STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion, to conduct a study on rate designs and options that will account for the changing customer use of the grid due to the adoption of new energy technologies.	)))))	Case No. U-20960

COMMENTS OF THE
<u>ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY</u>

I. INTRODUCTION

On February 4, 2021, the Michigan Public Service Commission ("MPSC" or "Commission") issued an Order in this docket directing that no later than September 1, 2021, the Regulatory Assistance Project ("RAP") was to file in this docket a draft report summarizing efforts of the Distributed Energy Resources ("DER") Rate Design workgroup to date, a thorough exploration of how customer-owned generation and energy storage are changing the way energy customers use the grid, cost allocation, and pros and cons of various rate design options, and may include recommendations for the Commission's consideration. Pursuant to that Order a draft report entitled Smart Rate Design for Distribution Energy Resources (the "Report") was filed in this docket on September 2, 2021. At the September 8, 2021 workgroup meeting for this proceeding Commission Staff requested stakeholders submit written comments on the Report by September 22, 2021. ABATE's comments thereon are included below.[1]

[1] ABATE's silence in these comments and recommendations with respect to any portion of the Report should not be interpreted as an endorsement of any position taken in the Report.

II. COMMENTS

A. Certain elements of the Report's cost allocation discussions are not relevant to developing DER rates or do not adequately describe cost causation.

1. The Report's cost allocation discussions include elements that are not relevant to designing DER rates.

Throughout the Report RAP opined on a number of cost allocation issues that are not relevant to the design of DER rates, such as the proper allocation of generation and transmission fixed costs and the proper classification of customer-related costs.[2] The Report's recommendations on these issues appear based on RAP's January 2020 Electric Cost Allocation for a New Era – A Manual ("RAP Electric Cost Allocation Manual"). (See Report at 19 n 39.) Over the past few months, ABATE's consultants in this proceeding (Brubaker & Associates, Inc. ("BAI")) prepared a rebuttal of the recommendations found in the RAP Electric Cost Allocation Manual ("BAI Rebuttal to the RAP Cost Allocation Manual").[3] Many of the points made in the BAI Rebuttal of the RAP Cost Allocation Manual also apply to many aspects of RAP's cost allocation recommendations in the Report. Furthermore, the Report's broader recommendations and discussions regarding the allocation of generation, transmission, fixed distribution, and advanced metering costs are not relevant to the design of DER rates and should therefore ultimately be excluded from the final report filed in this proceeding.[4]

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[2] The Report's recommendation to "[c]ollect and track distribution system cost data in a way that ensures reasonable calculation of class-level responsibility for site infrastructure" is, however, an important guiding principle for rates design. (Report at 57.)

[3] Rebuttal of the Key Recommendations in the Regulatory Assistance Project's Electric Cost Allocation Manual, Brubaker & Associates, Inc., September 2021 (attached as Attachment 1).

[4] Pursuant to the Commission's February 4, 2021 Order the final Report must summarize efforts of the workgroup to date, thoroughly explore how customer-owned generation and energy storage are changing the way energy customers use the grid, address cost allocation, and provide pros and cons of various rate design options.

2. Coincident Peak demands are the central driver for the incurrence of fixed generation and transmission system costs.

In discussing cost causation on the electric system the Report stated that "not all generation capacity costs are caused by system peaks or even reliability needs more broadly." (Report at 20-21.) As discussed in the BAI Rebuttal of the RAP Cost Allocation Manual, however, coincident peak demands are the central driver for the incurrence of fixed generation costs, including, but not limited to, capacity costs. In other words, while additional factors may contribute to fixed generation costs to some extent, the most important and impactful factor is system peak demands. (BAI Rebuttal of the RAP Cost Allocation Manual at 2-9). The final Report should be consistent with this point and relevant costs should be allocated accordingly.

The same is true for transmission system costs. The Report stated that "an analyst should look to the underlying purposes and benefits of investments to understand their role in system planning and to allocate and price them properly," and "[s]everal different kinds of transmission capacity are intended to deliver energy and are not designed primarily to meet reliability needs." (Report at 20-21.) The Report also recommended that "any peak- or demand-related costs for generation and transmission" should be allocated "using a broad resource adequacy measure, such as the highest 100 hours or an hourly weighting based on a loss-of-energy expectation study." (Report at 57.) Despite these assertions and recommendations, the high voltage bulk transmission system is designed and constructed to ensure sufficient transmission capacity to cover coincident peak demands. This is also discussed in detail in the BAI Rebuttal of the RAP Cost Allocation Manual. (BAI Rebuttal of the RAP Cost Allocation Manual at 9-12.) In other words, coincident peak demands more accurately reflect cost causation for generation and transmission fixed costs and these costs should be allocated on that basis.

