 Several utilities use allocation approaches, however there was no single consistent methodology used to calculate such factors.

non-coincident demand. The final approach was to calculate a percentage of costs for each of the three categories (Shared, Local and Customer) and then applying these percentages to the total revenue for the class. This approach, designated as "Allocated" below in Table 1, first required excluding certain costs related to general and administrative, then allocating the remaining costs among the categories, and finally calculating the ratios by dividing the total for each category by the sum of total costs for all categories (total less Administrative & General).

Table 1: Summary of IOU Filings: Cost Allocations by Cost Category

	Central Hudson	Con Edison	O&R	National Grid	NYSEG	RG&E
Sub-Transmission						
Transmission	Shared			Shared	Shared	Shared
Common Transmission	Local	Shared	Ratio	Shared	Shared	Shared
Sub-Transmission	Local			Shared	Shared	Shared
Primary Substation	Ratio	NA	Ratio	Shared	Shared	Shared
Primary Lines	NA	NA	NA	NA	NA	NA
Secondary Transformers	NA	NA	NA	NA	NA	NA
Secondary Lines & Services	NA	NA	NA	NA	NA	NA
Customer	Customer	Customer	Customer	Customer	Local	Local
Administrative & General	Allocated	Allocated	Allocated	Shared	Shared	Shared
Primary (Large)						
Transmission	Shared			Shared	Shared	Shared
Common Transmission	Local	Shared	Shared	Shared	Shared	Shared
Sub-Transmission	Shared			Shared	Shared	Shared
Primary Substation	Ratio	Ratio	Ratio	Ratio	Ratio	Ratio
Primary Lines	Local	Ratio		Ratio	Ratio	Ratio
Secondary Transformers	NA	NA	NA	NA	NA	NA
Secondary Lines & Services	NA	NA	NA	NA	NA	NA
Customer	Customer	Customer	Customer	Customer	Local	Local
Administrative & General	Allocated	Allocated	Allocated	Local	Local	Local
Secondary (Small)						
Transmission	Shared			Shared	Shared	Shared
Common Transmission	Shared	Shared	Shared	Shared	Shared	Shared
Sub-Transmission	Local			Shared	Shared	Shared
Primary Substation	Ratio	Ratio	Shared	Mix	Mix	Mix
Primary Lines	Local	Ratio	Ratio	Mix	Mix	Mix
Secondary Transformers	Local	Ratio	Ratio	Local	Local	Local
Secondary Lines & Services	Local	Ratio	Ratio	Local	Local	Local
Customer	Customer	Customer	Customer	Customer	Local	Local
Administrative & General	Allocated	Allocated	Allocated	Local	Local	Local

Once costs were allocated to Shared, Local, and Customer by Service Classification, the Joint Utilities used the results to develop Standby Service rates. Specifically, Shared costs are recovered through the Daily As-Used Demand Charge, Local costs are recovered through the

Contract Demand Charge, and finally Customer costs are recovered through the Customer Charge. It should be noted that in the 2019 Standby Order the Commission directed the Joint Utilities to keep customer charges constant at existing levels. Further, the same rates developed for Standby Service were used to develop updated Buyback Service rates for customers that export electricity onto the grid. These Buyback Service rates generally use the same rate components and rate levels for the Customer Charge and Contract Demand Charge as are applicable for Standby Service, but do not include a Daily As-Used Demand Charge.

Customers that take service under both Standby Service and Buyback Service, i.e., that both consume electricity from the grid and export electricity to the grid, are exempted from the Buyback Service Customer Charge, and are also exempted from the Contract Demand Charge under Buyback Service only to the extent that a customer's export capacity is less than or equal to that customer's Standby Service Contract Demand kilowatt (kW) amount. Customers whose export capacity to the grid exceeds their Standby Service Contract Demand kW amount must pay an incremental Contract Demand Charge under Buyback Service based on the difference between the maximum export to the grid and the Standby Service Contract Demand kW amount. Some of the Joint Utilities proposed that certain costs included in the Contract Demand (Local) costs be excluded from the Buyback rates if such costs are not influenced by exports. An example of such was Con Edison's proposal to exclude certain substation costs which would have otherwise been allocated to Local.

Proposed Standardized ACOS Methodology

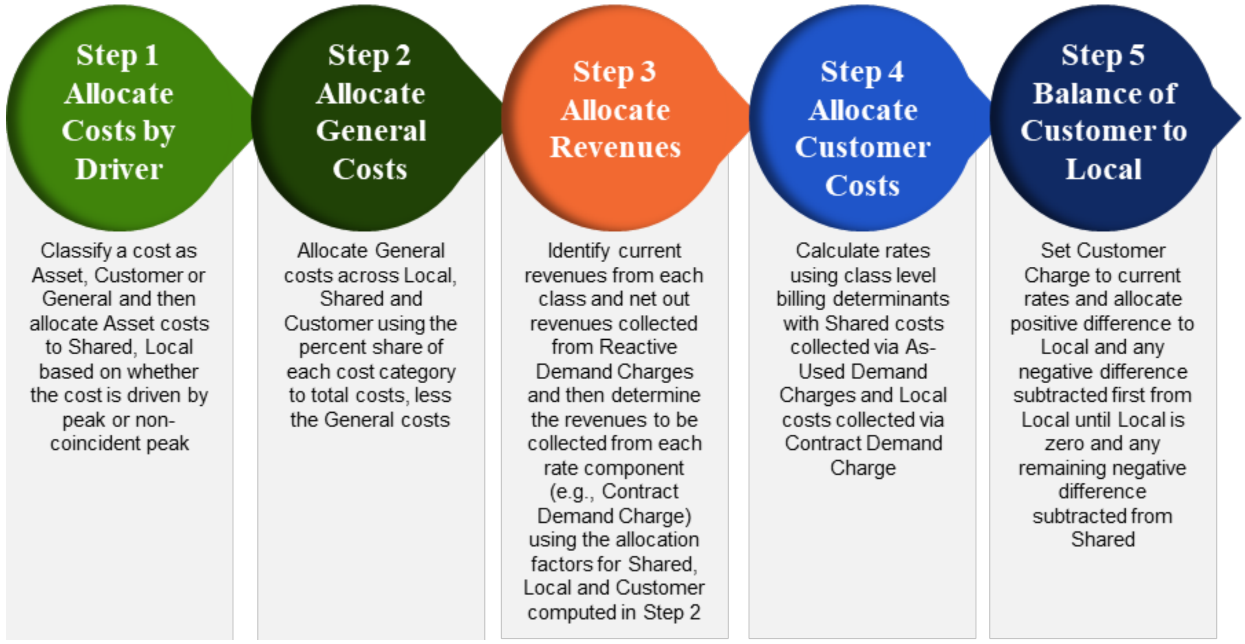
As noted above, the Joint Utilities allocated costs among Shared, Local and Customer categories in their ACOS filings. While each utility applied a consistent method across functions (e.g., Transmission, Primary Distribution, Primary Customer etc.) and customer classes within each utility, the allocation methods varied across all Joint Utilities. Based on its review of these filings, Staff notes several significant differences. First, each utility provided different levels of granularity within their respective ECOS study, resulting in a lack of consistency. Second, varied approaches were used to allocate each line item, with some relying completely on a binary basis (either 0% or 100%), while others applied some allocation of these line item costs to Shared or Local using various allocation factors. Among those utilities that allocated line item costs between Shared and Local the methodologies used to develop allocation factors were diverse. Finally, costs related to administrative and general activities, such as taxes and other costs that cannot be directly allocated to one of the three cost functions noted above, were treated differently.

The utility filings showed that there is a need for a standard, transparent, and repeatable methodology at a comparable level of granularity. To implement such a standard, transparent, and repeatable process for allocating costs, Staff recommends the Standardized ACOS Methodology below, which incorporates a "Decision Tree" approach. Staff's proposed Decision Tree is a series of standard "yes" or "no" questions which can be repeated for each FERC account (i.e., ECOS study line item) to determine if the cost should be allocated to Customer, Shared, Local, or some mix. Staff designed a standardized five-step process which incorporates the Decision Tree with a total of eight questions to determine how embedded costs are to be allocated to Shared, Local and Customer cost categories. This process was also used to develop Standby and Buyback Service rates. Using this Standardized ACOS Methodology provides a systematic approach with logical steps to allocate costs. It can be applied to each utility ECOS study, creating consistency amongst utilities and transparency regarding the process for designing rates. Additionally, each step for allocating costs is transparent, open to review and examination, and the logic of each determination is testable.

