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September 5, 2016

Minnesota Public Utilities Commission  
121 7th Place East  
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Saint Paul, Minnesota 55101

RE: Docket 16-512 Initial Comments

To Daniel P. Wolf:

Attached please find an updated version of Fresh Energy's and ELPC's initial comments in this docket. When e-filing on Friday, September 1<sup>st</sup>, part of our Exhibit C contained blank pages due to a technical error. The attached is our same initial comments with a complete Exhibit C.

Respectfully,

/s/ Allen Gleckner

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In the Matter of a Commission Investigation  
into Fees Charged to Qualifying Facilities by  
Cooperative Electric Associations under the  
2015 Amendments to Minn. Stat. § 216B.164,  
Subd. 3

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Docket No. E999/CI-16-512

**COMMENTS OF FRESH ENERGY AND ENVIRONMENTAL LAW & POLICY CENTER**

**I. INTRODUCTION**

Over the past 18 months, twenty-one Minnesota electric cooperative utilities began charging their solar and small wind customers extra monthly fees. These fees, ranging from \$5 per month for a very small system, to \$85 per month, would roughly double the fixed portion of the bill for many distributed generation (“DG”) customers, significantly eroding the benefit of solar in co-op territory in Minnesota.

The co-op’s trade association, Minnesota Rural Electric Association (“MREA”), claims that these fees are intended to recover the cooperatives’ “fixed costs” that DG customers avoid by self-generation. But MREA’s methodology does not actually measure the cooperatives’ fixed cost to serve DG customers. Instead, the fees are designed to recoup the cooperatives’ lost revenue from reduced electric sales. This is not legal. The applicable law requires fees to be based on “fixed costs not already paid for by the customer through the customer’s existing billing

arrangement.”<sup>1</sup> The law further requires these charges to be “reasonable and appropriate,” and “based on the most recent cost of service study.”<sup>2</sup> MREA’s methodology fails all three of these requirements.

The legislature recently amended some of the procedures governing future disputes with electric cooperatives, but the recent change in law does not affect this investigation. The substantive legal standard for co-op fees remains the same. Co-ops must still base their fees on “fixed costs,” not lost revenue.<sup>3</sup>

For the reasons discussed in more detail below and in the attached expert report of Paul Chernick, the commission should find that MREA’s methodology does not comply with the requirements of Section 216B.164 because: (1) the methodology is not based on a cost of service study; (2) the methodology is designed to recover lost revenue instead of “fixed costs”; and (3) the methodology is not “reasonable and appropriate” because it overstates DG costs and ignores DG benefits. Therefore, the Commission should order that the MREA methodology does not comply with state law, and it should require the changes we recommend below that would be necessary for a methodology to be consistent with the statute.

## **II. FACTUAL & PROCEDURAL BACKGROUND**

### **A. Procedural History**

#### *1. 2015 Dispute Resolution Dockets*

The Commission first addressed the issue of DG fees in a 2015 docket involving Peoples Electric Cooperative. In that case, Alan Miller, a customer of Peoples, filed a request for dispute resolution under Minn. Stat. § 216B.164, to contest a \$5-per-month “facility fee” that Peoples began charging Mr. Miller in 2014. The Commission resolved the dispute in favor of Mr. Miller,

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<sup>1</sup> Minn. Stat. §216B.164, subd. 3(a).

<sup>2</sup> *Id.*

<sup>3</sup> *Id.*

determining that Peoples had failed to demonstrate that the fee it imposed meets the criteria of Minn. Stat. § 216B.164.<sup>4</sup> In reaching its opinion, the Commission noted that the statute requires the Commission “to construe the statute in accordance with its intent to give maximum possible encouragement to cogeneration and small power production consistent with protection of ratepayers and the public.”<sup>5</sup> The Commission further directed staff to open a docket to further investigate DG fees assessed by other investor-owned, cooperative, and municipal utilities.<sup>6</sup>

## *2. 2015 Legislation*

Also in 2015, the Minnesota Legislature amended the portion of the net-metering statute addressing the amount cooperative and municipal utilities may bill DG customers. The 2015 amendments, highlighted below, permit electric cooperatives and municipal utilities to charge their DG customers additional fees to recover “fixed costs not already paid by the customer through the customer’s existing billing arrangement.” Importantly, however, any fees must be “reasonable and appropriate for that class of customer based on the most recent cost of service study.”

(a) This paragraph applies to cooperative electric associations and municipal utilities. For a qualifying facility having less than 40-kilowatt capacity, the customer shall be billed for the net energy supplied by the utility according to the applicable rate schedule for sales to that class of customer. A cooperative electric association or municipal utility may charge an additional fee to recover the fixed costs not already paid for by the customer through the customer's existing billing arrangement. Any additional charge by the utility must be reasonable and appropriate for that class of customer based on the most recent cost of service study. The cost of service study must be made available for review by a customer of the utility upon request. In the case of net input into the utility system by a qualifying facility having less than 40-kilowatt capacity, compensation to the customer shall be at a per kilowatt-hour rate determined under paragraph (c) or, (d), or (f).<sup>7</sup>

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<sup>4</sup> In the Matter of a Request for Dispute Resolution with People’s Energy Cooperative Under the Cogeneration and Small Power- Production Statute, Minn. Stat. § 216B.164, Docket No. E-132/CG-15-255, Order of September 21, 2015 (“Peoples Order”).

<sup>5</sup> Peoples Order at 6.

<sup>6</sup> *Id.* at 7.

<sup>7</sup> Amendments to Minn. Stat. § 216B.164, subd. 3 (a). 1Sp2015 c 1 art 3 s 21.

Following passage of this law, several cooperative utilities began to include new monthly fees for net metering customers in their 2016 tariff filings, filed in docket E-999/PR-16-09. The co-ops based each of these fees on MREA's lost revenue methodology that remains at issue in the present docket.

### *3. 2016 Complaint and Investigation*

In May 2016, ELPC and Fresh Energy filed an objection to fourteen co-op tariffs that included new DG fees based on MREA's lost revenue methodology.<sup>8</sup> ELPC and Fresh Energy argued that the co-op fees failed to meet the statutory requirements in the 2015 law because MREA's methodology was based on lost revenue recovery rather than cost causation:

The plain language of the statute allows utilities to propose a fee to recover the fixed costs not already paid for by the customer. It does not allow utilities to propose a fee to recover lost revenue resulting from self-generation. In order to calculate whether DG customers, as a class, are covering their fixed costs the utility would need to establish (1) the fixed costs the utility incurs to serve its DG customers, and (2) the amount that those DG customers, as a class, contribute to the utility's fixed costs of service, including through the system benefits provided by DG. That is why the statute requires such charges to be "based on the most recent cost of service study."<sup>9</sup>

The Department of Commerce filed comments agreeing that MREA's lost revenue methodology was not supported in the record at that time.<sup>10</sup> Several other solar industry and clean energy advocacy organizations, as well as 88 members of the public, also filed comments supporting ELPC and Fresh Energy's tariff objection. Furthermore, two additional customer complaints involving co-op fees were pending at the Commission at the time of Fresh Energy and ELPC's objection.<sup>11</sup>

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<sup>8</sup> ELPC and Fresh Energy Tariff Objection of May 25, 2016 (amended), Docket No. E999/PR-16-9.

<sup>9</sup> *Id.* at 3 (emphasis added).

<sup>10</sup> MN DOC comments, 5-25-16, docket 16-9 at 1. Available at: <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={B356B3F2-53BA-42A1-9576-BB01E1907E0D}&documentTitle=20165-121634-01>.

<sup>11</sup> See Docket No. E121/CG-16-240, Complaint of Keith Weber, against Meeker Cooperative Light and Power

On June 27, 2016 the Commission initiated a “generic investigation” to address the issues raised in the related tariff objection and customer complaint dockets involving co-op fees.<sup>12</sup> The Commission found that it had “ample authority” to determine whether the fees “comply with statutory standards.” The Commission was very clear in addressing the legal standard it would apply when reviewing these fees, explaining that:

Those standards are that fees (a) be limited to fixed costs not paid for through a customer’s existing billing arrangement; and (b) be reasonable and appropriate for the customer class to which the customer belongs, based on the utility’s most recent cost of service study. Applying these standards requires considering the methodologies used to determine fixed costs, their causation, and their allocation among customer classes, and these issues will be addressed in the course of the investigation.<sup>13</sup>

These are the same statutory standards and requirements that continue to apply to the Commission’s review of MREA’s lost revenue methodology today.

#### *4. 2017 Legislation and Scope of Review*

During the course of the present investigation in Docket 16-512, the Minnesota legislature amended the law again, providing electric cooperatives with the opportunity to “assume the authority” to enforce the provisions of Minnesota’s cogeneration and small power production statute with respect to their members. These opt-out provisions included specific conditions, including a requirement that the cooperatives adopt rules providing for a process to resolve disputes, including access to an “independent third-party” to mediate disputes.<sup>14</sup> Subdivision 11(d) of the new legislation also allowed the Commission to complete the current

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Association; Docket No. E123/CG-16-241, Complaint of Larry Fagen, against Minnesota Valley Electric Cooperative Light & Power.

<sup>12</sup> In the Matter of a Commission Investigation into Fees Charged to Qualifying Facilities by Cooperative Electric Associations under the 2015 Amendments to Minn. Stat. § 216B.164, Subd. 3, Docket No. E-999/CI-16-512, Order of June 27, 2016 (“Order Initiating Investigation”).

<sup>13</sup> Order Initiating Investigation at 6 (emphasis added), citing Minn. Stat. § 216B.164, subd. 3 (a).

<sup>14</sup> See 2017 Minn. Session Laws, Ch. 94—S.F. No. 1456 (adding Minn. Stat. 216B.164, Subd. 11). Available at: <https://www.revisor.mn.gov/laws/?id=94&year=2017&type=0#laws.10.8.0>.

investigation in Docket 16-512 “to assess whether the methodology used by cooperative associations to establish a fee ... complies with state law,” so long as the Commission determines that completing the investigation “is necessary to protect the public interest.”<sup>15</sup> Subdivision 11(d) reads in full:

(d) The Public Utilities Commission may complete its investigation in Docket No. 16-512 to assess whether the methodology used by cooperative associations to establish a fee under section 216B.164, subdivision 3, paragraph (a), complies with state law if the commission determines that completing the investigation is necessary to protect the public interest, in which case it shall complete the investigation no later than December 31, 2017. A methodology that the commission determines complies with state law may not be challenged in a dispute under this section. If the commission determines that a methodology does not comply with state law, it shall clearly state the changes necessary to bring the methodology into compliance, and a cooperative electric association shall modify its methodology in accordance with the commission's directives.

Although the 2017 legislation changed the procedures that will govern future disputes with electric cooperatives, the legislature did not change the substantive law that governs co-op fees. The law still requires co-ops to base fees on fixed costs, not lost revenue.<sup>16</sup> Just as the Commission observed in its initiating order, the law still requires that the methodology used to derive co-op fees: “(a) be limited to fixed costs not paid for through a customer’s existing billing arrangement; and (b) be reasonable and appropriate for the customer class to which the customer belongs, based on the utility’s most recent cost of service study.”<sup>17</sup> Furthermore, MREA has not changed its methodology since the initial filing in this investigation in 2016.<sup>18</sup> Thus, the scope and substance of this investigation remain unchanged since the Commission opened this docket. As the Commission’s most recent order states: “As required by statute, the investigation

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<sup>15</sup> The Commission determined that completing the investigation was necessary to protect the public interest in an order dated June 21, 2017.

<sup>16</sup> See Minn. Stat. 216B.164, subd. 3(a) (unchanged).

<sup>17</sup> Order Initiating Investigation, Docket No. 16-9 at 6 (June 27, 2016).

<sup>18</sup> MREA filing of 7/7/2017, Docket No. 16-512.

will focus squarely on the methodology and whether it complies with state law.”<sup>19</sup>

Finally, the legislative purpose of Chapter 216B.164 to encourage self-generation and the utilities’ burden of proof under the statute also remain the same and are relevant to the outcome of this investigation. Subdivision 1 states that “[t]his section shall at all times be construed in accordance with its intent to give the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public.”<sup>20</sup> The Commission must keep this legislative purpose in mind when determining whether MREA’s lost revenue methodology is based on principles of cost causation and complies with subdivision 3 of the chapter.

#### *5. Paul Chernick’s Expert Report*

The idea that rates should be set based on customer cost causation is a fundamental concept in rate design. ELPC and Fresh Energy commissioned rate design expert Paul Chernick of Resource Insight, Inc. to review MREA’s methodology. Mr. Chernick has thirty-nine years of experience in the electric and gas utility field and is a leading expert in electric utility cost allocation and rate design. He has testified in more than 300 regulatory and court proceedings and has performed a wide variety of studies for public agencies, utilities, energy companies, nonprofit organizations, and corporations. Mr. Chernick’s report, attached as Exhibit A to these comments, concludes that “MREA has failed to meet the most basic and clearest requirement in the statute,” explaining that MREA has not “actually conducted anything that could be reasonably called a cost-of-service study.”<sup>21</sup> MREA weakly counters that there are “alternative methods to develop a cost of service study.”<sup>22</sup> However, MREA’s attempt to describe its lost

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<sup>19</sup> Order to Complete Investigation and Appointing Administrative Law Judge, Docket No. 16-512, at 3 (June 21, 2017).

<sup>20</sup> Minn. Stat. 216B.164, subd. 1 (emphasis added).

<sup>21</sup> Ex. A at 10-11

<sup>22</sup> MREA filing of 7/7/2017, Docket No. 16-512.



revenue methodology as an “alternative cost of service study” does not comply with the legislature’s clear directive in the law.

## **B. Regional and National Context**

The Commission’s investigation in this case fits into a broader, evolving debate about electric utility rate design and distributed generation. In January 2013, the Edison Electric Institute described distributed energy resources (“DER”) as a “disruptive challenge” to the electric utility business model and recommended that utilities “[i]nstitute a monthly customer service charge ... to recover fixed costs and eliminate the cross-subsidy biases that are created by distributed resources and net metering, energy efficiency, and demand-side resources.”<sup>23</sup> Following the publication of this paper, a wave of utilities began proposing significant increases to their monthly fixed charges, changes to net metering tariffs, and (in a few cases) new solar fees and charges like the ones at issue in this case. This prompted a backlash from consumer and environmental advocates, resulting in bitter disputes and conflicts in many states.

While these disputes continue to play out today, a few trends have emerged. First, regulators have largely rejected fixed charges and solar fees that are not supported by cost causation and clear evidence in the record.<sup>24</sup> Regulators have been particularly skeptical of utility proposals that single out solar customers for additional fees and charges; commissions and courts in Utah, Louisiana, and Wisconsin have recently rejected solar fees similar to those proposed by the co-ops here.<sup>25</sup>

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<sup>23</sup> Edison Electric Institute, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*, at 18 (Jan. 2013).

<sup>24</sup> See Whited, M.; Woolf, T.; Daniel, J., (Feb. 9, 2016). *Caught in a Fix: The Problem with Fixed Charges for Electricity*. Synapse Energy Economics, Inc. Available at <http://consumersunion.org/wp-content/uploads/2016/02/Caught-in-a-Fix-FINAL-REPORT-20160208-2.pdf> (Accessed Sept. 1, 2017).

<sup>25</sup> Tracy, R. (2013, July 8). *Utilities Dealt Blow Over Solar Power Systems*. Wall Street Journal. Available at: <https://www.wsj.com/articles/SB10001424127887324507404578594122250075566>; Trabish, H. (2014, Sept. 3). Utah regulators turn down Rocky Mountain Power’s bid for solar bill charge. Available at: <http://www.utilitydive.com/news/utah-regulators-turn-down-rocky-mountain-powers-bid-for-solar-bill-charge/304455/>; Content, T. (2015, Oct. 30). Judge Rejects We Energies plan to assess solar power owners extra

Second, the national conversation has started to move beyond the zero-sum approach of increased fixed charges and discriminatory fees towards a more nuanced conversation about incremental change, dynamic rates, storage, and value-based compensation. There are many examples of this evolution. NARUC's Staff Subcommittee on Rate Design has encouraged regulators to "look closely at data, analyses, and studies" prior to undertaking any major reform of rate design to ensure that the new rates accurately reflect the true costs and benefits of distributed resources.<sup>26</sup> Peter Kind, the author of the original EEI Disruptive Challenges paper, more recently authored a new paper highlighting opportunities for utilities to work together with their customers to address utility revenue challenges without increasing fixed charges or penalizing solar or other DER.<sup>27</sup> The solar industry and its colleagues have developed a number of guiding principles for the evolution of net energy metering and rate design that reflect these trends.<sup>28</sup> Many of these trends and best practices were cogently summarized in a letter to the president of NARUC from a large coalition of consumer, low-income, environmental, and industry stakeholders.<sup>29</sup> In this letter, the broad and diverse coalition of stakeholders offered the following specific characteristics and best practices for utility rate design proceedings:

- It should include a *good process*; one that is transparent, fair, accessible and accountable;

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fees. Available at: <http://archive.jsonline.com/business/judge-rejects-we-energies-plan-to-assess-solar-panel-owners-extra-fees-b99606784z1-338962302.html/>.

<sup>26</sup> Distributed Energy Resources Rate Design and Compensation, A Manual Prepared by the NARUC Staff Subcommittee on Rate Design (Nov. 2016). Available at: <https://www.naruc.org/rate-design/>.

<sup>27</sup> CERES, Pathway to a 21<sup>st</sup> Century Utility (Nov. 2015). Available at <https://www.ceres.org/resources/reports/pathway-21st-century-electric-utility> (accessed August 25, 2017).

<sup>28</sup> Solar Energy Industries Association, Principles for the Evolution of Net Energy Metering and Rate Design (June 2017). Available at <http://www.seia.org/policy/distributed-solar/net-metering/principles-evolution-net-energy-metering-rate-design> (accessed August 25, 2017).

<sup>29</sup> Letter from 31 consumer, low-income, environmental and clean energy advocates to Travis Kavulla, NARUC President (June 23, 2016). Available at <http://blogs.edf.org/energyexchange/files/2016/06/Good-Rate-Design-Process-Letter-to-NARUC.pdf> (accessed August 25, 2017).

- It should be based on *good data and transparent modeling* that is credible and available to all parties.
- And it should have a *good sense of timing*. Instead of the traditional confrontation in a contested rate-case proceeding, it should look for opportunities to engage collaboratively in formal, constructive stakeholder processes that explore new ways of moving forward together, even if it takes a little longer.

The Iowa Utilities Board’s recent “Notice of Inquiry” docket is a good example of these “good process” principles in action. In response to utility criticism of net metering, the Board facilitated a two-year inquiry into Iowa’s DG policies and invited feedback from a wide array of stakeholders. Following a data-driven process, the Board concluded that the record lacked evidence of a net metering “cost-shift” and that any future decisions about DG policy would need to be based on real evidence in the record.<sup>30</sup>

In contrast to the “good process” principles outlined above, MREA’s lost-revenue methodology at issue in this case was not based on an open and public process. In fact, MREA repeatedly denied ELPC and Fresh Energy’s reasonable data requests seeking the basis for its proposal.<sup>31</sup> Instead, the co-op’s attempt to collect lost revenue from DG customers is reminiscent of some of the early attempts by utilities to discourage distributed generation and is out-of-step with the overall national trend towards data-driven rate design.

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For all of the reasons described in more detail below, the Commission should complete this investigation by determining that MREA’s lost-revenue methodology for computing DG fees

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<sup>30</sup> See IUB Docket NOI-14-0001, Orders of October 30, 2015 and July 19, 2016.

<sup>31</sup> MREA and Itasca-Mantrap Cooperative response to Fresh Energy IRs 1-4, attached as Exhibit B.

does not comply with the requirements of Minn. Stat. § 216B.164, subd. 3. As required by law, the Commission's order should "clearly state the changes necessary to bring the methodology into compliance."<sup>32</sup> Namely, the Commission should state that in order to satisfy state law, MREA should amend its methodology such that it (1) is based on an actual cost of service study, and that (2) accurately accounts for the characteristics of distributed solar when calculating the "fixed costs not already paid for by the customer through the customer's existing billing arrangement."<sup>33</sup>

### III. MREA'S METHODOLOGY DOES NOT COMPLY WITH STATE LAW

Minnesota law allows cooperative electric associations to charge DG customers additional fees under specific and limited circumstances which boil down to three central requirements:

- i) The charges must be based on a cost of service study made available to customers;
- ii) The charges must be designed to recover "fixed costs not already paid for by the customer through the customer's existing billing arrangement;" and
- iii) The charges must be "reasonable and appropriate for that class of customer."

The law spells out these three requirements in subdivision 3(a) of section 216B.164 of the Minnesota Statutes. The subdivision reads, in full, with emphasis added:

(a) This paragraph applies to cooperative electric associations and municipal utilities. For a qualifying facility having less than 40-kilowatt capacity, the customer shall be billed for the net energy supplied by the utility according to the applicable rate schedule for sales to that class of customer. A cooperative electric association or municipal utility may charge an additional fee to recover **the fixed costs not already paid for by the customer through the customer's existing billing arrangement.** Any additional charge by the utility **must be reasonable and appropriate for that class of customer based on the most recent cost of service study.** The cost of service study must be made available for review by a customer of the utility upon request. In the case of net input into the utility system by a qualifying facility having less than 40-kilowatt capacity, compensation to the customer shall be at a per kilowatt-hour rate determined under paragraph (c), (d), or (f).<sup>34</sup>

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<sup>32</sup> Minn. Stat. 216B.164, subd. 11.

<sup>33</sup> See *id.* at subd. 3.

<sup>34</sup> Minn. Stat. § 216B.164, subd. 3(a).

MREA's 'lost sales' methodology violates all three of the statute's central requirements: i) the MREA methodology does not use a cost of service study as its basis; ii) the methodology is designed to recover lost revenue instead of "fixed costs not already paid for by the customer," and iii) the MREA methodology is not "reasonable and appropriate" because the methodology contains several flawed and unreasonable assumptions that tend to overstate the cooperative utilities' actual costs and wholly ignores any distribution system benefits DG provides.

The following analysis will explain each of these flaws in MREA's lost revenue methodology, supporting the conclusion that the methodology does not comply with state law.

**A. MREA's Methodology Is Not Based On A Cost Of Service Study.**

MREA's methodology is not based on a cost of service study, as required by law. NARUC describes the cost of service study (or COSS) as one of "the basic tools of ratemaking."<sup>35</sup> The National Rural Electric Cooperative Association similarly describes the COSS as "the fundamental tool for the entire Rate Analysis process."<sup>36</sup> As further explained by NARUC, a COSS is "used by regulators [to] attribute costs to different categories of customers based on how those customers cause costs to be incurred."<sup>37</sup> The most basic and obvious feature of a COSS is that it must begin with an assessment of the utility's costs. However, MREA's lost revenue methodology (which it erroneously labels a COSS) does not begin with the utility's costs. Instead, MREA begins by summing up the utilities' existing rates and sales to determine the co-op's revenue loss attributable to distributed generation. This is not a valid way to estimate utility costs and it does not comply with Minnesota law.

*1. A Cost of Service Study Analyzes Utility Costs*

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<sup>35</sup> NARUC Electric Utility Cost Allocation Manual at 12 (Feb. 1992).

<sup>36</sup> National Rural Electric Cooperative Association / National Rural Utilities Cooperative Finance Corporation Retail Rate Guide ("NRECA/CFC Rate Guide"), Vol 1 at 13 (2017), attached as Exhibit C.

<sup>37</sup> Chernick Report at 5 (quoting NARUC Cost Allocation Manual).

Paul Chernick’s expert report explains the basic tenets of a COSS. “[A] cost-of-service study converts accounting data, load data, and other inputs into class cost allocations, typically through a three-step process of functionalization, classification and factor allocation.”<sup>38</sup>

Chernick quotes from NARUC’s *Electric Utility Cost Allocation Manual* to explain how a COSS uses cost information and classification to develop rates for different customer classes. “Utilities develop[] cost studies that [are] based on monies actually spent (embedded) for plant and operating expenses and divide[] those costs (fully allocate[] or distribute[] them) among the classes of customers according to principles of cost causation.”<sup>39</sup>

The co-op’s own national Retail Rate Guide similarly explains that a COSS starts with an analysis of costs to derive rates, not the other way around:

The COSS results provide the data to determine the revenue requirements for each rate class and the cost data needed to design rates. Using this data, the next step involves defining and evaluating rate design alternatives and rate design recommendations for the Board.<sup>40</sup>

The COSS “define[s] basic cost drivers needed to align cost causation with cost recovery.”<sup>41</sup>

The Commission’s rules also describe the basic elements of a COSS in a manner that is likewise consistent with the foundational elements in the NARUC and co-op rate manuals – most importantly that a cost of service study must analyze utility costs. Rule 7825.4300 requires that regulated utilities requesting a rate change provide:

A cost-of-service study by customer class of service, by geographic area, or other categorization as deemed appropriate for the change in rates requested, showing revenues, costs, and profitability for each class of service, geographic area, or other appropriate category, identifying the procedures and underlying rationale for cost and revenue allocations.<sup>42</sup>

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<sup>38</sup> *Id.* at 6.

<sup>39</sup> *Id.* at 5.

<sup>40</sup> NRECA/CFC Rate Guide, Vol 1 at 14.

<sup>41</sup> *Id.*

<sup>42</sup> Minn. Rule 7825.4300 C.

Each one of these sources (including Mr. Chernick's expert report) confirm that a COSS must start with utility "cost data ... to derive class revenue targets and rates" rather than MREA's approach, which "starts with existing rates and performs a series of computations to derive an estimate of costs."<sup>43</sup>

2. *MREA's Methodology Uses Existing Rates and Revenue to Estimate Costs, But Does Not Analyze Utility Costs*

MREA's methodology flips the fundamental concept of a cost of service study on its head by starting with existing rates to derive an estimate of utility costs. As Mr. Chernick found:

Despite its familiarity with the NARUC Manual, MREA does not follow the approach laid out by NARUC, and instead does the exact opposite: the MREA method starts with existing rates and performs a series of computations to derive an estimate of costs.<sup>44</sup>

MREA's description of its methodology is clear on this point. It states that the methodology's second step seeks to establish the utility's total costs using the past year's revenue. Here's how MREA describes its methodology:

The calculation starting point is total cost of service as determined by the local board and reflected in the annual revenue from board determined rates.<sup>45</sup>

This point bears repeating: MREA's own description of its methodology is that it is based on sales, and not actual costs.

Mr. Chernick's analysis demonstrates that MREA's methodology cannot be reasonably construed to be based on a cost of service study because it treats rates and costs as interchangeable and assumes residential rates mirror system-wide averages:

In order for MREA's method to reflect cost of service, one must assume that (1) the residential rate equals the residential cost of service, based on a cost-of-service study, and (2) that residential rate includes G&T charges at the system-wide

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<sup>43</sup> Chernick Report at 8.

<sup>44</sup> *Id.* at 7-8.

<sup>45</sup> *Id.* at 8.

average rate. Neither of those assumptions appears to be true and MREA has provided no evidence in the record supporting those assumptions.<sup>46</sup>

For these reasons, Mr. Chernick ultimately concludes that “the cooperatives’ fees result from a leap of faith, not a cost-of-service analysis.”<sup>47</sup>

Comparing MREA’s approach to the co-op’s national rate guide corroborates Mr. Chernick’s conclusion that MREA’s methodology is not based on cost causation or a COSS. When explaining that its methodology’s “starting point is total cost of service as . . . reflected in the annual revenue from board determined rates,” MREA also states that “RUS Annual Form 7 report, Part O, is the source for this information.”<sup>48</sup> Part O of the Form 7 is the part of the form dedicated solely to reporting utility revenue.<sup>49</sup> NRECA’s Retail Rate Guide, on the other hand, instructs that if Form 7 data is used to provide the cost inputs to determine the utility’s revenue requirement, that Form 7 Part A should be used. Form 7 Part A itemizes utility expenses and costs, and therefore, is the Form 7 data that is relevant for cost of service studies.<sup>50</sup> Again, NRECA’s rate guide recognizes that the first step of a cost of service analysis is determining a revenue requirement, “which is the sum of the total cost of providing service in a 12-month period plus the required operating margins,” and that this determination would be based on the utility’s costs, as reported in Form 7 Part A.<sup>51</sup> The fact that MREA’s

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<sup>46</sup> *Id.* at 10.