3. Cost allocation should remain consistent with cost causation.

The Report's discussion of certain specific cost allocation issues and approaches was also lacking. For instance, the Report suggested that "advanced metering infrastructure can be fairly allocated and efficiently charged to customers in a manner that reflects the[] broader purposes" of advanced metering infrastructure ("AMI"). (Report at 21, 57.) This claim should not be taken to suggest that AMI costs should be generally allocated beyond the customer classes which cause them. Specifically, costs incurred to deploy advanced metering for residential customers should not be allocated to non-residential customer classes, as discussed in the BAI Rebuttal of the RAP Cost Allocation Manual. (BAI Rebuttal of the RAP Cost Allocation Manual at 16-17.)

Further, while the Report discussed various approaches to cost allocation including whether various costs should be classified as demand-related, energy-related, or customer-related, it did not adequately address the minimum system approach to classifying distribution poles and wires. (Report at 29, 52, 57 ("Treat as customer-related only those costs that actually vary with the number of customers, generally known as the basic customer method").) There is a strong basis in cost causation for using the minimum system approach to classify and allocate a portion of distribution poles and wires costs on a customer basis. Further, customer-related costs should also include a portion of distribution line costs, as discussed in the BAI Rebuttal of the RAP Cost Allocation Manual. (BAI Rebuttal of the RAP Cost Allocation Manual at 12-15.)

In addition, the Report discussed the issue of cost shifting, including definitions thereof. (Report at 31.) Despite various approaches described in the Report the extent of interclass cost shifting is properly measured relative to a cost-based allocation by customer class, rather than by using some of the methods that RAP suggested in the Report.

Further, while the Report discussed the principle of efficient customer price signals and stated that it "is also generally the case that maximizing societal well-being requires the inclusion of externalities as a marginal cost," it failed to recognize that it is difficult to objectively quantify these externalities. (Report at 52.) Thus, the extent to which these unquantifiable factors "can justify a higher assignment of residual embedded costs to certain pricing elements, or the overall assessment of program costs and benefits using the societal cost test" is far from clear. (*Id*.) The final Report should therefore reflect the fact that these externalities cannot be sufficiently quantified and cannot justify excessive costs or unjustified increases.

B. Distribution and line transformer costs are primarily demand related and should be collected through a demand charge.

The Report suggested that for new residential DER customers import rates should "be redesigned to be time-varying for both supply and distribution" while export credit value "is set at time-varying supply rate" and "[a]ll residential customers have a monthly customer charge based on basic customer method, with tiered adders to recover incremental service line, secondary network and line transformer costs by type of customer." (Report at 59.) Contrary to this structure, costs associated with the distribution network and with line transformers are primarily demand-related and are more appropriately recovered through demand charges that are differentiated by voltage level. The Report and its recommended rate structure should reflect this fact and these costs should be collected accordingly.

C. The Report's description of an advanced residential rate design for DER pathway lacked certain information.

In addressing this proposal the Report stated that "customers with eligible generation technologies can receive an environmental value for exported energy, contingent on transferring RECs to the utility." (Report at 61.) The report did not, however, appear to specify whether non-residential customers would be eligible for such an environmental value credit. Also, the Report did not discuss how this environmental value would be quantified. The final Report should explicitly provide these details.

Further, the Report suggested that "[t]he three cost recovery elements are (1) a customer charge defined by the basic customer method, (2) an individual NCP demand charge to recover site infrastructure costs (service lines, secondary networks, and line transformers), and (3) a distribution flow charge on both imports and exports to recover a portion of shared distribution system costs, nonbypassable charges, and a share of A&G costs." (Report at 61.) Despite this proposal it is unclear why a distribution flow charge would be required in addition to the NCP demand charge. An NCP demand charge is the best means of ensuring that DER customers pay their appropriately allocated share of distribution system fixed costs. As such this charge should be the manner in which DER customers are allocated distribution system costs in accordance with their causation.

D. The suggested grid access charge is unclear.

The Report indicated that one rate choice "includes a grid access charge defined by installed capacity to recover an equitable portion of nonbypassable costs and a share of distribution system costs." (Report at 63.) It is not clear whether the suggested grid access charge would be designed as a per kW demand charge, or whether it would be designed on some other basis. The final Report should provide clarity on this charge's structure; specifically, the grid access charge should be designed on a per kW demand basis, particularly for larger customers who have demand meters.

E. Utilities are not the sole providers of DER services.

RAP's overall DER rate design recommendations in the Report appear to be premised on a paradigm in which the incumbent utility is the sole provider of power and DER services. This approach fails to recognize FERC Order 2222 and FERC's efforts to encourage the provision of DER services by third party providers. For instance, the Report noted that "[o]ne of the overarching goals of utility regulation is efficient choices of energy sources and, relatedly, allocation of resources across sectors," that "the goal that utilities should be regulated in order to mimic efficient market outcomes is a worthy one," and that "utility management should be incentivized to operate and invest efficiently in order to maximize the long-run value of their company in a manner that is consistent with the public interest." (Report at 17.) In addition to these points, regulation should ensure that utility management is not the only source of DER services. Thus, the Report should also address competition among traditional utility and third party DER providers, consistent with the framework contemplated in FERC Order 2222.