Ultimately, the Standardized ACOS Methodology results in all costs being allocated into the three categories first defined above: Shared, Local, and Customer. These cost categories are then used to set the revenues to be collected from each rate component in the Standby and Buyback rates.[9] Figure 1 below shows an overview of this five-step process, which will be described in detail.

[9] As noted above, Customer costs are collected via Customer Charge, Local costs are collected via Contract Demand Charges and, finally, Shared costs are collected via As-Used Demand Charges. Additionally, some Service Classification rates have reactive demand charges and those costs were pre-determined as part of the ECOS study and not impacted by the ACOS.

Figure 1: Proposed Standardized ACOS Methodology



Step 1 of the process is to first designate costs to be Asset, Customer or General costs. Asset costs are those costs that are associated with building and maintaining infrastructure to deliver electricity to customers and consists of both capital and expense related costs, to include meters. Customer costs are those costs related with connecting and serving the customer, such as billing, collections and education and outreach. Finally, General costs are related to activities that support all utility services and include FERC line items such as pensions, executive compensation and general taxes. Once costs are designated to Asset, Customer or General, then Asset costs are allocated to Customer, Shared and Local. Asset related Customer costs are Asset costs related to services to connect and meter customers. Many of the Joint Utilities designate Customer costs as part of their ECOS studies and these designations are maintained in Step 1.

Step 2 allocates General costs across Customer, Shared and Local. Steps 3 through 5 are applied to generate the final Customer, Contract Demand and As-Used Demand Charges for each parent Service Classification.[10]

[10] The parent Service Classification is the Service Classification a customer would take service under if they were not subject to Standby Service or Buyback Service.

Proposed Decision Tree

Figure 2: Proposed ACOS Decision Tree

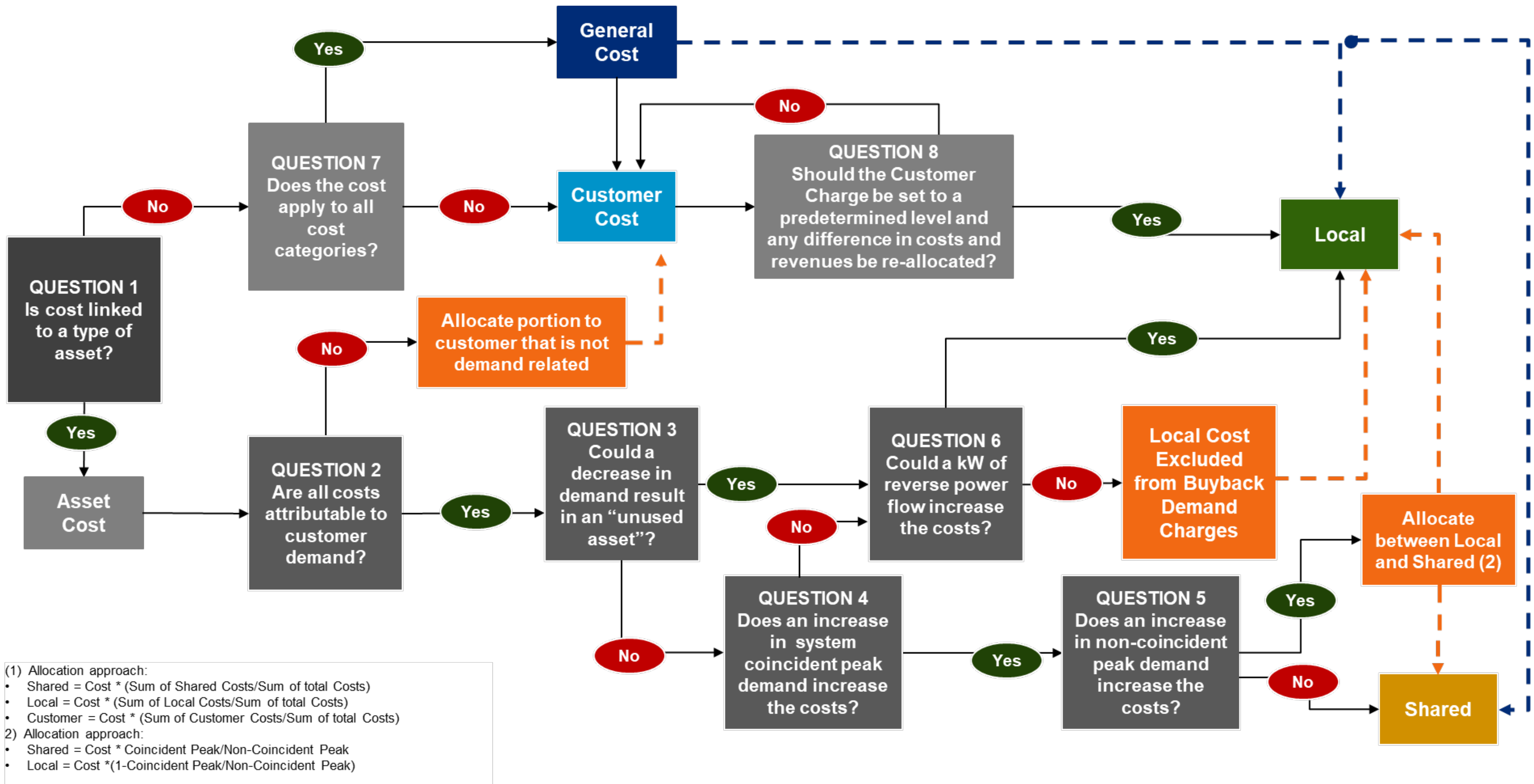


Figure 2 above shows the proposed Decision Tree that is applied to each FERC account to complete the steps described above. The Decision Tree is an easy to follow set of ordered decisions and is comprised of nine yes/no questions. Any residual costs that cannot be allocated exclusively to Customer, Shared, or Local at the end of the Decision Tree are allocated among Shared and Local using a specific pre-determined factor. How to address each question and the order in which to address each is shown in Figure 2.

The Decision Tree questions are applied to each line item of the FERC Form 1. The first question of the Decision Tree establishes whether a cost is Asset-based. Questions 2 through 6 are used to establish whether an Asset-based cost should be assigned entirely or in part to the Customer, Shared or Local category. The fourth and fifth questions in the Decision Tree establish whether Asset-based costs, which are also demand-based, should be allocated entirely to the Local category and if the final costs allocated to Local should be excluded from the Buyback Contract Demand Charge. Question 7 is used to designate and then allocate General costs to Customer, Shared and Local. Finally, Questions 8 and 9 are used to generate the Customer Charge. These last two steps were added because the Joint Utilities were directed to set the Customer Charge to current levels for this ACOS filing. In future filings this constraint may be removed, however, this methodology establishes a consistent approach for determining Customer Charge given any constraint created by designating a value for Customer Charge.

Note that Questions 1 and 2 apply to each FERC account line item and answers to these questions should be the same for all service classifications and voltage levels within a given utility. However, the answers to Questions 3-6 may differ by embedded costs designations as determined by each Joint Utility in their ECOS filing. That is, as part of the ECOS studies, costs were already separated by Transmission Demand, Primary Distribution Demand, and Secondary Distribution Demand as well as Primary Customer, Secondary Customer, and Other Customer costs.

Question 1: Is the cost linked to a type of asset?

This question allows for identification of costs that are Asset-related versus exclusively Customer or General. Asset costs are then further allocated to Shared, Local and Customer cost categories. By asking if the costs are tied to an asset, one can clearly distinguish that the cost is associated with physical plant to serve customers versus other operating expenses. If the cost is directly linked to the capital or operations of an asset the answer is “yes”, otherwise “no”. Note that the answer to Question 1 applies to the FERC line item and thus applies to the allocation of all costs in the line item to the Asset cost category regardless of whether the ECOS study further designates the costs to be Customer costs or demand costs.[11] If the answer to Question 1 is "yes", move on to Question 2. If the answer is "no", skip to Question 7.