<sup>47</sup> *Id.*

<sup>48</sup> MREA 2016 filing at 15.

<sup>49</sup> The USDA describes Part O as “All revenue from operating electric plant including kWh sales, penalties, income from utility property, and miscellaneous items is to be reported in this part.” UNITED STATES DEPARTMENT OF AGRICULTURE Rural Utilities Service BULLETIN 1717B-2.

<sup>50</sup> NRECA Rate Guide Vol. II, Schedule A-1.0, at 36, at 2 (“Appendix Schedule A-.10 shows the typical format for the determination of total revenue requirements.”) Attached as Exhibit C; UNITED STATES DEPARTMENT OF AGRICULTURE Rural Utilities Service BULLETIN 1717B-2 at Exhibit A pp. 8-9 (listing the following relevant items in Form 7 Part A: Power Production Expense, Cost of Purchased Power, Transmission Expense, Distribution Expense – Operation, Distribution Expense – Maintenance, Customer Accounts Expense, Customer Service and Informational Expense, Sales Expense, Administrative and General Expense, Total Operation and Maintenance Expense, Depreciation and Amortization Expense, Tax Expense - Property and Gross Receipts, Tax Expense – Other, Interest on Long-Term Debt, Interest Charged to Construction – Credit, Interest Expense – Other, Other Deductions, Total Cost of Electric Service).

<sup>51</sup> NRECA Rate Guide Vol II at 2.



methodology begins not with these Form 7 costs, but the Form 7 revenues, is another clear indication that its methodology is aimed squarely at developing a fee based on lost sales, and not on even the most basic notion of a cost of service study.

In sum, as detailed above, a cost of service study is a well-established ratemaking tool with the core attribute that it is an analysis stemming from utility costs. This fundamental premise of a cost of service study is recognized even by the co-op's own rate guide. While MREA's methodology claims to be based on a cost of service study, its foundation is the cooperative utility's past sales and revenues based on existing rates, and not any analysis of the utility's distribution system costs. Therefore, the MREA methodology fails the statute's plain terms – that any fee must be “based on the most recent cost of service study.”

**B. MREA's Methodology Is Not Designed to Measure the Actual “Fixed Costs” of Serving DG Customers.**

The plain language of the statute allows utilities to propose a fee to recover the fixed costs not already paid for by the customer. In order to calculate whether DG customers, as a class, are covering their fixed costs the methodology would need to establish (1) the fixed costs the utility incurs to serve its DG customers, and (2) the amount that those DG customers, as a class, contribute to the utility's fixed costs of service, including through the system benefits provided by distributed generation. As described above, MREA's lost revenue methodology does not attempt to quantify this cost of service data.

MREA's methodology is based on reduced sales, but the fact that a DG customer (or any customer, for that matter) consumes less than the class average does not prove that the individual customer has failed to pay their fair share of fixed costs. Stated another way, two identically situated customers (same peak load, same distribution circuit, same service drops, etc.) that consume different amounts of electricity will contribute different amounts towards

fixed costs under standard ratemaking approaches. Costs are apportioned and rates are designed across broad groups of customers, and no single customer has a rate that recovers precisely the proper cost of serving that customer. MREA has not provided any data in the record to determine whether DG customers, as a class, have usage patterns that differ from residential customers generally, or whether DG customers as a class impose costs that are out of sync with their average fixed cost recovery through existing rates.

In 2014, the Utah Public Service Commission rejected a lost revenue-based net metering fee that was similar to MREA's proposal here.<sup>52</sup> The Utah case helps to further illustrate the gaps in MREA's methodology, including MREA's failure to study, collect, or provide any data about the load characteristics of DG customers that have a bearing on the utility's costs of service. In the 2014 case, PacifiCorp proposed a "residential net metering facilities charge" to recover the revenue it was losing as a result of lost sales to distributed generation. Specifically, the utility intended to "recover from net metered customers an amount that will produce the same average monthly revenue per customer for distribution and customer costs that is recovered in energy charges from all residential customers based on the cost of service study."<sup>53</sup> PacifiCorp presented an exhibit indicating that residential net metering customers in its service territory "purchase less energy on average, about 518 kilowatt hours ("kWh") per month, than the residential class average of 698 kWh per month."<sup>54</sup> From this data, PacifiCorp estimated that "the cost shift from net metered customers to all customers is \$4.65 per month per customer ... based on forecasted test period billing units for residential

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<sup>52</sup> In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Docket No. 13-035-184, Report and Order of Aug. 29, 2014. Available at: <https://pscdocs.utah.gov/electric/13docs/13035184/260065%2013035184rao.pdf> (accessed 8/31/2017).

<sup>53</sup> *Id.* at 20.

<sup>54</sup> *Id.* at 22.

customers.”<sup>55</sup> The Company proposed a monthly net metering fee to “create an appropriate price structure for residential net metered customers before the shifting of distribution and customer costs from net metered customers produces a much larger cost burden on non-participating customers.”<sup>56</sup>

The Utah Commission rejected the Company’s proposal, finding that the simple fact that net metering customers, on average, purchase less electricity than the residential class as a whole does not necessarily mean that those customers, as a class, do not cover their fixed costs of service. The Commission found the absence of load characteristic data for residential net metered customers to be a “significant gap” in the record:

We cannot determine from the record in this proceeding that this group of [net metering] customers is distinguishable on a cost of service basis from the general body of residential customers. Simply using less energy than average, but about the same amount as the most typical of PacifiCorp’s residential customers, is not sufficient justification for imposing a charge, as there will always be customers who are below and above average in any class. Such is the nature of an average.

In this instance, if we are to implement a facilities charge or a new rate design, we must understand the usage characteristics, e.g., the load profile, load factor, and contribution to relevant peak demand, of the net metered subgroup of residential customers. We must have evidence showing the impact this demand profile has on the cost to serve them, in order to understand the system costs caused by these customers.<sup>57</sup>

Based on its review of the record, the Commission concluded that the evidence was “inconclusive, insufficient, and inadequate” to support PacifiCorps’ proposed DG fees, and that more “thorough analysis” such as a “load research study” and a “measurement of net metered customer usage at the time of system coincident peaks” would be necessary to justify any potential future proposals.<sup>58</sup>

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<sup>55</sup> *Id.* at 23.

<sup>56</sup> *Id.* at 21.

<sup>57</sup> *Id.* at 68.

<sup>58</sup> *Id.* at 63, 66.

MREA's lost revenue methodology suffers from the same analytical flaws as PacifiCorps' proposed net metering fee. It presumes, without any supporting load characteristic data, that DG customers are not paying their fair share of fixed costs simply because they purchase less electricity than they would have without self-generation. In addition to entirely ignoring the cost savings and other benefits attributable to distributed generation, MREA's methodology simply presumes that lost sales = costs, without actually studying the load characteristics of DG customers as compared to the residential class as a whole and analyzing how those similarities or differences have a bearing on the utility's costs of service.

Paul Chernick provides an example of why this matters. He points out that solar generation typically avoids above-average power costs and can help reduce load-related distribution costs. But MREA failed to produce any "useful data on the portion of distribution costs that are load-related, and the extent to which solar generation can reduce demand in the hours that drive load-related investments."<sup>59</sup> MREA's methodology is simply not designed to measure whether and to what extent DG customers are paying their fixed costs of service through their existing billing arrangement.

### **C. MREA's Lost Revenue Approach Is Not Reasonable and Appropriate**

1. *MREA's methodology overstates distribution system costs embedded in residential energy rates.*

The fact that MREA's methodology is based on rates, sales and revenues as opposed to utility cost of service is not only contrary to the statute, but results in tangible analytical flaws and, ultimately, arbitrary and unreasonable fees. One glaring example is that MREA's 'lost sales' method starts with the assumption that the distribution costs recovered in the residential energy

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<sup>59</sup> Chernick Report at 15-16.

rate are equal to the current residential energy rate, minus the system average purchased-power costs from the cooperative's G&T provider.

This assumption is flawed in both theory and practice, and results in MREA's methodology overstating the amount of distribution system costs that are actually allocated to residential customers in the cooperative rates. This distribution system cost over-allocation results from the MREA methodology assigning a lower amount of purchased power and transmission costs to residential customers than is actually allocated to those customers in the cooperative's actual rates. In other words, utilities most often charge the residential class proportionally more for generation and transmission costs than other customer classes, and the same is true for the cooperatives in this case. Because the MREA methodology is not based on costs, it does not account for this fact and, therefore, overstates the amount of distribution system costs embedded in residential energy rates. The methodology then translates this error into higher DG customer fees.

Mr. Chernick's report explains this error. "In reality, the generation and transition costs embedded in the residential rates, even assuming those rates were at some time set based evenly roughly on costs, would likely exceed the system average for at least four reasons."<sup>60</sup> Those four reasons are the following:

- First, utilities tend to charge the residential class more per kWh of sales for transmission and the demand-allocated portion of generation costs than they charge the non-residential classes because residential customers tend to have a lower load factor – or more “peaky” demand – than other classes.
- Second, residential load tends to vary more seasonally, which generally makes it

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<sup>60</sup> Chernick Report at 11.

more expensive to serve than average load for generation and transmission.

- Third, for energy-allocated portion of generation costs, utilities also tend to charge the residential class more than other classes. This cost allocation, again, reflects the tendency for residential customers to use a greater proportion of their energy at high-cost times than flatter or more off-peak loads, such as streetlighting, industry and irrigation.
- Fourth, losses between the transmission system and the residential meter are generally estimated to be greater than average because, among other considerations, residential customers are typically metered at secondary voltage, after power is stepped-down from primary to secondary, while larger non-residential customers are often metered at primary voltage, before the transformer.

Despite the fact that MREA does not provide enough information for the Commission and stakeholders to determine exactly the extent to which the cooperative rates in this case reflect each of these four effects (because actual COSSs were not provided), Mr. Chernick was able to identify representative examples for each in Minnesota cooperative rates.

Even more telling, Mr. Chernick found that the MREA methodology's assumed residential generation and transmission cost allocation results in negative or near-negative distribution system cost allocation to other customer classes. This finding demonstrates that the MREA methodology's base assumption and estimate of residential system costs is incorrect and results in inflated fees for residential customers. It is inconceivable that cooperatives would set non-residential customer class rates based on assigning near-zero or negative distribution system costs to some distribution-connected customer classes.

Mr. Chernick's analysis explains in detail how the MREA methodology's assumptions for

residential customers would have to assume negative cost allocation for other customer classes. He explains that “applying the MREA method to other rate classes demonstrates that MREA was wrong to assume that all retail rates reflect the average ¢/kWh system purchased-power charge for each customer class.”<sup>61</sup> “This is most clearly seen in the fact that MREA’s methodology produces negative distribution costs for the ‘Commercial & Industrial over 1,000 kVA’ category in the RUS Form 7, Part O, for three of the filing cooperatives.”<sup>62</sup> Table 2, reproduced below from Mr. Chernick’s expert report, highlights this problem with MREA’s methodology.<sup>63</sup>

**Table 1: Examples of MREA Method Showing Negative Distribution Rates<sup>64</sup>**

	<u><b>BENCo</b></u>	<u><b>Connexus</b></u>	<u><b>Mille Lacs</b></u>
<b>Purchased-Power Expense</b>	\$24,962,184	\$189,901,838	\$14,437,178
<b>Total kWh</b>	317,592,373	2,241,959,488	192,670,173
<b>Purchased Power Expense/kWh</b>	\$0.079	\$0.085	\$0.085
<u><b>Avg. Revenue, C&amp;I &gt; 1,000 kVA</b></u>	<u>\$0.067</u>	<u>\$0.079</u>	<u>\$0.067</u>
<b>Implied Distribution Rate</b>	<b>-\$0.012</b>	<b>-\$0.005</b>	<b>-\$0.018</b>

In addition to these instances of negative distribution costs for certain rate classes, Mr. Chernick found the following instances where distribution costs were near-zero, and likely would have found many more instances had MREA provided the information to do a similar analysis for all the cooperatives in this case.

- \$0.002/MWh for the < 1 MVA C&I rate for Freeborn-Mower.<sup>65</sup>

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<sup>61</sup> Chernick Report at 13.

<sup>62</sup> *Id.* at 14.

<sup>63</sup> *Id.*

<sup>64</sup> This table is reproduced from page 14 of Paul Chernick’s Expert Report, where it is labeled “Table 2.”

<sup>65</sup> Chernick Report at 14. In addition, Freeborn-Mower allows 1.7% discount for C&I customers metered at primary voltage, before the line transformer. Reducing the average revenue from the Freeborn-Mower < 1 MVA C&I by the

- \$0.005/MWh for larger C&I customers for both South Central and Steele-Waseca.<sup>66</sup>

Furthermore, these calculations are conservative because they do not account for customer charge revenues, which would reduce the implied distribution cost in the energy charge even more.

This analysis is clear evidence that MREA's methodology understates the residential purchased-power costs for customers, and therefore overstates the residential distribution system costs and the resulting fees seeking to recover distribution system costs. It also provides an important example of how the methodology's failure to use costs as its basis leads to absurd results. The cooperative's failure to comply with the plain terms of the statute is not just an issue of semantics. The legislature required that any fee be based on real utility costs through a cost of service study for a reason. As we've shown, the failure to do so leads to inflated and, ultimately, unsupported and arbitrary fees for utility customers. Therefore, the Commission should find that MREA's methodology does not comply with state law because it is not "reasonable and appropriate for that class of customer" to whom it is being charged. Minn. Stat. §216B.164, subd. 3(a). Finally, this error in customer class cost allocation stemming from a fundamental flaw in MREA's methodology is contrary to the statutory requirement that, in addition to requiring that any fees be based on a cost of service study, that the cost basis must be "appropriate for that class of customer" to whom the fee is charged. This evidence that the fees for residential DG customers are overstated violates this provision that requires a fee calculation is accurate for each customer class.

The MREA methodology's overstating residential distribution costs because of its failing

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primary-service discount and performing the computation in Table 2 would result in slightly negative implied distribution rate. *Id.*

<sup>66</sup> *Id.*



to use an actual cost of service is also evident when looking at real examples where a cooperative's real cost of service study is available. We analyzed DG fees from two utilities – Minnesota Valley and Dakota Electric and discuss this comparison in more detail below in section IV.B.<sup>67</sup> As part of that analysis, we compared each cooperative's fees<sup>68</sup> as calculated by the MREA methodology with what the cooperatives' fees would be if the same calculation is performed, but with information from their actual cost of service studies used in ratemaking. This comparison, in Tables 2, demonstrates that, even without additional adjustments we recommend (particularly limiting the distribution system costs to non-load, "customer-related"), the methodology results in inflated fees compared to fees calculated using the methodology, but with the cooperative's actual cost of service studies.<sup>69</sup> In other words, doing nothing more than substituting Minnesota Valley and Dakota Electric's actual cost of service study values into the MREA methodology results in a material reduction in those fees – 16 percent and 22 percent respectively.

**Table 2 – Comparison of MREA Methodology Using Minnesota Valley and Dakota Electric Cost of Service Inputs.**

	<u>Minnesota Valley</u>		<u>Dakota Electric</u>	
Fee in \$/kW-month and maximum fee as proposed with <u>Form 7 revenue data</u>	\$4.39/kW	\$85.00/kW	\$4.03/kW	\$28.00/kW
Fee in \$/kW-month and maximum fee with cost data from <u>actual cost of service study</u>	\$3.17/kW	\$61.00/kW	\$3.23/kW	\$23.00/kW
<u>Difference in \$</u>	\$1.21/kW	\$24.00/kW	\$0.80/kW	\$5.00/kW
<u>Difference in percentage</u>	<b>38%</b>	<b>39%</b>	<b>25%</b>	<b>22%</b>

<sup>67</sup> This analysis was limited to Minnesota Valley Cooperative Light & Power Association and Dakota Electric Association for reasons discussed in more detail below in Section IV.B.

<sup>68</sup> Dakota Electric is not proposing a DG fee at this time, so our analysis is based on an estimate using DEA Form 7 information and the MREA methodology. Dakota Electric's DG fee estimate is attached as part of Exhibit D.

<sup>69</sup> The complete analysis is attached as Exhibit D.

*2. MREA's Methodology ignores the distribution system benefits provided by customer DG.*

MREA's methodology does not comply with Minn. Stat. §216B.164, Subd. 3(a)'s requirement that any fee developed under its terms "must be reasonable" because the methodology does not account for any benefits that customer DG provides to the utility's distribution system. It is not possible to accurately estimate the costs of serving DG customers without accounting for the benefits of DG that can lower overall costs to the system. Ignoring DG benefits results in overstated DG costs. As Mr. Chernick's analysis found, "The MREA methodology also overstates the fixed costs it seeks to recover from solar customers because it significantly understates the costs avoided by solar generation."<sup>70</sup>

The fact that distributed solar photovoltaics provide distribution system benefits in the form of avoided, reduced or delayed utility costs is well understood in the electricity industry. Indeed, Minnesota law and the Commission recognize these benefits generally as well. Minn. Stat. §216B.164, subd. 10 directed the Department of Commerce to create a methodology to quantify the "value to the utility, its customers, and society for operating distributed solar photovoltaic resources interconnected to the utility system and operated by customers primarily for meeting their own energy needs." In doing so, it recognizes that DG solar may provide benefits, including utility distribution system avoided costs. Subd. (f) states that "The distributed solar value methodology established by the department must, at a minimum, account for the value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value." The value of solar methodology ultimately developed by the Department and approved by the Commission contains multiple distribution

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<sup>70</sup> Chernick Report at 14.

system-related utility avoided costs, or benefits, including a benefit component calculating the distribution capacity benefit provided by DG solar.<sup>71</sup> When approving the Department of Commerce’s value of solar methodology, the Commission found that each of the methodology’s “proposed value components are consistent with the methodology standards established in Minn. Stat. § 216B.164, subd. 10(f).” And that “Each component represents a category of costs—to the utility, its customers, or society—that grid-connected solar PV installations can avoid.”<sup>72</sup>

Despite the general and wide acceptance of the fact that distributed generation produces distributed system benefits, MREA’s description of its methodology in response to PUC Staff IR No. 5(c) is explicit that zero DG system benefits are included in the fee calculation. Without providing any supporting analysis, it states that “there are no consumer or capacity-related distribution fixed cost reductions attributable to the energy use reduction.”<sup>73</sup> This statement is not only technically inaccurate, but is clear evidence that MREA’s methodology does not comply with the statute’s “reasonableness” requirement.<sup>74</sup>

MREA’s choice to ignore any and all DG distribution system benefits results in overstated utility costs, and therefore, in inaccurately high DG fees seeking to recover those costs. Mr. Chernick’s report identifies a number of fundamental ways that, contrary to MREA’s unsupported statement, DG load reduction can provide utility cost savings.

- “Regardless of how much generation and transmission charges are included in the distribution cooperatives’ residential rates, solar generation would typically avoid power-supply costs that are more expensive than average.”<sup>75</sup>
- “Distribution costs are mostly variable with respect to load. The size of many distribution components (e.g., the diameter of conductors, the capacity of

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<sup>71</sup> See *inter alia* VOS Methodology at 34.

<sup>72</sup> PUC Order Approving VOS Methodology at 14.

<sup>73</sup> MREA filing at 16.

<sup>74</sup> MREA’s description of its methodology, which MREA did not file, provides additional explanation on why it does not include any DG benefits (provided herein as Exhibit G). Mr. Chernick’s report responds to MREA’s limited analysis in detail, finding it “unsupported and analytically incorrect” at 18.

<sup>75</sup> Chernick Report at 14.

transformers) is load-related, as are the number and other characteristics of some distribution components.”<sup>76</sup> Therefore, DG load reductions can defer the need for increased distribution capacity.

- “While distribution costs are driven by load levels, the maximum load on each piece of equipment is not the only important load. . . the length of the peak and the energy use prior to those hours can also affect the sizing and service life of transformers and underground lines.”<sup>77</sup> Therefore, solar generation, even accounting for its variability, can defer increased distribution capacity and reduce wear and tear on distribution equipment, which defers utility spending.

The Utah Commission’s order rejecting PacifiCorps’ DG fees further illustrates this point.

In addition to PacifiCorp’s failure to accurately estimate the costs of serving DG customers, the Utah Commission found that the PacifiCorps estimate of costs was “misleading” because the PacifiCorps methodology “contain[s] no discussion at all of net metering program benefits.”<sup>78</sup> The Commission concluded that this failure resulted in a record that was “inconclusive, insufficient, and inadequate” to make a determination that the proposed DG fees were “just and reasonable” under Utah law.<sup>79</sup> This is very similar to the “reasonable and appropriate” legal standard that the Commission must apply here under Minnesota law. Indeed, MREA’s failure to account for any DG distribution benefits results in an inflated estimate of the co-ops’ costs to serve DG customers and the methodology is therefore unreasonable and unlawful.

Moreover, the statute’s requirement that any fees are limited to recovering “the fixed costs not already paid for by the customer through the customer's existing billing arrangement,” suggests a requirement that, in addition to a DG benefits analysis, the methodology also incorporates an analysis that ensures fixed costs are not double-charged to a DG customer. This type of analysis is exactly what the Utah Commission found it would require before authorizing a net metering charge. It stated: “if we are to implement a facilities charge or a new rate design,

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<sup>76</sup> *Id.* at 18.

<sup>77</sup> *Id.*

<sup>78</sup> PacifiCorps Order at 59, 65.

<sup>79</sup> *Id.* at 66.

we must understand the usage characteristics, e.g., the load profile, load factor, and contribution to relevant peak demand, of the net metered subgroup of residential customers. We must have evidence showing the impact this demand profile has on the cost to serve them, in order to understand the system costs caused by these customers.”<sup>80</sup> Similarly, in this case, the co-op’s methodology must include an analysis of what fixed costs are incremental to the costs “already paid for by the customer through the customer’s existing billing arrangement” to comply with Minnesota law.

In sum, it is generally well established in Minnesota, as well as in the evidence in this case, that DG can provide distribution system benefits in the form of avoided utility costs. MREA has not met its burden demonstrating that, for some reason, this well-known phenomenon does not apply to cooperative utilities. Indeed, there’s nothing to suggest that MREA or its members have done any meaningful analysis on the subject. MREA’s failure to account for DG system benefits results in distribution costs that are almost certainly overstated for residential DG customers and therefore cannot be considered reasonable and appropriate as required by Minnesota law. In addition, the MREA methodology is unlawful because it lacks any analysis ensuring that the costs it seeks to recover are “not already paid for by the customer through the customer’s existing billing arrangement.”

#### **IV. RECOMMENDATIONS**

MREA and the cooperative utilities charging DG fees have not met their burden demonstrating that their methodology complies with Minnesota law, particularly in light of the intent of the statute to “give the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public.” Minn. Stat. §

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<sup>80</sup> *Id.* at 68.

216B.164, subd. 1. Instead, the evidence shows that the MREA methodology is fundamentally contrary to state law because i) it is not based on a cost of service study; ii) it is designed to recover lost revenue and not “fixed costs not already paid for by the customer through the customer’s billing arrangement”; and iii) it contains fundamental flaws that result in fees that are not “reasonable and appropriate for that class of customer.” Minn. Stat. § 216B.164, subd. 3(a). Therefore, under its authority per the 2017 amendment to Minn. Stat. § 216B.164, the Commission should find that the MREA methodology, as proposed, does not comply with state law.<sup>81</sup>

In addition, consistent with that amendment, which states that “If the commission determines that a methodology does not comply with state law, it shall clearly state the changes necessary to bring the methodology into compliance”<sup>82</sup>, we recommend that the Commission require the following changes: 1) that the methodology is based on a cost of service study that includes basic elements identified by NRECA, NARUC and Minnesota rules, and that the cost of service study is “the most recent” one used by the cooperative utility in setting general customer rates 2) that the “fixed costs” the methodology seeks to recover are the distribution system costs allocated as “customer” costs in the cost of service study; and 3) that the methodology correct the methodological flaws that result in overstated costs, by including a reasonable quantification of DG system benefits for the cooperative utility that result in lower overall costs of service and an analysis of its DG customer’s load characteristics demonstrating that any identified costs are not already being paid through the customer’s existing billing arrangement

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<sup>81</sup> Minnesota Session Law 2017 Chapter 94, S.F. 1456, Article 10, Section 8 (amendment adding subd. 11(d).

<sup>82</sup> Minnesota Session Law 2017 Chapter 94, S.F. 1456, Article 10, Section 8

***A. The Commission should Require that the Methodology is Based on a Cost of Service Study as Commonly Understood and that is the Most Recent Cost of Service Study Used by the Utility in Setting its General Rates***

MREA' methodology is not based on any reasonable definition of a cost of service study, contrary to statute. We recommend that as one of the "changes necessary to bring the methodology into compliance," the Commission should order that a cooperative utility DG fee methodology must be based on a cost of service study that uses the common elements as described by the NARUC and NRECA manuals. This would include that the study determines the revenue requirement based on utility costs and contains the other basic elements. We recommend the following definition that is taken directly from the co-op's rate manual and that is consistent with the NARUC manual and Minnesota Rules if the Commission wishes to include a specific definition in its order:

"A cost of service study is an analysis that:

- 1) determines the revenue requirement consisting of:  
[adjusted test year operating cost + margins necessary to meet cooperative's financial objectives - other operating revenue]; and
- 2) allocates the revenue requirement as follows:
  1. Define the rate classification.
  2. Define the cost functions (aligned with the unbundled rate components).
  3. Classify the cost to fixed (demand), variable (energy), customer and any applicable direct assignments for each cost function.
  4. Develop allocation factors based on rate class use profiles.
  5. Allocate each cost component to define the individual class revenue requirement (operating margins)."<sup>83</sup>

The Commission should also require that the cost of service study used in the fee methodology be the most recent cost of service study that was used by the utility in setting general customer rates, not a cost of service study developed solely to calculate DG fees. First, such a requirement

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<sup>83</sup> NRECA/CFC Rate Guide Vol. II at 19 (punctuation and formatting changed for clarity).

is implied in the statute's language. The statute specifically states that any fee must be based on the cooperative's "most recent cost of service study." Including "most recent" implies that the cost of service study the statute is referencing is a cost of service study from the most recent rate-setting by the cooperative board. This interpretation makes sense because cost of service studies are considered to be a basic element of rate setting that a utility would have developed in its most recent rate case or board rate determination. If the legislature presumed a cost of service study would be performed solely to set DG fees, it would be superfluous for it to include the "most recent" language.

In addition to being consistent with, and implied in, the statute, requiring that the cost of service study be a study from the most recent rate-setting provides important consumer protections. Allowing the cost of service study in the fee methodology to be focused only on setting DG fees risks being discriminatory and skewed to unfairly charge those customers more (as we have seen is the case here). Instead, requiring that the same cost of service study that is used in the cooperative utility's general rate making provides the assurance that it is based on the same utility costs and assumptions that are applied to all of the utility's customers. Doing so will also be a safeguard against flawed assumptions that lead to unreasonable results, such as MREA's assumption that overstates residential purchased power costs.

***B. The Commission should Require that the "Fixed Costs" Considered in the Methodology are Limited to those Classified as Customer-Related Distribution Costs in the Cost of Service Study.***

MREA's methodology does not comply with the statute's requirement that any charges must be designed to recover "fixed costs not already paid for by the customer through the customer's existing billing arrangement" and "reasonable and appropriate for that class of customer". To remedy these shortcomings in part, we recommend that the Commission require that "fixed costs" that the fee methodology seeks to recover be limited to those functionalized



and classified as “customer-related distribution” costs (or the equivalent) in the utility’s cost of service study. The Commission should include this requirement because it will help to ensure that any “fixed costs” the utilities seek to recover are not all costs for anything related to the utility’s distribution system, but instead are limited to common practice regarding customer “fixed costs”. Moreover, doing so will also help ensure that load-related, incremental distribution system costs that DG may avoid are not included in fees.