F. The Report does not adequately contemplate the practical application of its recommendations to large customers.

The Report discussed how "[n]ew residential distributed generation customers, as well as customers with storage or EVs with vehicle-to-grid (V2G) capabilities who wish to export to grid, are placed by default onto year-round time-of-use rates that are generally available to all residential customers." (Report at 59.) The Report's DER rate design recommendations appear to be largely focused on residential DER customers. As such, the Report failed to acknowledge that time of use rates are not typically necessary for larger DER customers who already have three-part rates that include demand charges. The demand charge already provides a price signal to reduce customer demand, and that price signal could be refined by introducing on-peak and off-peak demand charges into the rate structure. This existing rate structure must be reflected in the Report's recommendations.

III. CONCLUSION

Pursuant to Staff's solicitation of input and for the reasons set forth herein, ABATE recommends the comments and recommendations above be incorporated into the Report and reflected in any eventual rate designs.

Respectfully submitted,

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Rebuttal of the Key Recommendations in the Regulatory Assistance Project's Electric Cost Allocation Manual

Report

September 2021

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Abbreviations and Acronyms

A&E	Average and Excess
A&G	Administrative and General
BIP	Base-Intermediate-Peak
CP	Coincident Peak
Manual	Electric Cost Allocation for a New Era – A Manual
NARUC	National Association of Regulatory Utility Commissioners
POD	Probability of Dispatch
RAP	Regulatory Assistance Project

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Brubaker and Associates, Inc.
Rebuttal of the Key Recommendations in the
Regulatory Assistance Project's Electric Cost Allocation Manual
September 2021

Introduction

In January 2020, the Regulatory Assistance Project ("RAP") released an electric cost allocation manual entitled Electric Cost Allocation for a New Era ("Manual").[1] The authors of the Manual are Jim Lazar, Paul Chernick and William Marcus. Our report herein provides a high-level summary and critique of the Manual's major cost allocation recommendations.

The Manual offers numerous recommendations for electric cost allocation that, in the view of the Manual's authors, should be adopted to incorporate what they describe as "modern" cost of service methodologies that allegedly reflect changes in the electric industry such as expanded reliance on renewable resources and the increased deployment of storage technologies. The Manual is extensive and its cost allocation recommendations touch on virtually the entire range of utility cost categories, including generation, transmission and distribution fixed and variable costs, as well several categories of administrative and general ("A&G") expenses.

The Manual generally sets forth the traditional positions and arguments that small consumer advocates typically make in state regulatory proceedings with respect to the allocation of electricity costs. From a cost perspective, the most impactful recommendations in the Manual include 1) advocating for the Probability of Dispatch ("POD") and the Base-Intermediate-Peak ("BIP") allocation methods for generation fixed costs; 2) allocating a significant portion of transmission fixed costs on an energy basis; and 3) rejecting the Minimum System approach for classifying a portion of distribution fixed costs on a customer basis and instead allocating distribution investment on a demand and energy basis.

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[1]Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). *Electric cost allocation for a new era: A manual*. Montpelier, VT: Regulatory Assistance Project.

The underlying premise of the Manual's cost allocation recommendations is that most electric utility system costs should be allocated on the basis of energy consumption and recovered on a kWh basis.[2] Moreover, the common theme among the Manual's recommended cost allocation approaches is that they would have the effect of shifting a greater share of costs to large, high load factor loads relative to more widely accepted cost allocation methods that typically rely on customer demands to allocate most, if not all, fixed system investment costs.

The balance of this report briefly summarizes the major electric cost allocation recommendations contained in the Manual and provides a high-level rebuttal of these recommendations. The report does not attempt to address each and every cost allocation recommendation in the Manual, nor does it attempt to rebut every argument that the Manual raises to support its cost allocation recommendations. Rather, the report focuses on the most impactful recommendations in the Manual in terms of their dollar impact on the allocation of costs to large high load factor customers and outlines the arguments that most effectively counter the Manual's main recommendations.

This report can provide a foundation for a more detailed and comprehensive electric cost allocation white paper that would provide a counter-weight to the Manual's recommendations. The report can also be used as a framework for developing testimony to rebut the key cost allocation arguments in the Manual, to the extent that witnesses for other parties rely on the Manual to develop cost allocation proposals in the context of an electric utility rate proceeding.

Allocation of Generation Fixed Costs

The Manual argues that the fixed cost of generation resources is in large part determined by energy requirements because the most expensive generating units from a capital cost perspective are used to provide energy during all hours of the year. Therefore, the Manual

[2] Manual at page 245.

argues that the POD and BIP allocation methods have the highest correlation to cost causality for such resources.[3]

Rebuttal

The POD and BIP allocation methods recommended in the Manual are not appropriate for the allocation of generation fixed costs. These allocation methods are inconsistent with cost causation because they rely on energy consumption throughout the year to allocate fixed generation costs that are in fact driven by customer class loads at the time of annual system peak demand.