Question 2: Are all the costs attributable to customer demand?

Question 2 is asked if the answer to Question 1 is "yes." Question 2 is designed to determine if the Asset-related costs are primarily driven by increases in the number of customers or increases in customer demand, and therefore whether such costs should be recovered through the Customer Charge or other demand-related charges.

If the answer to Question 2 is "yes", then the Asset-related costs are caused by customer demand and not the number of customers, and therefore should be recovered through demand-related charges. If the answer is "no", then the costs are caused by the number of customers, irrespective of such customers' usage. Examples of Asset-related costs driven by the number of customers are line extensions and meter installation. These costs are incurred regardless of the level of a customer's use, peak demand, non-coincident demand or other consumption-related drivers.

In cases where the utility further segments a FERC line-item cost between Demand and Customer, the costs that are customer related are allocated to the Customer cost category, and remaining costs for that FERC line item are then allocated based on the answers to Questions 3 through 6 in the Decision Tree.

Question 3: Could a decrease in demand result in 'unused assets'?

This question is asked to identify costs that would be stranded if the customer load on that asset decreases. If an asset would be stranded if the customer's (or small group of customers) load on that asset declines, then the costs were most likely incurred specifically to serve that customer (or group of customers) and thus should be considered Local. This question is the first after determining if the cost is load (customer demand) related because if the answer is "yes", those costs should be entirely allocated to Local. If these costs are indeed stranded as a result of a customer or small group of customers no longer using the asset, the asset was, by

[11] As noted previously, ECOS studies broke out costs into Production, Transmission, Primary Demand, Primary Customer, Secondary Demand, Secondary Customer and Other Customer. The FERC line items were then allocated to each of these six categories in the ECOS studies. Question 1 applies to the line item, not the subsections of the ECOS study.

definition, built specifically for that customer or small group and thus should be designated Local. If the answer is "no", then Question 4 applies.

Question 4: Does an increase in system coincident peak demand increase the costs?

Questions 4 and 5 are linked, but the order is important. Question 4 is asked first and focuses on whether the costs were driven by individual customer non-coincident demand or by system-coincident peak demand. If an increase in system-coincident peak demand on the asset does not result in increased costs, then that asset must be linked to serving individual customer demands instead of the combined demand of many customers, and the associated costs are therefore entirely Local.

If the answer is yes, the cost is either entirely Shared, or partially Shared and partially Local). Question 5 then determines if the costs are partially Local.[12] The ordering of Questions 4 and 5 is consistent with Staff's approach to determining which costs are entirely Customer, Local, or Shared prior to determining if certain costs are partially one category and partially another.

Question 5: Does an increase in non-coincident peak demand increase the costs?

If the costs are incurred to meet the system coincident peak load (that is, the answer to Question 4 is "yes"), then such costs must be at least partially Shared, however, additional information is required to determine if the costs are exclusively Shared. Question 5 identifies whether the costs are also driven by increases in non-coincident peak and therefore costs should be allocated between Shared and Local. Prior to Question 5, all costs are allocated in a binary fashion (either 0% or 100%) to either Local or Shared. Question 5 provides consideration for costs that may be both Shared and Local. This is necessary since the cost data are not disaggregated sufficiently within FERC accounts to distinguish if the costs are exclusively Shared or Local, even after ECOS allocations are applied. Specifically, FERC accounting is structured to capture similar costs within certain categories without any determination of what causes the costs. Therefore, the next step in the Decision Tree is to allocate the line-item costs between Shared and Local using a predetermined factor.

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[12] Reversing the order of Questions 5 and 6 typically results in higher than reasonable allocations to the Local category.

For Question 5, a "yes" answer results in costs being allocated between Shared and Local using an Allocation Factor. A "no" answer results in the costs being allocated exclusively to Shared.

Question 6: Could a kW of reverse power flow increase the costs?

Question 6 is the last question related to allocation of Asset costs and addresses whether exports onto the grid that create reverse flow on the asset represented by the cost element, would change the costs. If it is determined that exports would not drive additional costs, these costs should be excluded from the Contract Demand Charge in the Buyback Service rate. An answer of "no" results in the costs being excluded from this Contract Demand Charge while an answer of "yes" would result in the costs being included in both the Buyback and Standby Service rate Contract Demand Charge. Note this question is asked after all costs are allocated to Local and Shared either in a binary fashion or using an allocation factor.

Upon completion of Question 6, all Asset costs are fully allocated to Customer, Shared and Local and costs that should be excluded from the Contract Demand Charge for the Buyback Service rate have been identified. The next step is to move to Question 7 to determine appropriate treatment of General costs and the calculation of the Customer Charge.

Question 7: Does the cost apply to all cost categories?

Question 7 is asked if the answer to Question 1 is "no". Question 7 is used to identify those specific costs that are driven by customer service and support activities and thus are entirely allocated to the Customer cost category. This question further segments costs not identified as Asset-related between Customer and General. Customer costs are expenses related to metering, billing, collections and customer services. These expenses are usually designated in the FERC accounts specifically and are easily identified. General costs, on the other hand, are typically allocated among customer groups based on share of total costs rather than a single cost driver because these costs are related to necessary systems and activities to support all aspects of utility service.

As noted above, because General costs are related to activities that support all utility services, these costs should be allocated across the three categories. Therefore, it would be unreasonable to assume these costs should be collected solely through any one of these rate components (Customer Charge, As-Used Demand Charge, and Contract Demand Charge). An equitable method for allocating these costs to Customer, Local and Shared categories is to allocate by percent of each of these costs to the total (e.g., the portion allocated to Local is based on Local costs divided by the total of Local, Customer and Shared costs). As a result, Staff recommends allocating such costs to the Customer, Shared, and Local categories in equal proportion to each cost category's cost share of total non-General costs.[13] Also note that General costs allocated to Local are not excluded from the Buyback Service Contract Demand Charge.

Question 8: Should the Customer Charge be set to a predetermined level and any difference in costs and revenues be re-allocated?

As directed by the Commission in the 2019 Standby Rate Order, the Customer Charge for new Standby and Buyback Service rates should be set equal to the current Customer Charge applicable to the parent Service Classification. This may result in the revenues from the Customer Charge for any class being greater or less than the total costs allocated to the Customer cost category. To ensure all costs are fully collected, and not over-collected, any difference in customer charge revenues must be allocated to either Shared, Local, or both. A strict implementation of cost-based rate design would dictate that all Customer costs be collected through Customer Charges, since that is not possible in this instance any excess or uncollected Customer costs should be added to or deducted from the next-most similar cost category – Local costs. Therefore, any identified Customer costs that cannot be recovered through the Customer Charge should be first allocated to Local. Similarly, any negative difference between Customer Charge revenues and Customer costs should be credited first to Local. If the customer class' Local costs are less than this negative difference, any remaining difference is then subtracted from Shared costs.

It is important to note that some Service Classifications have Reactive Demand Charges. Since those charges are already pre-determined outside the ACOS framework, those rates did not change, and the revenues collected from those charges were netted from total revenues to be collected to achieve revenue neutral rates. Specifically, the proposed approach nets out the reactive demand revenues from total revenue requirement and then allocates the remaining

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[13] For example, assume total costs of 110, General costs of 10, Customer costs of 20, Local costs of 50 and Shared Costs of 30. In this example, the General costs of 10 would be allocated to Customer, Local and Shared based on their percentage of costs related to the remaining 100. Specifically, General costs would be allocated to Customer, Local and Shared 2, 5, and 3, respectively, leaving total Customer at 22, Local at 55 and Shared at 33, totaling 110.

revenues to Shared, Customer and Local based on the calculated percentages outlined in Steps 1 through 6 in the Decision Tree.

This is a deviation from the approach taken by some of the Joint Utilities, which first applied the Shared allocation factor to all revenue requirements and then netted out the revenues from the Reactive Demand Charges, further reducing the allocation of costs to Local. The proposed approach differs because those costs are already designated as reactive power costs via the ECOS. Removing those revenues from the total revenues to be collected from Customer Charge, As-Used Demand Charges and Contract Demand Charges should be based on the actual allocation factors applied to net revenue requirement to preserve both the ECOS allocation process and the ACOS approach for identifying and categorizing costs as Shared, Local and Customer.

