BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St Paul MN 55101-2147

In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in the State of Minnesota	OAH Docket No. 22-2500-37994 MPUC Docket No. E-002/GR-21-630

SURREBUTTAL TESTIMONY AND ATTACHMENTS OF BEN HAVUMAKI

ON BEHALF OF

THE DIVISION OF ENERGY RESOURCES OF
THE MINNESOTA COMMERCE DEPARTMENT

DECEMBER 6, 2022

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I. INTRODUCTION

Q. Please state your name, occupation, and business address?

A. My name is Ben Havumaki. I am a Senior Associate at Synapse Energy Economics, located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

Q. On behalf of what party are you testifying in this proceeding?

A. I am testifying on behalf of the Minnesota Department of Commerce.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is address portions of Xcel Energy's ("the Company" or "Xcel') rebuttal testimony. I address rebuttal testimony from Xcel witnesses Mr. Mensen and Mr. Barthol opposing my recommendation to modify the allocation of FLISR costs and require more robust performance tracking and customer protections if FLISR is approved. I also address Xcel witness Mr. Quirk's rebuttal testimony responding to my recommendation that the Commission deny cost recovery for DI. Finally, I respond to Mr. Mensen's rebuttal testimony opposing my grid modernization process improvements recommendations by explaining why these improvements are needed.

Q. Has Xcel introduced any data or arguments that have led you to change your recommendations provided in direct testimony?

A. No. However, I will respond to several of these arguments from the Company to illustrate why I continue to believe my direct testimony recommendations are warranted.

II. FLISR COST ALLOCATION

Q. Please summarize your direct testimony recommendations concerning modifying cost allocation for FLISR.

A. Based on my review of the Company's cost-benefit analysis (CBA), I concluded that its Fault Location, Isolation and Service Restoration (FLISR) proposal did not appear to be cost effective for residential customers under the default approach to cost allocation, requiring them to pay 66 percent to 71 percent of FLISR costs while receiving only about 2.5 percent of the projected benefits, using assumptions included in the Company's CBA.[1] Based on this finding, I recommended that 97 percent of FLISR costs be allocated to commercial and industrial customers, in approximate proportion to the share of the benefits that these customers are expected to receive from FLISR.

Q. How does the Company respond to the recommendation to modify the class cost allocation for FLISR?

A. Mr. Mensen suggests that the CBA does not provide a definitive picture of the distribution of benefits from FLISR to the various classes, stating that FLISR is "a reliability program that aims to improve reliability for all customer classes and to deliver

[1] Ex. DOC-___ at 23 (Havumaki Direct).

those benefits as widely as possible."[2] However, Mr. Mensen does not directly refute my claim that about 97 percent of the benefits of FLISR are expected to flow to commercial and industrial customers.

Separately, Mr. Barthol asserts that cost allocation is conducted on the basis of cost causation, and that a value-based allocation of FLISR costs would be "impractical" and would represent "a significant shift in a fundamental tenet of ratemaking."[3]

Q. Do you agree with Mr. Mensen that the CBA is an inappropriate basis for altering FLISR cost allocation because it does not reflect the full scope of FLISR benefits?

A. No. The CBA provides the most concrete information currently available on the costs and benefits of the proposed FLISR project. Moreover, I do not believe that Mr. Mensen has demonstrated, against the evidence from the CBA, that FLISR would be cost effective for residential customers under the default cost allocation scheme. As I noted above, the default approach to cost allocation would require residential customers to pay for between 66 percent and 71 percent of total FLISR costs while the CBA demonstrates that they will receive only about 2.5 percent of total FLISR benefits.[4]

Q. Do you agree with Mr. Barthol that allocating FLISR costs on the basis of expected benefits represents a "significant shift" from standard ratemaking practices?

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[2] *Id.* at 35.
[3] Ex. Xcel-___ at 24-25 (Barthol Rebuttal).