The most appropriate approach for allocating generation fixed costs is the coincident peak ("CP") demand method. A CP demand allocation methodology allocates fixed generation costs to customer classes based on each class' demand at the time of the system peak demand interval(s). The CP allocation can be performed based on the forecasted or historical demand of the customer at annual system peak hour or interval (1 CP). Alternatively, the allocation can be based on a historical average of customer demand during the system peak hour or interval for several individual months during a calendar year (e.g., 3 CP or 4 CP) if the peak load profile of a utility system is such that there are several months of the year that are determined to be of near equal importance with respect to when the annual system peak demand will occur.

There are a number of considerations that make the CP allocation method the most appropriate method for allocating generation fixed costs. First, a CP allocation method is consistent with cost causation principles for the incurrence of fixed generation costs. Such an allocation method recognizes the fact that generation resource adequacy planning is based on ensuring that there are sufficient resources in place to meet the maximum simultaneous peak demand imposed by customers on the system. A CP allocation method properly recognizes this cost causative factor that gives rise to the incurrence of fixed production costs.

[3]Manual at pages 55-56 and 132.

Because energy cannot be economically stored in large quantities for significant periods of time, and customers expect their lights to go on when they turn on the switch, generating plants must be sized to meet the peak annual demand of the system, even if the actual system demand is much lower in most hours of the year. In addition, to address forecast uncertainty with respect to the magnitude of peak annual demand, generation resource and transmission outages and the availability of renewable resources, typically a generation reserve margin in excess of the projected system peak demand is carried in order to provide reliable service. This reserve margin, often referred to as planning reserve margin, is typically determined through probabilistic loss of load expectation studies that aim to keep the forecasted frequency of firm load curtailment due to resource unavailability to less than one day within in a specified number of years. Typically, the specified number of years is ten, but, for some utilities in unique situations, it can be as little as five years. This planning reserve margin is expressed as a percentage of the peak annual demand of the system and, in conjunction with annual system peak demand, is used to assess the need for incremental capacity.

A projection that the actual reserve margin during the forecasted planning horizon will fall below the level required to maintain reliability within loss of load expectation requirements provides the indication that additional generating capacity must be installed to preserve an adequate planning reserve margin. Therefore, it is clear that growth in system peak demand is the trigger for generation additions and dictates the size of such additions. This means that customer demand at the time of the system peak demand interval (the CP demand of those customers) is the driver for the incurrence of incremental fixed generation costs.

The CP allocation method also provides appropriate price signals to minimize the incurrence of incremental fixed generation costs. Given that the system peak demand is the driver for the incurrence of additional generation investment, the CP method sends a strong, cost-based price signal to discourage power use at the time of the system peak demand. This benefits all customers on the system by reducing the rate of growth in the system peak demand and thereby deferring the need to construct incremental generation plant.

In addition, the CP allocation method appropriately reflects the economic classification of costs by recognizing the fixed nature of generation capital investments. Once a generation investment decision is made, the costs associated with such capital investments are fixed and sunk because they can longer be avoided. Consequently, these generation capital costs do not vary with the amount of energy generated or consumed on the system or with the number of customers taking service. Therefore, it is appropriate to allocate these generation fixed costs on a CP demand basis. This means that state regulatory commissions should reject energy-based allocation methods for generation fixed costs, such as the BIP and POD methods proposed in the Manual.

The Manual contends that generation capital investments should be treated as variable costs based on the theory that all costs are variable over a very long time horizon of several years.[4] This argument is without merit. While a utility can retire generation and replace it with other generation sources or purchased power contracts, the capital costs of the generation units that are already in the utility's rate base remain fixed, sunk costs that cannot be avoided until the units are fully depreciated. Therefore, over the utility's rate and planning horizon, it is clear that generation capital costs are fixed costs that it cannot avoid once the investment is made, even if energy consumption levels on the utility's system change. This reality must be recognized by allocating generation capital costs on a demand rather than on an energy basis.

An electric utility system predominantly consists of fixed costs that must be accurately allocated to cost causers using a class cost of service study that recognizes the demand-related nature of these fixed costs. An appropriately designed class cost of service study can capture the cost-causative effects of differing customer class load shapes in a manner that properly

[4]Manual at pages 78-79.

reflects the differences in the coincidence of customer loads with the cost-causative utility system peaks.

In addition to being inconsistent with cost causation principles as outlined above, the BIP and POD methods suffer from critical conceptual flaws that undermine their validity. The POD method allocates generation capital costs to individual hours of the year based on the frequency with which each individual generating plant is dispatched to serve the utility's load. These hourly capacity costs for each generating plant are then summed and assigned to the customer classes based on the hourly class contributions to the total system load. The BIP method classifies and assigns individual generating assets based on their specific role in a utility's generation portfolio. Under the BIP method, typically "Base" load units are classified and allocated on energy, "Intermediate" units are classified and allocated as demand and energy based on their capacity factor, and "Peak" units are classified and allocated on peak demand.

The underlying premise of the POD and BIP methods is that load duration and the economic trade-off between capacity and energy costs are the driving forces behind generation investment decisions. This argument misrepresents the utility planning process. In reality, the most important consideration in the generation planning process is the need to preserve system reliability by ensuring that there is sufficient generation capacity to meet the utility's system peak demand requirements, plus a reasonable planning reserve margin.