Allocation to both Shared and Local Costs using a predetermined factor

The binary process dictated by the Decision Tree leads to allocation of costs of each FERC line item that can be justified with the answer to each question. As discussed above, not all costs can be entirely attributed to only a single cost category due to the nature of aggregation of costs and accounting processes. To allocate the final 'non-binary' costs resulting from answering "yes" to Question 5 requires some assumption on a just and reasonable means for allocating these costs between Shared and Local. Staff recommends using the ratio of coincident peak demand to non-coincident peak demand, since this allocation factor represents overall use of the asset by customers.

In an undiversified system, the system peak and the non-coincident peak would be the same and therefore it is clear that all customers use the asset equally and thus should pay for the asset equally. As a system becomes more diversified, the non-coincident peak diverges from the coincident peak. In a diverse system, it is no longer clear that all customers use the asset equally, but rather some smaller group or individual customers are using the asset more than others. The ratio of coincident peak and non-coincident peak is a proxy for identifying the use of the asset and thus fairly allocates costs between Shared and Local. Further, because the Joint Utilities' ECOS studies allocate costs to Primary, Secondary and Transmission level services, this ratio should be calculated at the same level.

Staff also considered allocating costs equally between Shared and Local, leading to a 50/50 allocation. Although simple and straightforward to apply, this formulaic approach is not based on appropriate cost categorization, and therefore was rejected by Staff as a viable alternative.

Data Needs

To apply the Decision Tree, the cost data need to be at a level of granularity to distinguish costs appropriately. FERC account level cost classification provides a sufficient level of granularity as well as a consistent approach for all utilities. Below is an example of the FERC cost allocation categories for distribution costs.[14]

- Land and Land Rights
- Structures and Improvements
- Station Equipment
- Poles, towers and fixtures
- Overhead conductors, devices
- Underground conduits
- Underground conductors, devices
- Line transformers

In addition to cost data, additional data are needed for developing the allocation factor. Specifically, the coincident peak demand to non-coincident peak demand ratio is needed. For this whitepaper, only the billing determinants were available as a proxy for this allocation factor. Going forward, each utility should use the results from its last Class Demand Study, used to develop the ECOS study, to determine this allocation factor.

Outcomes of the Decision Tree Analysis

Staff applied the proposed Standardized ACOS Methodology to calculate new rates for three of the Joint Utilities for illustrative purposes only: National Grid, NYSEG, and RG&E. Appendix B provides a summary of the change in the allocation factors for Shared, Local and Customer. The new rates, as well as a comparison of the new rates to what the utilities have filed for certain parent Service Classifications, are shown in Table 2. Note that, consistent with

[14] See Appendix A for example of detailed list of FERC line items that should be applied to the Decision Tree approach. See Appendix C for a step-by-step example of the calculation of rates using the Standardized ACOS Methodology.

the Joint Utilities filings, Customer Charges were set to current levels and thus there were no changes to those rates for each Service Classification.

A review of the implications of applying the proposed Standardized ACOS Methodology to the remaining utility filings was not possible because some needed data was not available for all utilities.[15] For each utility that Staff was able to apply the Standardized ACOS Methodology and analyse the resulting rates, Staff observed several variations from the rates proposed by each utility. In many cases, General costs were fully allocated to Local or Customer by the utilities, while the proposed approach does not presume these costs are fully Local or Customer. Further, for the utilities where Staff applied the Standardized ACOS Methodology, the proposed approach results in more costs allocated to Shared, thereby decreasing Contract Demand Charge rates and increasing Daily As-Used Demand rates. Staff anticipates that similar impacts will occur at the utilities that were not able to be analyzed as part of this Whitepaper.

Additionally, some utilities allocated fully on a binary basis and, therefore, some adjustments are made for those costs that are not allocated using the allocation factor. Finally, some utilities applied different allocation factors for different costs, in part to distinguish allocation of General costs. Nevertheless, the allocation factors that result from the proposed Standardized ACOS Methodology may differ because these factors are calculated at the Service Classification level.

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[15] Notably, Central Hudson, Con Edison, and O&R did not provide their ECOS and ACOS studies broken out by FERC account, but instead aggregate multiple FERC accounts together by function. Such aggregation makes applying Staff's proposed ACOS methodology impractical, therefore Staff was unable to analyze bill impacts for these utilities. Such bill impact analyses will be possible once Central Hudson, Con Edison, and O&R file new ACOS studies with appropriate granularity at the FERC account level.

Table 2: Comparison of Filed versus Proposed Standardized ACOS Methodology Rates[16]

NATIONAL GRID	Small General - Demand Charge	Large General - Secondary	Large General - Primary	Large General Sub-Transmission	Large General TOU - Primary & Secondary	Large General TOU - Sub-Transmission	Large General TOU - Transmission
Classification	SC2 D	SC3 SEC	SC3 PRI	SC3 SUB/TRAN	SC3A SEC/PRI	SC3A SUB	SC3A TRAN
Filed							
Customer Charge	$52.52	$390.00	$436.70	$427.37	$1,666.67	$2,088.00	$4,513.00
Contract Demand Charge	$2.36	$1.24	$0.02	$0.00	$0.84	$0.00	$0.00
As-Used Demand Charge - Peak	$0.4103	$0.3307	$0.3326	$0.1221	$0.3358	$0.1272	$0.1234
As-Used Demand Charge - Super Peak	$0.6703	$0.6041	$0.6087	$0.2228	$0.6130	$0.2350	$0.2424
Proposed							
Customer Charge	$52.52	$390.00	$436.70	$427.37	$1,666.67	$2,088.00	$4,513.00
Contract Demand Charge	$1.91	$0.68	$0.00	$0.00	$0.30	$0.00	$0.00
As-Used Demand Charge - Peak	$0.4479	$0.3590	$0.3340	$0.1221	$0.3605	$0.1272	$0.1234
As-Used Demand Charge - Super Peak	$0.7316	$0.6558	$0.6111	$0.2228	$0.6580	$0.2350	$0.2424
Difference							
Customer Charge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Contract Demand Charge	-$0.45	-$0.56	-$0.02	$0.00	-$0.54	$0.00	$0.00
As-Used Demand Charge - Peak	$0.0375	$0.0283	$0.0013	$0.0000	$0.0246	$0.0000	$0.0000
As-Used Demand Charge - Super Peak	$0.0613	$0.0518	$0.0024	$0.0000	$0.0450	$0.0000	$0.0000

16 Customer Charges were set to current levels, thus these values did not change and are not shown in Table 2.

Table 2: Comparison of Filed versus Proposed Standardized ACOS Methodology Rates – Cont.

NYSEG							
	Small General - Demand Charge	Large General - Primary	Large General - Sub-Transmission	Large General TOU - Secondary	Large General TOU - Primary	Large General TOU - Sub-Transmission	Large General TOU - Transmission
Classification	SC2	SC3 P	SC3 SUB	SC7-1	SC7-2	SC7-3	SC7-4
Filed							
Customer Charge	$24.31	$101.17	$333.06	$160.65	$561.77	$1,169.55	$2,641.63
Contract Demand Charge	$3.51	$2.22	$0.15	$1.50	$0.96	$0.00	$0.00
As-Used Demand Charge - Peak	$0.1800	$0.1561	$0.1295	$0.1927	$0.1709	$0.0621	$0.0276
As-Used Demand Charge - Super Peak	$0.3599	$0.3123	$0.2590	$0.3855	$0.3417	$0.1241	$0.0551
Proposed							
Customer Charge	$24.31	$101.17	$333.06	$160.65	$561.77	$1,169.55	$2,641.63
Contract Demand Charge	$1.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
As-Used Demand Charge - Peak	$0.2473	$0.2069	$0.1335	$0.2530	$0.2072	$0.0621	$0.0276
As-Used Demand Charge - Super Peak	$0.4947	$0.4138	$0.2670	$0.5060	$0.4143	$0.1241	$0.0551
Difference							
Customer Charge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Contract Demand Charge	-$1.84	-$2.22	-$0.15	-$1.50	-$0.96	$0.00	$0.00
As-Used Demand Charge - Peak	$0.0674	$0.0508	$0.0040	$0.0603	$0.0363	$0.0000	$0.0000
As-Used Demand Charge - Super Peak	$0.1347	$0.1016	$0.0079	$0.1205	$0.0726	$0.0000	$0.0000