A. No. First, my recommendation applies only to FLISR costs, not all distribution related investment proposed in this case. As explained below, I believe FLISR costs would be incurred by ratepayers, if approved, for fundamentally different reasons than traditional poles and wires investment. Second, Mr. Barthol is incorrect that my recommendation to allocate costs based on benefits represent some new paradigm of ratemaking. The Regulatory Assistance Project's Electric Cost Allocation Manual, for example, explains that a "costs follow benefits" approach is "usually, but not always, the superior principle" to cost allocation.[5] Regarding whether my recommendation follows "cost causation" principles, I believe it does. Cost causation asks the question: *why were the costs incurred*?[6] In this case, costs will be incurred to attain the expected benefits, which my analysis based on the Company's CBA shows will accrue almost exclusively to commercial and industrial customers. In this case, the principles of cost causation and allocating costs based on benefits are two sides of the same coin.

To be clear, I do not offer an opinion on how distribution infrastructure costs should be allocated as a general matter. My recommendation is limited to Xcel's Unlike standard distribution equipment and investment, FLISR is entirely elective. It is not needed for the safe, reliable delivery of electricity.

[5] Ex. DOC-___, BH-S-1 at 3 (Havumaki Surrebuttal) (Jim Lazar et al, Electric Cost Allocation for a New Era: A Manual 18 (2020), www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf).
[6] *Id.* at 18.

Q. Do you support FLISR cost recovery if allocated to customers using standard distribution infrastructure allocators?

A. No. As stated above, the standard distribution cost allocators would disproportionately burden the residential class, such that costs would significantly outweigh benefits. Rather than recommend FLISR be rejected entirely, which is the best option should my cost allocation recommendation not be approved, I recommended a different cost allocation to ensure residential ratepayer benefits will roughly equal allocated costs.

III. FLISR PERFORMANCE TRACKING AND CUSTOMER PROTECTIONS

Q. Please summarize the recommendations concerning performance tracking for FLISR included in your direct testimony.

A. I recommended that the Commission establish specific metrics to capture performance on feeders with FLISR and to track differences between forecast costs and actuals for FLISR. I also recommended that the Commission establish performance targets for FLISR, and that cost recovery for FLISR be made at least partly contingent on Company performance.

Q. How does the Company respond to these recommendations on performance tracking?

A. Mr. Mensen indicates that the Company supports “robust and meaningful data tracking and reporting,” and he proposes that the Company continue with its reliability reporting through the Annual Service Quality Reports and the Performance-Based Ratemaking

Reports and also report on certain new metrics related to the initial deployment.[7] However, Mr. Mensen does not support reporting that would compare reliability performance for circuits before and after receiving FLISR. Further, Mr. Mensen neither supports the adoption of performance targets nor agrees that cost recovery should be made at least partly contingent on performance.

Q. Why does the Company oppose your proposal for new FLISR metrics?

A. Mr. Mensen appears to believe that Xcel has already met the Commission's requirements for the Company to "[i]dentify cost categories and benefit categories used (explain metrics) including an explanation of how benefits can be monitored over time and proposal for reporting to Commission."[8] Mr. Mensen claims that benefits were identified and explained in Ms. Bloch's direct testimony and the supporting CBA. He further indicates that the Company will continue with its existing reliability reporting regime, which he notes includes reporting on reliability by feeder, and that it will continue to report on FLISR costs.[9]

Q. Why does the Company oppose your specific proposal for a feeder-level reliability metric?

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[7] Ex. Xcel-___ at 40, 42 (Mensen Rebuttal).

[8] *In re Pet. of N. States Power Co. for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2017 & 2018, & Revised Adjustment Factor*, Docket No. E002/M-17-797, ORDER AUTHORIZING RIDER RECOVERY, SETTING RETURN ON EQUITY, AND SETTING FILING REQUIREMENTS at 14-15 (Sept. 27, 2019) (citing Order Point 9(B)(2)).

[9] *Id.* at 41-42.