Such a requirement is also consistent with MREA’s stated definition of fixed costs and other Minnesota cooperative utility practice. MREA’s filing in response to PUC staff defines fixed costs as “those costs to serve the member-owner regardless of how much or little electricity they use.”<sup>84</sup> In other words, fixed costs for this purpose should exclude costs driven by a customer’s load. This position is consistent with our recommendation. It is also consistent with Dakota Electric Association’s (“DEA”) approach to fixed costs as collected through its customer charge. DEA explains that it limits its calculation of the costs for its fixed charge to a subset of the customer-related distribution costs:

As Dakota Electric testified in our last general rate case, we believe it is appropriate for the monthly fixed charge to recover costs we incur to stand ready to provide electric service, excluding costs for primary line. Such costs to be included in the monthly fixed charge include the monthly cost of a transformer, meter and service, customer accounting, as well as taxes and margin associated with plant costs proposed for recovery in the monthly fixed charge.<sup>85</sup>

Therefore, as DEA’s customer charge approach highlights, limiting the scope of “fixed costs” to “those costs to serve the member-owner regardless of how much or little electricity they use,” as MREA puts it, is necessary to ensure the methodology does not target “fixed costs not already paid for by the customer through the customer’s existing billing arrangement”.

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<sup>84</sup> MREA response to Staff IR 5 (e) at 19.

<sup>85</sup> Dakota Electric Association Prefiled Direct Testimony Of Douglas R. Larson, VP Of Regulatory Services Dakota Electric Association at 33, line 9-14, Docket No. E-111/GR-14-482.

Finally, this requirement is practical to implement because functionalizing, classifying and assigning distribution system costs is a standard step in any cost of service study, so is a cost category and cost information that is already available to utilities.<sup>86</sup>

To illustrate how our proposed recommendations related directly to the cost of service study would change the cooperatives' DG fees, we provide a comparison of two cooperative DG fees, one as proposed by Minnesota Valley Cooperative Light & Power Association and one based on an example fee for Dakota Electric Association.<sup>87</sup> We would like to have provided the same comparison for all the cooperative utilities that charge DG fees, but MREA refused to provide any information to Fresh Energy and ELPC, as well as the Department of Commerce, through information requests in this docket despite multiple requests and offers for parties to sign protective agreements for trade secret filings.<sup>88</sup> As such, we are limited to providing comparisons of the Minnesota Valley and DEA fees, because Minnesota Valley filed the necessary information in customer dispute docket,<sup>89</sup> and because DEA is rate regulated by the Commission and therefore the necessary information is publicly available. Moreover, we expect that all, or nearly all, of the cooperative fees would show similar results to Minnesota Valley and DEA if we were able to perform the analysis.

To compare the two cooperative fees derived from the MREA methodology and the two fees derived from the MREA methodology with our recommended cost-based modifications, we 1) calculated the monthly per/kW fee amount and the maximum fee amount using inputs from

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<sup>86</sup> See e.g., NRECA/CFC Rate Guide Vol. I at 27 ("A Cost of Service Study (COSS) should identify the customer-related cost of providing service. . . The customer charge should reflect recovery of costs that are driven by just being a member-consumer, no matter how small.")

<sup>87</sup> DEA is not currently proposing to implement a DG fee, but we provide an estimate based on DEA Form 7 information and the MREA methodology. The DEA estimate is included as part of Exhibit E.

<sup>88</sup> See MREA and Itasca-Mantrap Cooperative response to Fresh Energy IRs 1-4, attached as Exhibit B. This unjustified failure to provide information by MREA and the other cooperative utilities is yet more evidence that they have not met their burden to demonstrate that their DG fees are legal.

<sup>89</sup> Docket No. E123/CG16-241.

the cooperative utilities’ actual cost of service studies that were used in each of the utilities’ most recent rate-setting; and 2) substituted the cost of service studies’ ‘customer-related’ distribution costs for the MREA methodology’s incorrect revenue-based distribution system cost estimate. The overall results in Tables 3 and 4 below show a meaningful change in the DG fees when our recommendations are applied – a 207% change for Minnesota Valley and ~72% change for DEA. The full comparison analysis is provided in Exhibit E.

**Table 3: Minnesota Valley Cooperative Light & Power Association Fee Comparison**

	<u>Monthly per kW fee</u>	<u>Maximum Monthly fee</u>
<u>MREA Methodology</u>	\$4.39/kW	\$85.00/month
<u>With Recommended Changes</u>	\$1.50/kW	\$29.00/month
<u>Difference in dollars</u>	<b>\$2.89/kW</b>	<b>\$56.00/month</b>
<u>Difference in percentage</u>	<b>193%</b>	<b>193%</b>

**Table 4: Dakota Electric Association Example Fee Comparison**

	<u>Monthly per kW fee</u>	<u>Maximum Monthly fee</u>
<u>MREA Methodology</u>	\$4.03/kW	\$28.00/month
<u>With Recommended Changes</u>	\$2.04/kW	\$14.00/month
<u>Difference in dollars</u>	<b>\$1.99/kW</b>	<b>\$14.00/month</b>
<u>Difference in percentage</u>	<b>97%</b>	<b>100%</b>

These examples illustrate our cost of service study recommended changes only. They do not correct the other methodological flaws identified by Mr. Chernick that result in overstated

cost estimates, MREA's failure to account for distribution system benefits, or the lack of analysis regarding whether identified costs are already accounted for in a DG customer's billing. As such, the MREA methodology must be further adjusted per our final recommended change below.

***C. The Commission Should Require That the Methodology Include A Reasonable Analysis And Quantification Of DG System Benefits And A Netting Of Those Benefits With Costs.***

MREA's methodology overstates the fixed costs of serving DG customers and does not comply with Minn. Stat. §216B.164, Subd. 3(a)'s requirements that any fee developed under its terms "must be reasonable" and that any fee is limited to "the fixed costs not already paid for by the customer through the customer's existing billing arrangement" because the methodology does not account for any benefits of distribution generation that tend to reduce overall distribution system costs for the utility and lacks an analysis of what, if any, fixed costs are incremental to the costs "already paid for by the customer through the customer's existing billing arrangement". Therefore, the Commission should order that, as part of "the changes necessary to bring the methodology into compliance"<sup>90</sup> with state law, the cooperative DG fee methodology must be modified to include: i) a reasonable analysis of DG benefits to the utility in the form of avoided and deferred distribution system and power supply costs; ii) an analysis of the utility's DG customer's load characteristics demonstrating that any identified costs are not already being paid through the customer's existing billing arrangement; and iii) a calculation that nets the DG benefits against the methodology's identified costs and removes any costs "already paid for by the customer". This recommendation ensures that cooperative utilities reasonable analyze and quantify DG benefits for their distribution systems and avoided purchased power costs and incorporate these benefits into any fees through a netting calculation.

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<sup>90</sup> Minnesota Session Law 2017 Chapter 94, S.F. 1456, Article 10, Section 8

***Recommendations***

We respectfully recommend the Commission order:

1. That the MREA methodology used to determine DG fees charged by the Minnesota electric cooperatives in this docket does not comply with Minn. Stat. §216B.164.

And, pursuant to changes to Minn. Stat. §216B.164 in Minnesota Session Law 2017 Chapter 94, S.F. 1456, Article 10, Section 8, which states that “If the commission determines that a methodology does not comply with state law, it shall clearly state the changes necessary to bring the methodology into compliance,” we recommend the Commission order that:

2. The cooperative DG fee methodology must be modified so that it is based on a cost of service study as that term is commonly understood and that is the most recent cost of service study used by the utility in setting general customer rates.
3. The cooperative DG fee methodology must be modified such that the distribution system “fixed costs” considered in the methodology are limited to those functionalized and classified as “customer-related distribution costs” (or the equivalent) in the utility’s cost of service study.
4. The cooperative DG fee methodology must be modified to include: i) a reasonable analysis of DG benefits to the utility in the form of avoided and deferred distribution system and power supply costs; ii) an analysis of the utility’s DG customer’s load characteristics demonstrating that any identified costs are not already being paid through the customer’s existing billing arrangement; and iii) a calculation that nets the DG benefits against the methodology’s identified costs and removes any costs “already paid for by the customer.”

Respectfully submitted,

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DATED: September 1, 2017

**Review of the Net Metering Proposal  
of the Minnesota Rural Electric Association**

*Paul Chernick  
President  
Resource Insight, Inc.*

*February 6, 2017*

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## Summary

A group of Minnesota electric co-operatives have proposed to impose punitive fees on customers who install renewable generation (entirely solar to date) on their property. Each utility in Minnesota is required to allow customers to install those systems and credit customers for energy delivered to the utility at essentially the same rate it charges the customer. Co-operatives are allowed to charge a fee to customers with renewable generation, under specific conditions, including that the fee is reasonable, derived from a cost-of-service study and collects only unrecovered fixed costs. In addition, Minnesota law requires that utility rates not be unduly discriminatory. Unfortunately, the co-operatives' proposal fails all these tests.

- The fees are not based on cost-of-service studies. The co-operatives compute the fees from existing rates, not from the underlying costs. That error violates the legal requirement that the fee collect only fixed costs that are required to serve a customer, regardless of the customer's usage.
- The co-operative fees are designed to collect all distribution costs, including such load-related equipment as line transformers, primary lines, and substations. This exceeds the co-operatives' legal authority to charge only for any uncollected fixed costs.
- In computing the fees, the co-operatives assume that the clearly variable generation and transmission costs in the existing residential rates equal the average ¢/kWh for the entire utility. This assumption is incorrect and will overstate the distribution costs in the residential rate.
- The co-operatives' method results in negative distribution costs for some classes of large customers, and hence clearly overstates the distribution costs in the residential rates.
- Even if the co-operatives had properly estimated the generation and transmission costs in the residential rates, they would have underestimated those costs avoided by solar generation, which is concentrated in the summer, when power supply prices are their highest.
- The co-operatives discriminate against solar panels owned by their customers and third parties by not applying the same surcharges to customers who lease solar panels from the co-operatives' centralized solar facilities. This discrimination violates core principles of regulatory fairness and also raises anti-trust law concerns.



- Customers have many ways to reduce their consumption of utility electricity, from efficient lighting to heat pumps. The co-operatives have proposed to impose penalties for just one technology: solar installations<sup>1</sup>. No other customers are charged extra for buying less electricity.

In short, the charges proposed by the co-operatives are illegal, excessive, improperly estimated, and discriminatory.

## Background

In Minnesota Public Utilities Commission Docket No. 16-512, the Minnesota Rural Electric Association (MREA) has proposed a method for deriving a charge to customers with behind-the-meter distributed generation. That charge takes the form of a charge per kilowatt of installed capacity, for capacity in excess of 3.5 kW. MREA also proposes a method for selecting a cap on the monthly distributed-generation charge.

Twenty-one co-operatives have adopted the MREA methodology and established charges of \$2 to \$5.57/kW for the installed capacity of solar panels in excess of 3.5 kW per member.<sup>2</sup> The various co-operatives propose to cap the charges at the equivalent of about 11 kW to 27 kW. (MREA Response to Staff I.R 5a) Table 1 lists those distribution co-operatives, along with the generation and transmission (G&T) co-operative serving each of them. In the remainder of this report, I will refer to these as the “filing co-operatives.”

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<sup>1</sup> While the fees may apply to any qualifying facility under Minn. Stat. 216B.164, the co-operative fees were specifically designed to target solar panels and the co-operatives have applied the fees only to solar-powered systems.

<sup>2</sup> The proposals of twenty of these co-operatives, and supporting data, were filed in MREA’s September 19, 2016 response to the PUC questions, some of which were refiled in more legible form on October 6, 2016. The Co-operative L&P information was filed in MREA’s supplemental response on November 23, 2016.

**Table 1: Distribution Co-operatives Proposing to Apply the MREA Methodology and Establish a DG Charge**

<b>Distribution Co-operative</b>	<b>G&amp;T Co-operative</b>
Blue Earth-Nicollet-Faribault (BENCo)	Great River Energy
Brown County	Great River Energy
Co-operative Light & Power	Great River Energy
Connexus Energy	Great River Energy
Federated	Great River Energy
Freeborn-Mower	Dairyland Power
Goodhue County	Great River Energy
Itasca-Mantrap	Great River Energy
Lyon-Lincoln	East River Electric
Meeker	Great River Energy
McLeod	Great River Energy
Mille Lacs	Great River Energy
Nobles	Great River Energy
North Star	Minnkota
People's	Dairyland Power
PKM	Minnkota
Redwood	Great River Energy
Runestone	Great River Energy
South Central	Great River Energy
Stearns	Great River Energy
Steele-Waseca	Great River Energy

## Legislative Direction

The Legislature requires that all “co-operative electric associations and municipal utilities” bill customers with less than 40 kilowatts of renewable capacity “for the net energy supplied by the utility according to the applicable rate schedule for sales to that class of customer.” (Minn. Stat. §216B.164, subd. 3(a)) In other words, the co-operatives must credit renewable distributed-generation customers (most of whom will have solar panels) for power fed back into the distribution system at essentially the same rate the customer is charge for energy provided by the co-operative. The same legislation gives the co-operatives some limited flexibility in charges to these customers:

A co-operative electric association or municipal utility may charge an additional fee to recover the fixed costs not already paid for by the customer through the customer’s existing billing arrangement. Any additional charge by the utility must be reasonable and appropriate for that class of customer based on the most recent cost of service study. The cost of service study must be made available for review by a customer of the utility upon request. (Minn. Stat. §216B.164, subd. 3(a))

In setting rates, the commission shall consider the fixed distribution costs to the utility not otherwise accounted for in the basic monthly charge and shall ensure that the costs charged to the qualifying facility are not discriminatory in relation to the costs charged to other customers of the utility. (ibid, subdivision 3(c))

The legislative language makes five points:

- Any additional fee can only recover fixed costs. No costs that can be avoided or reduced due to distributed generation can be recovered in the additional fee.
- The fee can only consider the fixed costs of the distribution utility. Any costs that may be borne by wholesale suppliers (including the G&T co-operatives listed in Table 1) are not eligible to be collected through an additional fee.
- Any additional fee must be reasonable and appropriate and based on “the most recent cost of service study” for the utility.
- “The cost of service study must be made available for review.”
- The charges to the net metering customers must not be “discriminatory in relation to the costs charged to other customers of the utility.”

### **Minnesota PUC Issue List**

In its Notice of Comment Period (November 4, 2016), the PUC identified a number of “topics open for comment,” including the following:

- Do the fees properly recover fixed costs not already paid for by the customer through the customer’s existing billing arrangement?
- Do the fees only recover the fixed distribution costs to the utility not otherwise accounted for in the basic monthly charge?
- Are the fees discriminatory in relation to the costs charged to other customers of the utility?
- Are the fees reasonable and appropriate for that class of customer?
- Was the cost of service study used by MREA as support for the fees reasonable and appropriate?

As I show below, MREA’s proposal fails all these tests. MREA has not identified any unrecovered fixed costs justifying the fees, the fees are clearly discriminatory and unreasonable, and the filing co-operatives have not produced cost-of-service studies.

# From COSS to NEM Rates

## What is a “cost of service study”?

The NARUC Electric Utility Cost Allocation Manual (February 1992) observes that “Cost of service studies are among the basic tools of ratemaking” and “Cost studies are therefore used by regulators [to] “attribute costs to different categories of customers based on how those customers cause costs to be incurred,” among other things. (page 12) The Manual also observes that “the prime purpose of cost of service studies is to aid in the design of rates” and lists the four basic steps, the last two of which involve the use of cost studies.

**The cost allocation procedure**—The total revenue requirement of the utility is attributed to the various classes of customers in a fashion that reflects the cost of providing utility services to each class. The cost allocation process consists of three major parts: functionalization of costs, classification of costs, and allocation of costs among customer classes.

**Design of rates**—Regulators design rates, the prices charged to customer classes, using the costs incurred by each class as a major determinant. Other non-cost attributes considered by regulators in designing rates include revenue-related considerations of effectiveness in yielding total revenue requirements, revenue stability for the company and rate continuity for the customer, as well as such practical criteria as simplicity and public acceptance. (Manual, page 13)

The Manual explains that, in justifying rates, “Utilities developed cost studies that were based on monies actually spent (embedded) for plant and operating expenses and divided those costs (fully allocated or distributed them) among the classes of customers according to principles of cost causation. The task for the analyst was to allocate, among customers, the costs identified in the test year for which the revenue requirement had been calculated.” (Page 13) The Manual describes two types of cost-of-service studies: embedded studies, which allocate the test-year costs among classes, and marginal studies, which determine “the change in cost due to the production of one unit more or less of the product,” where the products are various types of peak demands and period energy consumption,<sup>3</sup> which may then be reconciled to total revenue requirements (page 14).

The Manual (at pages 18–23) describes the cost allocation process at length, explaining the basic steps of a cost-of-service study as including cost

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<sup>3</sup> The results of a marginal cost-of-service study can guide rate-design decisions, without reconciliation to embedded costs.

functionalization, classification of costs, and allocation of costs among customer classes.

In summary, a cost-of-service study converts accounting data, load data, and other inputs into class cost allocations, typically through a three-step process of functionalization, classification and factor allocation. The principal objective of a cost-of-service study is the fair and equitable sharing of the utility's total revenue requirement among the rate classes.

### **What are “fixed costs”?**

While the nature of a cost-of-service study is clear, the meaning of the term “fixed costs” is not. The Legislature does not appear to have defined this term, which is used in multiple ways in utility regulation. At one extreme, “fixed cost” is sometimes used to identify costs that are fixed over the year, not varying in the short run in response to changes in customer usage. By this definition, almost all of the distribution costs of the co-ops are fixed, while costs for generation energy, generation capacity and transmission are almost all variable.<sup>4</sup>

At the other extreme, “fixed cost” is often meant to apply only to costs that are invariant with respect to load or usage, and thus not avoidable by reducing load. By this definition, many categories of distribution costs are variable, not fixed. Higher loads result in utilities needing more and larger substations, more and larger feeder conductors, three-phase rather than single-phase primary, higher distribution voltages (which require taller poles), and more and larger line transformers. Increasing the number of hours with high loads also shortens the useful life of transformers, both for substations and line transformers, as well as underground lines and some overhead lines. In this sense, fixed costs comprise the following categories:

- legacy costs, such as environmental remediation of spilled PCBs from old transformers;
- costs that vary with the number of customers (meters, meter-reading, billing, and most of the costs of residential service drops), regardless of the customers' usage; and
- costs that vary with the area to be served, such as a portion of the costs of poles and conductors.

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<sup>4</sup> Some of the co-ops purchase power from parties other than their G&T co-ops, under contracts that require them to purchase a fixed amount of energy, or all available energy.

In determining whether the net-metering customers are paying a fair share of their co-op's costs, the second sense of "fixed" is relevant. If the reduction in load due to distributed generation can defer or avoid load-related upgrades, or extend the life of transformers and lines, those costs are not fixed. As MREA says, "Fixed costs on the other hand are those costs to serve the member-owner regardless of how much or little electricity they use." (MREA response 5(e)) By MREA's own standard, the computation of the fixed charge would be limited to the costs incurred only for connecting a particular customer, excluding any costs driven by the customer's load; these costs would be a small fraction of the costs that the co-operatives are proposing to collect through the net-metering fee.

### **What is the Legislative Framework for Co-op Net-Metering Charges?**

The Legislative conceptual framework for controlling the maximum fee the co-ops can charge to net-metering customers is thus quite simple:

- The co-op must conduct a cost-of-service study.
- The fee "must be reasonable and appropriate," in light of the co-op's cost-of-service study.
- The fee must be limited to fixed costs not already paid by the customer.
- The fee must not be discriminatory.

### **MREA Interpretation of the Legislative Mandate**

MREA does not provide much conceptual or policy support for its proposal. In MREA's response to Staff IR 5(c), MREA quotes the NARUC Manual on the range of uses of cost-of-service studies, but not the Manual's description of how cost-of-service studies are structured. Among the cited list of cost-of-service-study applications, only three are relevant to this proceeding:<sup>5</sup>

- To attribute costs to different categories of customers based on how those customers cause costs to be incurred.
- To determine how costs will be recovered from customers within each customer class.
- To calculate costs of individual types of service based on the costs each service requires the utility to expend.

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<sup>5</sup> The other two applications that MREA lists involve separating costs between monopoly and competitive services, or between jurisdictions.

In each of these applications, the NARUC Manual is clearly talking about starting with cost data and using the cost-of-service studies to derive class revenue targets and rates.

Despite its familiarity with the NARUC Manual, MREA does not follow the approach laid out by NARUC, and instead does the exact opposite: the MREA method starts with existing rates and performs a series of computations to derive an estimate of costs.

## **MREA's Non-Cost-Based Computation**

The formula that MREA designed for the co-operatives to use in setting a surcharge for distributed-generation customers is not based on the costs of serving customers with distributed generation, as I explain below. While it is readily apparent that MREA's approach is not based on the common understanding of a cost of service study, correcting MREA's errors is complicated by the difficulty of finding data on the co-operatives' cost structures. MREA has filed two pages of the 2015 RUS form 7 for each of the filing co-operatives, which the co-operatives generally do not release publicly, and portions of the filing co-operatives' tariffs. MREA did not file other important data for the filing co-operatives, such as:

- The distribution co-operatives' monthly loads, energy use, or power bills.
- Recent and planned distribution investments.
- Historical and projected load growth.
- The G&T co-operatives current rate structures.<sup>6</sup>
- The timing of the G&T co-operatives' monthly peak loads.
- The hours that determine the generation and transmission charges of the filing co-operatives.

All these data would be available in any contested proceeding for regulated utilities, and much of the data for an investor-owned utility would normally be available on line, on the utility's web site, in its annual reports and in routine filings with FERC and the Minnesota PUC. The lack of data complicates review of the MREA approach.

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<sup>6</sup> Elk River Municipal Utilities posted the Great River Energy all-requirements tariff for 2008 in its November 5, 2007, information packet for its Utilities Commission, marked as confidential. I have not been able to find a more recent set of these tariffs or any comparable tariffs for the other G&T co-operatives.

## MREA's Formula

The computation proposed by MREA for the net-metering distributed-generation charge consists of the following steps:<sup>7</sup>

1. Assume that the portion of the co-operative's purchased power costs (including transmission) charged to its residential customers in 2015 equaled the ratio of residential sales to total sales.
2. Subtract that estimate of residential purchased-power costs from 2015 residential revenues. Assume that the difference is the distribution revenue from residential customers in 2015.
3. Compute 2015 revenue from the residential customer charge (which MREA sometimes calls the "Consumer Charge") and subtract those revenues from the estimate of distribution revenue. Assume that the result was the 2015 "Distribution Fixed Costs Recovered in Residential Energy Rate."
4. Divide the estimate of the "Distribution Fixed Costs Recovered in Residential Energy Rate" by 2015 residential sales to express the estimate in \$/kWh.
5. Multiply that \$/kWh rate by 109.5 (= 730 hours per month times a 15% capacity factor) to estimate the monthly distribution fixed costs that a customer would save due to the energy production of one kW of solar output.<sup>8</sup>

In addition, MREA proposes that the maximum distributed-generation charge be computed as follows:

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<sup>7</sup> The various co-operatives have different definitions of the tariff(s) (called residential, general, or farm and general, and sometimes divided between single-phase and three-phase) including residential customers; it is not clear how the co-operatives distinguish residential load from farm, commercial or other uses covered under the general tariffs. Freeborn-Mower performed this computation separately for both its legacy customers and its entire residential customer base, including its recently-acquired service territory. Itasca Mantrap performed the computation separately for both residential and commercial customers.

<sup>8</sup> Most of the filing co-operatives used this result as the distributed-generation penalty charge. People's selected a lower value "To account for the future effect the service territory acquired from Alliant Energy would have on the methodology" (MREA updated response p. 13). It is worth noting that this approach is unreasonable for charges to small wind systems, as it is based on a solar pv capacity factor estimate. {The fee per kW would be higher for a wind or biogas system, because the system would have a capacity factor > 15% }



6. Divide the estimated residential distribution energy revenue (from step 3) by the number of residential customer-months.

The first four steps of the MREA method are equivalent to following computation in ¢/kWh:

*Average residential energy revenue – Average system-wide purchased-power cost*

Note that this computation mixes a rate and a cost, as well as a residential value component and a system-wide component. In order for MREA's method to reflect cost of service, one must assume that (1) the residential rate equals the residential cost of service, based on a cost-of-service study, and (2) that residential rate includes G&T charges at the system-wide average rate. Neither of those assumptions appears to be true and MREA has provided no evidence in the record supporting those assumptions. Therefore, the co-operatives' fees result from a leap of faith, not a cost-of-service analysis.

### **MREA's Defense of its Method**

MREA does not demonstrate any of the facts that would be necessary to support its method, such as the following:

- That the co-operatives set their rates based on a cost-of-service study.
- That the residential rate approximates cost of service.
- That the residential rate is based on the average purchased-power charge.

MREA does not demonstrate that any of these conditions have been met, that the existing rates represent cost causation, or even that any of the individual co-ops have actually conducted anything that could be reasonably called a cost-of-service study. Instead, MREA just calls its computation a "cost-of-service study" and alleges that it has met the statutory standard. As MREA explains in its response declining to answer Fresh Energy Information Requests 1–4 (RE: Mn PUC Docket 16-512; Fresh Energy Information Requests 1–4, 11/18/2016):

MREA adopts a common understanding of a cost of service study to be a study used to determine the cost to serve a member of a utility. The cost of service studies already provided to the Commission are based on the specific costs to serve members from each named co-operative and are updated annually using a readily accessible reporting form. The cost of service study approach is reasonable, transparent, equitable to all members, and meets the requirement within Minnesota Statute 216B.164 Subd. 3(a).

...pertinent information regarding the cost of service studies used to determine the cost recovery charges allowable under Minnesota Statute 216B.164 Subd. 3(a) were...provided to the Commission in our September 19, 2016 filing.

Interestingly, MREA starts with a reasonable definition of a cost-of-service study as “a study used to determine the cost to serve a member of a utility,” but then asserts that MREA’s computations represent cost-of-service studies for each of the 21 filing co-operatives. It is safe to say that regulators would be shocked if any regulated utility filed computations that started with the existing rates and claimed those were cost-of-service studies.

MREA offers a slightly different explanation of how the distributed generation penalties could be based on a cost-of-service study when it asserts that “The calculation starting point is total cost of service as determined by the local board and reflected in the annual revenue from board determined rates.” (MREA Response to Staff IR 5c) Yet the only “total” cost used in MREA’s computation is the total residential revenue from RUS Form 7. MREA essentially asserts that an actual cost-of-service study is unnecessary because customers and the PUC should assume that each local board has set rates based on cost, without seeing any computation of a residential “total cost of service” used in the boards’ determination of residential rates. This could not be the sort of cost-of-service study that the Legislature had in mind when it mandated that “the cost of service study must be made available for review.”

In short, MREA has failed to meet the most basic and clearest requirement in the statute: that any distributed-generation fee be based on a cost-of-service study.

## **Errors in the MREA Approach**

MREA’s approach contains multiple basic errors that further demonstrate it is not accurately cost-based and results in fees well beyond “fixed costs not already paid for by the customer through the customer’s existing billing arrangement.” The following sections discuss some of these errors.

### ***Residential Purchased-Power Costs Exceed the System Average***

The MREA method effectively assumes that the distribution costs recovered in the residential energy rate equal the residential energy charge (in ¢/kWh) minus the system average purchased-power costs (also in ¢/kWh). In reality, the generation and transition costs embedded in the residential rates, even assuming those rates were at some time set based evenly roughly on costs, would likely exceed the system average for at least four reasons:

First, utilities tend to charge the residential class more per kWh of sales for transmission and the demand-allocated portion of generation costs than they charge the non-residential classes. Utilities treat these costs as being driven by some measure of peak loads (most appropriately, coincident loads, but sometimes class non-coincident loads) and generally find that residential customers use less energy per kilowatt of peak load than many other categories of customers, including industry, streetlighting and some commercial facilities.<sup>9</sup> The ratio of average load to peak load is defined as the class “load factor.”

It is reasonable to assume that the distribution co-operatives attempt to reflect in their rates, the rate design of the tariffs charged to them by the G&T co-operatives. While those tariffs are not generally available, I have been able to glean a few important elements from public documents:

- The Great River Energy and Dairyland co-operatives’ annual informational filings at FERC in response to ER16-1034 (and earlier dockets) indicate that their transmission rates are stated in terms of a \$/kW rate for each kilowatt of the twelve monthly coincident peak demands of the G&T co-operative (or, in the case of Great River Energy, the peak demands of various transmission zones).<sup>10</sup>
- The Great River Energy proposal for 2008 rates, which the Elk River Municipal posted on its website, includes charges for a significant portion of generation on the basis of each distribution co-operative’s contribution to Great River Energy peak monthly loads.
- The Dakota Electric Association (a non-filing co-operative customer of Great River Energy), which is rate-regulated by the Minnesota PUC, estimates load factors of 60% for its residential class, and 102% for its other classes (largely due to interruptible loads and irrigation), based on annual energy and the average monthly demands.<sup>11</sup> Dakota allocates 68% more transmission cost and

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<sup>9</sup> The pattern of load factors across classes varies with the timing of the utility peaks (summer/winter and morning/mid-day/evening) and the composition of the non-residential loads.