RG&E							
	Small General - Demand Charge	Large General - Secondary	Large General TOU - Secondary	Large General TOU - Primary	Large General TOU - Sub-Transmission	Large General TOU - Transmission	Large General TOU - Transmission Industrial
Classification	SC2	SC3 S	SC8 S	SC8 P	SC8 T	SC8 Sub	SC8 TIND
Filed							
Customer Charge	$21.38	$297.13	$910.47	$1,144.87	$3,703.73	$1,969.55	$2,116.77
Contract Demand Charge	$2.13	$3.57	$1.63	$1.23	$0.00	$0.00	$0.00
As-Used Demand Charge - Peak	$0.1596	$0.4736	$0.4419	$0.4359	$0.3128	$0.2770	$0.3165
As-Used Demand Charge - Super Peak	$0.3191	$0.9473	$0.8838	$0.8719	$0.6255	$0.5539	$0.6329
Proposed							
Customer Charge	$21.38	$297.13	$910.47	$1,144.87	$3,703.73	$1,969.55	$2,116.77
Contract Demand Charge	$0.90	$0.21	$0.00	$0.00	$0.00	$0.00	$0.00
As-Used Demand Charge - Peak	$0.2015	$0.5893	$0.5090	$0.4901	$0.3128	$0.2770	$0.3165
As-Used Demand Charge - Super Peak	$0.4030	$1.1786	$1.0180	$0.9802	$0.6255	$0.5539	$0.6329
Difference							
Customer Charge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Contract Demand Charge	-$1.23	-$3.36	-$1.63	-$1.23	$0.00	$0.00	$0.00
As-Used Demand Charge - Peak	$0.0419	$0.1157	$0.0671	$0.0541	$0.0000	$0.0000	$0.0000
As-Used Demand Charge - Super Peak	$0.0839	$0.2313	$0.1341	$0.1083	$0.0000	$0.0000	$0.0000

Table 2 shows that the new Standardized ACOS Methodology results in lower Contract Demand rates and higher As-Used Demand Rates. National Grid's rates change by the least amount. This in part is because the methodology initially proposed by National Grid was the most consistent with the proposed methodology.

To review the impact of these new rates, a bill impact analyses was completed for the three utilities (National Grid, NYSEG, and RG&E) to which Staff was able to apply the Standard Methodology. To examine bill impacts on a range of customer usage profiles, bill impacts based on a customer with a higher than average load factor and a customer with a lower than average load factor were calculated. Staff also reviewed potential bill impacts for customers that use storage to offset peak demand use (i.e., "behind the meter" systems) and customers with stand-alone storage who charge from the grid during low cost periods and export during high cost periods. Table 3 shows the bill impact scenarios reviewed. The variability in rates for each of these scenarios was reviewed by applying a 10% change to non-coincident demand (Contract Demand) and then a 10% change in As-Used Peak demand. This comparison shows the bill sensitivity of the rate components for each customer profile.

Table 3: Description of Bill Impact Scenarios

Scenario	Description
Offsets All Super Peak	Storage system charges in Off-Peak and is sized to off-set all energy in Super Peak reducing Super Peak As-Used Demand charges to zero
Offsets All Peak	Storage system charges in Off-Peak and is sized to off-set all energy in Super Peak and Peak periods reducing all As-Used Demand Charges to zero
Oversized	Storage system charges in Off-Peak and oversized such that it covers all Super Peak and Peak period consumption and there is still excess to inject back into the grid
Stand-Alone	Storage system that is built to just provide power to the grid, charging only in the off-peak hours
Standby - Peaky	Standby only customer (no storage) but faces new standby rates – this customer has peak load twice that of NCP
Standby - Inverted	Standby only customer (no storage) but faces new standby rates – this customer has inverted load meaning their NCP is twice is as high peak

The results of the bill impact analyses are shown in Table 4. Specifically, Table 4 shows the percentage change in several Service Classifications for those three utilities. These results show that most customers would experience a bill decrease while some specific use-cases would see only slightly higher bills, driven mostly by the change in Contract Demand rates overall and the already set relationship between Peak and Super Peak As-Used Demand rates.

Table 4: Bill Impacts of New Rate for Selected Joint Utilities

NATIONAL GRID							
	Small General - Demand Charge	Large General - Secondary	Large General - Primary	Large General Sub-Transmission	Large General TOU - Primary & Secondary	Large General TOU - Sub-Transmission	Large General TOU - Transmission
Classification	SC2 D	SC3 SEC	SC3 PRI	SC3 SUB/TRAN	SC3A SEC/PRI	SC3A SUB	SC3A TRAN
Offset Super-Peak	-5%	-8%	-1%	0%	-10%	0%	0%
Offset All Peak	-5%	-8%	-1%	0%	-10%	0%	0%
Oversized	-43%	-52%	-9%	0%	-69%	0%	0%
Stand-Alone	-46%	-44%	-5%	0%	-63%	0%	0%
Standby - Peaky	2%	2%	0%	0%	2%	0%	0%
Standby - Inverted	-4%	-5%	0%	0%	-5%	0%	0%

NYSEG							
	Small General - Demand Charge	Large General - Primary	Large General - Sub-Transmission	Large General TOU - Secondary	Large General TOU - Primary	Large General TOU - Sub-Transmission	Large General TOU - Transmission
Classification	SC2	SC3 P	SC3 SUB	SC7-1	SC7-2	SC7-3	SC7-4
Offset Super-Peak	-26%	-4%	-44%	-33%	-30%	0%	0%
Offset All Peak	-26%	-4%	-44%	-33%	-30%	0%	0%
Oversized	-49%	-20%	-93%	-87%	-90%	0%	0%
Stand-Alone	-45%	-8%	-81%	-74%	-79%	0%	0%
Standby - Peaky	8%	1%	8%	8%	6%	0%	0%
Standby - Inverted	-13%	-1%	-17%	-15%	-13%	0%	0%

RG&E							
	Small General - Demand Charge	Large General - Secondary	Large General TOU - Secondary	Large General TOU - Primary	Large General TOU - Sub-Transmission	Large General TOU - Transmission	Large General TOU - Transmission Industrial
Classification	*SC2*	*SC3 S*	*SC8 S*	*SC8 P*	*SC8 T*	*SC8 Sub*	*SC8 TIND*
Offset Super-Peak	-14%	-27%	-18%	-16%	0%	0%	0%
Offset All Peak	-14%	-27%	-18%	-16%	0%	0%	0%
Oversized	-37%	-82%	-81%	-82%	0%	0%	0%
Stand-Alone	-24%	-69%	-63%	-67%	0%	0%	0%
Standby - Peaky	4%	6%	4%	4%	0%	0%	0%
Standby - Inverted	-6%	-13%	-9%	-8%	0%	0%	0%

These results show a decrease in rates for all customers except those with load profiles that have demand during the Super-Peak and Peak periods that are significantly higher than the Off-Peak period due to the increase in As-Used Demand Charges and decrease in Contract Demand rates. The reason for this is that for all customers, the amount allocated to Local and thus reflected in Contract Demand Charge declined using the proposed Standardized ACOS Methodology.

Staff's proposed Standardized ACOS Methodology includes allocating General across Shared, Local and Customer costs based on an allocated percent of those costs to the total. As noted above, this recommendation is consistent with allocation of General costs as these costs do not meet the requirement to be considered exclusively Local.

As Table 4 shows, Staff compared bills for stand-alone energy storage systems. These results show that the average stand-alone energy storage customer experiences much greater bill impacts than the average Standby Service customer[17], showing that these applications are more sensitive to the rate design and changes in Contract Demand. This is the result of stand-alone energy storage customers paying Contract Demand Charges for both charging (Standby Service) and exports (Buyback Service).

Staff's proposed Standardized ACOS Methodology results in reasonable Standby and Buyback Service rates and charges for most customers, however, additional consideration is still required for stand-alone energy storage systems. The Standardized ACOS Methodology results in an appropriate allocation of costs between Customer, Shared, and Local charges, and results in appropriate Standby Service rates for average Standby Service customers. Staff's Standardized ACOS Methodology similarly results in appropriate Standby Service rates for customers using energy storage systems or other actions to offset their peak demands. The bill impact analyses also revealed, however, that despite improvement for some customers using energy storage technologies, stand-alone energy storage customers would continue to be impacted more than the other typical applications.