A. Mr. Mensen grounds his opposition to this metric on the basis that it may not be possible "to attribute changes solely or directly to FLISR implementation at this time."[10]

Q. Are concerns about causal attribution a justification for not reporting on reliability performance by feeders before and after installation of FLISR?

A. No. While I acknowledge that reliability performance may be influenced by several factors, I do not view this as a barrier to reporting reliability by circuit before and after FLISR installation. Moreover, the Commission appears to share this view. In Docket No. E002/M-20-406 concerning the Company's required annual performance reporting, the Commission directed the Company to compare its of SAIDI, SAIFI, CAIDI, and MAIFI reliability results "for feeders with grid modernization investments such as Advanced Metering Infrastructure or Fault Location Isolation and Service Restoration to the historic five-year average reliability for the same feeders before grid modernization investments."[11] My proposal for a FLISR feeder-level metric therefore represents just a modest modification of the Company's existing reporting obligations.

Q. Why does the Company oppose setting performance targets for FLISR?

A. Mr. Mensen argues in part that it is premature to set targets for FLISR.[12] Mr. Mensen points to the Commission's performance based ratemaking docket (Docket No. E002/CI-

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[10] *Id.* at 42.

[11] *In re Xcel Energy's Annual Report on Safety, Reliability, and Service Quality for 2019; and Petition for Approval of Electric Reliability Standards for 2020*, Docket No. E-002/M-20-406, ORDER ACCEPTING REPORTS, REQUIRING ADDITIONAL FILINGS, AND ESTABLISHING WORKSHOPS at 4 (Dec. 18, 2020) (eDocket No. 202012-169158-02).

[12] *Id.* at 43.

17-401) and the process for formulating targets established in the Commission's February 2, 2022 Order in this proceeding as setting the standard for development of performance targets.

Q. Would it be premature to set performance targets for FLISR?

A. No. The Company already has reliability data by feeder provided in its Annual Service Quality Reports that could serve as a baseline, and it has provided projected reliability benefits through its CBA that could serve as the basis for performance targets. Formulating performance targets based upon the projected benefits from the CBA is sensible when one objective of these performance targets is to evaluate the performance of the FLISR investments against projected performance. However, I am also supportive of harmonizing the processes of establishing FLISR metrics and performance targets and effectuating contingent cost recovery with the standards established through the PBR docket. I acknowledge that the Commission may find it more appropriate to establish performance targets for FLISR and/or mechanisms to effectuate contingent cost recovery for FLISR through the process underway in Docket No. E002/CI-17-401.

Q. Are there any other customer protections that you support?

A. Yes, I support the implementation of cost caps for FLISR similar to the recommendation from Clean Energy Organizations (CEOs) set forth in direct testimony.[13] However, I do

[13] Ex. CEO-___ at 23 (Volkmann Direct).

not support setting the cost cap at the total value of benefits for FLISR as suggested by CEO. Instead, I recommend that the cap be set at the level of the total cost recovery permitted in this proceeding. Under my recommended approach, the Company would be prohibited from seeking additional funds for FLISR until its next rate case. I note that the Commission has supported cost caps for other grid modernization investments in past proceedings.

Q. Please clarify your recommendations for limiting recovery for FLISR to three years.

A. While the Company indicates that it is seeking only three years of cost recovery,[14] I maintain this recommendation given the possibility that the MYRP term could nonetheless be set to five years.

IV. DISTRIBUTED INTELLIGENCE

Q. Please summarize the recommendations concerning DI included in your direct testimony.

A. I recommended that the Commission not approve the Company's proposed distributed intelligence (DI) spending, as the Company has not shown it to be cost effective or demonstrated otherwise that DI is a necessary or beneficial investment for ratepayers.

Q. How does the Company respond to your conclusion about DI cost effectiveness?

[14] *Id.* at 31.