<sup>10</sup> I have not found a similar document for Minnkota or East River. The PKM Large Power tariff suggests that Minkota may bill based on the highest coincidental demand during the winter period, the highest coincidental demand in the summer period, and for some other coincidental transmission peak.

<sup>11</sup> Cost of Service Analysis Exhibit DEA-3 to Direct Testimony of Doug Larson. In addition, recent cost-of-service studies by Minnesota Power and Xcel Energy show lower load factors for residential customers.

77% more generation demand-allocated costs to each kWh of residential sales than to non-residential sales.

Second, the seasonality of residential load may make it more expensive to serve than average load. Great River Energy charges higher generation capacity rates in the summer than the winter, and still lower rates in the shoulder months. In 2008, the ratio of prices in \$/kW-month were 3:2:1 for summer, winter and shoulder months. Many industrial customers would have essentially the same loads each month, and some agricultural-processing loads would be concentrated in the autumn, while residential load may be more heavily concentrated on the summer air-conditioning peaks and the winter space-heating peaks.

Third, utilities also tend to charge the residential class more per kWh for energy-allocated portion of generation costs, to reflect the tendency for residential customers to use a greater proportion of their energy at high-cost times than flatter or more off-peak loads, such as streetlighting, industry and irrigation. Great River Energy charges higher energy rates in the on-peak period (10 AM to 8 PM, Monday to Friday) than in the off-peak, and still higher prices in critical-peak hours that Great River Energy designates the previous day.<sup>12</sup> Depending on the timing of the critical peaks and the nature of the non-residential loads, residential customers may be using a more expensive mix of energy than the distribution co-operative's average cost.

Fourth, losses between the transmission system and the residential meter are generally estimated to be greater than average. Among other considerations, residential customers are almost always metered at secondary voltage, after the line transformer (overhead or pad-mounted) transforms power from primary to secondary. Utilities therefore incur transformer losses on behalf of residential customers, while larger non-residential customers are often metered at primary voltage, before the transformer. Freeborn-Mower explicitly lists a 1.7% credit on energy and demand charges for primary metering of Large Power customers in its new service territory; it is not clear how large a primary-metering credit may be folded into the large-customer rates of the other co-operatives.

Unfortunately, MREA does not provide enough information for the PUC to determine what purchased-power costs are folded into the residential rate, to reflect each of these four effects. However, applying the MREA method to other rate classes demonstrates that MREA was wrong to assume that all retail rates reflect the average ¢/kWh system purchased-power charge for each customer

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<sup>12</sup> Since MREA has not provided the rate schedules for any of the G&T co-operatives, we do not know whether the other suppliers use energy schedules similar to Great River Energy's.

class. This is most clearly seen in the fact that the MREA methodology produces *negative* distribution costs for the “Commercial & Industrial over 1,000 kVA” category in the RUS Form 7, Part O, for three of the filing co-operatives, as shown in Table 2.

**Table 2: Examples of MREA Method Showing Negative Distribution Rates**

	<b>BENCo</b>	<b>Connexus</b>	<b>Mille Lacs</b>
<b>Purchased-Power Expense</b>	\$24,962,184	\$189,901,838	\$14,437,178
<b>Total kWh</b>	317,592,373	2,241,959,488	192,670,173
<b>Purchased Power Expense/kWh</b>	\$0.079	\$0.085	\$0.085
<b>Average Revenue C&amp;I &gt;1,000 kVA</b>	\$0.067	\$0.079	\$0.067
<b>Implied Distribution Rate</b>	-\$0.012	-\$0.005	-\$0.018

These computations ignore the customer-charge revenue, which would further reduce the implied distribution costs in the energy charge. In most cases, MREA has not provided the co-operatives’ non-residential tariffs, so we cannot perform this step.

The MREA method also produces barely positive estimates of distribution rates for some of these categories for other filing co-operatives: \$0.002/MWh for the < 1 MVA commercial and industrial (C&I) rate for Freeborn-Mower and \$0.005/MWh for larger C&I customers for both South Central and Steele-Waseca. These thin margins may be negative after accounting for the customer charge, or for rate classes within the broad categories (C&I <1 MW, C&I ≥1 MW, irrigation, public authorities ) reported in the RUS Form 7 schedules. For example, Freeborn-Mower allows 1.7% discount for C&I customers metered at primary voltage, before the line transformer. Reducing the average revenue from the Freeborn-Mower < 1 MVA C&I by the primary-service discount and performing the computation in Table 2 would result in slightly negative implied distribution rate. The same may be true for additional tariffs (such as primary-voltage and interruptible rates) within the C&I classes of filing co-operatives; we just do not have enough data to be sure.

Thus, it is clear that the MREA method understates the residential purchased-power costs for customers, and therefore overstates the residential distribution costs.

### ***Solar Generation Typically Avoids Above-Average Power Costs***

The MREA methodology also overstates the fixed costs it seeks to recover from solar customers because it significantly understates the costs avoided by solar generation. Regardless of how much generation and transmission charges are

included in the distribution co-operatives' residential rates, solar generation would typically avoid power-supply costs that are more expensive than average.

As noted above, the Great River Energy generation tariff charges 50% more for coincident load in the summer months and three times as much in the summer as in the winter fall and spring. And Great River Energy's critical peak pricing hours have occurred only in the summer, starting at 1, 2, or 3 PM and concluding at 7 or 8 PM.

There is also anecdotal evidence that variability of fuel and energy prices add to the co-operatives' summer purchased-power costs. For example, the McLeod co-operative experienced a 2¢/kWh surcharge from Great River Energy in July 2016, which McLeod describes as due to higher gas costs and weather (McLeod Co-operative Power Association News, September 2016, p. 2) Considering the domination of GRE's fuel mix by coal and renewables, in order for the prices of natural gas and/or spot power purchases to be responsible for this spike in costs, the marginal cost of power must have been very high, in the range of 10¢/kWh or more.<sup>13</sup> Since most of the filing co-operatives are also served by Great River Energy, it is likely that they all experienced similar increases in summer power costs.

Again, without knowing the times of the monthly peaks for the Great River Energy regions, or the even the nature of the loads used in determining charges from the other three G&T co-operatives, we cannot refine the estimate of the costs avoided by distributed solar generation. But to the extent that the distribution utility avoids higher purchased-power costs than those originally used in designing the residential rates, the fixed cost—the allocated costs minus the cost avoided—will be reduced.

## **Determining Fixed Residential Distribution Costs**

In addition to subtracting the variable purchased-power costs of the distribution co-operative, following the legislative mandate requires that the co-operative remove the variable distribution costs, to identify the fixed costs, as discussed in Section 0. However, MREA ignores this requirement.

## **MREA Ignores Variable Distribution Costs and Benefits**

MREA could have provided useful data on the portion of distribution costs that are load-related, and the extent to which solar generation reduces demand in the hours

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<sup>13</sup> Again, the limited data released by the co-operatives (both distribution and G&T) restricts our ability to determine their cost structures.

that drive load-related investments. Instead, MREA simply asserts that solar “production does not correlate to distribution peaks” and “production is intermittent” (Cost Analysis and Rate Design for Net Energy Metering, MREA, 10/7/15, p. 7) The only evidence that MREA offers for this assertion are a series of four graphs, which are not well labeled, but appear to represent the following:

Slide 8: The load and output of a single distributed generation customer on some unidentified day, measured at five-minute intervals.

Slide 9: The load and output of a single distributed generation customer for the week of July 1, 2015.

Slide 10: Solar insolation and power output from some facility, on September 7, 2014, without any scale.

Slide 11: Solar insolation and power output from some facility, on August 27, 2014, showing the short-term variability (dominated by drops of as little as about five minutes) due to “intermittent clouds.”

From this smattering of data, MREA asserts as follows:

- Demand is no longer correlated to energy use.
- DG customers with low or zero usage will continue to need distribution system.
- Use of energy as a proxy for charging for use of distribution system no longer works.
- Result is within residential rate class, DG customers under pay for use of distribution system. (Slide 12)

In their newsletters provided in Attachment D of MREA’s Response to the PUC’s IR 6, several of the filing co-operatives (e.g., Itasca-Mantrap, McLeod, North Star, Runestone, Redwood, South Central, SWCE), , claim that “Distributed generators demand as much (or more) from the grid than the rest of the membership. But, because they offset some or all of their energy usage, they no longer pay their fair share to maintain the grid.”<sup>14</sup>

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<sup>14</sup> People’s Co-operative claims that “There are also additional equipment and administrative costs to the Co-operative when a distributed generation system is interconnected to the Co-operative’s electrical system.” (MREA Attachment A, Part 2, p. 13 Charging the distributed-generation customer for the costs of the safety switch or other direct costs of interconnection would be reasonable, but that one-time cost is not reflected in the MREA proposal.

The data provided by MREA (assuming that the graphs represent actual data) do not support the conclusions to which MREA and its members leap.

- Slide 8 appears to represent a single distributed generation customer with minimal usage from 8 AM to 5 PM on a particular day. This pattern may be typical of some members, such as households with all members employed outside the home. It would not be typical of a working farm, nor of a family with young children at home, older latch-key children, retired people, shift-work employees or a home-based business.
- Slides 8, 9 and 11 show the output of a single distributed generation installation one to five days. MREA does not provide any data on the cumulative effect on distribution system loads of multiple installations served by a particular feeder or a particular substation. While an intermittent cloud may briefly reduce the output of one solar array (e.g., from 1:00 PM to 1:05 PM), other solar arrays on the feeder will be in full sun; the overall load relief will be much smoother than shown on Slide 11.<sup>15</sup>
- For significant parts of the distribution system, variability in load within an hour is less important than the average level of load over many hours. The short variations in solar output shown in Slide 11 are not very important, and the solar load relief prior to peak load is very helpful, for the reasons listed below:
  - The capacity of a transformer is limited by the build-up of heat created by energy losses in the equipment. Every time a transformer approaches or exceeds its rated capacity (a common occurrence, since transformers can typically operate well above their rated capacity for short periods of time), its internal insulation deteriorates and it loses a portion of its useful life. Low loads in the hours preceding the peak allow the transformer to enter the peak period cool, so that it can tolerate a higher peak current. And peak load lasting a few minutes, due to a passing cloud, is of little consequence.
  - Energy load over the course of many hours also affects the sizing and cost of transmission. Underground transmission is particularly sensitive to the build-up of heat around the lines, so the length of peak loads and the extent to which loads decline from the peak period to the off-peak period affects the sizing of underground lines. An underground line may be able to carry twice as much peak load after a day of low loads than it

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<sup>15</sup> Even slides 8 and 9 show much more uniform output during the day than the does slide 11.



could with a high daily load factor. To reduce losses and the build-up of heat, utilities must install larger cables, or more cables, than they would to meet shorter loads.

- The capacity of overhead lines is often limited by the sagging caused by thermal expansion of the conductors, which also occurs more readily with summer peak conditions of high air temperatures, light winds and strong sunlight. Overheating and sagging also reduce the operating life of the conductors.

Therefore, MREA's assertion that solar "production does not correlate to distribution peaks" and "production is intermittent" is unsupported and analytically incorrect.

## **Fixed and Variable Distribution Costs**

Since MREA's method does not distinguish between fixed and variable distribution costs, it completely ignores the benefits customer-sited solar provides to the distribution system and the corollary avoided distribution costs. Distribution costs are mostly variable with respect to load. The size of many distribution components (e.g., the diameter of conductors, the capacity of transformers) is load-related, as are the number and other characteristics of some distribution components. In many situations, additional conductors are added to increase capacity, rather than to reach an additional customer. For example, as load grows, utilities build an additional feeder along the route of an existing feeder (or even on the same poles); loop a second feeder to the end of an existing line, to pick up some load from the existing line; build an additional feeder in parallel with an existing feeder, to pick up the load of some of its branches; and upgrade feeders from single-phase to three-phase. Feeder voltages may also be increased to carry more load, requiring early replacement of some equipment with more expensive equipment (e.g., new transformers, increased insulation, higher poles).

While distribution costs are driven by load levels, the maximum load on each piece of equipment is not the only important load. As explained above, the length of the peak and the energy use prior to those hours can also affect the sizing and service life of transformers and underground lines.

The variable distribution costs avoided by a load reduction may be greater or less than the existing average costs. The existing system was built years ago and financed with bonds that have largely amortized, so the variable costs may be high compared to the existing system. On the other hand, the additional costs of expanding capacity may be reduced by the ability to use existing equipment (such as adding phases to a single-phase primary line) or the timing of upgrades to

coincide with replacement of deteriorated equipment (such as increasing pole height and feeder voltage as existing rotting poles are replaced).

The savings from load reductions may also be lower than the costs of increased load. Where load is growing, the capacity freed up by load reductions from distributed generation can defer upgrades. Where loads are static, load reductions are unlikely to avoid upgrades, although they may extend the life of existing equipment.

Solar generation added by a residential customer in a town may free up capacity on its line transformer that can meet growth in usage by several neighbors, as well as feeder and substation capacity serving hundreds or thousands of customers. In a rural setting, the line transformer may serve only that one customer, so load reductions may just create additional spare capacity on the transformer. The same may be true for a section of primary line serving only the distributed generation customer. As in any other rate-design exercise, the co-operatives must determine a reasonable average value for the variable or avoidable distribution costs.

MREA has not provided any information on historical or planned investments by the distribution co-operatives to accommodate load growth, so it cannot determine the “fixed costs not already paid for by the customer through the customer’s existing billing arrangement,” which would be the embedded costs minus the variable distribution costs.

## **Discrimination**

MREA’s proposal to penalize customers for reducing their load is discriminatory in two ways. First, the penalty would apply only for distributed generation, not for other technologies reducing use of the co-operative’s services, such as installation of ground-source heat pumps, biomass heating, or increasing insulation.

Second, the surcharge would be applied to customer-owned and third-party distributed generation, but not to customers who purchase co-operative-owned distributed generation. Most of the Great River Energy member co-operatives have constructed community solar installations, which they lease to members. These programs are described at:

- [connexusenergy.com/residential/programs-rates/solarwise](http://connexusenergy.com/residential/programs-rates/solarwise)
- [itasca-mantrap.com/content/solarwise](http://itasca-mantrap.com/content/solarwise)
- [meeker.co-op/content/renewable-energy](http://meeker.co-op/content/renewable-energy)
- [mcleodco-op.com/products-services/solar/](http://mcleodco-op.com/products-services/solar/)

- [peoplesenergy.co-op/content/peoples-community-solar](http://peoplesenergy.co-op/content/peoples-community-solar)
- [redwoodelectric.com/content/community-solar](http://redwoodelectric.com/content/community-solar)
- [runestoneelectric.com/pdf/solar\\_Q&A\\_phase\\_II.pdf](http://runestoneelectric.com/pdf/solar_Q&A_phase_II.pdf)
- [stearnselectric.org/programs-services/communitysolar/](http://stearnselectric.org/programs-services/communitysolar/)
- [southcentralectric.com/content/community-solar](http://southcentralectric.com/content/community-solar)
- [swce.co-op/swce-field-services/renewables/](http://swce.co-op/swce-field-services/renewables/)

The retail members who lease the solar panels receive a kWh reduction in their metered usage, just as if the panels were behind their meter. Load reductions from these centralized installations will have the same value to the system as the customer-sited distributed generation, or less, since the community solar require the co-operative to add line transformers and other equipment to accommodate this concentrated injection of power (while customer-sited solar can avoid or defer equipment additions and replacements). Yet the filing co-operatives are not proposing to apply any penalty charges to their community-solar customers. The penalties would only apply to the customers of companies who compete with the co-operatives to offer solar energy. On its face, this policy represents blatant discrimination in favor of the monopoly's product in a competitive market, which may be illegal under anti-trust law.

## Conclusion

The MREA methodology for setting surcharges for customers with distributed generation is entirely inappropriate and grossly overstated. The approach violates the co-operatives' existing legal authority and incorporates multiple logical and factual errors. Contrary to the assumptions in MREA's methodology:

- Residential rates include higher generation and transmission charges than the system average, so the distribution portion of the rates is lower than assumed by MREA.
- Solar energy displaces generation and transmission costs higher than the average charges for residential customers, further reducing potentially under-recovered costs.
- Load reductions from solar energy reduce distribution costs, reducing potentially under-recovered costs even more.
- The only truly fixed customer costs are those for the connection and meter, which amount to a small fraction of the total distribution costs.

In addition to all these methodological errors, many of the filing co-operatives propose to implement the fees in a discriminatory manner, exempting customers from the fees if they purchase solar power from the co-operative and imposing them on the customers who install their own systems.

## Allen Gleckner

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**From:** Mike Monsrud <MMonsrud@itasca-mantrap.com>  
**Sent:** Friday, November 18, 2016 10:29 AM  
**To:** Jim Horan; Allen Gleckner; whensel@benco.org; m.solie@bcrea.coop; b.bradburn@bcrea.coop; brian.burandt@connexusenergy.com; info@federatedrea.coop; jkrueger@fmcs.coop; df@gccea.com; Tony Nelson; Esther Simon; toleary@llec.coop; kdybdahl@llec.coop; gheffele@llec.coop; mcpainfo@mcleodcoop.com; fsdaggs@meeker.coop; kdolan@meeker.coop; skosbab@meeker.coop; mlarson@meeker.coop; tmergen@meeker.coop; bzelenak@mlecmn.com; rschwartau@noblesce.com; sswanson@noblesce.com; atromblay@noblesce.com; robynsec@wikel.com; nsec@wikel.com; egarry@peoplesrec.com; rea@runestoneelectric.com; rhorman@redwoodelectric.com; mschmidt@minnkota.com; sgroebner@redwoodelectric.com; manderson@southcentralelectric.com; jhaler@southcentralelectric.com; dgruenes@stearnselectric.org; swce@swce.coop; Kristin Dolan  
**Cc:** Terwilliger, Hanna (PUC); Bahn, Andy (PUC); Peirce, Susan (COMM); Bradley Klein  
**Subject:** RE: MN PUC Docket 16-512; Fresh Energy Information Requests 1-4

Thanks Jim,

A good response to their requests and a restatement of our sentiment of locally owned and controlled.

Keep in our back pocket that these cost of service studies contain private information that only our Members should have access to, other than the over view authority of the PUC.

Mike Monsrud

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**From:** Jim Horan [mailto:Jim@mrea.org]  
**Sent:** Friday, November 18, 2016 9:20 AM  
**To:** Allen Gleckner <gleckner@fresh-energy.org>; whensel@benco.org; m.solie@bcrea.coop; b.bradburn@bcrea.coop; brian.burandt@connexusenergy.com; info@federatedrea.coop; jkrueger@fmcs.coop; df@gccea.com; Mike Monsrud <MMonsrud@itasca-mantrap.com>; Tony Nelson <TNelson@itasca-mantrap.com>; Esther Simon <ESimon@itasca-mantrap.com>; toleary@llec.coop; kdybdahl@llec.coop; gheffele@llec.coop; mcpainfo@mcleodcoop.com; fsdaggs@meeker.coop; kdolan@meeker.coop; skosbab@meeker.coop; mlarson@meeker.coop; tmergen@meeker.coop; bzelenak@mlecmn.com; rschwartau@noblesce.com; sswanson@noblesce.com; atromblay@noblesce.com; robynsec@wikel.com; nsec@wikel.com; egarry@peoplesrec.com; rea@runestoneelectric.com; rhorman@redwoodelectric.com; mschmidt@minnkota.com; sgroebner@redwoodelectric.com; manderson@southcentralelectric.com; jhaler@southcentralelectric.com; dgruenes@stearnselectric.org; swce@swce.coop; Kristin Dolan <kristin.dolan@runestoneelectric.com>  
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**Subject:** RE: Mn PUC Docket 16-512; Fresh Energy Information Requests 1-4

MREA Response to Information Requests from Fresh Energy, Dated November 7, 2016

Minnesota Rural Electric Association (MREA) represents the interests of the state's 44 electric distribution cooperatives and the six generation and transmission cooperatives that supply them with power. Our member cooperatives are not-for-profit electric utility businesses that are locally owned and governed by the member-consumers they serve.

The 44 electric distribution cooperatives in Minnesota are governed by their democratically elected board of directors. These boards of directors are the regulators for their respective cooperatives. In this regulatory role,

the cooperative boards of directors balance the interests of their membership, within the requirements of the law and applicable rules, to set policies including setting rates, fees and charges. This authority is established in Minnesota Statute 216B.01. We have asked the Public Utilities Commission (Commission) to respect the authority of democratically elected boards of directors to exercise their statutory authority to set policies, including rates, fees and charges. MREA would like to reiterate to parties' part of docket E-999/PR16-512 and interested groups not party to docket E-999/PR16-512 that pertinent information regarding the cost of service studies used to determine the cost recovery charges allowable under Minnesota Statute 216B.164 Subd. 3(a) were already provided to the Commission in our September 19, 2016 filing.

Minnesota Statute 216B.01 provides that cooperatives are not subject to rate regulation beyond that provided by their democratically elected governing boards. This local control authority has been confirmed by the Minnesota Supreme Court in *Taylor v. Beltrami Electric Cooperative, Inc.*, 319 N.W.2d 52, 55 (Minn.1982) and *Frost-BENCO Electric v. Minnesota Public Utilities*, 358 N.W.2d 639 (1984). Based on the information requests by Fresh Energy, MREA is concerned that there is some confusion over the authority of electric cooperatives to local regulatory control. The local governing boards of the electric cooperatives develop rates based on a cost of service approach. The inputs into and the design of that cost of service study are determined by the governing boards through their regulatory authority. For the Fresh Energy, the Commission or any other entity other than the governing boards of the electric cooperatives to dictate the inputs into or the design of a cost of service study would result in duplicative rate regulation and be directly counter to statute and established Minnesota Supreme Court precedent.

MREA adopts a common understanding of a cost of service study to be a study used to determine the cost to serve a member of a utility. The cost of service studies already provided to the Commission are based on the specific costs to serve members from each named cooperative and are updated annually using a readily accessible reporting form. The cost of service study approach is reasonable, transparent, equitable to all members, and meets the requirement within Minnesota Statute 216B.164 Subd. 3(a).

Cooperatively Yours,

Jim Horan

Director of Government Affairs and Counsel  
Minnesota Rural Electric Association  
763-424-7237

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**From:** Allen Gleckner

**Sent:** Monday, November 7, 2016 4:23 PM

**To:** [whensel@benco.org](mailto:whensel@benco.org); [m.solie@bcrea.coop](mailto:m.solie@bcrea.coop); [b.bradburn@bcrea.coop](mailto:b.bradburn@bcrea.coop); [brian.burandt@connexusenergy.com](mailto:brian.burandt@connexusenergy.com); [info@federatedrea.coop](mailto:info@federatedrea.coop); [jkrueger@fmcs.coop](mailto:jkrueger@fmcs.coop); [df@gccea.com](mailto:df@gccea.com); [mmonsrud@itasca-mantrap.com](mailto:mmonsrud@itasca-mantrap.com); [tnelson@itasca-mantrap.com](mailto:tnelson@itasca-mantrap.com); [esimon@itasca-mantrap.com](mailto:esimon@itasca-mantrap.com); [toleary@llec.coop](mailto:toleary@llec.coop); [kdybdahl@llec.coop](mailto:kdybdahl@llec.coop); [gheffele@llec.coop](mailto:gheffele@llec.coop); [mcpainfo@mcleodcoop.com](mailto:mcpainfo@mcleodcoop.com); [fskaggs@meeker.coop](mailto:fskaggs@meeker.coop); [kdolan@meeker.coop](mailto:kdolan@meeker.coop); [skosbab@meeker.coop](mailto:skosbab@meeker.coop); [mlarson@meeker.coop](mailto:mlarson@meeker.coop); [tmergen@meeker.coop](mailto:tmergen@meeker.coop); [bzelenak@mlecmmn.com](mailto:bzelenak@mlecmmn.com); [rschwartz@noblesce.com](mailto:rschwartz@noblesce.com); [sswanson@noblesce.com](mailto:sswanson@noblesce.com); [atromblay@noblesce.com](mailto:atromblay@noblesce.com); [robynnsec@wikel.com](mailto:robynnsec@wikel.com); [nsec@wikel.com](mailto:nsec@wikel.com); [egarry@peoplesrec.com](mailto:egarry@peoplesrec.com); [rea@runestoneelectric.com](mailto:rea@runestoneelectric.com); [rhorman@redwoodelectric.com](mailto:rhorman@redwoodelectric.com); [mschmidt@minnkota.com](mailto:mschmidt@minnkota.com); [sgroebner@redwoodelectric.com](mailto:sgroebner@redwoodelectric.com); [manderson@southcentralelectric.com](mailto:manderson@southcentralelectric.com); [jhaler@southcentralelectric.com](mailto:jhaler@southcentralelectric.com); [dgruenes@stearnselectric.org](mailto:dgruenes@stearnselectric.org); [swce@swce.coop](mailto:swce@swce.coop)

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**Subject:** Mn PUC Docket 16-512; Fresh Energy Information Requests 1-4

Sent on behalf of Allen Gleckner, please find Fresh Energy's Information Requests Nos. 1-4 for the utilities listed below. If you have any questions, please do not hesitate to contact me.

BENCO Electric Cooperative

Brown County Rural Electric Association  
Connexus Energy  
Federated Rural Electric Association  
Freeborn-Mower Cooperative Services  
Goodhue County Cooperative Electric Association  
Itasca-Mantrap Cooperative Electric Association  
Lyon-Lincoln Electric Cooperative, Inc.  
McLeod Cooperative Power Association  
Meeker Cooperative Light & Power  
Mille Lacs Energy Cooperative  
Nobles Cooperative Electric  
North Star Electric Cooperative, Inc.  
People's Energy Cooperative  
PKM Electric Cooperative  
Redwood Electric Cooperative  
Runestone Electric Association  
South Central Electric Association  
Stearns Electric Association  
Steele-Waseca Cooperative Electric

Thanks,

Allen Gleckner  
Director, Energy Markets  
Fresh Energy

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## Allen Gleckner

---

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**Cc:** Terwilliger, Hanna (PUC); Bahn, Andy (PUC); Peirce, Susan (COMM); Bradley Klein; 'Jim@mrea.org'  
**Subject:** Mn PUC Docket 16-512; Fresh Energy Information Requests 1-4  
**Attachments:** Fresh Energy\_16-512\_IRs 1-4\_11-7-16.docx; Fresh Energy\_16-512\_IRs 1-4\_11-7-16.pdf

Sent on behalf of Allen Gleckner, please find Fresh Energy's Information Requests Nos. 1-4 for the utilities listed below. If you have any questions, please do not hesitate to contact me.