Staff Recommendations for Treatment of Stand-Alone Storage

Given the impact of Standby and Buyback Service rates on stand-alone storage project economics, Staff recommends providing relief in the near-term to enable these stand-alone storage systems to gain greater penetration in the market. Therefore, Staff recommends that

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[17] Each rate is based on the billing determinants of the customer class to which the rate applies, and thus an 'average' customer profile can be identified by taking each billing determinant and dividing by the number of customers. Rates are then designed to result in revenue neutrality or rather the bill for the 'average' customer as defined above does not change.

stand-alone energy storage be exempted from Contract Demand Charges for injections under Buyback Service.

During charging, stand-alone energy storage systems pay a Contract Demand Charge along with a Daily As-Used Demand Charge, if applicable. Staff finds this treatment under Standby Service is appropriate and should continue. While Staff conceptually supports imposing the Buyback Service Contract Demand Charge for exports in excess of the Contract Demand kW used for Standby Service, in practice it is not reasonable to impose such charges for stand-alone storage systems at this time.[18]

When the Commission expanded eligibility under the Value of Distributed Energy Resources (VDER) tariff to stand-alone energy storage systems,[19] it explicitly recognized the value that energy storage will provide ratepayers as New York's clean energy policies are achieved. This includes the Climate Leadership and Community Protection Act (CLCPA)[20] requirements for 70% of electricity to come from renewable sources by 2030, 100% of electricity to come from zero carbon sources by 2040, and an 85% reduction in greenhouse gases by 2040, as compared to 1990 levels. Achieving these simultaneous renewable energy and greenhouse gas reduction goals is not possible without significant quantities of energy storage. The Commission therefore ordered a 3,000-megawatt (MW) energy storage goal by 2030, building off Governor Cuomo's interim target of 1,500 MW by 2025.[21] In order to achieve these goals, it is imperative to develop the energy storage market in New York without delay.

Since NYSERDA launched its energy storage incentive programs in Spring 2019, over 80% of the retail incentives awarded were for storage projects co-located with community solar, which already receive exemption from Standby and Buyback rates.[22] In total, approximately 25 stand-alone storage projects have been incentivized by NYSERDA that would likely be subject

[18] Staff continues to support imposition of these charges for other technologies, many of which do not face the same issues, nor are as critically important to meeting New York State's clean energy policy goals.

[19] Case 15-E-0751, Value of Distributed Energy Resources, Order on Value Stack Eligibility Expansion and Other Matters (issued September 12, 2018).

[20] Public Service Law § 66-p(b)(2)

[21] Both goals are now codified in the CLCPA.

[22] Energy storage assets co-located with Solar are not subject to charges under Buyback service per PSL §66(j).

to these demand charges during injections absent the co-located solar configuration. Of these projects, 13 are retail projects under 5 MW each, while 12 projects are Bulk Storage projects intending to provide wholesale market services to the New York Independent System Operator (NYISO) from their locations on utility-controlled distribution and sub-transmission networks. Staff understands that these Bulk Storage projects participate in the NYISO markets through the NYISO's Open Access Transmission Tariff (OATT), regulated by FERC. Staff also understands that the Buyback Service rates established by distribution utilities can sometimes impact the rates set under the OATT. To help clarify the areas where distribution utility Buyback Service rate design impacts customers participating in NYISO markets through the OATT, Staff requests that Stakeholders provide comments detailing the expected interaction between charges related to participation in the wholesale market and utility Standby and Buyback Service charges.

For all the reasons discussed above, Staff recommends that the Commission exempt stand-alone energy storage systems from Buyback Service Contract Demand charges. If desired, the Commission could place a limitation on the number of projects or timeframe within which this exemption is granted, however, Staff recommends that the Commission allow a 20-year exemption from Contract Demand Charges under Buyback Service be provided to all stand-alone energy storage projects interconnected and operational by December 31, 2025,[23] coinciding with the interim storage target. Any project not interconnected by that deadline should pay the Buyback Service Contract Demand Charges in effect at that time. Allowing an exemption is warranted in the short term, given the lengthy timeframes involved in designing new rate classes, the nascent stage of New York's storage market, and the importance of continuing to develop the energy storage market to help meet New York's aggressive clean energy policy goals. Further, imposing a capacity limitation to this exemption adds project development risk to developers and financiers because neither know whether a project will receive the exemption, potentially stifling the market or increasing the cost of financing and building such projects.

One concern often raised by Stakeholders when any exemption is recommended is the potential for a cost shift from participating to non-participating customers. Staff finds it unlikely that stand-alone storage will cause significant impacts to other customers. First, these stand-

[23] Such exemption should be available for the entire duration of an installation's useful service life. Repowering battery cells, for example, to maintain rated capacity, should not preclude this exemption from continuing.

alone storage customers will continue to be a small percentage of all utility customers, therefore even if a cost shift is created the impact on other customers will be very small. Second, these customers are creating new load, potentially decreasing rates for all customers as they contribute to fixed costs. Cost shifts arise when a customer is given an incentive for installing behind the meter equipment that is greater than the value of the distribution system costs avoided by reducing or shifting energy use with that equipment. Stand-alone storage systems are designed to consume electricity for the sole purpose of supplying electricity at a different time, presumably when the value of injections is higher than the costs of charging. As a result, these customers are creating new load by charging the battery, paying the Standby Service rates for that electricity service, and incrementally contributing to grid fixed charges while covering costs their new load creates.

Staff concludes that the potential for cost shift that could result from this recommended exemption as the number of stand-alone storage projects increases will likely be small, and is likely to be far outweighed by other ratepayer benefits, including the achievement of economic savings and beneficial system operations that storage provides. These benefits are particularly salient in areas where injections during high demand periods can offset congestion and additional distribution-level costs. These benefits continue to become even more attractive with increasing electric vehicle and other DER penetration.

Treatment of Existing Stand-Alone Storage Projects

Staff recommends that any stand-alone energy storage project that is interconnected prior to an exemption taking effect should be included in the exemption, with the exception of any project contracted under a utility NWA that did not receive a NYSERDA Market Acceleration Bridge Incentive.[24] . While this legacy treatment may be contrary to the terms and conditions offered in the past to various exemptions for other technologies, it is nevertheless reasonable to include existing stand-alone energy storage projects in this exemption as well due to the small number of projects impacted.

Prior to the release of this Whitepaper, NYSERDA included injection demand charges in its estimation of project economics and the necessary incentive level for retail storage projects.

[24] Existing NWA contracts are already finalized, and the costs associated with those contracts were already factored into the bid price requested. Granting this exemption to those systems without changing the prices paid create an unreasonable windfall to these customers.

Therefore, any project that was awarded a NYSERDA Market Acceleration Bridge Incentive under Rest of State Blocks 1-3, Con Ed Westchester Block 1, or Con Ed NYC Blocks 2-3, will only qualify for the exemption if it forfeits $50 per kilowatt-hour (kWh) of the incentive amount awarded by NYSERDA. NYSERDA project modeling, and discussions with storage developers, indicates the impact of the injection exemption is approximately $75-$100/kWh. Reducing existing awards that benefit from this exemption by $50/kWh recognizes that these earlier projects may likely have higher costs with permitting, siting, and financing, as these are the first of any stand-alone storage VDER projects built in the state. Any reduced incentive funds made available will be included as part of a new NYC Block 4 that NYSERDA anticipates issuing shortly.[25] No action is required for Bulk Storage projects as the incentive calculations for the Bulk Program did not include injection demand charges.

Process Recommendations

Staff plans to hold a technical conference to describe the proposal and answer any questions Stakeholders may have on the application. This feedback should help inform the written comments to be received. Based on the comments, Staff will present a final proposal to the Commission for consideration.

[25] There are approximately 300 MWs of stand-alone storage in utility interconnection queues, almost exclusively in Con Edison's service territory.

Appendix A

This Appendix includes examples of the application of the Decision Tree to costs from NYSEG's ACOS filing. Tables A-1 through A-4 below show examples of applying the Decision Tree that yield Shared, Local, Allocated, Customer and General costs using RG&E's GS Small ACOS results. This includes applying Question 9, which results in costs to be excluded.