A. Mr. Quirk states that Mr. Remington's supplemental direct testimony provides sufficient detail to demonstrate the cost-effectiveness of DI.[15] While he acknowledges that assessing benefits using avoided costs is standard utility practice, he asserts that bill savings are conservatively representative of DI's expected impact.[16]

Q. Do you agree with Mr. Quirk that the Company has shown DI to be cost effective?

A. No. The fact that the Company relied on bill savings benefits –which accrue solely to program participants– and not the avoided costs that benefit all ratepayers is a fundamental flaw. The fact is that the results of this analysis are not responsive to the question of whether ratepayers should invest in DI. Furthermore, even if the Company's approach to valuing bill savings were accepted, the results from its CBA would not be particularly encouraging. The Company reports a minimum benefit-cost ratios (BCR) of 0.98 for its DI program (with 95 percent certainty) in its updated Monte Carlo simulation results.[17] In other words, DI is barely cost effective even when bill savings are (incorrectly) used as the quantified benefit.

Q. Why is it inappropriate to use bill savings in the CBA?

A. Bill savings are calculated using the Company's retail energy rates. This approach calculates only the benefit that customers participating in the Energy Analysis program will experience, assuming Xcel's assumptions are correct, but says nothing about

[15] Ex. Xcel-___ at 10 (Quirk Rebuttal).
[16] *Id.* at 11-12.
[17] Ex. Xcel-___ at 35 (Quirk Rebuttal). A Monte Carlo simulation is a model used to predict the probability of a variety of outcomes when the potential for random variables is present.

impacts to non-participants – ratepayers who do not use or participate in the program. Put differently, there's a risk that participating customers who save money may do so at the expense of other non-participating customers absent an evaluation of avoided costs. Since the Company proposes to recover the costs of DI from all customers, its CBA should evaluate the technology from a ratepayer perspective, not a participant perspective.

Q. What is the correct value for the total benefits to customers from the Energy Analysis use case that should have been included in the CBA?

A. It is not possible to say based on the information provided by the Company. The value of this benefit should account for the total utility-system savings – that is, the reduction in the Company's revenue requirement. The critical input for this calculation is avoided costs – yet the Company did not provide any estimate of avoided capacity costs resulting from DI or the Energy Analysis use case.

Q. Did the Company state why they did not use avoided costs in the DI CBA?

A. Yes. In his rebuttal testimony, Mr. Quirk explains that the Company is currently unable to quantify any Energy Analysis benefits besides bill savings with sufficient certainty to use in a CBA. He states that DI will first have to be deployed before avoided costs can be estimated, specifically due to challenges in estimating avoided capacity costs.[18]

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[18] *Id. at* 12.

Q. How do you respond to Mr. Quirk's explanation of why the Company did not use avoided costs in the DI CBA?

A. The Company should not deploy DI before it is able to evaluate its cost-effectiveness. Noting that the Company is unable to calculate avoided capacity costs at this time, avoided energy costs can be used to quantify the benefits of the Energy Analysis use case for ratepayers. This would be an improvement over using the retail rate, which reflects the benefits to participants alone rather than indicating the total impact to all customers.

Q. Has the Company adequately evaluated alternatives to DI?

A. No. Mr. Quirk asserts that the Company is not aware of any reasonable alternatives to DI and suggests that the lack of comparison with any specific alternatives in my direct testimony supports the Company's argument that no such alternatives exist.[19] While Mr. Quirk acknowledges that I have discussed TOU and DR programs as possible alternatives to DI,[20] he argues that these are not comparable alternatives to DI because they do not provide all the same benefits.[21] However, by definition, a comparison of alternatives involves outlining the different benefits and costs that each offers. If the benefits and costs were identical, then there would be no reason to compare the alternatives.

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[19] *Id.* at 19.
[20] *Id.* at 18.
[21] *Id.* at 20.

Q. Should approval of DI-capable advanced metering infrastructure (AMI) meters necessarily mean that the proposed investments for DI are approved?