BENCO Electric Cooperative  
Brown County Rural Electric Association  
Connexus Energy  
Federated Rural Electric Association  
Freeborn-Mower Cooperative Services  
Goodhue County Cooperative Electric Association  
Itasca-Mantrap Cooperative Electric Association  
Lyon-Lincoln Electric Cooperative, Inc.  
McLeod Cooperative Power Association  
Meeker Cooperative Light & Power  
Mille Lacs Energy Cooperative  
Nobles Cooperative Electric  
North Star Electric Cooperative, Inc.  
People's Energy Cooperative  
PKM Electric Cooperative  
Redwood Electric Cooperative  
Runestone Electric Association  
South Central Electric Association  
Stearns Electric Association  
Steele-Waseca Cooperative Electric

Thanks,

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## Fresh Energy Information Request

Docket No.: E999/CI-16-512

Requestor: Allen Gleckner

Requested From: Cooperative Electric Associations in Table 1 below

Cc: Minnesota Rural Electric Association

Date of Request: November 7, 2016

Information Request Nos. 1-4

Response Due Date: November 17, 2016

---

Re: Class Cost of Service Studies used to set rates for Cooperative Electric Association customers

This information request applies to the following cooperative electric associations:

Table 1

BENCO Electric Cooperative
Brown County Rural Electric Association
Connexus Energy
Federated Rural Electric Association
Freeborn-Mower Cooperative Services
Goodhue County Cooperative Electric Association
Itasca-Mantrap Cooperative Electric Association
Lyon-Lincoln Electric Cooperative, Inc.
McLeod Cooperative Power Association
Meeker Cooperative Light & Power
Mille Lacs Energy Cooperative
Nobles Cooperative Electric

North Star Electric Cooperative, Inc.
People's Energy Cooperative
PKM Electric Cooperative
Redwood Electric Cooperative
Runestone Electric Association
South Central Electric Association
Stearns Electric Association
Steele-Waseca Cooperative Electric

The above Cooperative Electric Associations provided their Form 7 Finance and Operation Data that is filed annually with the United States Department of Agriculture Rural Utility Services Department.<sup>1</sup>

1. In addition to the provided Form 7s, how many of the above cooperative electric associations have performed a class cost of service study used by the cooperative electric association to inform setting and/or designing the electric rates charged to its customers? For each cooperative electric association that has performed a class cost of service study used by the cooperative electric association to inform setting and/or designing the electric rates charged to its customers, what year was the most recent study performed?
2. For each cooperative electric association that has a class cost of service study used by the cooperative electric association for setting and/or designing electric rates charged to customers identified in question 1, please provide the amount the most recent study identified as the monthly fixed cost per customer for the residential customer class.
3. For each cooperative electric association that has a class cost of service study used by the cooperative electric association for setting and/or designing electric rates charged to customers identified in question 1, please provide the amount the most recent study identified as the monthly fixed cost per customer for the small commercial customer class.

---

<sup>1</sup> Minnesota Rural Electric Association, Response to Public Utilities Commission Information Requests, September 19, 2016.

4. For the cooperative electric associations that have class cost of service studies used by the cooperative electric associations for setting and/or designing electric rates charged to customers identified in question 1, please provide a copy of the most recent class cost of service study in native electronic format with all cells and formulas intact that was used by the cooperative electric association to inform setting and/or designing the electric rates charged to customers. If the study is designated trade secret, please contact Allen Gleckner to arrange for a protective order.

Response:

---

Preparer:

Title:

Department:

Telephone:

Date:

# RETAIL RATE GUIDE

---

Volume I



**NRECA**  
America's Electric Cooperatives



**National Rural Utilities  
Cooperative Finance Corporation**

This Rate Guide is jointly owned by the National Rural Electric Cooperative Association (NRECA) and the National Rural Utilities Cooperative Finance Corporation (CFC) with authorship contributions from C.H. Guernsey & Company.

For more information about the Rate Guide, please contact: Jan Ahlen at [jan.ahlen@nreca.coop](mailto:jan.ahlen@nreca.coop) or 703.907.5859.

---

### Disclaimers

The information in this guide is intended to be a helpful and educational resource. The information is not an exhaustive and complete examination of rate issues. The guide contains ideas to give cooperatives a starting point for board and management discussions regarding rates. NRECA, CFC and the authors are not attempting to render specific legal or other professional advice in this guide. We, therefore, encourage cooperatives to consult with qualified attorneys, consultants, accounting and tax advisers when undergoing a rate analysis or implementing any rate design changes.

Case studies are provided in the guide as examples only to illustrate how various rate designs and related practices have worked in some cooperatives. NRECA and CFC are committed to complying fully with all applicable federal and state antitrust laws. NRECA, CFC and the authors are not endorsing any particular rate design or practice featured in these case studies and are not suggesting they are appropriate for every cooperative. Electric cooperatives are: (1) independent entities; (2) governed by independent boards of directors; and (3) affected by different member, financial, legal, political, policy, operational, and other considerations. For these reasons, each electric cooperative should make its own business decisions on whether and how to use this information and on what rate designs are appropriate for that cooperative's own circumstances.

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## Foreword

Proper ratemaking remains a cornerstone of electric cooperative financial strength. Rates also offer a terrific touch point and opportunity for enhancing member education, discussing the cooperative difference, and establishing your cooperative as a trustworthy source of information.

Today's evolving utility marketplace raises important concerns regarding how electric cooperative rates are structured. New technologies such as advanced metering infrastructure (AMI) and behind-the-meter communications devices are making new rate designs possible, while advancements in efficiency, distributed generation and energy storage are challenging the viability of traditional ratemaking structures. At the same time, electric cooperative member-consumer preferences are evolving. In many cases, member-consumers are demanding new services and asking for more control over their energy use.

To best mitigate risks and advance opportunities, CFC and NRECA offer this guide, and its companion communications toolkit, *Introducing a Rate Change to Member-Consumers*, as a comprehensive resource on ratemaking. Given the diversity of electric cooperatives, no one-size-fits-all solution exists. The guide is meant to provide electric cooperatives with a suite of rate options and considerations that will help you tailor rates to fit your own system needs and member-consumer preferences.

We hope that this guide is a valuable resource to America's Electric Cooperatives as you navigate a fast-changing industry environment.

Sheldon C. Petersen  
*Chief Executive Officer*  
National Rural Utilities Cooperative  
Finance Corp.

Jim Matheson  
*Chief Executive Officer*  
National Rural Electric  
Cooperative Assn.

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# Overview

Technology is driving profound changes in the electric utility industry. The changes are especially apparent in three areas:

1. **Power Supply Resources:** The proliferation of distributed energy resources (DER) has created a paradigm shift. The old paradigm was the utility-owned central station resource model with power flow from the source to the load. The emerging paradigm is a portfolio model with resources located, owned, and operated across the energy value chain from central station to the retail member-consumer with option of power flow from the member-consumer to the grid.
2. **System Operations:** The application of new technology will provide opportunities to accommodate the portfolio resource model, improve distribution system reliability and reduce the cost of providing service to the retail member-consumer. This is being realized by a transition of the distribution system from a radial design to an intelligent network design involving smart grid and micro grid applications with the two-way flow of electrons and data.
3. **Member-consumer Involvement:** Many of the technology changes are at the retail level and directly involve the retail member-consumer. As a result the retail member-consumer will be seeking opportunities to participate in the economic benefits and other benefits associated with the application of the technology. The member-consumer will transition from a passive to an active agent. The results are increased opportunities for energy conservation and service from alternative energy resources which means a decrease in energy sales by the distribution cooperative.

**“The utility of the future will need to recognize that pricing will become increasing complex”<sup>2</sup>**

Along with these changes, there is evolving within the industry a new entity, the Distribution System Operator (“DSO”). The DSO will be responsible for implementation of, and optimization of investments in, technology at the distribution level and the allocation of the economic benefits of the technology to the participants and system. The DSO may take many shapes, from the existing distribution wires provider to a new third party. Distribution cooperatives are uniquely positioned to take on the role of a DSO.

In “The 51st State | Phase II, The Consumer-Centric Utility Future”<sup>1</sup>, NRECA introduced the concept of the Consumer-Centric Utility (CCU) business

model and proposed that the distribution cooperative is best positioned to perform the DSO functions of optimizing technology and allocating economic benefits. The report identified specific issues related to pricing and rates that the distribution cooperative will need to address:

*“The utility of the future will need to recognize that pricing will become increasing complex.”<sup>2</sup>*

*“Improper cost recovery implementation and management can lead to sending wrong signals to consumers regarding investments. That said, the Future State will require rate and price setting that will require balancing far more levels of complex inputs....”<sup>3</sup>*

<sup>1</sup> The 51st State Phase II, The Consumer-Centric Utility future, Prepared by: The National Rural Electric Cooperative Association, March 23, 2016, page 4.

<sup>2</sup> Ibid, page 35.

<sup>3</sup> Ibid, page 35.

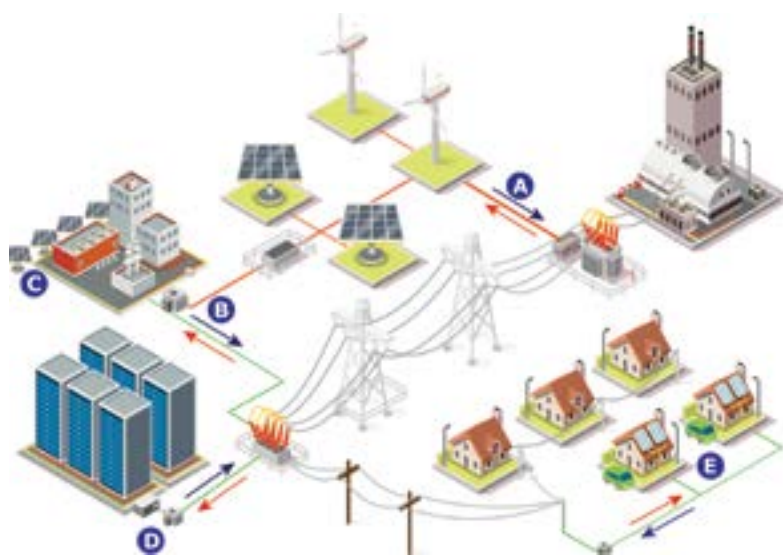
Each distribution cooperative is unique and will determine its best strategy to recognize changing technology and define its role as system optimizer

*"New additions to the grid, like solar panels, energy storage, micro grids and DSO functions will require new thinking in terms of how people are paying for their energy."<sup>4</sup>*

Each distribution cooperative is unique and will determine its best strategy to recognize changing technology and define its role as system optimizer. The degree of involvement will vary and clearly one size will not fit all. However, to be successful the cooperative must provide:

*"..rate and price setting that will require balancing far more levels of complex inputs than in the past."<sup>5</sup>*

## Technologies and Power Flow



- A. Utility-scale renewables impact wholesale markets with periods of low cost generation.
- B. Utility-scale renewables provide resources for C&I member-consumers.
- C. On-site renewables reduce retail kWh or capacity depending on the rate pricing signal.
- D. On-site DER can provide peak load shaving.
- E. DER, electric car-charging and battery storage alter load profiles. Member-consumers may be compensated for excess generation.

Understanding the factors involved in achieving a fair and equitable balance of complex inputs is a process that will take some time given our starting point. Historically, the rate and price setting reflected the source of power and the nature of distribution:

1. Power flow was from the central station resource to the member-consumer with the distribution cooperative serving as the aggregator of wholesale power supply and providing the distribution wires for service to the member-consumer. The cooperative bundled the total cost of providing service, averaging allocations across wide classes of member-consumers.
2. The cooperative would develop prices for electric service by grouping together member-consumers with a similar load profile and design rates to serve that profile. The concept of homogeneity within a member-consumer class has always been an approximation, although it has served the industry well in developing rates that reflect cost and are generally viewed as fair and equitable.

**So what is changing?** The notion of homogeneity within a customer class and the concept of fixed load profile based on the rate classification begin to erode as technological advances allow the member-consumer to become an active agent. With DER, micro grids, home energy management systems, electric storage capability, etc., the member-consumer transitions from a passive load center to an active agent on the electric grid with the ability to change individual load profiles. Given traditional rate design and the expansion of new technology that changes the member-consumer's load profile in a rate class, the end result can be both inter- and

<sup>4</sup> Ibid, page 35.

<sup>5</sup> Ibid, page 35.

**The distribution cooperatives face a paradigm shift with the application of new technology**

intra-class cross subsidies and instability in revenue recovery. The most apparent example is the unintended consequences of the rooftop solar photo voltaic (PV) applications through net metering.

The distribution cooperatives face a paradigm shift with the application of new technology and this extends to their suppliers, whether generation and transmission associations, independent suppliers, wholesale markets, etc. What will be the path forward to effectively address this shift? Over the near term the focus will likely be on “innovative rates” or “innovative pricing.” Although these terms can have different meanings to different people, for many they likely mean the development of tariffs and pricing that:

- include incentives to reward particular behavior.
- increase fixed charges and minimize the reliance on consumption-based pricing for fixed-cost recovery.<sup>6</sup>
- develop “valuation methodology” including:
  - value of service<sup>7</sup>
  - value of resource<sup>8</sup>
  - transactive energy<sup>9</sup>
- respond to member-consumer expectations related to conservation.
- accommodate technology specific applications.

Chasing technology and chasing value are difficult tasks that can create uncertainty for not only the member-consumer but, more importantly, the cooperative. Even within a particular application of a technology, there can be differences in the resultant member-consumer load profile. For example, tariffs based on “value of solar” end up reflecting an average of load profiles that ignore the ratio of solar capacity vs. the load served and the angle of inclination for different arrays. The member-consumer may want value recognized for a service that a cooperative has not previously quantified, such as certain distribution ancillary services.

Advances in advanced metering infrastructure (AMI) technology may in the extreme case result in treating each consumer as a unique node. The cost incurred in serving a load in an interval may be independent of how the energy in that interval is used. Rather than pricing based on a rate class, the pricing may reflect attributes of the service at the node, i.e., voltage, real and reactive power requirements, and frequency that reflect real time conditions at the node. Perhaps one future state involves the cooperative’s development of a single set of pricing metrics that are applied independently of the rate classification.

<sup>6</sup> Some proposals suggest increasing the customer charge to recover total distribution wires cost.

<sup>7</sup> Value of Service requires a functional unbundling of the distribution services and a value placed on each service. The cooperative would then pay the DER for the service provided. The VOS focuses on services provided and not on a specific type of resource or technology.

<sup>8</sup> Value of Resource involves identifying the value of benefits and costs to the grid, other customers, and society associated with a specific type of resource. The value can change over time based on different factors such as location on the grid, gas prices, etc.

<sup>9</sup> Transactive Energy (“TE”) is a concept by which customer-sited resources can be interactive with the grid by using value as a common language to combine economic and control techniques and to align value streams for all parties. The process is highly reliant on price signals and rules allowing for markets to develop that enable a wide variety of participants to interact directly with each other. TE can enable a much larger set of value streams for customer-sited resources. Reference: Distributed Energy Resources Rate Design and Compensation” NARUC November, 2016, page 139. “IEEE Electrification Magazine”, December, 2016, page 2.

The path to deal with new technology will be different for each cooperative and will reflect the conditions unique to the cooperative

A cooperative's rate pricing may also recognize value provided by the member-consumer in the form of distribution ancillary services such as voltage support, real and reactive support, reduction in congestion at the node, etc. The value of resource and value of service options require that value be placed on certain distribution ancillary services that, to date, have not been quantified.<sup>10</sup>

This Rate Guide does not attempt to define specifics of the "future state." The path to deal with new technology will be different for each cooperative and will reflect the conditions unique to the cooperative. However, there are

certain key steps along the path that the cooperative should take to meet the financial and rate objectives established by the Board. The Rate Guide provides a structure and process to evaluate the issues, analyze the alternatives, and independently develop pricing and rates that balance the complex inputs and are aligned with the needs of the cooperative.

Importantly, statements in the Rate Guide that an electric cooperative, its employees, or its board of directors should, must, or need to take or avoid certain acts, and similar statements, do not suggest, imply, or support a legal conclusion, requirement, or standard.

## Reading the Rate Guide

The Rate Guide is developed with three readers in mind:



**Board of Directors ("Board"):** The Board has ultimate responsibility for the rates charged to the member-consumer consumers of the cooperative. The rates must be adequate to maintain the financial viability of the cooperative and must reinforce Board policies related to strategic financial goals, rate design criteria, and desired DSO participation.



**Management:** Cooperative management consists of the CEO/General Manager who has responsibility for leading the preparation of a Rate Analysis. The analysis may be prepared by either cooperative staff or cooperative staff working with a third party specialist. Management should have sufficient background knowledge of the process to review the work product for completeness and communicate results to the Board.



**Staff:** Cooperative staff should be involved in the Rate Analysis process. The degree of involvement will vary depending on staff's availability, resources, and previous experience with Rate Analysis issues.

<sup>10</sup> For years wholesale ancillary services were not recognized as separate services with separate rates. Today, six separate transmission ancillary services are recognized by FERC and markets exist for these services. Distribution ancillary services are also likely to evolve with separate pricing and perhaps, a market for these services.

Each cooperative will have specific issues that need to be addressed and will have its own perspective as how best to address those issues. The Rate Guide describes the complete rate analysis process that will provide the detailed information needed for the cooperative to develop “rate and price setting that balances the complex inputs” specific to the cooperative.

Some cooperatives may already have in place an understanding of the steps involved in the rate analysis process, be aware of the interrelationships of the various elements of the process, have cost data, and understand the cost drivers for their system. Their immediate concern is to evaluate different rate options that will allow their cooperative to deal with new technology and changing consumer expectations. Therefore, the Rate Guide is presented in two volumes. Volume I focuses on the overall process, a discussion of rate options, and the presentation and implementation of the rate proposal to the member-consumers. Volume II focuses on the other steps in the rate analysis process used to develop rates.

## VOLUME I

**Section 1** is particularly intended for the cooperative director. It describes the rate design process, the issues to consider in the implementation of the process, the importance of the financial and rate policies in the process, and the specific role of the director in the process.

**Section 2** explains the importance to the Board of the twelve to twenty four month “look ahead” of cooperative revenue and margins and why it is a critical element of the Rate Analysis process.

**Section 3** outlines various rate options, as well as the advantages and disadvantages of the different rate options.

**Section 4** describes factors to consider in making final decisions related to the selection of the proposed rates.

**Section 5** outlines factors to consider in the “roll-out” of rates to the member-consumers and the communication that needs to occur.

## VOLUME II

**Section 1** describes the process for developing the revenue requirement including the selection of the Test Year and the development of the appropriate expense adjustments.

**Section 2** describes the development of the margin component of the revenue requirement. This section is particularly important because it provides recommendations of how to define the margin component of the revenue requirement based on the Board’s financial objectives.

**Section 3** describes the steps involved in the development of the cost of service study.

**Section 4** describes how the results of the cost of service are used to make decisions related to rate class revenue requirements and provide input data for rate design.

# 1.0

## The Director's Roadmap to the Rate Analysis Process

*The following is a summary of the Rate Analysis process and the key issues that need to be considered by the cooperative's Board of Directors.*

### 1.1

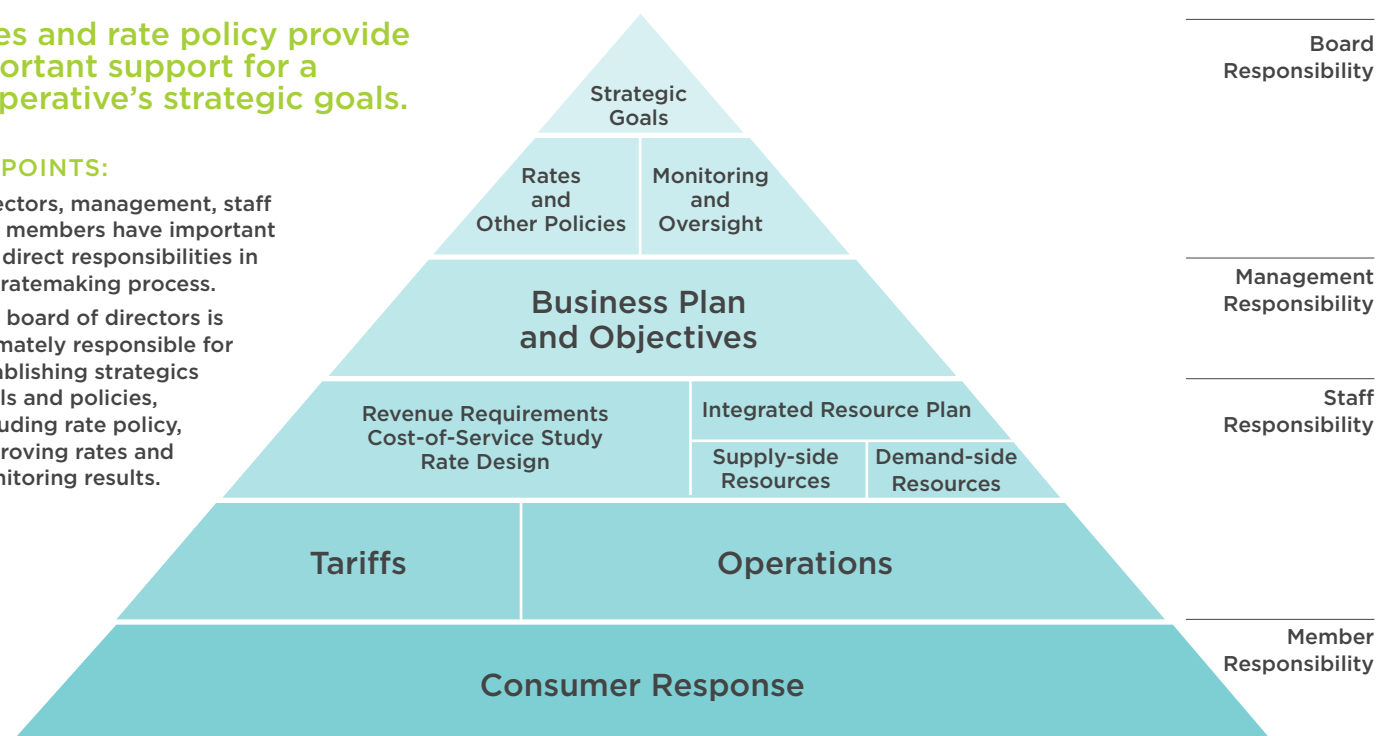
#### What policies should the Board have in place?

The determination of rates charged by the cooperative is one of the most important responsibilities of the Board. It is essential that the final rates approved by the Board are in line with the policies the cooperative has in place. The general areas of responsibility are shown below.<sup>11</sup>

**Rates and rate policy provide important support for a cooperative's strategic goals.**

#### KEY POINTS:

- Directors, management, staff and members have important but direct responsibilities in the ratemaking process.
- The board of directors is ultimately responsible for establishing strategic goals and policies, including rate policy, approving rates and monitoring results.



<sup>11</sup> NRECA 2011 Rate Strategies for 21st Century Challenges (A guide to rate innovation for cooperatives)



The Board needs to have in place three specific Board policies and the rates designed need to provide positive feedback and reinforcement of the policies. The three Board policies are:



#### Financial Strategy or Equity Management Plan



#### Rate Design Policy



#### Distribution System Operator (DSO) Operating Policy

The cooperative should already have in place a Financial Strategy or Equity Management Plan and Rate Design Policy. The DSO Operating Policy likely does not yet exist because the role of the cooperative as a Consumer-Centric Utility (CCU) serving as a DSO has only recently been introduced.

### 1.1.1

#### WHAT ARE THE COOPERATIVE'S FINANCIAL STRATEGY OR EQUITY MANAGEMENT PLAN OBJECTIVES?

Alignment with the financial strategy policy is most important. The Board needs to have in place a strategy (a financial strategy plan, an equity management plan, etc.) which defines long-term income statement and balance sheet objectives for four basic metrics:

- Desired margin defined in terms of financial metrics such as TIER, DSC, ROR, MFI. (Times Interest Earnings Ratio, Debt Service Coverage, Margin For Interest, respectively).
- Desired equity levels
- Desired liquidity levels
- Desired capital credit retirement levels

These four objectives are all interrelated. The cooperative's revenue requirement is driven by the Board's target values for each of the four metrics as a result of the projected capital expenditures ("CAPEX") for the cooperative and interest rate on long-term debt. Volume II, Section 2.0 describes how the various values are interrelated and suggests tools that can assist the Board in developing target values. The Board should have defined the financial strategy and the key financial metrics prior to starting the rate analysis.

### 1.1.2

#### WHAT IS THE COOPERATIVE'S RATE DESIGN POLICY?

The cooperative should have a policy defining guiding principles or criteria that the Board expects to be followed in the development of rates. It is a three-step process in which the Board discusses and defines philosophy, states the philosophy in terms of a policy, and then defines specific criteria for the implementation.

Although the Board should begin with a discussion of rate philosophy, sometimes this can be a difficult discussion. One approach is to begin with a basic set of criteria and then allow the underlying philosophy to be defined in terms of how the Board believes the criteria should be applied.

The typical starting point is that rates:

- Are easily understood.
- Provide the required revenue.
- Provide revenue stability from year to year.
- Are cost-based and provide a fair apportionment of cost to member-consumers served.
- Send the proper pricing signals.
- Are not unduly discriminatory<sup>12</sup>.

The cooperative should have a policy defining guiding principles or criteria that the Board expects to be followed in the development of rates

<sup>12</sup> James C. Bonbright, *Principles of Public Utility Rates* (New York: Columbia University Press, 1961), pages 291 – 292.

The wholesale power cost represents a disproportionate share of the cooperative's revenue requirement

However, the devil is always in the details, and the Board needs to decide its position on certain basic issues, and when possible, to provide some quantification of its position. Different Boards will have different views with regard to the following:

- What constitutes a fair apportionment of cost and what defines undue discrimination? This Rate Guide will provide a metric to evaluate discrimination between rate classifications using the relative rate of return (RROR).<sup>13</sup> However, this is not the only basis for evaluation. The Board should decide:
  - What is the appropriate metric for the cooperative?
  - What are allowable differences in relative margins between rate classes?
  - For rate classifications with a metric above or below the allowable difference, what is the plan to move to an acceptable level:
    - What are allowable maximum class rate increases relative to system average?
    - Should a rate class ever receive a rate decrease?
    - How should a rate class with minimum investment be evaluated?<sup>14</sup>
- To what extent should externalities, non-cost based and social factors be considered in the rate design and in the determination of the revenue requirement? Are these externalities a basis for a differential in the rates charged?
- Do we need to consider the impact on low income member-consumers and do we equate low income with low energy usage?
- Do we want to discourage energy usage by putting in place inclining block rates even if there is no cost based justification in our wholesale rate?
- To what extent do we want to recover the full customer cost component in the customer or facility charge and what is the plan to reach the target goal?
- Do we consider the subsidy provided by government programs as sufficient to deal with social issues and should our rates be based only on the cooperative's cost of service?
- What are the externalities that need to be considered for my cooperative?
- Do we have specific goals in terms of renewable resources and what are the implications for rate design?
- Does our current rate structure accommodate member-consumers' use of rooftop solar, and does it do so in compliance with governing law and with fairness to non-users?
- To what extent do we want to encourage community solar as an alternative to roof-top solar?

The Rate Design Policy may differ if the cooperative's operating area is single or multiple certificated or if the cooperative operates under a state law that permits customer choice.

The wholesale power cost represents a disproportionate share of the cooperative revenue requirement. The wholesale power cost is defined by the wholesale power supplier's rates. This suggests the importance of alignment between the cooperative and wholesale power supplier's rate design. If service is from an

<sup>13</sup> See Section Volume II, Section 4.0.

<sup>14</sup> A large power customer may have minimum investment to serve and a RROR will not be an appropriate metric.



All these are functions of the DSO. The distribution cooperative is well positioned to be the entity for integration of the new technology and the development of rate and pricing for services that accommodate the member-consumer's requirements

However, to be successful the cooperative needs to understand the changes that are occurring, decide the role it wishes to play and translate that role into a policy

Investor Owned Utility (IOU) or federal marketing entity, the ability to align rate design with wholesale power rates will be limited. However, wholesale service from a G&T should provide greater opportunity to coordinate the wholesale and retail rate designs. The distribution cooperative Board always has responsibility for the retail rates charged. However, even though a distribution cooperative and its G&T are separate legal entities and are not a joint venture or single enterprise, the Board should consider the alignment between wholesale and retail rates. The two-tier (sometimes three-tier) pricing scheme makes it difficult to align retail price and wholesale cost.<sup>15</sup>

### 1.1.3

#### WHAT IS THE COOPERATIVE'S DISTRIBUTION OPERATING POLICY?

Distribution cooperatives have always served as power supply aggregator and interface between the retail member-consumer and the wholesale supplier be it a G&T, an IOU, a federal marketing authority, etc. Historically, the boundaries were very clear with the power flow from the wholesale supplier through the distribution cooperative to the retail member-consumer.