Table A-1: Cost Allocation Example: Transmission Station Equipment (RG&E)

TRANSMISSION: STATION EQUIPMENT						
	Transmission ECOS	Primary Demand ECOS	Primary Customer ECOS	Secondary Demand ECOS	Secondary Customer ECOS	Other Customer ECOS
Question 1: Is cost linked to a type of asset?	Yes	Yes	Yes	Yes	Yes	Yes
Question 2: Does the cost apply to all cost categories?	No	No	No	No	No	No
QUESTION 3 Are all costs attributable to customer demand?	Yes	Yes	Yes	Yes	Yes	Yes
Question 4: Could a decrease in demand result in an "unused asset"?	No	No	No	No	No	No
Question 5: Does an increase system peak demand increase the costs?	Yes	Yes	Yes	Yes	Yes	Yes
Question 6: Could the increase in demand increase non—coincident peak and thereby increase cost?	No	No	No	No	No	No
Question 9: Does an increase in non-coincident demand increase cost?		Yes	Yes	Yes	Yes	Yes
Categorization	**Shared**	**Shared**	**Shared**	**Shared**	**Shared**	**Shared**
FERC Line Item Cost	34,036,251	0	0	0	0	0
Percent to Shared	100%	100%	100%	100%	100%	100%
Percent to Local	0%	0%	0%	0%	0%	0%
Percent to Customer	0%	0%	0%	0%	0%	0%
Percent to General	0%	0%	0%	0%	0%	0%
Shared	34,036,251	0	0	0	0	0
Local	0	0	0	0	0	0
Customer	0	0	0	0	0	0
General	0	0	0	0	0	0
Exclude from Buyback	0	0	0	0	0	0

Table A-2: Cost Allocation Example: Distribution Structures & Improvements

DISTRIBUTION: STRUCTURES & IMPROVEMENTS						
	Transmission ECOS	Primary Demand ECOS	Primary Customer ECOS	Secondary Demand ECOS	Secondary Customer ECOS	Other Customer ECOS
Question 1: Is cost linked to a type of asset?	Yes	Yes	Yes	Yes	Yes	Yes
Question 2: Does the cost apply to all cost categories?	No	No	No	No	No	No
QUESTION 3 Are all costs attributable to customer demand?	Yes	Yes	Yes	Yes	Yes	Yes
Question 4: Could a decrease in demand result in an "unused asset"?	No	No	No	No	No	No
Question 5: Does an increase system peak demand increase the costs?	Yes	Yes	Yes	No	No	No
Question 6: Could the increase in demand increase non—coincident peak and thereby increase cost?	No	Yes	Yes	Yes	Yes	Yes
Question 9: Does an increase in non-coincident demand increase cost?		No	No	No	No	No
Categorization	**Shared**	**Allocate**	**Allocate**	**Local**	**Local**	**Local**
FERC Line Item Cost	0	721,194	77,880	226,070	42,066	0
Percent to Shared	0%	78%	78%	0%	0%	0%
Percent to Local	0%	22%	22%	100%	100%	100%
Percent to Customer	0%	0%	0%	0%	0%	0%
Percent to General	0%	0%	0%	0%	0%	0%
Shared	0	559,079	60,373	0	0	0
Local	0	162,114	17,506	226,070	42,066	0
Customer	0	0	0	0	0	0
General	0	0	0	0	0	0
Exclude from Buyback	0	162,114	17,506	226,070	42,066	0

Table A-3: Cost Allocation Example: Customer Assistance – Non-Residential

CUSTOMER ASSISTANCE - NON-RESIDENTIAL						
	Transmission ECOS	Primary Demand ECOS	Primary Customer ECOS	Secondary Demand ECOS	Secondary Customer ECOS	Other Customer ECOS
Question 1: Is cost linked to a type of asset?	No	Yes	Yes	Yes	Yes	Yes
Question 2: Does the cost apply to all cost categories?	No	No	No	No	No	No
QUESTION 3 Are all costs attributable to customer demand?	Yes	No	No	No	No	Yes
Question 4: Could a decrease in demand result in an "unused asset"?	No	No	No	No	No	No
Question 5: Does an increase system peak demand increase the costs?	Yes	Yes	Yes	Yes	Yes	No
Question 6: Could the increase in demand increase non—coincident peak and thereby increase cost?	No	No	No	No	No	Yes
Question 9: Does an increase in non-coincident demand increase cost?		Yes	Yes	Yes	Yes	No
Categorization	**Customer**	**Customer**	**Customer**	**Customer**	**Customer**	**Customer**
FERC Line Item Cost	0	721,194	77,880	226,070	42,066	0
Percent to Shared	0%	0%	0%	0%	0%	0%
Percent to Local	0%	0%	0%	0%	0%	0%
Percent to Customer	100%	100%	100%	100%	100%	100%
Percent to General	0%	0%	0%	0%	0%	0%
Shared	0	0	0	0	0	0
Local	0	0	0	0	0	0
Customer	0	721,194	77,880	226,070	42,066	0
General	0	0	0	0	0	0
Exclude from Buyback	0	0	0	0	0	0

Table A-4: Cost Allocation Example: A&G Salaries

A&G SALARIES						
	Transmission ECOS	Primary Demand ECOS	Primary Customer ECOS	Secondary Demand ECOS	Secondary Customer ECOS	Other Customer ECOS
Question 1: Is cost linked to a type of asset?	No	Yes	Yes	Yes	Yes	Yes
Question 2: Does the cost apply to all cost categories?	Yes	No	No	No	No	No
QUESTION 3 Are all costs attributable to customer demand?	Yes	No	No	No	No	Yes
Question 4: Could a decrease in demand result in an “unused asset”?	No	No	No	No	No	No
Question 5: Does an increase system peak demand increase the costs?	Yes	No	No	No	No	No
Question 6: Could the increase in demand increase non—coincident peak and thereby increase cost?	No	No	No	No	No	Yes
Question 9: Does an increase in non-coincident demand increase cost?		Yes	Yes	Yes	Yes	No
Categorization	**General**	**General**	**General**	**General**	**General**	**General**
FERC Line Item Cost	62,274	184,105	25,050	41,022	7,938	76,293
Percent to Shared	0%	0%	0%	0%	0%	0%
Percent to Local	0%	0%	0%	0%	0%	0%
Percent to Customer	0%	0%	0%	0%	0%	0%
Percent to General	100%	100%	100%	100%	100%	100%
Shared	0	0	0	0	0	0
Local	0	0	0	0	0	0
Customer	0	0	0	0	0	0
General	62,274	184,105	25,050	41,022	7,938	76,293
Exclude from Buyback	0	0	0	0	0	0

Table A-5 through A-8 walk through an example of the calculation for Rates for RG&E's SC 8-T.

Table A-5: Summary of Costs Allocated to Function (RG&E SC-8T)

Step 1: Allocate Costs to Shared, Local and Customer			
	Proposed Allocation	**IOU Allocation**	**Difference**
Shared	**22,460,926**	**25,105,724**	**-2,644,798**
Local	**6,398,384**	**14,665,348**	**-8,266,964**
Customer	**1,129,268**	**0**	**1,129,268**
General	**10,801,967**	**0**	**10,801,967**
Total	**40,790,545**	**39,771,072**	**1,019,473**

Table A-6: Allocate General to Function (RG&E SC-8T)

Step 2: Allocate General				
	Total	**Percent**	**General Allocated**	**Allocated Total**
Shared	**22,460,926**	**75%**	**8,090,486**	**30,551,412**
Local	**6,398,384**	**21%**	**2,304,715**	**8,703,099**
Customer	**1,129,268**	**4%**	**406,765**	**1,536,034**
Total	**29,988,578**		**10,801,967**	**40,790,545**

Table A-7: Calculate Rates (RG&E SC-8T)

Step 3: Calculate Rates								
	Share of RRQ	**2020 RRQ**	**Allocated 2020 RRQ**	**Customer Charge**	**Overage**	**Percent Allocation**	**Reallocated to Local**	**Final Allocated RRQ**
Daily As-Used Demand Charge	**75%**		**42,758,760**			**0%**	**0**	**42,758,760**
Contract Demand Charge	**21%**		**12,180,574**			**100%**	**-7,665,339**	**4,515,235**
Customer Charge	**4%**		**2,149,783**	**9,815,121**	**-7,665,339**	**-100%**	**7,665,339**	**9,815,121**
Total	**100%**	**57,089,117**	**57,089,117**			**-159%**		**57,089,117**