A. No. Mr. Quirk and Mr. Mensen both state that it is appropriate to consider the Company's FLISR and DI proposals in this current case separate from AMI deployment.[22] The Company has proposed DI-capable AMI meters based on their non-DI benefits and costs, and approval of this technology does not necessarily mean that the additional costs and benefits of DI should be approved.

Q. What are your overall recommendations regarding DI?

A. It is not reasonable to predicate DI investment on the promise of showing cost effectiveness *after* in-servicing of the investment, especially given that DI is an entirely elective program. As the Company has not demonstrated that DI is cost-effective, I continue to recommend denial of cost recovery for DI at this time. The Company should not deploy DI until it has taken the time to further develop its proposal, both in terms of planning and assessing cost-effectiveness. The Company has not yet constructed a clear picture of DI or its benefits. This ambiguity is evidenced by the fact that the Company refers to theoretical future use cases that could exist but have not been developed.[23] The Company has not sufficiently investigated the capabilities and avoided costs associated with DI and deploying it at this stage would be premature.

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[22] *Id.* at 10; Ex. Xcel-___ at 48 (Mensen Rebuttal).
[23] Ex. Xcel-___ at 41-42 (Remington Supplemental Direct Testimony).

V. GRID MODERNIZATION PROCESS IMPROVEMENTS

Q. Please summarize the recommendations for process improvements included in your direct testimony.

A. I recommended that the Commission seek to improve the efficiency of grid modernization evaluation by consolidating dockets to reduce fragmentation and enhance cohesion. I also included additional recommendations aimed at standardizing grid modernization filings and at enhancing the overall quality of information available to the Commission and stakeholders when reviewing grid modernization proposals. To this end, I recommended that the Commission require that future grid modernization proposals include a road map with all planned and contemplated future grid modernization investments, a complete accounting of historical and anticipated future grid modernization costs, and a table indicating where within the given application the Commission's filing requirements for grid modernization proposals had been met. Finally, I recommended that the Commission standardize grid modernization filing requirements so that they are applicable in all instances in which grid modernization proposals are brought forward.

Q. How does the Company respond to these recommendations?

A. Mr. Mensen argues that these recommendations extend beyond the scope of the instant proceeding.[24] He further asserts that the new requirements recommended would be unnecessary, may not be applicable to all instances, might be overly broad,

[24] Ex. Xcel-___ at 45 (Mensen Rebuttal).

and "would require speculation on the future that almost certainly would change in one way or another."[25]

Q. Do you agree that your recommended requirements are unnecessary?

A. On the contrary, I believe that these requirements are very much needed. The Company has pursued a piecemeal and fragmented approach to grid modernization over recent years with proposals for various, often interdependent components staggered across multiple proceedings. The recommended filing requirements, if adopted by the Commission and standardized across all grid modernization proposals, could help stakeholders formulate a better understanding of the Company's overall vision and the implications for customers.

Q. Can you provide an example of interdependent components proposed in different proceedings?

A. Yes – the Company has proposed cost recovery for DI-enabled AMI meters through its transmission cost rider (TCR), and it has separately proposed cost recovery for DI in the instant proceeding. Yet DI can only be implemented with AMI meters in place, and the value proposition for the selected DI-enabled AMI meters– as against the value of other meter alternatives without DI functionality– can only be fully ascertained through joint consideration of the costs and benefits of both the meters and the DI functionality. While the proposed additional requirements might not completely obviate the

[25] *Id. at* 45-48.

challenges associated with separate review of these highly integrated investments, it could help to provide some additional clarity and insight.

Q. Are the Company's concerns about the practicality of new requirements well founded?

A. No. While I do understand that the filing requirements might not be equally relevant in all instances, I suggest that they would nonetheless be valuable as a standard and for standardization. Moreover, there would not necessarily be an expectation that any future plans disclosed by the Company at any filing would be binding forever into the future. Rather, the Company would merely be expected to provide information in good faith that was reflective of the current state of its plans.