As wholesale markets have evolved, the wholesale supplier has adapted to changes in the interface between the distribution cooperative and wholesale market. The wholesale supplier navigated new rules dictated by FERC Order 888 (1996) and FERC Order 2000 (1999), the introduction of the "exempt wholesale generator," and the roles of the Regional Transmission Operator (RTO) and Independent System Operator (ISO) in the wholesale markets. Today, two-thirds

of the electricity consumed in the United States is delivered in service areas with wholesale electric markets.<sup>16</sup>

The wholesale suppliers have had to adjust to the changes. The distribution cooperative needs to understand the changes that are occurring and decide the role they wish to play as the distribution system operator (DSO). One aspect involves the integration of the distributed energy resources and the associated operational and safety issues. Another aspect involves implementation of smart grid and micro grid applications and the possible transition from a radial system to an intelligent distribution system. Another is the utilization of AMI and the development of detailed data allowing the cooperative to provide improved service and reliability to the member-consumers. In order to fully integrate new technology the cooperative needs to evaluate interoperability and communication security issues. Given the changing role of the member-consumer as an active agent able to change a load profile and able to provide services to the distribution cooperative, the cooperative needs to consider the member-consumers expectations in terms of rates and pricing for service and how the cooperative will respond to these expectations.

All these are functions of the DSO. The distribution cooperative is well positioned to be the entity for integration of the new technology and the development of rates and pricing for services that accommodate the member-consumer's requirements. However, to be successful the cooperative needs to understand the changes that are occurring, decide the role it wishes to play and translate that role into a policy, i.e., the Distribution Operating Policy.

<sup>15</sup> Given the structure of the G&T and distribution cooperative, there will always be two tiers of pricing. G&T wholesale rate price to cooperative and cooperative retail rate to member consumer. In some instances, a G&T is serving transmission cooperatives who in turn serve the distribution cooperative, which creates the three tiers of pricing. This configuration provides great opportunities to distort the pricing signal to the ultimate retail member-consumer.

<sup>16</sup> NARUC Distributed Energy Resources Rate Design and Compensation, November 2016, page 38.

## 1.2

### What steps should the Board expect in the development of a Rate Analysis?

At a minimum, the Board should have the Financial and Rate Design policies in place. The Board should have had discussions about future changes in the industry and the role they believe their cooperative should play in the implementation of new technology at the distribution level, as well as the extent they wish to be proactive in allowing their member-consumers opportunities to be active agents.

The Board should expect a process consisting of seven steps. Depending on the objectives established in Step #2, the focus and level of detail of the remaining steps will vary. If the cooperative is regulated, the Rate Analysis process will be influenced by the requirements of the regulator. The following are the specific steps involved in the development of a Rate Analysis:

1. Continually monitor the performance of the existing rates and identify when a rate change is required to maintain financial integrity.
2. Determine the Rate Analysis objectives, the criteria for evaluation and the expected deliverables.
3. Determine the revenue requirements for the test year.
4. Prepare the cost of service study (COSS) and identify the:
  - a. Relative margins from each rate class
  - b. Required increase in rate class revenue to realize revenue requirement objectives while reflecting rate policy criteria.
  - c. Identify key cost drivers to be reflected in rates.
5. Identify rate options and, using data from the COSS, evaluate the options and develop proposed rates.
6. Review the implementation of the proposed rates in terms of impact on existing policies and programs.
7. Present final rates and communicate to member-consumers the reasons for the proposed changes.

A key responsibility of the Board is to maintain the financial integrity of the cooperative

The Board and management should be clear as to the reasons for the Rate Analysis

### 1.2.1

#### STEP 1: WHAT SHOULD THE BOARD MONITOR?

A key responsibility of the Board is to maintain the financial integrity of the cooperative. To do this, the Board needs to determine how the current rates are performing in terms of the financial objectives established by the Board and if and when rate revisions are required. The Board cannot rely on only current Form 7 data to make that decision. Management must provide and the Board must have in place data showing expected financial performance at least twelve months in the future and if regulated at least twenty-four months in the future.

The projected income statement metrics are typically in the form of a projected financial ratio such as TIER, OTIER, DSC, MFI or ROR. The projected balance sheet metrics are either equity as percent of assets or equity as percent of capitalization and liquidity. The relevant metric should be one that the Board references in the development of the Strategic Financial Plan or Equity Management Plan.

Each month the Board should have available the projected performance data. Volume I, Section 2.1 describes the tools available for development of the projections and Section 2.2 describes the factors to consider in determining the timing of the need for a rate adjustment.

### 1.2.2

#### STEP 2: WHAT IS THE REASON FOR THE RATE ANALYSIS AT THIS TIME?

The Board and management should be clear as to the reasons for the Rate Analysis. The typical reasons for a rate analysis include:

- The Board and management are monitoring the cooperative's revenue and margins and based on current trends the projected revenue and margins from current rates are not acceptable. The revenue level needs to be increased in order to meet the financial objectives as outlined in the cooperative's Strategic Financial Plan or Equity Management Plan.
- Based on previous rate analysis, the cooperative has identified earning differential issues either on an inter-class or intra-class basis that need to be corrected. The cooperative has committed to change rates to adjust rate class margin differentials.
- The current rates have been in place for years and during this time changes have occurred. The changes may include rate of load growth for the cooperative, member-consumer desire for new service and changes in the wholesale rate design and associated price signals and cost drivers. Changes in technology and in particular AMI allows the cooperative to more accurately track costs and increase inter/intra class fairness and equity. If regulated, there may be changed requirements related to application of specific rates or services.
- Member-consumers are requesting new services or applications that did not exist when the current rates were designed and rates need to be revised to accommodate the current member-consumer needs and application of new technology.

- The cooperative has used automatic adjustment provisions to recover increases in costs (typically the purchased power cost adjustment rider with all purchased power cost increase recovered on an energy adjustor) and it has become necessary to restate certain cost components in the rate charges in order to properly align cost causation with cost recovery.

The Board and management need to not only define the reasons for the analysis and the expected deliverables, but more importantly, be clear as to the criteria that will be applied. The policy guides are the Financial Objectives/Equity Management Plan, the Rate Design Policy and the DSO Policy.

### 1.2.3

#### **STEP 3: WHAT IS THE TOTAL REVENUE REQUIREMENT AND HOW WAS IT DEVELOPED?**

Determining the revenue requirement is the most fundamental element of the process and is linked to the financial objectives defined in the Strategic Financial Plan or Equity Management Plan. There are two components to the revenue requirement:

1. Total annual operating cost
2. Margin requirement

To determine the total annual operating cost the Board should consider:

1. What test year was selected to determine the revenue requirement? Reference Volume II, Section 1.2.
2. If a historic test year is being used, the Board then needs to understand the cost adjustments that were made and the extent to which the adjustments are forward looking. Reference Volume II, Sections 1.3 and 1.4.

To determine the margin component of the revenue requirement, the Board and management need to define four basic financial objectives:

1. The minimum acceptable financial coverage ratio. This value may be an accrual metric such as TIER, OTIER, MFI or a cash based metric such as DSC. Typically, both metrics are applicable and the determining factor will be the relationship between depreciation and principal payments for debt service. The minimum acceptable level should not be the defaults in the debt indenture. The minimum acceptable value should be some cushion above the debt requirements. Reference Volume II, Section 2.1.1.
2. The long term equity objective recognizing the balance between the cost of debt and impact on rates and the cost of capital credit program. Reference Volume II, Section 2.1.2.
3. The liquidity objectives. Reference Volume II, Section 2.1.3.
4. The capital credit retirement objectives. Reference Volume II, Section 2.1.4.

To determine the margin required to meet the financial objectives, management needs to provide to the Board the projected CAPEX over the forecast period. The forecast period is typically not less than three years or longer than ten years.

The objective is to determine the margins (typically defined by the coverage metric) needed to meet the equity, liquidity and capital credit retirement program given the projected CAPEX. If the resultant coverage ratios are equal to or greater than the minimum acceptable values in #1, then the resultant values are used. If the resultant values are less than the minimum acceptable values in #1, the coverage values in #1 should be used and the Board should determine the corresponding adjustment to be made in the equity, liquidity and capital credit program. Reference Volume II, Section 2.3.

The cost of service study (COSS) is the fundamental tool for the entire Rate Analysis process

The development of the COSS involves a number of steps that should involve cooperative staff from a number of different departments

### 1.2.4

#### STEP 4: WHY IS A COST OF SERVICE STUDY NECESSARY AND WHAT INFORMATION DOES IT PROVIDE?

The cost of service study (COSS) is the fundamental tool for the entire Rate Analysis process. The COSS provides information to allocate the total system revenue requirement to the individual rate classes. The data from the COSS is then used to allocate the class revenue requirement to individual member-consumers in the rate class, i.e., the rate design. The ability of the cooperative to realize the Rate Design Policy objectives is dependent on how the COSS is developed and utilized.

The development of the COSS involves a number of steps that should involve cooperative staff from a number of different departments. The steps include:

1. Define the retail rate classes that will be served. Reference Volume II, Section 3.1.
2. Define the functions of plant and operating expenses associated with providing service (functionalization of cost). At a minimum, the functionalization needs to be aligned with the expected unbundled rate components. Reference Volume II, Section 3.2.
3. Define the cost drivers for the plant investment and expenses associated with providing service (classification of cost). Reference Volume II, Section 3.3.
4. Determine the usage characteristics for each rate class and develop the associated allocation factors for each rate class. Reference Volume II, Section 3.4.
5. Allocate the revenue requirement to each rate class. Reference Volume II, Section 4.0.

6. Determine class revenue requirements recognizing rate impact issues and other factors that would affect the recommended revenue requirement for a rate class and that are reflected in the cooperative Rate Design Policy. Reference Volume II, Section 4.2.

The questions or considerations the Board should ask related to the COSS include:

1. To what extent are the existing rates cost based and what is the margin provided by each rate class relative to the system? Knowing the relative rate of return (or other metric defined in the Rate Design Policy) from each class will indicate to the Board margin differentials in the current rates.
2. What is the magnitude of rate change required for each rate class to realize the objectives defined in the Rate Design Policy?
3. Given the rate class revenue requirement from the COSS and the Rate Design Policy, the Board will then need to determine the allowable increase or decrease for each rate class. It is possible that the allowable increase will not provide sufficient revenue to meet the total revenue requirement target. If this is the case, the Board needs to revisit the total revenue requirement objective.
4. Based on the COSS, what are the appropriate customer or service charges for each rate class? What are the cost based energy charges for two part rates and the cost based demand and energy charges for three part and four part rates? Knowing the cost based components, the Board can evaluate rate options proposed by management and staff. Reference Volume II, Section 4.3.



The Board needs to clearly understand how the proposed rates and any changes in the rates are aligned with and will reinforce other cooperative programs

### 1.2.5

#### STEP 5: WHAT SHOULD THE BOARD CONSIDER WHEN A RATE CHANGE OR NEW RATE IS PROPOSED?

Step 5 merges the Board's Rate Design Policy and Financial Policy criteria and the Board's position related to adoption and integration of new technology into specific rates to the member-consumer. The determination of total system revenue requirement, the definition of applicable rate classifications, and the allocation of total system revenue requirement to a rate class have been addressed and the COSS has defined the basic cost drivers needed to align cost causation with cost recovery.

In step five, the revenue requirements are assigned to individual member-consumers as part of the rate design. In reviewing the recommendations, the primary questions asked by the Board should be:

1. Does the rate change or new rate properly address the issues identified in Step 2?
2. Have we addressed the need for any new rate classes based on requests from our member-consumers or because of the need to accommodate technology changes?
3. To what extent are the proposed individual components in the rate aligned with cost drivers defined in the cost of service? Stated another way, is the proposed rate sending the proper pricing signals and is there an alignment of cost causation and cost recovery? If costs are not fully recovered in a particular component, where are they recovered?

4. Will adoption of the changed or new rate result in any cost shifting between existing customer classifications?
5. What is the impact of the proposed rate change on customers at different usage levels? Are the impacts proposed consistent with the Rate Design Policy?
6. If competition is an issue, the Board will need a comparison of proposed cooperative rates and corresponding competitive rates.

### 1.2.6

#### STEP 6: HOW WILL THE PROPOSED RATES CHANGE IMPACT OTHER COOPERATIVE PROGRAMS?

The Board needs to clearly understand how the proposed rates and any changes in the rates are aligned with and will reinforce other cooperative programs. Examples include:

- Alignment of the line extension policy and required Contribution in Aid of Construction ("CIAC") given the capital cost recovered in the retail rate.
- Alignment with load management or energy conservation programs.
- Alignment with cooperative DSO Operating Policy.
- Implications related to the cooperative's position on DER and potential energy storage programs.

Ideally, the rates will reinforce other programs, or in the alternative, identify the changes that need to be made in other programs.

The communication of final rates is critical to a successful conclusion of the Rate Analysis process

### 1.2.7

#### **STEP 7: WHAT IS THE PLAN FOR THE ROLL-OUT, IMPLEMENTATION AND COMMUNICATION OF THE PROPOSED RATE CHANGE?**

The communication of final rates is critical to a successful conclusion of the Rate Analysis process. The management and staff need to outline to the Board the proposed steps to present, explain and implement the revised rates. For example:

1. Meetings with member-consumers to explain the reasons for the proposed changes, describe the new rates, and define the estimated impact on the individual rate classifications and member-consumers taking service under the rate classification.
2. Mailings to the member-consumers.
3. Articles in the cooperative's newsletter and local newspapers.
4. Information on the cooperative's website and social media.

### 1.3

#### **Role of the Regulator**

From the cooperative's perspective, the Board provides the balance between the interests of the member-consumer and the cooperative, and is the final authority for rates charged. For cooperatives operating in a regulated environment, the Board may not be the final decision maker, but rather the decision maker for the requested rates. Some states have very active regulation of all cooperative activities and others regulate only certain activities. For the regulated cooperative, the cooperative needs to consider the potential impact of a regulator in the process. The regulator can impact the process in a variety of ways including:

- The requirement to prepare specific documentation and analysis in support of any proposed rate change and associated rate filing. The required "Rate Filing Package" defined by the regulator may be very comprehensive.
- The time frame required to implement any rate adjustments.
- The cost of the rate change process including legal, audit and consulting services.
- The total revenue requirement that will be allowed for the cooperative.
- Test year cost adjustments that will be required or permitted.
- The magnitude of rate change that may be imposed on a particular customer class relative to the system average.
- The rate structure that may be reflected in a rate design.
- Recognition of statewide issues that the regulator may require to be addressed (value of solar, demand-side management, time-of-use rates, etc.).
- Notice requirement for rate change may include specific content, public meetings and notice period.

Management may find it beneficial to adopt certain typical regulatory requirements even if they are not regulated. Many of the recommendations related to the process described in the Rate Guide reflect typical regulatory requirements that a cooperative needs to consider even if not regulated.

## 1.4

### **Risk Considerations**

Risk is the underpinning consideration in any discussion of the processes and issues described above and the options to deal with those issues. The questions the Board should be considering in the discussion include:

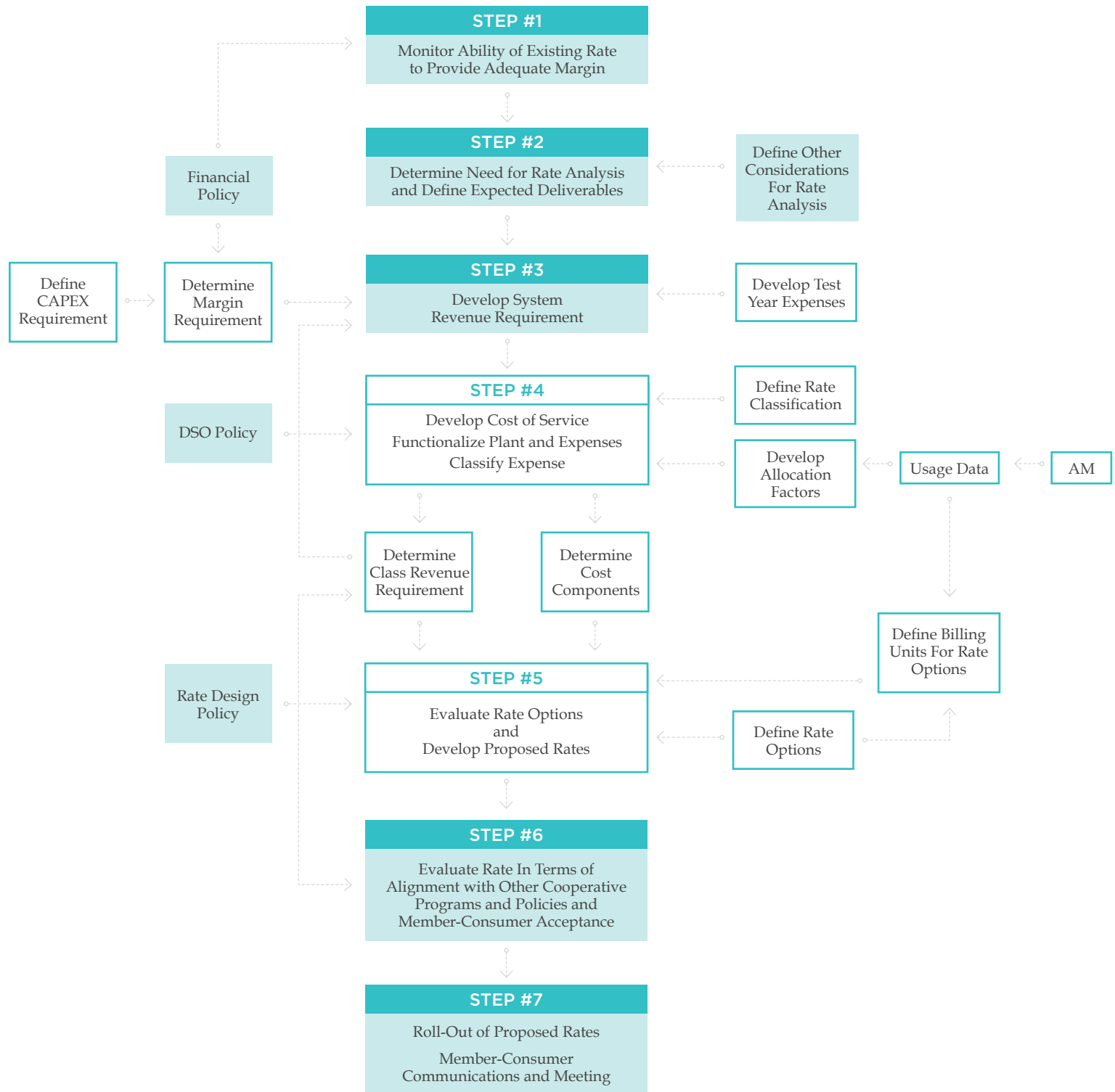
1. What kind of processes do we have in place to identify risks, including new and changing risk to the cooperative?
2. Does Management's method of defining and quantifying risk seem reasonable?
3. Have we missed key risk areas in the past related to any of the activities described above? If yes, why?
4. What is our "risk appetite" and "risk tolerance" particularly in dealing with:
  - a. Implementation of new technology?
  - b. Seeking a balance between maintaining margins necessary to ensure financial integrity while at the same time minimizing cost to our member-consumers?
  - c. Implementing new rates on a system wide basis or on a pilot basis?

## 1.5

### **Block Diagram of Process**

The diagram on the following page is a summary of the Rate Analysis process. The specific functions in which the Board and management have direct involvement with have been highlighted.





# 2.0

## Defining the Need for Rate Analysis and Timing Considerations

*Before the Rate Analysis begins, the Board will need to agree on the underlying issues to address and the expected deliverables. Section 1.2.2 identifies the most common issues as inadequate revenue and margins, rate class subsidies, distorted pricing signals, outdated rates, and mismatch between cost recovery and cost causation. While the trigger may be caused by any combination of these issues, the primary one is usually inadequate revenue and margins that will no longer achieve the metrics in the cooperative's Financial Strategic Plan or Equity Management Plan. The first step in the Rate Analysis process is actually an on-going process to determine when the existing rates are likely to no longer provide adequate margins to meet financial objectives. Section 2.1 outlines a monitoring process and Section 2.2 and 2.3 describe factors to consider in defining the appropriate "look-ahead" period for the cooperative.*

**The cooperative should not evaluate need by looking at current revenue and margins but instead consider forward-looking trends**

### 2.1

#### Projecting the Need for Change in Revenue Requirement

The cooperative should not evaluate need by looking at current revenue and margins but instead consider forward-looking trends. If the cooperative waits until the margin adequacy tipping point has been reached to begin work on the Rate Analysis, it is too late. Section 2.2 discusses the schedule and the sequence of events required to implement a rate change. At least twelve months is likely required. If the cooperative is regulated the time frame will more likely be twenty four months. Each cooperative should identify the time line applicable to its specific situation and adjust its planning horizon accordingly.

The financial "look-ahead" should be prepared on a regular basis. Several monitoring tools are recommended. The first is to restate Form 7 historical financial data to reflect performance on a rolling twelve-month basis ("Financial Profile"). The Financial Profile should be prepared for at least the previous twenty-five periods in order to identify trends. At a minimum, the Financial Profile should include rolling twelve-month performance data for the following:

- Energy Sales (billing units)
- System margins with the emphasis on the metric(s) most meaningful to the cooperative:
  - Operating or net margin
  - Financial ratio (TIER, MFI, DSC, ROR)

Reference Appendix Schedules A-1.0 through A-5.0 for examples of selected Financial Profile reports and graphs.

The important point is that tools are in place to monitor trends in expected margins over the next twelve to twenty four months and this information is provided to the Board

A more comprehensive Financial Profile will report statistics by individual rate classes and by individual components of expenses. The latter provides more detailed information as to why the system is behaving the way that it is and may identify the specific component causing the erosion in earning. For a cooperative with power cost recovery clauses it is important to confirm the flow through provision is working properly. This means monitoring on a rolling twelve-month basis:

- The actual power cost incurred.
- The wholesale base power cost embedded in the rates.
- The difference between the actual wholesale power cost and the embedded or base wholesale power cost.
- A comparison of the calculated recoverable value with the actual power cost recovery.

The rolling twelve-month Financial Profile is an essential tool for monitoring the cooperative performance in order to evaluate the start date of a Rate Analysis.

The second tool is the budget which provides an indication of expected financial performance over the budget period. The trends resulting from the Financial Profile analysis can be compared with the budget values.

A third tool that provides a longer view is the Financial Forecast. Ideally, to better understand long-term financial trends, the cooperative should update their Financial Forecast every year with the first year being the budget data.

The Financial Profile, budget, and Financial Forecast are the three recommended reports to monitor trends in the cost and revenue and margins metrics. Keep in mind that the revenue

stream used to compute the margins and associated financial metrics for these reports is the product of the existing rates times billing units. Therefore, it is also important to monitor trends in billing units for at least the major rate classes.<sup>17</sup>

The Financial Profile analysis can provide trends in not only financial data but also usage data based on information reported in Part O of the RUS Form 7 and Part R of the CFC Form 7.

The review of trends in usage data (billing units) needs to be tempered with consideration of weather data. Some systems include as a part of the rolling twelve-month usage profile weather data such as heating and cooling degree days. This allows for normalization to reflect normal weather conditions. The tool available to the cooperative to normalize billing units over the long term is the power requirement study (PRS). The PRS forecasts usage data taking into account normalized weather and other trends reflecting econometric data for the cooperative's service area.

The important point is that tools are in place to monitor trends in expected margins over the next twelve to twenty four months and this information is provided to the Board. The expected margins should then be compared with target values established by the Board and management as a part of the Financial Strategy and any differences identified. Different Boards will have different views as to what conditions trigger a Rate Analysis and possible rate adjustment. Some Boards prefer to delay rate adjustments and are willing to seek larger adjustments made infrequently whereas others prefer smaller adjustments at more frequent intervals. The financial targets and implementation strategy should be defined by the Board well in advance of any detailed rate analysis work and communicated to management.

<sup>17</sup> Billing units include both demand and energy values applicable to individual rates and absent contract amounts will typically reflect member-consumer usage.

## 2.2

### Time Frame Required to Develop Rates

The previous section suggested a look-ahead window of twelve to twenty-four months to conduct a Rate Analysis. To better define the look-ahead period, The Board and management should consider the events that must occur to implement any rate adjustment and then develop a schedule specific to the cooperative.

The following is a list of the typical events defining the time-frame:

- Select a test year (a twelve-month period)
- Gather test year data
- Prepare adjustments to the test year (expenses and revenue)
- Develop a pro-forma income statement defining margins earned under current rates given adjusted test year expenses and usage
- Develop the COSS
- Review the COSS to determine:
  - Revenue requirements by rate class
  - Rate design alternatives
  - Recommended rates
- Presentation of proposed rates for Board review
- Board approval of rates

The test year is the basis for the Rate Analysis. It can be any twelve-month period unless regulatory requirements define specific periods. The development of the Rate Analysis and the cost of service process in particular require a significant amount of detailed data. Because most cooperatives will typically prepare this data for various RUS/CFC annual reports, the calendar year twelve-month period is generally preferred. If a historic test year is selected, the data will generally not be available until the first quarter. (Test year options are discussed in detail in Volume II, Section 1.2.) Whereas it is desirable to use audited data (the audit report may not be available until the second quarter), it is acceptable to begin the analysis with unaudited data and update when audited data is available.

Much of the test year data will be readily available from standard reports such as the General Ledger or Trial Balance for accounting and monthly Sales Reports from rate billing (either in-house billing software or out sourced billing provider). Special queries of the billing system database may be required for some detailed usage and billing data. Engineering cost data may need to be compiled from recent work orders. The cooperative needs to discuss the availability of the required data when deciding on a test year since this can affect the selection. With a calendar year test year, the test year data will likely be available in the first quarter.

The next step is to review the test year and develop necessary adjustments for changes in revenues and expenses that are “known, measurable, and continuing in nature”. (Test year adjustments are discussed in detail in Volume II, Section 1.2.) Ideally, the Management and Board have already identified the financial objectives so it is a matter of comparing the adjusted test year financial data given existing rates and the resultant margin with the strategic objectives to determine the initial estimate of the rate change. If Management and Board wait to define the margin objective, the schedule will need to be extended. The pro forma income statement with test year adjustments would typically be available within another thirty to sixty days.

The COSS assigns the plant and expenses to the rate classes. The development of the COSS is discussed in Volume II, Section 3. The COSS may require thirty to sixty days to complete.

The COSS results provide the data to determine the revenue requirements for each rate class and the cost data needed to design rates. Using this data, the next step involves defining and evaluating rate design alternatives and the development of rate design recommendations for the Board. This activity can take thirty to sixty days.

The Board has the responsibility of approving the overall class revenue requirements and the rate designs. If not rate regulated, the Board approved rates are the implemented rates. If rate regulated, the Board approves the rates that are requested from the regulatory authority. The Board should “own” the rates and that ownership will only come with a thorough understanding of the basis for the recommendations. The level and schedule for Board involvement needs to be determined early in the process to assure the project stays on schedule. Some Boards separate the process into three steps:

1. A meeting or Board retreat to review the procedure, discuss concepts, and seek input related to rate design options.
2. Followed by a second meeting to review results and discuss specific rate design options.
3. A third meeting to approve final rates.

Depending on the extent of Board involvement and the schedule for Board review, the final approval may not occur until the third quarter.

Rate implementation is dependent on Bylaw and/or other notice requirements. There may be a thirty to sixty day notice requirement (or longer) to member-consumers for any rate change. Working from the perspective of an effective date, this means that the final Board approval needs to take place at the October or November Board meeting for an effective date of January 1. The sequence described above should allow the Board to meet the January 1 effective date.

Given the tasks described above, this effectively forces at least a twelve-month planning horizon to revise rates. If regulated, the schedule will need to accommodate the regulatory process. This may mean another twelve months which stretches the planning horizon to twenty-four months.

Some jurisdictions allow an option of an abbreviated rate filing. While an abbreviated filing reduces the planning horizon, it may also limit the ability of the cooperative to adjust rates. In some states with abbreviated or accelerative rate filing options, the cooperative is limited to the manner in which rates can be adjusted.

## 2.3

### Other Considerations

Other considerations may apply in deciding on the timeline and effective date of a rate change. For example, the power supplier may be planning to implement a rate change and the cooperative may want to schedule its change to be effective at the same time or to purposely delay implementation in order that the impact not be compounded. The cooperative may not want to put new rates in place that could adversely impact seasonal loads right before the beginning of the season (such as a June effective date with large irrigation systems or a January effective date if there is sensitivity to heating loads). Conversely, the opposite may be true if the cooperative is trying to capture the revenue associated with a rate change from seasonal loads. Events such as the cooperative’s annual meeting or construction of a new headquarters building may affect the implementation of a rate change.

The Board needs to be aware of the activities required, the involvement of the Board, and the intended and possible unintended consequences of requested effective dates to identify how long it takes to implement an increase in rates. The point is to establish a mindset where the Board is always thinking in terms of expected revenue and margins twelve to twenty-four months in the future, not just the latest Form 7 report, and the management and staff is providing the information necessary for the Board to evaluate those future revenues and margins.