By contrast, there is no clear cost-causation relationship between the duration of customer loads and resource planning. Utilities identify a need for new resources when generating capacity is needed to meet peak day demands and capacity reserves. These reserve margin requirements are tied to the utility's highest system peak demands in the year. Therefore, it is system peak demand, rather than the duration of resource use, that drives incremental resource additions.

The POD and BIP methods are also flawed because they oversimplify the utility generation planning process. Important factors such as fuel costs, technological innovations and environmental requirements can change significantly, distorting the dispatch order of a utility's generating resources over time. Changes in these factors can alter the frequency with which generating units are dispatched and can also impact the designation of units as Base, Intermediate or Peaking. Moreover, the dispatch order of generating units can be distorted by the addition of new plants that result in a different generation mix.

The POD and BIP methods ignore these significant factors that can alter the dispatch arrangement of generation units and that can impact the designation of Base, Intermediate or Peaking resources. Therefore, these allocation methods do not properly reflect the dynamic nature and the complexities of the utility system planning or dispatch processes.

Another flaw with the POD and BIP methods is that they frequently average fuel costs for all utility generating units and allocate these costs across customer classes based only on energy usage. However, to be consistent with the theory behind the POD and BIP method for allocating fixed costs, customer classes should receive a corresponding allocation of the fuel costs from the specific generation resources that are allocated to them using these methods. For example, customers that are allocated a larger percentage of baseload generating resource fixed costs should benefit from receiving a higher allocated share of the lower fuel costs associated with such baseload units. Customers who are allocated a higher percentage of peaking unit costs should pay the higher fuel costs of the peaking units because they pay a lower allocated share of baseload capacity costs. This is commonly known as the fuel symmetry issue.

This approach would reflect fuel symmetry by ensuring that customers that pay higher capital costs for baseload units under the POD and BIP methods benefit by receiving the lower energy costs produced by those units. Conversely, customers assigned the fixed costs for a less costly combination of Base, Intermediate and Peak units from a capital cost perspective should be assigned the higher fuel costs associated with this higher cost mix of resources. (It should be noted that Average and Excess ("A&E") cost allocation methods for production fixed costs do not suffer from the fuel symmetry problem.)

For all of the foregoing reasons, the POD and BIP allocation methods recommended in the Manual are fundamentally flawed and are inappropriate for the allocation of generation fixed costs. As discussed above, the driver for the incurrence of generation fixed costs is the contribution of customers to the system peak demand. Therefore, a CP allocation method for generation fixed costs is the most appropriate method that conforms to cost causation principles.

It should be noted that class cost of service studies that apportion generation fixed costs on the basis of the contribution of customer classes to the relevant system peaks are quite common in the electric utility industry. Indeed, customer class allocations of fixed costs based on the CP allocation method are similar in popularity to the A&E cost allocation methods that other parties have advocated for production fixed costs in utility rate proceedings. Moreover, for the major customer classes on many utility systems, an allocation of utility generation fixed costs using a 4CP allocation method would be relatively similar to the customer class allocation that results from applying the A&E-4NCP method for most classes.

A&E cost allocation methods allocate a portion of production fixed costs to the customer classes based on average demand (energy consumption) times the system load factor. The excess demand component above the average demand is allocate to the classes using some form of peak demand allocator.[5] By linking the energy component of the class allocation factors to the system load factor, the A&E method provides for a more reasonable energy weighting of fixed production and transmission costs that is more reflective of the actual operating

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[5]A specific application of the A&E method is the A&E-4NCP methodology. Under this approach, a customer class's allocation factor for fixed production and transmission costs consists of two components. The first component (the average demand factor) is determined using average demand (energy consumption) times the system load factor. The second component of the class allocation factor (the excess demand factor) is determined as the proportion of the difference between the sum of the classes' 4 non-coincident peaks and the system average demand.

characteristics of the Company's system relative to other allocation methods such as POD and BIP. Therefore, the A&E method is a more reasonable and balanced allocation approach relative to the POD and BIP methods.

Allocation of Transmission Fixed Costs

The Manual categorizes the transmission system into various cost buckets and recommends different cost allocation methods for each category of costs. The proposed methods would generally classify a significant portion of transmission costs as energy-related and allocate such costs based on energy usage. For example, the Manual contends that all bulk transmission costs that are incurred to allow centralized generation and economic dispatch should be allocated on an energy basis. Any remaining bulk transmission costs would be deemed demand-related and allocated using a broad demand allocator that uses the highest 100 hours of usage in the year. This broad demand allocator is essentially another form of energy allocation that relies on a more targeted set of hours relative to a traditional energy allocator.

For local network transmission costs, the Manual recommends that any costs that are incurred to prevent overheating of conductors and related equipment[6] should be classified as energy-related and allocated using an on-peak energy allocator. Any remaining local transmission costs would be considered demand-related and allocated using a 4CP or 12CP demand allocator. Alternatively, the Manual suggests that all fixed transmission costs could be allocated in proportion to class energy usage in all of the hours in which the transmission facility is needed to provide service. The latter approach would essentially rely on a form of energy allocation for all generation fixed costs.[7]

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[6]The Manual does not specify how conductor overheating costs would be determined.
[7]Manual at page 141.