VI. SUMMARY OF RECOMMENDATIONS

Q. Do you maintain each of the recommendations from your direct testimony?

A. Yes.

Q. Has the financial impact of your recommendations changed from your direct testimony.

A. Yes, in part. Although I continue to recommend that cost recovery for Xcel's DI proposal be fully denied, the company provided refinements to my disallowance calculations, as shown in Ex. Xcel-___, BCH-R-4 (Halama Rebuttal). If the Commission accepts my recommendation to exclude all DI costs, I agree the company's corrected disallowance amounts should be used. My FLISR recommendation, however, remains unchanged.

Q. Does this complete your surrebuttal testimony?

A. Yes.

Electric Cost Allocation for a New Era

A Manual

By Jim Lazar, Paul Chernick and William Marcus

Edited by Mark LeBel

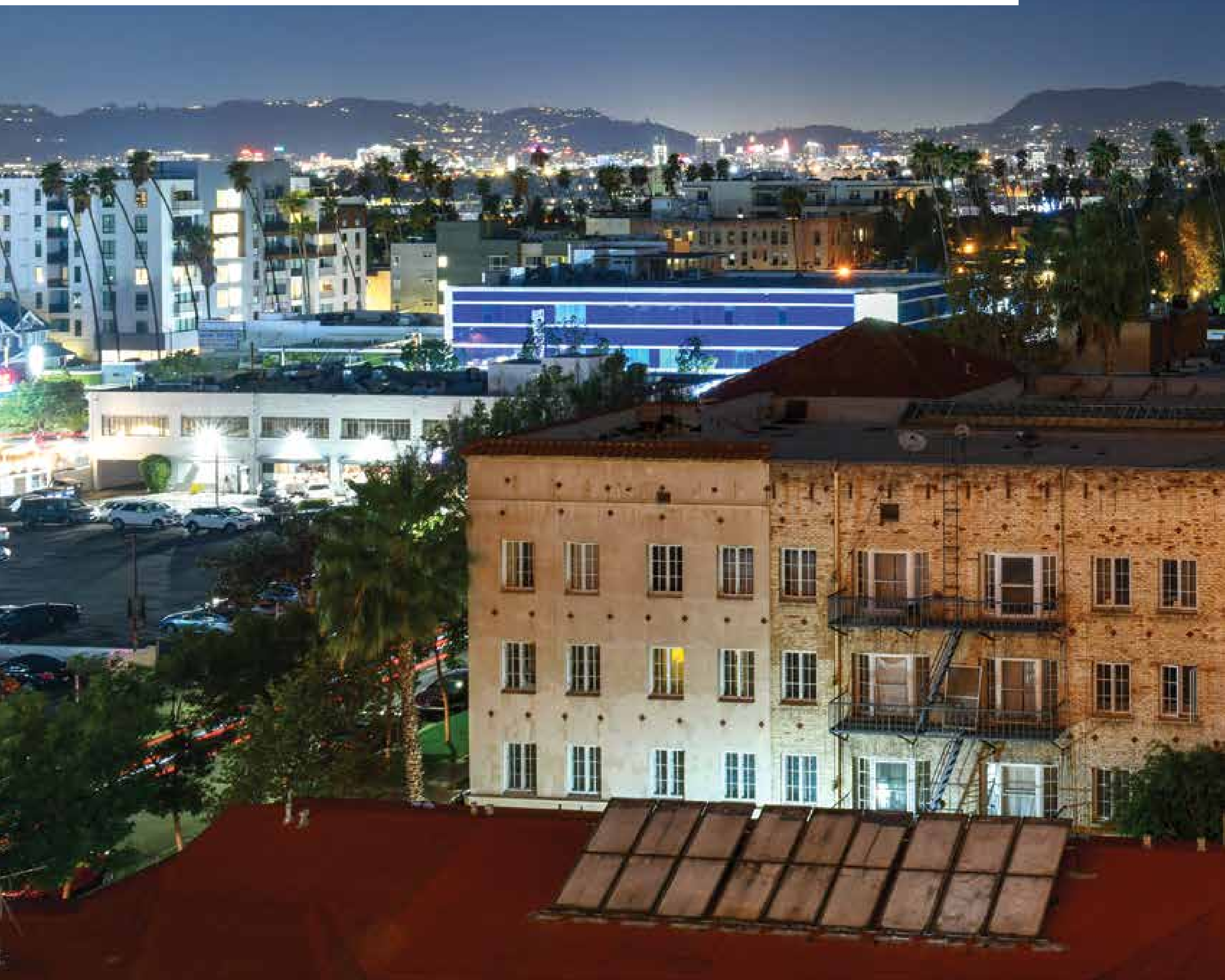

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Table 1. Types of meters and percentage of customers with each in 2017

	Residential	Commercial	Industrial
Advanced metering infrastructure	52.2%	50.0%	44.5%
Automated meter reading	29.5%	26.5%	28.0%
Older systems	18.3%	23.5%	27.5%

Data source: U.S. Energy Information Administration. *Annual Electric Power Industry Report, Form EIA-861: 2017* [Data file]. Retrieved from https://www.eia.gov/electricity/data/eia861/

In addition, many utilities now collect much more granular data than was possible in the past, due to the widespread installation of **advanced metering infrastructure** (AMI) in many parts of the country and other advancements in the monitoring of the electric system. As a result, utility analysts often have access to historical hourly usage data for the entire utility system, each distribution **circuit**, each customer class and, increasingly, each customer. Some **automated meter reading** (AMR) systems also allow the collection of hourly data, typically read once per billing cycle. Table 1 shows the recent distribution of meter types across the country, based on data from the U.S. Energy Information Administration. Improved data collection allows for a wide range of new cost allocation techniques.

In addition, meters have been primarily treated as a customer-related cost in older methods because their main purpose was customer billing. However, advanced meters serve a broader range of functions, including demand management, which in turn provides system capacity benefits, and **line loss** reduction, which provides a system energy benefit. This means the benefits of these meters flow beyond individual customers, and logically so should responsibility for the costs.