# 3.0

## Developing Rate Options

Changes in volumetric billing units (kWh sales) whether caused by new technology, energy efficiency improvements or member-consumer behavior poses a very real concern regarding recovery of costs

Recognition of the membership's increasing concern for social and environment issues must also be considered

*The process for the development of the complete rate analysis is outlined in Volume I Section 1.0. In order to develop rates it is essential to identify the total revenue requirement, determine a fair and equitable allocation of the system revenue requirement to the rate class, and identify cost drivers that define the allocation of the class revenue requirement to individual member-consumers in that class in a manner that meets the cooperative Rate Design Policy objectives. The details of the activities involved in Steps 1 through 4 are described in Volume II.*

Some cooperatives may have already completed these activities and are interested in options available in meeting a series of evolving challenges, which include adapting to a cycle of evolving technology and changing member-consumer expectations. Changes in volumetric billing units (kWh sales) whether caused by new technology, energy efficiency improvements or member-consumer behavior poses a very real concern regarding recovery of costs. Recognition of the membership's increasing concern for social and environment issues must also be considered. Additionally, since the wholesale cost of power comprises such a significant component of the distribution cooperative's cost, the wholesale pricing signal and issues facing the wholesale provider should also be considered. These issues could include such factors as the costs of production capacity and transmission investments, the impact of distributed energy resources (DER) on the wholesale provider and the costs associated with environmental compliance.

This section focuses on Step 5 which involves defining various rate options and evaluating these options. This Section provides an overview of rate designs beginning with the common two-part rate design and extending to four-part rates, time-of-use rates and rates applicable for specific applications. There is also discussion of various proxies that can be applied. Specific examples are developed in this section to better understand how the option discussed translates to a specific rate design. The data for examples is from the cost of service discussion in Volume II. The results of the cost of service and the data used in the development of the rate options is shown in Schedules B-1.0 through B-5.0 and Schedules C-1.0 through 2.0 in the Appendix. In all examples, the rate design produces the same revenue requirement.

This list of rate options presented is certainly not a comprehensive listing of all possible options. The options listed should however, provide a sense of the alternatives to consider and provide a framework for determining options that could fit the cooperative's needs.



**It is important for the Board and the Team to be on the same page in developing and implementing these criteria so all aspects of the rate design process work together**

### 3.1

#### Rate Design Criteria

Each cooperative should develop rate design criteria that reflect its own goals and objectives. These rate design criteria serve as the guiding principles that inform how rates are developed. It is important for the Board and the Team<sup>18</sup> to be on the same page in developing and implementing these criteria so all aspects of the rate design process work together. The Board should work with the Team to determine the challenges it sees as outlined in Section 1 of this Volume and then to determine how it can address these challenges through its rate making procedure. Once it has established this “rate plan of work,” it will become the cooperative Board’s rate philosophy and a roadmap for specific rate designs.

Whether specifically written down or not, the Board in practice will have a philosophy of rate making. Part of the rate philosophy includes how specific criteria are prioritized and weighted. In general, all of the rate criteria are important, though Boards determine an appropriate balance of them as part of any rate change process. The following describes the core rate design criteria:

- Fair and non-discriminatory – Similarly situated member-consumers should be treated in a consistent

manner. Each member-consumer should pay his or her share of the costs of providing service. The Board should move rates toward cost of service as a means of minimizing subsidies and maintaining fairness.

- Minimize impact on member-consumers – An important criteria for the Board to consider is the impact that rate changes have on individual member-consumers. In some cases the Board may decide that the benefit derived from the rate change is outweighed by negative member-consumer impact and seek an alternative rate design option. It is also important to understand that any time rate structures change, some member-consumers benefit and others do not. Communicating with member-consumers throughout the rate analysis process is one key to minimizing member-consumer distress.
- Send the proper pricing signals to member-consumers– It is important that rates are designed to reflect cost causation. The vast majority of the distribution cooperative’s delivery costs are fixed; therefore, rates should be designed to reflect this. To the extent possible, retail rates should reflect the price signal sent by the wholesale cost of power.
- Understandable – Rates cannot be effectively used by member-consumers unless they are understood. As discussed later in this section, rates that provide the most precise pricing signal may be so complex that member-consumers cannot effectively use them. On the other hand, simple rate designs, such as traditional two-part rates, may be insufficient to achieve the cooperative’s desired objectives.

#### CORE RATE DESIGN CRITERIA

- Fair and non-discriminatory
- Minimize impact on members-consumers
- Send the proper pricing signals
- Understandable
- Encourage efficient and responsible usage
- Other possible societal considerations
- Manage evolving member-consumer expectations
- Integrate new technologies

<sup>18</sup> The Team is discussed in detail in Volume II, Section 1.8. The Team includes staff from financial/accounting, billing and customer accounting, engineering and operations, member services, communications, information technology, and management.

One of the most important Board rate making roles is to consider each of these possible rate design criteria and then to weigh and balance their importance

- Encourage efficient and responsible usage – Conservation, energy efficiency and the use of renewables provide member-consumers the opportunity to lower their bill and also lower the cooperative's costs. Rates can be developed that permit the cooperative to achieve any desired objectives it identifies in this area.
- Other possible societal considerations – Some cooperatives have additional "societal" objectives, such as assisting low income member-consumers, retirees, military or injured member-consumers. Some jurisdictions mandate that member-consumers be permitted to "opt out" of certain cooperative programs such as AMI. Cooperatives might identify objectives to assist emergency services, schools, churches, parks, etc. Rates can be developed to achieve those objectives.
- Manage evolving member-consumer expectations – Technologically savvy member-consumers expect the cooperative to offer more sophisticated services. Real time pricing, three- or four-part rates, prepaid metering, critical peak pricing rates and others are just some possible member-consumer expectations that rates might need to provide. Many member-consumers today expect their service providers to provide them with choices and options.
- Integrate new technologies – Member-consumers are adopting a variety of new technologies to their homes and businesses. These technologies include, among a host of others, back-up generation, renewable energy and other DER technology; vehicle charging, energy efficiency and demand-side management (DSM); battery backup and storage; etc. In order to be able to take advantage of these technologies as a part of rate-making, the cooperative will require metering and billing technology that will permit it to do so. Most advanced metering infrastructure (AMI) meters provide at least some expanded ability for the cooperative to consider new rate options such as multi-part rates and real time pricing. While not within the scope of this Rate Guide, the cooperative should be sure that its long-term AMI plans will result in information technology (IT), AMI and other infrastructure that will allow it to implement any long-term rate objectives it may adopt as part of its rate criteria.

#### NOTE:

As a part of the rate discussion in this section, rates have been developed for a mythical "Standard Electric Cooperative." All of the rate options shown generate the same revenue from the rate class. The rates are shown unbundled so it is possible to determine, not only the total rate, but the major cost components of the rate and how different rate options recover the cost of providing service in different components with different billing units. While the rate designs for Standard are consistent with the Standard COSS, they are for illustration only.

One of the most important Board rate making roles is to consider each of these possible rate design criteria and then to weigh and balance their importance. For example, the Board may wish to increase the existing customer charge high enough that the full customer-related cost of providing service is recovered in the customer charge. But when it weighs this desired result against the member-consumer impact such a change would produce, may instead decide to apply the increase in phases over time. Or the Board may decide to encourage renewable energy, but when weighed against the need to continue to recover its fixed cost of providing distribution service, the Board may put member-consumer education as the short-term priority.



Cooperatives  
should focus on  
rates that meet  
their needs

Justification for  
the two-part  
rate remains  
strong

### 3.2

#### Traditional Versus Innovative Rate Design

Much discussion around Board tables and at industry gatherings has focused on innovative rate designs. All too often this term encourages the cooperative to “chase technology” by designing rates focused on technological issues. For example, in the past cooperatives carved out groups of residential member-consumers with electric water heaters because their usage was different from other residential member-consumers. Today, cooperatives are carving out net metering, vehicle charging, and other specific rate class objectives. As a result, the cooperative ends up in the position of chasing (or hopefully anticipating) the newest technology as it is adopted by member-consumers.

Each cooperative must determine for itself the objectives it desires to achieve and develop a rate philosophy to achieve those objectives. It must then determine criteria to weigh the relative importance of each possible rate option.

Cooperative Boards and regulatory bodies across the country have adopted a variety of effective and efficient rate design structures. Some are often labeled “traditional” while others are labeled today as “innovative.” Regardless of label, cooperatives should focus on rates that meet their needs.

### 3.3

#### Traditional Residential Rate Designs: The Two-Part Rate

The Two-Part Rate (Customer Charge and Energy Charge) has been the “go-to” rate for most electric utilities almost since central station electric power began. While today many cooperatives are considering other designs, justification for the two-part rate remains strong.

- Minimal technological requirements – Two-part rates have minimal requirements for metering, meter reading and billing—only a standard mechanical meter registering energy usage and standard billing software. These meters were historically less costly and easy for individual residential member-consumers to read themselves each month – as was the case for many years.
- Easy to understand – Member-consumers are not required to understand complex issues related to time-based usage or demand. Electricity is priced based on volume, similar to water or other commodities. Of course, the trade-off of a simple -rate design is less flexibility and accuracy. Additionally, the emphasis is placed on selling a product rather than providing a service. On the plus side, when the cooperative has a traditional two-part rate and intends to maintain this rate structure, communication with member-consumers is relatively simple.
- Inertia and regulatory influence – The two-part rate is so common that some regulatory commissions are reluctant to consider anything else. And many Boards are cautious about moving to different rate structures, particularly if neighboring utilities maintain traditional rate structures.
- Minimum member-consumer impact – If the two-part rate is maintained, impact on individual member-consumers is mitigated.

The customer charge should reflect recovery of costs that are driven by just being a member-consumer, no matter how small

3.3.1

THE CUSTOMER CHARGE (OR SERVICE AVAILABILITY CHARGE)

Many cooperatives discover, when changing rates and communicating with member-consumers, that no single issue causes more misunderstanding and unrest than changes to customer charges, also known as service availability charges. When considering the customer charge, the Team must carefully balance the same types of criteria it does with overall rate designs, including the length of time since the last change in the charge, the cooperative’s customer charge compared to other utilities, the number of low and minimum use member-consumers it has and any other issues unique to its member-consumers.

CUSTOMER CHARGES:

- Perhaps no issue has been of more general interest to and more widely considered by cooperative Boards than the Customer Charge.
- Cooperatives should consider either setting their fixed customer charges at the fixed customer-related cost of providing service or at minimum moving toward that ultimate goal as a part of any rate and cost of service analysis.

Cost Recovery and Rate Design

Two Part Flat Rate

Cost Components	Allocation Factor	Retail Rate Design
<b>Power Supply</b> Demand Energy	Power Supply CP Energy	Energy Energy
<b>Power Supply Delivery</b> Transmission Substation Ancillary – Demand Ancillary – Energy	Transmission CP Cooperative CP Cooperative CP Energy	Energy Energy Energy Energy
<b>Distribution Demand</b> Sub-Transmission/Substation Backbone Demand Distribution Demand	Cooperative CP Cooperative CP Cooperative NCP	Energy Energy Energy
<b>Distribution Customer</b> Distribution Customer Customer Services Customer Ancillary	Customers Customers Customers Customers	Customer Charge Customer Charge Customer Charge Customer Charge
<b>Margin</b>	Distribution Components	Distribution Components

The two-part rate recovers many fixed costs through energy charges, creating a mismatch between how costs are incurred and how costs are recovered from members-consumers.

Definitions of chart elements, descriptions of allocation factors and costs are how they are typically derived is described in Volume II, Section 3.

To the extent the cooperative does not fully recover its fixed customer-related costs in a monthly fixed charge, it is relying upon other billing units to recover those costs

A Cost of Service Study (COSS) should identify the customer-related cost of providing service. (See Volume II and Schedule F-2.0 in the Appendix.) The customer charge should reflect recovery of costs that are driven by just being a member-consumer, no matter how small. These costs would include items such as the cost of maintaining the minimum distribution system to serve the member-consumer, metering, meter reading, accounting, customer services and a share of required margins. Regulators and Boards sometimes find it difficult to recover the full customer-related cost of service through the monthly customer charge. The primary concern is often two-fold: member-consumer impact and comparisons to neighboring system customer charges.

Cooperatives, particularly those with more rural service areas, may find that their customer-related cost of providing service is far higher than for neighboring IOUs and municipal electric systems, primarily due to the lower line density of the cooperative's service territory. This disparity should be continually explained to member-consumers and regulators.

It is not uncommon for the Team to find their existing customer charge is so much lower than the actual customer-related cost of service, that it cannot implement the increase in a single rate adjustment without high levels of member-consumer impact. Many cooperatives have historically set customer charges below the full customer-related cost of service. To the extent the cooperative does not fully recover its fixed customer-related costs in a monthly fixed charge, it is relying upon other billing units

to recover those costs. If those billing units are variable in nature, such as an energy charge, the cooperative risks under-recovering fixed costs from low consumption member-consumers and over-recovering from high consumption member-consumers. In addition, member-consumers have been provided with a pricing signal that inflates the value to the cooperative of member-consumers lowering their energy usage.

In some regulated environments, many regulators have deliberately required customer charges be kept low. They believe this is a "progressive" step of requiring high usage customer/member-consumers (assumed to be high income) to subsidize low usage customer/member-consumers (assumed to be low income). In fact, many low income member-consumers have quite high usage and the resulting shift in fixed cost recovery is actually regressive. As a part of any rate and cost of service study, the Team should consider either setting their fixed customer charges at the fixed customer-related cost of providing service or in any case moving toward that ultimate goal.

### 3.3.2

#### THE ENERGY CHARGE

In theory, the energy charge in the two-part rate should recover the purchased power cost and the distribution costs associated with the load size. In actual practice, the energy charge recovers these in addition to the customer costs not recovered in the customer charge.

This rate is simple to administer, easy to understand and less subject to error

It provides no signal that the price of energy purchased actually varies based on the time of the day or season

It may not even include recovery of the full customer-related cost of providing service in the monthly customer charge

3.3.2.1 TWO-PART FLAT RATE

The two-part flat rate has a monthly fixed or customer charge and a single energy or volumetric charge based on total kWh usage. As shown in the chart, and as explained in Volume II, Section 3, a distribution cooperative’s own cost of providing wires service is fixed, and a two-part rate with all of its obvious benefits, is not the closest match to how costs are incurred.

This rate is simple to administer, easy to understand and less subject to error. If maintained, it results in less individual member-consumer impact than typically results from changes in basic rate structures. It does not provide a clear pricing signal that a sizable portion of the cooperative’s own cost of maintaining its facilities (system wires cost) is fixed based on capacity (demand). In particular, it provides no signal that the price of energy purchased actually varies based on the time of the day or season. And it may not even include recovery of the full customer-related cost of providing service in the monthly customer charge.

Example of a two-part flat rate:

	Power Supply			Distribution		TOTAL
	Demand	Energy	Delivery	Demand	Customer	
Customer Charge	\$0.00	\$0.00	\$0.00	\$0.00	\$27.72	\$27.72
Energy Charge	\$0.03018	\$0.03516	\$0.00952	\$0.02588	\$0.00000	\$0.10074

3.3.2.2 SEASONAL ENERGY RATES

The Seasonal rate provides a pricing signal that the cooperative’s power cost varies by season, typically by weighting the energy charge for a season that drives costs year round or when the wholesale cost is higher in a particular season.

Example of a two-part seasonal rate:

	Power Supply			Distribution		TOTAL
	Demand	Energy	Delivery	Demand	Customer	
Customer Charge	\$0.00	\$0.00	\$0.00	\$0.00	\$27.72	\$27.72
Energy Charge (June-Sept)	\$0.04482	\$0.03516	\$0.01245	\$0.02588	\$0.00000	\$0.11831
Energy Charge (Oct-May)	\$0.01982	\$0.03516	\$0.00745	\$0.02588	\$0.00000	\$0.08831

The increased cost of the “peak season” (in the case of the example, the summer months) signals that power cost is driven more by summer usage than is the case in other seasons and that lowering summer usage is more valuable to the cooperative. This rate is sometimes seen as encouraging electric heat usage during off-peak periods rather than discouraging usage during on-peak periods.

### 3.3.2.3 BLOCKED ENERGY RATES

When the cooperative has a customer charge set below its customer cost of providing service, the Team may want to recover the remaining unrecovered portion in the first block of energy used. This rate design has been referred to historically as a “declining block” rate because it once served the function of promoting electric sales for added devices such as electric heat, water heat, etc. Today, this rate structure is intended to recover fixed costs in early blocks. In some states, regulators and others object that this rate structure discourages energy efficiency and renewables by pricing the final blocks of energy at a lower rate.

*Example of a two-part rate blocked rate:*

	Power Supply			Distribution		TOTAL
	Demand	Energy	Delivery	Demand	Customer	
Customer Charge	\$0.00	\$0.00	\$0.00	\$0.00	\$20.00	\$20.00
First 100 kWh	\$0.03018	\$0.03516	\$0.00952	\$0.04822	\$0.05702	\$0.18010
Next 900 kWh	\$0.03018	\$0.03516	\$0.00952	\$0.02786	\$0.00385	\$0.10657
Next 1000 kWh	\$0.03018	\$0.03516	\$0.00952	\$0.01900	\$0.00000	\$0.09386

### 3.3.2.4 INCLINING OR INVERTED ENERGY RATES

Inclining or inverted rates are generally designed such that the final block(s) have higher charges than the first blocks. This rate design is generally used for two possible objectives:

- If the Team wants to move toward higher customer charges that are more reflective of actual customer-related costs of providing service, but is concerned about impact for the average member-consumer, this rate structure can be effective. Higher customer charges (which result in higher percentage increases for low usage member-consumers) coupled with an inverted rates (which result in higher percentage increases for high usage member-consumers), can help manage member-consumer impact.
- When the Team has an objective of encouraging energy efficiency and renewable energy, inverted rates provide the highest per kWh savings for reduced kWhs. This type of pricing signal is an example of the cooperative weighing the value of promoting reductions in power use ahead of recovering costs strictly based on cost of service.

*Example of a two-part rate inverted blocked rate:*

	Power Supply			Distribution		TOTAL
	Demand	Energy	Delivery	Demand	Customer	
Customer Charge	\$0.00	\$0.00	\$0.00	\$0.00	\$20.00	\$20.00
First 400 kWh	\$0.03018	\$0.03516	\$0.00952	\$0.02592	\$0.00657	\$0.10735
Next 400 kWh	\$0.03018	\$0.03516	\$0.00952	\$0.00000	\$0.00000	\$0.07486
Over 800 kWh	\$0.03018	\$0.03516	\$0.00952	\$0.03951	\$0.01001	\$0.12438

3.3.2.5 RAISED MINIMUM CHARGES

Some two-part rates include a monthly minimum charge higher than the monthly customer charge. This approach may be particularly helpful if the Team is not ready to move the customer charge to the full customer-related cost of providing service for low usage member-consumers, but there are large numbers of minimum-usage member-consumers within a rate class that the Team feels should see the full cost of providing service. It may also be helpful to ensure member-consumers with renewable or other distributed energy resources (DER), for example, return some minimum amount of billing to recover their fixed cost of service.

*Example of a two-part rate raised minimum rate:*

	Power Supply			Distribution		TOTAL
	Demand	Energy	Delivery	Demand	Customer	
Customer Charge	\$0.00	\$0.00	\$0.00	\$0.00	\$20.00	\$20.00
Energy Charge	\$0.03018	\$0.03516	\$0.00952	\$0.02588	\$0.00584	\$0.10658
Minimum Bill per Month	\$0.00	\$0.00	\$0.00	\$0.00	\$32.50	\$32.50

*In this example, the member-consumer pays \$32.50 until their consumption exceeds 117 kWh.*

3.3.2.6 SUMMARY - TWO-PART RATES

Traditional two-part rates have been in place since the start of the electric utility industry and still have a place today. They should be considered as part of the rate balancing that is part of any rate design process.

PROS	CONS
Easy to understand by member-consumers	Not the strongest rate structure related to how costs are incurred
Easy to administer	Little pricing signal to control wires capacity costs
Historically popular – often what has always been used	Little pricing signal to control purchased power capacity costs
Often historically used by neighboring utility systems	Provides a pricing signal to lower energy without lowering capacity
Often historically favored by regulators	Not strongly time-based
Advanced metering and bill processing not required	May result in margin instability during periods of reduction in energy sales for any reason(s)
Less new education required	



Most billing systems can now adapt to somewhat more complex rates without expensive reprogramming

Member-consumers are familiar with complicated rates used by cell phone, cable television, internet and other service providers

### 3.4

#### Rate Designs Based on Capacity/Demand

Two-part rates have been used for many years. And many cooperatives continue to determine, after balancing the pros and cons for their system, that a two-part rate is meeting their individual needs.

But the Team should consider evolving changes in the industry. Most cooperatives have in place some type of AMI that permits more complex rates than in prior years for all member-consumers. Most billing systems can now adapt to somewhat more complex rates without expensive reprogramming. Also, member-consumers are familiar with complicated rates used by cell phone, cable television, internet and other service providers.

Some member-consumers are using power quite differently now, with increasing differences in average usage among member-consumers of rate classes. For example, residential member-consumers with electric car charging devices have quite different load curves, than residential member-consumers with distributed generation, or certain home-based businesses.

We will discuss common variations in rate designs, without claiming our list is all-encompassing.

### 3.5

#### The Multi-Part Rate – Four-Part and Three-Part Rate Designs

A common rate design option offered for years to large power and large commercial member-consumers is the three-part rate (customer charge, demand charge and energy charge). These rates are sometimes called demand/energy rates or just demand rates. The fact that these rates have been used for many years is an indication that cooperatives have always understood demand rates provide a more accurate recovery of costs than the standard two-part rate. Modern metering technology, an increase in the number of member-consumers wanting billing options, and other reasons, has led to increased consideration of multi-part rates for all rate classes. The cooperative Team and Board should consider the pros and cons of this rate structure.

#### PURPA DECOUPLING STANDARD

The PURPA decoupling standard requires utilities to consider recovery of fixed costs of providing service through fixed billing units rather than volumetric ones like kWh sales. The concept is that the utility should not have a financial disincentive to promote renewable energy efficiency and conservation.

There are a variety of means for a cooperative to accomplish this task. One is consider a factor similar to a power or fuel cost recovery factor.

A simpler solution is to move rates closer to the cost of service, recovering fixed costs through fixed billing units such as customer charges and demand charges. So a multi-part rate IS in effect a decoupling rate.

*Cobb Electric Membership Corporation (Cobb) is a Georgia cooperative serving 180,000 meters spread over 432 square miles. Over a period of years, Cobb identified a trend of growth in plant and member-consumers coupled with reductions in revenues and kWh sales. In part to address this concern, Cobb has developed a three part rate consisting of customer charge, demand charge, and energy charge. Based on extensive discussions with focus groups Cobb decided to reflect the demand charge as a \$/kwh/hour rate rather than a \$/kW rate. Cobb carefully measured the impact of the new rate on member-consumers and set their capacity charges well below actual capacity costs as a balance of cost recovery versus individual impact. Cobb adopted special educational material and terminology to explain the entire process to member-consumers. Click [here](#) for more information.*

Rates with a demand component provide a mechanism to communicate to member-consumers how costs are incurred so they can modify their usage and control their power cost

As explained in Volume II, Sections 3 and 4, a significant portion of BOTH the cooperative's purchased power capacity costs and own distribution wires cost are often driven by peak load (demand). Introducing a demand billing component to rates offers the cooperative the ability to recover costs in a manner that more closely tracks how those costs are incurred. Rates with a demand component provide a mechanism to communicate to member-consumers how costs are incurred so they can modify their usage and control their power cost.

With regard to purchased power capacity costs, the Team should consider how capacity or demand related costs are billed by the cooperative's power supplier. (See Volume II, Sections 3 and 4.) While not always the case, purchased power capacity cost is often billed based on the member's contribution to some measure of the wholesale supplier's peak demand. A retail rate which includes a Coincident Peak (CP) Demand rate component provides the member-consumer a pricing signal that can allow the member-consumer to lower the retail billing and also allow the cooperative to lower purchased power demand billing.

With regard to the distribution wires costs, the Team should consider that the majority of a cooperative's distribution capacity-related cost of providing service is based on the individual rate class and individual member-consumer's contribution to the distribution cooperative's non-coincident peak (NCP). A retail rate which includes an NCP demand rate component provides the member-consumer a pricing signal to lower peak usage across the month. When coupled with similar reductions from other member-consumers, the cooperative may be able to lower plant investment required to meet that peak load and thus reduce the distribution wires cost of providing service.

## MULTI-PART RATE

Historically used quite commonly by cooperatives for billing large commercial and large power member-consumers, this rate structure provides a close alignment of how costs are incurred to the recovery of those costs in rates. The multi-part rate typically includes a customer charge, a volumetric variable energy charge and one or more demand or demand proxy charges such as connected horsepower, installed kVA, etc.



## Cost Recovery and Rate Design

### Four Part Flat Rate

Cost Components	Allocation Factor	Retail Rate Design
<b>Power Supply</b> Demand Energy	Power Supply CP Energy	CP Demand Energy
<b>Power Supply Delivery</b> Transmission Substation Ancillary – Demand Ancillary – Energy	Transmission CP Cooperative CP Cooperative CP Energy	CP Demand CP Demand CP Demand CP Demand
<b>Distribution Demand</b> Sub-Transmission/Substation Backbone Demand Distribution Demand	Cooperative CP Cooperative CP Cooperative NCP	NCP Demand NCP Demand NCP Demand NCP Demand
<b>Distribution Customer</b> Distribution Customer Customer Services Customer Ancillary	Customers Customers Customers Customers	Customer Charge Customer Charge Customer Charge Customer Charge
<b>Margin</b>	Distribution Components	Distribution Components

*The four-part rate closely aligns cost recovery with how costs are incurred, but requires four billing units and greater complexity.*

### 3.5.1

#### VARIATIONS ON MULTI-PART RATE DESIGNS

##### 3.5.1.1 FOUR-PART RATE

A four-part rate design typically includes an appropriate demand charge for recovery of wholesale capacity related costs, an NCP demand charge for recovery of distribution delivery costs, a customer charge to recover customer related costs and an energy charge to recover the variable cost components (power supply energy related costs).

This rate is sometimes called “partially unbundled” because it prices distribution wires cost recovery separately from the wholesale power cost recovery. A member-consumer can identify potential savings from reducing or eliminating peak usage at the time of the power supplier’s peak. A member-consumer wanting to reduce their contribution to distribution wires cost would need to reduce usage in all intervals. If the cooperative and/or its power supplier offers Demand Side management rates or credits, this rate structure permits the cooperative to offer self-directed savings achieved from changes in patterns of usage.

A primary disadvantage of a four-part rate is added complexity of metering and meter reading. Not all cooperative AMI systems provide the data needed and not all billing systems can bill it. In addition, the rate is more complex, making it prone to misunderstandings.

A rate with a demand charge is sensitive to load factor, whereas a two-part rate is not. Transitioning to a multi-part rate will affect two customers with identical monthly energy use quite differently, if the two customers have different load factors.

*Example of a four-part rate:*

	Power Supply			Distribution		TOTAL
	Demand	Energy	Delivery	Demand	Customer	
Customer Charge	\$0.00	\$0.00	\$0.00	\$0.00	\$27.72	\$27.72
CP Demand Charge	\$11.65	\$0.00	\$3.68	\$0.00	\$0.00	\$15.33
NCP Demand Charge	\$0.00	\$0.00	\$0.00	\$3.38	\$0.00	\$3.38
Energy Charge	\$0.00000	\$0.03516	\$0.00000	\$0.00000	\$0.00000	\$0.03516

If the cooperative is not prepared to implement a four-part rate structure, the Team may wish to consider a three-part rate design.

### 3.5.1.2 THREE-PART RATE TO RECOVER FIXED DISTRIBUTION WIRES CAPACITY COST IN THE DEMAND CHARGE

One of the greatest concerns facing cooperatives with respect to rate design, is the recovery of its fixed distribution wires costs from member-consumers whose kWh energy sales have been reduced as a result of DER, energy efficiency or other measures. This rate structure is designed to recover only the fixed distribution wires cost in the demand charge. The capacity-related wholesale purchased power costs are recovered in the energy charge.