Rebuttal

The Manual's suggestion that transmission capital investment should be allocated to customer classes primarily on an energy basis should be rejected because it is inconsistent with cost causation principles. The most appropriate method for allocating transmission capital costs is the CP allocation method.

Several considerations favor applying the CP allocation method to allocate and recover bulk transmission costs. First, a CP allocation method is consistent with cost causation principles for the incurrence of capacity costs. Such an allocation method recognizes the fact that transmission planning is based on ensuring that there is sufficient transmission capacity in place to meet the maximum simultaneous peak demand imposed by customers on the transmission system. A CP allocation method properly recognizes this cost causative factor that gives rise to the incurrence of fixed transmission costs.

In order to preserve system reliability, bulk transmission facilities must be sized to meet the annual system peak demand, even if the actual system demand is much lower in most hours of the year. Consistent with this reality, transmission planners principally conduct their bulk transmission planning for system reliability purposes using power flow models that assess power flows during system CP conditions. Therefore, growth in the system CP demand is the trigger for bulk transmission additions and dictates the size of such additions. This means that customer demands at the time of the system peak demand intervals are the driver for the incurrence of transmission investment costs.

The CP method also provides appropriate price signals to minimize the incurrence of incremental capacity costs. Given that growth in the system peak demand is the driver for the incurrence of additional bulk transmission investment, the CP method sends a strong, cost-based price signal to discourage power use at the time of the system peak demand. This benefits all customers on the system by reducing the rate of growth in the system peak demand and thereby deferring the need to construct additional transmission plant.

Finally, the CP allocation method appropriately reflects the economic classification of costs by recognizing the fixed nature of transmission capital investments. Once a transmission investment decision is made, the costs associated with such capital investments are fixed and sunk and cannot be avoided. Consequently, these capital costs do not vary with the amount of energy generated or consumed on the system or with the number of customers taking service. Therefore, it is appropriate to allocate these transmission fixed costs on a CP demand basis.

An allocation method for transmission capital investment that is based largely on energy consumption, as suggested in the Manual, is flawed for a number of reasons. First, an energy-based allocation method ignores the proper classification of electricity costs by using variable energy consumption levels to allocate fixed and sunk transmission costs that do not vary with energy consumption. From an economic standpoint, it is more efficient and more consistent with cost causation to classify and to allocate fixed capital costs on a demand basis.

Second, the Manual's proposed allocation approach would give weight to energy use during all hours of the year in determining the allocation of transmission costs. However, this approach ignores the fact that the incurrence of transmission costs is driven by customer demands at the time of the system peak demand intervals. Therefore, an energy-based allocation method violates principles of cost causation and results in a cost allocation that does not reflect customer contributions to the incurrence of transmission costs.

Finally, by focusing on consumption during all hours of the year, an energy-based allocation method fails to send a focused and efficient price signal to customers to reduce their demands at the time of the annual system peak demand intervals. By diluting the price signals that incentivize customers to reduce their electricity demands at the time of the system peaks, an energy-based method allocation method would contribute to the inefficient incurrence of incremental transmission costs that could have been avoided through proper, cost-based price signals that are focused on the system peak demand intervals.

One potential variation of an energy-based allocation method for transmission costs that the Manual proposes is to focus the energy-based cost allocation on a specific range of hours (such as on-peak hours). Another alternative would be to apply a weighted energy cost allocation method that assigns greater weight to the on-peak hours of the day and year in establishing cost responsibility for transmission costs, relative to off-peak hours. However, these allocation approach are sub-optimal and fail to send focused and efficient price signals that are consistent with cost causation principles. Specifically, these approaches send an inefficient price signal that is inconsistent with cost causation to the extent that they give any weight at all to the off-peak hours of the day or the year or to on-peak hours that are outside of the system peak demand intervals. Energy use during these hours should not influence the allocation of transmission investment because these hours have no relevance to the incurrence of bulk transmission costs that are driven by the need to plan the bulk transmission system to meet the CP demands.

Even a weighted energy consumption method that gives weight only to the on-peak hours of the day or year would be inconsistent with cost causation because it would assume that all on-peak hours are relevant to the establishment of the system peak demands that drive the incurrence of bulk transmission costs. In reality, only a handful of hours in the summer and/or winter seasons play a meaningful role in establishing the system peak demand. Weighting all on-peak hours equally in the allocation method would inappropriately dilute the strong price signals inherent in the CP allocation method and weaken the customer price response to these signals, making it more difficult to control the rate of growth in the system peak demand.