These are just two examples of how recent technological advances affect appropriate cost allocation. In subsequent chapters, this manual will address each major cost area for electric utilities, the changes that have occurred in how costs are incurred and how assets are used, and the best methods for cost allocation.

Principles and Best Practices

There is general agreement that the overarching goal of cost allocation is equitable division of costs among customers. Unfortunately, that is where the agreement ends and the arguments begin. Two primary conceptual principles help guide the way to the right answers:

1. Cost causation: Why were the costs incurred?
2. Costs follow benefits: Who benefits?

In some cases these two frameworks point to the same answer, but in other cases they conflict. The authors of this manual believe that "costs follow benefits" is usually, but not always, the superior principle. Other helpful questions can be asked to illuminate the details of particularly difficult questions, such as:

- If certain resources were not available, which services would not be provided, and what different resources would be needed to provide those services at least cost?
- If we did not serve this need in this way, how would costs change?

In the end, cost allocation may be more of an art than a science, since fairness and equity are often in the eye of the beholder. In most situations, cost allocation is a zero-sum process where lower costs for any one group of customers lead to higher costs for another group. However, the techniques used in cost allocation have been designed to mediate these disputes between competing sets of interests. Similarly, the data and analysis produced for the cost allocation process can also provide meaningful information to assist in rate design, such as the seasons and hours when costs are highest and lowest, categorized by system component as well as by customer class.

In that spirit, we would like to highlight the following current best practices discussed at more length in the later chapters of this manual. To begin, there are best practices that apply to both embedded and marginal cost of service studies:

- Treat as customer-related only those costs that actually vary with the number of customers, generally known as the **basic customer method**.
- Apportion all shared generation, transmission and distribution assets and the associated operating expenses