Rate Component	**Billing Determinant**	**Allocated Revenue**	**Rate**
As-Used Demand Charge – Peak	**44,845,235**	**25,616,778**	**0.57**
As-Used Demand Charge - Super Peak	**30,009,091**	**17,141,982**	**1.14**
Contract Demand Charge	**3,097,240**	**4,515,235.5**	**1.46**
Customer Charge		**9,815,121.4**	**88.77**

Table A-8: Calculate Buyback Discount (RG&E SC-8T)

Step 4: Exclude Costs from Buyback			
	Billing Determinant	**Revenues to Exclude**	**Buyback Discount**
Contract Demand Charge	**3,097,240**	**519,433.5**	**0.17**
Buyback Contract Demand			**1.29**

Appendix B

Table B1: Comparison of Cost Allocations Among Shared, Local and Customer

NATIONAL GRID	Small General - Demand Charge	Large General - Secondary	Large General - Primary	Large General Sub-Transmission	Large General TOU - Primary & Secondary	Large General TOU - Sub-Transmission	Large General TOU - Transmission
Classification	***SC2 D***	***SC3 SEC***	***SC3 PRI***	***SC3 SUB/TRAN***	***SC3A SEC/PRI***	***SC3A SUB***	***SC3A TRAN***
Filed							
Shared	57%	70%	86%	76%	84%	87%	90%
Local	27%	13%	0%	0%	10%	0%	0%
Customer	16%	17%	14%	24%	6%	13%	10%
Proposed							
Shared	62%	76%	86%	76%	91%	87%	90%
Local	22%	7%	0%	0%	3%	0%	0%
Customer	16%	17%	14%	24%	6%	13%	10%
Difference							
Shared	5%	6%	0%	0%	7%	0%	0%
Local	-5%	-6%	0%	0%	-7%	0%	0%
Customer	0%	0%	0%	0%	0%	0%	0%

NYSEG	Small General - Demand Charge	Large General - Primary	Large General - Sub-Transmission	Large General TOU - Secondary	Large General TOU - Primary	Large General TOU - Sub-Transmission	Large General TOU - Transmission
Classification	***SC2***	***SC3 P***	***SC3 SUB***	***SC7-1***	***SC7-2***	***SC7-3***	***SC7-4***
Filed							
Shared	52%	67%	58%	65%	75%	76%	76%
Local	37%	22%	2%	20%	16%	0%	0%
Customer	12%	11%	40%	14%	9%	24%	24%
Proposed							
Shared	71%	89%	60%	86%	91%	76%	76%
Local	18%	0%	0%	0%	0%	0%	0%
Customer	12%	11%	40%	14%	9%	24%	24%
Difference							
Shared	19%	26%	2%	20%	16%	0%	0%
Local	-19%	-26%	-2%	-20%	-16%	0%	0%
Customer	0%	0%	0%	0%	0%	0%	0%

Table B1: Comparison of Cost Allocations Among Shared, Local and Customer – Cont.

RG&E	Small General - Demand Charge	Large General - Secondary	Large General TOU - Secondary	Large General TOU - Primary	Large General TOU - Sub-Transmission	Large General TOU - Transmission	Large General TOU - Transmission Industrial
Classification	**SC2**	**SC3 S**	**SC8 S**	**SC8 P**	**SC8 T**	**SC8 Sub**	**SC8 TIND**
Filed							
Shared	36%	69%	24%	91%	64%	62%	91%
Local	16%	18%	4%	8%	0%	0%	0%
Customer	47%	13%	73%	1%	36%	38%	9%
Proposed							
Shared	46%	86%	27%	99%	64%	62%	91%
Local	7%	1%	0%	0%	0%	0%	0%
Customer	47%	13%	73%	1%	36%	38%	9%
Difference							
Shared	10%	17%	4%	8%	0%	0%	0%
Local	-10%	-17%	-4%	-8%	0%	0%	0%
Customer	0%	0%	0%	0%	0%	0%	0%

Appendix C: Step-By-Step Example of Rate Calculation

STEP 1: Allocation to Customer, Shared and Local	Proposed Allocation
Shared	302,868
Local	78,649
Customer	380,354
General	388,305
Total	1,150,176

Step 1:
Using Standardized ACOS Methodology answer each question in Decision Tree that results in allocation of costs to Shared, Local, Customer and General

Step 2: Allocate General	Total	Percent	General Allocated	Allocated Total
Shared	302,868	40%	154,364	457,232
Local	78,649	10%	40,085	118,734
Customer	380,354	50%	193,856	574,210
Total	761,871		388,305	1,150,176
To Be Allocated	388,305			

Step 2:
Take difference between total less Shared, Local and Customer Allocations. Create ratios by dividing total into each category, then apply each ratio total to get allocation of generatl

Step 3: Calculate Rates	Allocated Total	Share of RRQ	2020 RRQ	Allocated 2020 RRQ	Customer Charge Revenue	Under (Overage)
Daily As-Used Demand Charge	457,232	40%		369,133,668		
Contract Demand Charge	118,734	10%		95,856,695		
Customer Charge	574,210	50%		463,572,526	304,108,716	159,463,810
Total	1,150,176	100%	928,562,889	928,562,889		

Step 3: Using Shared, Local and Customer Allocated Totals, calculate a Share of RRQ percentage. Apply this percentage to the required Revenue Requirement for the class and create an allocated RRQ. Calculate the Customer Charge Revenues by applying the current Customer Charge Rate to Customer Charge Billing Determinants. Take difference between Customer Allocated RRQ and Customer Charge Revenue to get Overage (Negative value and Customer Charge collects more than the costs) or Under (Positive Value and Customer Charge Does not collect all Customer Costs). Allocated RRQ should be Revenue Requirement after subtracting any revenues collected from Reactive Power Charges. Next, allocate the Under/(Overage) to Local. If the (Overage) is greater, in absolute value, than Local (such that allocating (Overage) to Local would cause Local to be negative), set Local to zero and allocate the remaining (Overage) ((Overage)+Local) to Shared.

	Percent Allocation	Reallocated	Final Allocated RRQ
Daily As-Used Demand Charge	0%	0	369,133,668
Contract Demand Charge	100%	159,463,810	255,320,505
Customer Charge	-100%	-159,463,810	304,108,716
Total	60%		928,562,889

Step 4: Calculate Rates					
Rate Component	Billing Determinant	Allocate to Rate	Allocated BD	Allocated Revenue	Rate
Daily As-Used Demand Charge					
Final Allocated RRQ				369,133,667.7	
Super Peak to Peak Ratio		229%			
As-Used Demand Charge - Peak	685,573,760	100%	685,573,760	221,480,201	0.32
As-Used Demand Charge - Super Peak	200,012,620	229%	457,049,174	147,653,467	0.74
Total BDs As-Used			1,142,622,934		
Contract Demand Charge					
Contract Demand Charge	92,302,421	100%		255,320,505.3	2.77
Customer Charge					
Customer Charge	17,888,748	100%		304,108,716.4	17.00

Step 4: Calculate New Rates. Apply Billing determinants to allocated revenues for each Rate component. Use same allocations between peak and super peak As-Used Demand Charges

Step 5: Review Rates	
Rate Component	New Rate
Peak As-Used Demand Charge	0.3231
Super Peak As-Used Demand Charge	0.7382
Contract Demand Charge	2.77
Customer Charge	17.00

Step 5: Review Rates

Step 6: Adjust Contract Demand for 'Exclude'					
Contract Demand Charge	Billing Determinant	Allocated Revenue	Excluded Revenue	Buyback revenue	Buyback Rate
Contract Demand Charge	92,302,421	255,320,505	-1,545.9	255,322,051.14	2.77
Buy-Back Contract Demand					2.77

Step 6: Calculate Buy-Back Contract Demand Rate. Subtracted Excluded Revenue from Decision Tree allocations from Allocated Local Revenues and, using same billing determinants, calculate Buy-Back Contract Rate