Allocation of Distribution Fixed Costs

The Manual argues that only meters and a portion of service drop costs should be considered customer-related and allocated on a customer basis, particularly in relatively densely populated service territories. The Manual also contends that all shared distribution network costs should be treated as demand-related or energy-related. Moreover, the Manual specifically rejects the Minimum System method that many regulatory commissions use to classify and to allocate a portion of distribution system costs on a customer basis. Instead, the Manual recommends that that distribution fixed costs be classified into demand and energy components. The demand-related costs would be allocated using a broad set of hours that encompasses both high-load hours and hours that are prior to the high-load hours. Alternatively, the Manual recommends what it characterizes as an ideal allocation method for distribution plant that would model and reflect the contribution of each class to the load on each individual substation, feeder or transformer during the hours when the class loads contribute to the potential for overloading of each distribution system element. While the Manual does not define precisely how this allocation would be accomplished, this is essentially a prescription for allocating all distribution plant using a form of energy allocator that relies on energy consumption during a fairly wide range of hours.[8]

Rebuttal

The Manual's suggestion that some distribution investment should be classified as energy-related is inappropriate and inconsistent with cost causation. For the reasons set forth above with respect to the allocation of transmission capital costs, an appropriate approach to the allocation of distribution capital costs must recognize the fixed nature of distribution system investments by allocating the cost of such investments using the customer demands imposed on the delivery system. These investments, and the associated customer class demands used to develop the demand allocator, should be differentiated by voltage level, such that customers who take service from the primary distribution system are not required to pay for secondary distribution system facilities that they do not use.

[8]Manual at pages 145-151.

In contrast to the use of CP demands to allocate transmission costs, distribution investments can be allocated based on the maximum localized (non-coincident peak) demands that customers impose on the utility system. This non-coincident peak demand approach acknowledges that the downstream, localized nature of distribution investments yields fewer demand diversity benefits relative to upstream transmission system investments that are more geographically distant from the end-use customer. Because distribution investments must be sized to meet the maximum localized demands that customers impose on these facilities, there is no cost causative link between customer energy consumption throughout the year and the level of distribution investment. Therefore, there is no basis for the Manual's suggestion that a portion of distribution investment should be allocated on an energy basis.

In the alternative, distribution investments can be allocated using a 1 CP allocation method based on the system peak demand for each voltage class of distribution facilities. This approach recognizes that there is a continuum ranging from individual customer NCP being the cost driver for distribution investments at the lowest voltage, least networked level of the distribution system (i.e., secondary voltage class) to customer demand at the system peak being the driver at the highest voltage, most networked part of the distribution system. It should be noted that, for some rate classes, the annual peak demand behavior of individual members of the class highly conforms to the annual peak demand of the system as a whole, such that NCP and CP demand are currently the same (e.g., residential class), though that may be changing as residential rooftop solar penetration increases.

Moreover, the Manual's argument that no portion of distribution investment is customer-related is fundamentally flawed and inconsistent with cost causation principles. The primary purpose of the distribution system is to deliver power from the transmission grid to the customer. Certain distribution investments, including investments in distribution poles and wires, must be made simply to connect a customer to the system and to meet the National Electric Safety Code. These investments are customer-related. A utility must incur costs to construct a distribution line to connect customers to its system, irrespective of the amount (i.e., energy) or rate (i.e., demand) of electricity usage on its system. Therefore, a portion of distribution line costs is properly classified and allocated as customer-related. The remaining distribution investment is needed to provide sufficient capacity to meet customers' demands when they arise. This remaining portion of the distribution investment is demand-related.

This customer/demand-related approach to classifying distribution line costs is widely accepted. On this topic, the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual, which is widely quoted in the electric utility industry, states that:

> "Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system."[9]

One of the methods that the NARUC Manual discusses for establishing the customer and demand components of distribution investment is the Minimum System method. The Minimum System method determines the minimum size distribution system that could be built to serve the minimum load requirements of customers on the system. This method involves determining the smallest size pole, conductor, cable and transformer that is currently installed by the utility. The cost of the smallest size facility is classified as customer-related. The demand-related cost is the difference between the total cost and the customer-related cost. Using this widely applied approach, the customer classification of distribution investment can be determined using current engineering cost data and characteristics that are specific to the utility's distribution system. Therefore, this approach is a conceptually sound and practical means of calculating the customer component of distribution investment.

[9]National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, page 90.

Allocation of Smart Meter Costs

The Manual contends that the benefits of smart metering are very broadly distributed because these meters enable improved peak load management and provide reliability benefits and distribution line loss savings. Therefore, the Manual argues that it is incorrect to allocate smart meter costs on a customer basis. Rather, the Manual asserts that such costs should be broadly functionalized and allocated to generation and distribution functions.[10]

Rebuttal

While advanced metering devices may be capable of providing some system benefits as discussed in the Manual, the bulk of the benefits from such meters accrue directly to the customers who install the device through more rapid identification of outages at their premises and by enabling these customers to better control their electricity consumption. Therefore, it is appropriate to directly assign these smart metering costs to the residential and small commercial classes that receive the benefits of utility smart meter rollouts. The cost of smart metering rollouts can run into the hundreds of millions of dollars. Large customers should not be required to subsidize the substantial cost of these smart meter rollouts when the bulk of the benefits from these meters will accrue to residential and small commercial customers.

Moreover, most large customers had advanced interval metering devices installed on their premises many years ago. These meters provide granular information regarding customer usage to the utility, and this information can be used to provide the same types of broader system benefits that the Manual identifies with respect to the smart meters that many utilities are now installing for residential and small commercial customers. Nevertheless, the Manual does not propose to broadly allocate the cost of advanced large customer meters in a manner that would require residential and small commercial customers to pay a large share of these

[10]Manual at pages 157-158.

metering costs. This asymmetrical approach to the allocation of metering costs as suggested in the Manual is inappropriate and should be rejected by state regulatory commissions.

Allocation of Uncollectible Accounts Expenses

The Manual rejects the more accepted method of allocating uncollectible costs on a customer basis. Instead, the Manual contends that uncollectible costs are related to class revenue and should therefore be allocated in proportion to class revenues.[11]

Rebuttal

A long established principle of cost allocation holds that costs should be directly assigned to customer classes where there is sufficient data to directly assign the costs in question. In the case of uncollectible costs, it is generally straightforward to track the source of customer payment defaults by customer account and by customer class. Therefore, it is typically not difficult to directly assign uncollectible costs that are associated with a specific customer class directly to that class, and this is the preferred method of recovering these costs from customers.

A broad allocation of uncollectible costs across all customer classes based on class revenues, as suggested in the Manual, would unfairly require large customers to pay a large share of uncollectible costs that are directly associated with residential accounts. Such an outcome would be inequitable and inconsistent with cost causation.

Allocation of Customer Service Costs

The Manual recommends that customer service costs should be allocated based on class energy consumption or class revenues rather than in proportion to customer numbers.[12]

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[11]Manual at pages 162-163.
[12]Manual at pages 163-164.

Rebuttal

Clearly, there is a correlation between the number of customers and the costs that a utility incurs to field service calls and to provide customer assistance. Utilities must dedicate more personnel and resources to field the numerous customer service calls they receive from the large number of residential customers on their systems, relative to the service calls that receive from the smaller number of industrial customers that they support. By contrast, there is no clear cost causative link between customer energy consumption or revenues and the amount of customer service support that the utility must provide. Therefore, direct assignment of customer service costs by customer class or an allocation of such costs by customer count are the most appropriate treatment of these costs for ratemaking purposes.

Allocation of Sales and Marketing Costs

The Manual contends that marketing costs should be allocated using base rate revenues or another broad allocation factor such as rate base, rather than the more common method that relies on a customer allocator. The Manual alleges that a broader revenue or rate base allocator is justified because the Manual's authors contend that these marketing costs are incurred to increase electric loads.[13]

Rebuttal

It is clear that a utility's sales costs will increase in proportion to the number of customers that it targets through its sales activities. For example, the cost of distributing promotional materials via mail increases as the number of customers that are targeted by these mailing efforts increases. The same is the case for promotional sales calls via telephone. Therefore, the utility will incur higher sales costs to reach a large number of residential customers relative to a smaller number of large commercial or industrial customers. Accordingly, the use of a customer allocator for sales and marketing costs is consistent with

[13]Manual at page 164.

cost causation principles. A broader allocation of these costs using a revenue or rate base allocator, as proposed in the Manual, would inappropriately force large customers to subsidize costs that the utility incurs to target residential and small commercial customers with its marketing activities.

Analysis of Cost of Service Study Results

The traditional approach to evaluating the extent of inter-class subsidies in a utility rate case is to analyze the cost of service study results using a uniform rate of return applied to each customer class. The Manual suggests that it may be appropriate for regulators to deviate from this approach by assigning a higher required rate of return to industrial customers relative to residential customers to reflect what it characterizes as the higher risks of serving industrial loads through the economic cycle.[14]

Rebuttal

The Manual's suggestion that industrial customers should be assigned a higher required rate of return relative to other customer classes would be a significant and unwarranted departure from the widely accepted practice of evaluating class cost of service study results using a uniform rate of return. Moreover, the Manual's contention that industrial customers create higher financial risks to the utility due to the impacts of business cycles is severely flawed because it considers only one aspect of a utility's financial risk.

Other important customer and rate design characteristics suggest that industrial customers in fact pose a lower financial risk to the utility relative to residential customers. For example, the consumption levels of the residential class are very sensitive to weather fluctuations because much of residential customer energy consumption is associated with heating and cooling requirements that can vary significantly from year to year. By contrast, the

[14] Manual at page 231.

energy consumption levels of the industrial class are more closely linked to production processes that are much less weather sensitive.

Moreover, industrial customer rate designs generally utilize a three-part rate structure that includes a demand charge. This rate structure provides greater revenue stability and imposes less financial risk on the utility relative to the typical residential class rate design that contains no demand charge and relies on energy charges for the bulk of customer revenues. The heavy reliance on energy charges in residential rate design leads to wider swings in utility revenue from year to year based on weather and other factors that influence energy usage.

Based on the foregoing considerations, it is clear that there is no basis for the Manual's argument that utilities should assign a higher required rate of return to industrial classes relative to other customers on the utility's system.

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