This rate design provides a clear price signal to member-consumers that fixed distribution wires costs are driven by the maximum load the distribution facilities must serve and cannot be avoided simply by shifting usage from one period of time to another. The primary advantage of this rate is that it helps ensure recovery of the cooperative's cost of providing wires service from all member-consumers fairly. The primary disadvantage of this type of rate is that it is difficult for a member-consumer to modify usage in such a way as to lower their retail billing. It is highly effective in allowing the cooperative recovery of its wires costs, even from member-consumers who dramatically lower usage because of DER, energy efficiency or conservation.

Cost Recovery and Rate Design  
Three Part Flat Rate - Wires Demand Only

Cost Components	Allocation Factor	Retail Rate Design
<b>Power Supply</b> Demand Energy	Power Supply CP Energy	Energy Energy
<b>Power Supply Delivery</b> Transmission Substation Ancillary – Demand Ancillary – Energy	Transmission CP Cooperative CP Cooperative CP Energy	Energy Energy Energy Energy
<b>Distribution Demand</b> Sub-Transmission/Substation Backbone Demand Distribution Demand	Cooperative CP Cooperative CP Cooperative NCP	NCP Demand NCP Demand NCP Demand
<b>Distribution Customer</b> Distribution Customer Customer Services Customer Ancillary	Customers Customers Customers Customers	Customer Charge Customer Charge Customer Charge Customer Charge
<b>Margin</b>	Distribution Components	Distribution Components

Example of a three-part rate –demand charge is only wires demand:

	Power Supply			Distribution		TOTAL
	Demand	Energy	Delivery	Demand	Customer	
Customer Charge	\$0.00	\$0.00	\$0.00	\$0.00	\$27.72	\$27.72
NCP Demand Charge	\$0.00	\$0.00	\$0.00	\$3.38	\$0.00	\$3.38
Energy Charge	\$0.03018	\$0.03516	\$0.00952	\$0.00000	\$0.00000	\$0.07486

There are many ways to design three-part rates

NCP Demand can be measured at the time of the member-consumer’s monthly peak or the higher of the member-consumer’s monthly peak, the highest measured peak in the previous 12 months or a contract amount.

3.5.1.3 THREE-PART RATE TO RECOVER WHOLESALe CAPACITY BILLING COST IN THE DEMAND CHARGE

There are many ways to design three-part rates. One of these is to align the retail rate with the wholesale cost drivers. This can be accomplished with a three-part rate design including a demand charge that recovers only the wholesale purchased power demand-related costs. The fixed distribution demand cost of providing service is typically recovered in the energy charge. A customer charge is also typically applicable.

This rate design does not focus on the recovery of the fixed distribution demand costs. With this rate design, a member-consumer reducing their energy consumption by installing DER will cause the cooperative’s revenue to be reduced without a corresponding reduction to the cooperative’s distribution demand cost of providing service.

The main advantage of this rate design is the price signal that allows member-consumers the ability to control their cost while at the same time reducing the cooperative's wholesale power costs

### Cost Recovery and Rate Design

#### Three Part Rate—Purchased Power Demand

Cost Components	Allocation Factor	Retail Rate Design
<b>Power Supply</b> Demand Energy	Power Supply CP Energy	CP Demand Energy
<b>Power Supply Delivery</b> Transmission Substation Ancillary – Demand Ancillary – Energy	Transmission CP Cooperative CP Cooperative CP Energy	CP Demand CP Demand CP Demand Energy
<b>Distribution Demand</b> Sub-Transmission/Substation Backbone Demand Distribution Demand	Cooperative CP Cooperative CP Cooperative NCP	Energy Energy Energy
<b>Distribution Customer</b> Distribution Customer Customer Services Customer Ancillary	Customers Customers Customers Customers	Customer Charge Customer Charge Customer Charge Customer Charge
<b>Margin</b>	Distribution Components	Distribution Components

The main advantage of this rate design is the price signal that allows member-consumers the ability to control their cost while at the same time reducing the cooperative's wholesale power costs.

*Example of a three-part rate - purchased power demand charge only:*

	Power Supply			Distribution		TOTAL
	Demand	Energy	Delivery	Demand	Customer	
Customer Charge	\$0.00	\$0.00	\$0.00	\$0.00	\$27.72	\$27.72
CP Demand Charge	\$11.65	\$0.00	\$3.68	\$0.00	\$0.00	\$15.33
Energy Charge	\$0.00000	\$0.03516	\$0.00000	\$0.02588	\$0.00000	\$0.06104

*This rate will provide a pricing signal to avoid power supplier peaks but is not effective at protecting recovery of the cooperative's own cost of providing wires service to the member-consumer.*

### 3.5.1.4 THREE-PART HYBRID RATE

If the Board desires to move toward the four-part rate but believes two different demand charges are too complex for a residential rate, the three-part hybrid rate might be instituted. In this rate design, the retail demand charge is intended to recover all of the fixed distribution demand cost of providing service plus a base portion of the purchased power demand related cost through an NCP demand charge. Any remaining unrecovered purchased power demand cost is recovered in the energy charge.

An advantage of this rate structure is that it is simpler than a four-part rate and most AMI systems can capture the necessary data required for billing. Using the NCP demand as the billing unit provides a secure means of recovering costs. Conversely, the primary disadvantage of this rate is that member-consumers are not easily able to avoid or reduce the NCP demand billing units. As a result, this rate design does not lend itself to peak load management applications.

While not shown in the example, it is possible to design this rate with a CP demand charge that includes both recovery of purchased power capacity costs and all or a portion of distribution demand cost of service. However, including distribution demand costs in a CP demand charge introduces a significant measure of risk. To the extent that a member-consumer is able to avoid or reduce its CP demand billing units, the cooperative will not receive a full recovery of the distribution demand costs.

*Example of a three-part hybrid rate— recover purchased power demand costs and capacity-related distribution wires costs in a demand charge:*

	Power Supply			Distribution		TOTAL
	Demand	Energy	Delivery	Demand	Customer	
Customer Charge	\$0.00	\$0.00	\$0.00	\$0.00	\$27.72	\$27.72
NCP Demand Charge	\$2.37	\$0.00	\$0.75	\$3.38	\$0.00	\$6.50
Energy Charge	\$0.01205	\$0.03516	\$0.00379	\$0.00000	\$0.00000	\$0.05100

*Example of an hours-use three-part rate:*

	Power Supply			Distribution		TOTAL
	Demand	Energy	Delivery	Demand	Customer	
Customer Charge	\$0.00	\$0.00	\$0.00	\$0.00	\$27.72	\$27.72
NCP Demand Charge	\$0.00	\$0.00	\$0.00	\$3.38	\$0.00	\$3.38
First 200 kWh/NCP kW	\$0.04191	\$0.03516	\$0.01323	\$0.00000	\$0.00000	\$0.09030
Next 200 kWh/NCP kW	\$0.02434	\$0.03516	\$0.00768	\$0.00000	\$0.00000	\$0.06718
Over 200 kWh/NCP kW	\$0.00000	\$0.03516	\$0.00000	\$0.00000	\$0.00000	\$0.03516
Embedded Demand (if over 400 kWh/kW)	\$13.25		\$4.18			\$17.43

When accompanied by a well-designed member-consumer education program, the multi-part rate can provide an effective method for recovery of costs and providing the member-consumer with the appropriate pricing signals

3.5.1.5 HOURS-OF USE THREE-PART RATE

Another means of moving toward a four-part rate without multiple demand charges is the hours-use rate. It is a variation of the three-part hybrid rate and has been used in large power and irrigation rates for years. The NCP demand charge in this rate recovers only the distribution demand cost of providing service. The rate recovers the purchased power capacity-related cost in energy rate blocks based on the monthly NCP demand. With the wholesale demand component embedded in the hours use energy blocks, the cost recovery is based on load factor. The assumption is that member-consumers with higher load factors are more likely to be operating at times of the purchased power peaks. Since the rate embeds demand within the blocks, member-consumers reaching the bottom block are paying a much higher equivalent demand charge. The rate does not impose a higher demand charge on member-consumers with poor load factors.

While the rate is less complex than the four-part rate, care should be taken to ensure that member-consumers understand how the rate works.

The Team should be generally aware that multi-part rates are possible and design them to meet their rate criteria.

3.5.1.6 SUMMARY – FOUR-PART AND THREE-PART RATES

Historically, multi-part rates were limited to large power and industrial member-consumers. The cost of demand meters and special meter reading requirements limited their widespread application. Reductions in AMI and meter reading costs, as well as the need to address concerns related to lost fixed cost recovery, are leading many cooperatives to consider application of these rate designs to other rate classes. Multi-part rates are somewhat more complex. However, when accompanied by a well-designed member-consumer education program, the multi-part rate can provide an effective method for recovery of costs and provide the member-consumer with the appropriate pricing signals.

PROS	CONS
Decoupled rate structure strongly tied to how costs are incurred	More complex
Can provide a strong pricing signal for member-consumer to reduce overall peak demand and thus contribute to a reduction in distribution demand costs	More complicated to administer
Can provide a strong pricing signal for member-consumer to reduce demand contribution at the time of the purchased power capacity peak to reduce purchased power capacity costs	No strong historical background for residential and small commercial
History of use for large commercial and industrial member-consumers	Requires advanced metering and bill processing
Greater margin stability, particularly during periods of kWh reductions	Less likely to be used by neighboring utility systems
	Not always favored by regulators
	More education and communication required

3.6

Other Rate Designs

3.6.1

DEMAND PROXY

Three-part rates provide cooperatives a specific billing mechanism for recovery of demand costs of providing service. However, not all cooperatives desire to or are able to bill three-part rates for all rate classes. Some cooperatives do not have the necessary metering while others feel that using a proxy is easier to understand than an actual three-part rate. The proxy may include:

- **Transformer Size**—some cooperatives include either a monthly fixed or monthly kVA charge based on installed transformer size. This permits a demand related billing component without the requirement for monthly demand readings. A secondary advantage is that the member-consumer has a disincentive to request an over-sized transformer. A main disadvantage is the transformer must be sized to the member-consumer’s load and a means must be developed to deal with situations where multiple meters are connected to a transformer bank.
- **Service Size**—the service entrance size (100 amp, 200 amp, etc.) is used to determine a customer or capacity charge. This can also discourage oversizing.

DEMAND PROXY RATE

Used where a desired demand billing value is either not available or where the cooperative does not desire to implement a demand charge with revenue that may well vary by month across the year.

Some cooperatives find it easier to explain a capacity-related cost based on transformer size as opposed to explaining kW and the concept of capacity.

- **Demand-Based Customer Charges**—the utility measures the peak demand over some period of time for each member-consumer. The member-consumer is billed monthly based on the highest demand, but not with a demand charge. This could be a customer or fixed capacity charge.
- **Horsepower Charges**—the utility records the installed or operating horsepower for each member-consumer. The member-consumer is billed either monthly or seasonally based upon the installation’s motor size. This could be a customer or fixed capacity charge.

*Example of a proxy demand charge - billed as a fixed monthly customer charge:*

Amp Service	Customer Charge per month
100 Amp Service or Up to 10 kVA or Up to 10 kW	\$10.00
200 Amp Service or 10 kVA – 25 kVA or 10 kW – 30 kW	\$20.00
400 Amp Service or 25 kVA – 50 kVA or 30 kW – 60 kW	\$35.00
Over	\$50.00



Time-based rates provide the member-consumer the ability to control their own billing by reducing usage during peak periods or by shifting usage from peak periods to non-peak period

3.6.2

TIME-BASED RATE OPTIONS

The primary goal of a time-based rate design is to provide a pricing signal to member-consumers that reflects the relative cost of power from one time period as compared to another. Since the majority of the distribution cooperative’s delivery costs are fixed, the focus of time-based rate designs is the time related cost differences in the wholesale purchased power cost. Time-based rates provide the member-consumer the ability to control their own billing by reducing usage during peak periods or by shifting usage from peak periods to non-peak periods.

TIME-BASED RATES

Rates used to identify differences in power cost related to time periods. They are most often offered as an optional rate, though some utilities offer only time-based rates.

The on and off peak periods can be based on a power supplier’s peak periods or on periods of time when the utility is historically most likely to peak.

3.6.2.1 TIME OF USE (TOU) ENERGY RATE

A time of use energy rate is typically designed with pricing for energy consumption based on different time periods. Those time periods typically include an on-peak period and an off-peak period. Other periods can also be included to reflect critical peak, shoulder peak, or other relevant time periods.

The purpose of the rate is to reflect the relative underlying differences in costs associated with the different time periods. A time of use energy rate is typically applied to those rate classes where demand charges are not utilized.

Time of Use Energy rates are easiest to design when the wholesale power supplier has defined on- and off-peak periods with different energy charges during each time period. If this is the case, the distribution cooperative can mirror the wholesale time periods and differences in the retail rate.

Cost Recovery and Rate Design  
Time of Use Energy

Cost Components	Allocation Factor	Retail Rate Design
<b>Power Supply</b> Demand Energy	Power Supply CP Energy	Energy – On peak Energy
<b>Power Supply Delivery</b> Transmission Substation Ancillary – Demand Ancillary – Energy	Transmission CP Cooperative CP Cooperative CP Energy	Energy – On peak Energy – On peak Energy – On peak Energy – On peak
<b>Distribution Demand</b> Sub-Transmission/Substation Backbone Demand Distribution Demand	Cooperative CP Cooperative CP Cooperative NCP	Energy Energy Energy
<b>Distribution Customer</b> Distribution Customer Customer Services Customer Ancillary	Customers Customers Customers Customers	Customer Charge Customer Charge Customer Charge Customer Charge
<b>Margin</b>	Distribution Components	Distribution Components



A time-of-use rate design with long periods of on-peak pricing or that lack a meaningful pricing difference between the on and off peak periods might result in little to no participation

A more significant challenge is faced when the cooperative is determining how to best recover wholesale generation and delivery capacity-related costs through time-of-use energy rates. The distribution cooperative should carefully review the wholesale rate to identify, not just the magnitude of the capacity cost being billed, but how that cost is billed. The power supplier may be measuring billing demand units only during peak periods, which might only occur in a particular window of time or a particular season of the year. This will help the retail cooperative determine retail on- and off-peak windows for consideration.

The cooperative Team should also consider how the rate will be used by the member-consumer. Generally speaking, the greater the difference between the on- and off-peak energy charges, the more likely that member-consumers will respond by reducing peak consumption. A time-of-use rate design with long periods of on-peak pricing or that lack a meaningful pricing difference between the on and off peak periods might result in little to no participation. The cooperative in this case may wish to base the on-peak window on a narrower period of time in which peaks have historically most often occurred, even if this does not include all of the possible peak periods.

The Team should also consider whether the on and off peak time periods and charges should change based on season, and should include holidays and weekends. Changing member-consumer demographics and consumption patterns have caused the peaking periods for many cooperatives to change over time. The application of the time-based rate structure itself can result in a change in member-consumer consumption patterns and result in a change in peak loading patterns. Schedules C-1.0 and C-2.0 show example peak day load profiles for July and January, respectively.

Finally, it is important for the Team to understand that a strictly energy based TOU rate may have far less effect on reducing peak purchased power cost than some other rates, particularly those including demand charges. For example, a residential member-consumer responding to an energy-only TOU rate might reduce energy consumption significantly in summer months by modifying thermostat settings. However, at the same interval that determines the wholesale purchased power demand billing, the member-consumer's HVAC system could still be running. While the time-of-use energy rate provides a price signal, it is not as effective as a time-of-use demand based rate in recovery of capacity related costs.

In most cases, the on-peak *energy charge is related to recovery of purchased power capacity* costs. But this is not always the case. Note in the example below that in this case, the cooperative has identified its own capacity-related distribution wires cost of providing service. The cooperative Team determined that for it, the peak time periods for its internal needs match-up well with purchased power peak periods. So, in this particular case, in addition to weighting the on-peak energy charges, the Standard Electric Team have decided to recover its own capacity-related distribution wires cost through on-peak energy charges instead of all energy charges.

Example of a Time of Use Energy Rate:

	Power Supply			Distribution		TOTAL
	Demand	Energy	Delivery	Demand	Customer	
Customer Charge	\$0.00	\$0.00	\$0.00	\$0.00	\$27.72	\$27.72
kWH On-Peak	\$0.10059	\$0.03516	\$0.03175	\$0.04960	\$0.00000	\$0.21710
kWH Off-Peak	\$0.00000	\$0.03516	\$0.00000	\$0.01571	\$0.00000	\$0.05087

Energy only time-of-use rates are widely used and provide a mechanism by which the cooperative can provide its member-consumers a price signal that certain costs vary based on the time period of consumption.

*Mid-Carolina Electric Cooperative (MCEC) is a South Carolina cooperative serving 45,000 meters spread over 4,100 square miles. MCEC developed and implemented a three part rate with on-peak capacity charges to ensure collection of fixed costs through non-volumetric billing units. The cooperative balanced establishing a peak window wide enough to reflect peak periods versus the need to keep windows narrow enough that member-consumers would participate in the program. In addition, MCEC measured the impact of the rates on each individual within each rate class and determined some within each rate class had greater negative impact from the rate change—resulting in modifications in rates to mitigate those impacts. Education was key, both in advance of implementation of the rates and continuing over time. Click [here](#) for more information.*

PROS

Provides a price signal that power costs vary in different time periods

Allows member-consumers the ability to actively engage in controlling their bill

Easy to understand

Common rate design that is widely used by many utilities

Track record of regulatory approval

CONS

Design of an effective energy only TOU rate is dependent on price signal in the wholesale rate to the cooperative

Recovery of wholesale peak demand costs less certain than a demand-based TOU rate

Depending on the cooperative’s AMI technology, changes in on- and off-peak periods may require programming changes to meters

3.6.2.2 TIME-OF-USE DEMAND RATE

A TOU demand rate is a standard three- or four-part rate with on- and off-peak energy charges and a demand charge for the recovery of demand related costs. The demand charge may be either based on an NCP demand billing unit or on a CP demand billing unit. A CP demand charge would provide an additional time-based price signal for the recovery of power supply capacity costs.

For more discussion on the differences between CP and NCP demand, see Volume II, Sections 3 and 4.

The time-of-use demand rate with an NCP demand billing unit recovers the fixed distribution demand costs in the demand charge. The time based cost differences in the wholesale purchased power cost are reflected in the on and off peak energy charges. This provides greater stability for the recovery of distribution demand costs. The on and off peak energy charges should provide some measure of the price signal in the wholesale power supplier’s rate. With this rate option, member-consumers have the ability to reduce their billing by managing their consumption while also reducing the cooperative’s costs.

*Example of a three-part time of use rate – with NCP demand billing:*

	Power Supply			Distribution		TOTAL
	Demand	Energy	Delivery	Demand	Customer	
Customer Charge	\$0.00	\$0.00	\$0.00	\$0.00	\$27.72	\$27.72
NCP Demand Charge	\$0.00	\$0.00	\$0.00	\$3.38	\$0.00	\$3.38
kWH On-Peak	\$0.10059	\$0.03516	\$0.03175	\$0.00000	\$0.00000	\$0.16750
kWH Off-Peak	\$0.00000	\$0.03516	\$0.00000	\$0.00000	\$0.00000	\$0.03516

A time-of-use rate with a NCP demand billing unit is not intended to provide recovery of the wholesale demand related costs in the demand charge. The NCP demand billing unit is intended to reflect the member-consumer’s contribution to distribution wires demand cost. The purchased power demand costs are recovered through the on peak energy charge and, to the extent the member-consumer can avoid energy usage during the time period in which the wholesale power supply demand costs are determined, the member-consumer will reduce their billing.

As is the case with all TOU rates, this rate must be structured reflecting the embedded cost and structure of the wholesale purchased power rates. TOU rates can also be designed with CP demand billing units included – but this is essentially either the four-part rate or the three-part rate with CP demand.

Time-of-use demand rates provide stronger pricing signals related to the recovery of demand related costs than do energy only TOU rates

Member-consumers have high potential for savings if they can respond to market pricing signals but are assuming far more market risk given that the power cost might vary enormously based on the market price at any given time

### 3.6.2.3 REAL-TIME PRICING AND PARTIAL REAL-TIME PRICING

Real-Time Pricing provides member-consumers pricing during intervals or blocks of time during the year. It can be simply a rate that bills the market prices, or a program that allows member-consumers access to the market in some way. Or it may be a more complex version of a TOU rate, recognizing likely market prices for time intervals across the year. Member-consumers have high potential for savings if they can respond to market pricing signals but are assuming far more market risk given that the power cost might vary enormously based on the market price at any given time. Before considering this approach, the cooperative Team should fully understand the capabilities of their AMI system.

The cooperative also needs to know whether it has the ability to give member-consumers access to the market in this way. Some cooperative power supply contracts obligate them to purchase power for all of their member-consumers under a single wholesale rate. Other contracts permit the retail member-consumer to have access to market prices, but the power supplier must make the market purchase on behalf of the member-consumer system and end-use member-consumer.

The technological, billing and contractual requirements are the reasons why real-time pricing, even when offered, is often limited to large power or industrial member-consumers. The cost of administering the program has been generally prohibitive to offer to smaller member-consumers. But modern technology is breaking down this barrier and more and more cooperatives are considering offering customer choice on a “sell through” or “virtual” customer choice option.

### REAL-TIME PRICING RATES

Rates that allow access in some manner to potential market pricing savings and to the risk of potential market costs.

Can be direct access or the cooperative may simply offer a more complex TOU rate based on anticipated market pricing at different time intervals

If the cooperative Team is considering offering real-time pricing to residential member-consumers, it should be sure that it has all facilities and technology in place now.

One approach would be for the Team to consider a hybrid of real-time pricing and TOU. This approach requires the cooperative to review the average costs of market purchases at different intervals during the year. A more complex version of the TOU rate can then be developed with a variety of peak blocks that serve as a proxy for real-time pricing. This type of dynamic pricing must be continually monitored to ensure that the components of the rate are reflective of the market prices.

*Example of a hybrid TOU-RTP rate:*

	Power Supply			Distribution		TOTAL
	Demand	Energy	Delivery	Demand	Customer	
Customer Charge	\$0.00	\$0.00	\$0.00	\$0.00	\$27.72	\$27.72
Energy Charge-Summer (June-Sept)						
kWH Critical Peak	\$0.53472	\$0.03516	\$0.16877	\$0.02588	\$0.00000	\$0.76453
kWH High Peak	\$0.07130	\$0.03516	\$0.02250	\$0.02588	\$0.00000	\$0.15484
kWH Medium Peak	\$0.00713	\$0.03516	\$0.00225	\$0.02588	\$0.00000	\$0.07042
kWH Off Peak	\$0.00000	\$0.03516	\$0.00000	\$0.02588	\$0.00000	\$0.06104
Energy Charge Shoulder (April, May, Oct)						
kWH High Peak	\$0.07130	\$0.03516	\$0.02250	\$0.02588	\$0.00000	\$0.15484
kWH Off Peak	\$0.00000	\$0.03516	\$0.00000	\$0.02588	\$0.00000	\$0.06104
Energy Charge-Winter (November-March)						
kWH Critical Peak	\$0.26736	\$0.03516	\$0.08438	\$0.02588	\$0.00000	\$0.41278
kWH High Peak	\$0.07130	\$0.03516	\$0.02250	\$0.02588	\$0.00000	\$0.15484
kWH Medium Peak	\$0.00713	\$0.03516	\$0.00225	\$0.02588	\$0.00000	\$0.07042
kWH Off Peak	\$0.00000	\$0.03516	\$0.00000	\$0.02588	\$0.00000	\$0.06104

Real-time pricing rate programs offer member-consumers access to market pricing. The member-consumer is provided a greater degree of choice and information with regard to price, but also assumes more risk.

## PROS

More accurate tracking of wholesale power costs

Provides significant opportunity for savings by the member-consumer

Minimum risk to the cooperative, allowing lower rates

Likely large power member-consumers requesting this rate will be well versed in its application

## CONS

Complex structure to administer

May not be permitted by regulators and by wholesale power purchase agreements

Requires advanced AMI, communications and billing systems

Member-consumers must be highly educated in how market prices work

### 3.6.2.4 LOAD CONTROL / DEMAND SIDE MANAGEMENT (DSM)

For purposes of this document, renewable programs will be treated separately in Section 3.

While DSM and TOU are sometimes thought of as similar rates, they are quite different. Traditional TOU rates, even those with demand components, are based on peak blocks of time during which power is more costly. This is often reflected in wholesale market pricing. Typically, load control or DSM rates are a response to wholesale rate structures or market prices and must be individually tailored.

For example, the cooperative may have a CP demand or other capacity pricing signals in their wholesale rate encouraging them to reduce or shift usage, at a single interval of time. Or the wholesale rate may be focused on the individual member-consumer system peak. The general approach to this rate will be to avoid individual peak usage at peak times.

For years, some cooperatives have offered a demand side management (DSM) rate for many rate classes. The purpose of this rate is typically to provide an incentive to encourage reductions in peak demand or to directly control member-consumer load in order to reduce demand during peak periods. A sample of these programs include:

#### RESIDENTIAL

- Air Conditioning Control
- Water Heater Control
- Three or Four-part Rates
- Incentives to Control Pool Pumps
- Peak Shaver Rates/ Notice

#### COMMERCIAL

- Irrigation Control
- Industrial Curtailable Rates
- Dairy/Commercial Curtailable/DER Rates
- Unbundled/RTP Rates
- Buy-Through/Market Rates

Programs of this type may be divided into two categories. There are programs organized and administered by the power supplier and programs organized and administered by the distribution cooperative. In both cases the intent is to reduce load. The customer removes load either to reduce

capacity during all peak periods or only when requested to do so to avoid critical peaks, to provide system security, and/or at times of high market or system pricing.

A reduction in capacity load should ideally result in corresponding reductions in wholesale costs of operations or in the cost of future capacity additions.

When the program is administered by the power supplier, the distribution system receives either a benefit related to reductions in billing under a standard wholesale rate, credits, or other benefits provided by the power supplier for program participation. These credits might reflect the total benefit to be derived by the power supplier or a portion of the benefit, with the remainder of the benefits flowing through to all member-consumer systems. The distribution cooperative can themselves offer some type of DSM program or rate that transfers this benefit to participating member-consumers.

The alternative is for the distribution cooperative to offer a DSM program on its own, basing its program on the wholesale rate for purchased power, or looking through the wholesale rate to wholesale cost.

The value of DSM to the wholesale supplier is not always perfectly aligned with the value of DSM communicated through the wholesale rate structure. This can result in potential issues with distribution load control rates that are not administered by the wholesale supplier. One wholesale customer could devise a DSM rate that, while fully reflecting wholesale costs, shifts a portion of their cost recovery to the other wholesale customers.

### LOAD CONTROL & DSM

Rates that pass through power cost savings to member-consumers willing and able to either replace peak load with self-generation, reduce peak load with conservation, or relocate peak load to other non-peak time periods.



It should be noted again that these issues are strongly related to the structure of the wholesale rate and billing units. The DSM program being considered by any distribution cooperative will be individually tailored by the Team to reflect how the cooperative incurs generation capacity costs.

Some cooperatives and regulators include consideration of the member-consumer's investment to participate in any program. When the investment is high, some would consider that the program is regressive. The cooperative must use care that its DSM does not result in cost recovery being shifted to other of its own member-consumers without corresponding reductions in costs. It is important for the Team to determine the rate criteria result it desires from any TOU or DSM rate.

Does it wish to encourage reductions of peak demand usage only during peak intervals based on a wholesale rate? If so, a DSM rate is more likely to accomplish this task.

Does it wish to encourage generally lower usage across a block of time, reflecting market pricing and/or their wholesale rate? If so, a TOU rate might be better.

Does it wish to simply provide information related to costs and allow member-consumers to select how they can participate? If so, a Four-part rate with on- and off-peak energy charges might be highly effective assuming member-consumers understand the rate.

To illustrate how different rate designs affect member-consumers with different usage characteristics, seven of the rate designs were compared. The following graph shows how the billing is similar for the class average member-consumer. All of the rate designs being shown generate the same total billing for the Standard Electric residential rate class as a whole. But the impact on individual member-consumers can be quite different, depending on individual usage. Please note, however, that for member-consumers with class average usage, the impact is similar under all rate options.

## OFFERING OPTIONAL RATES

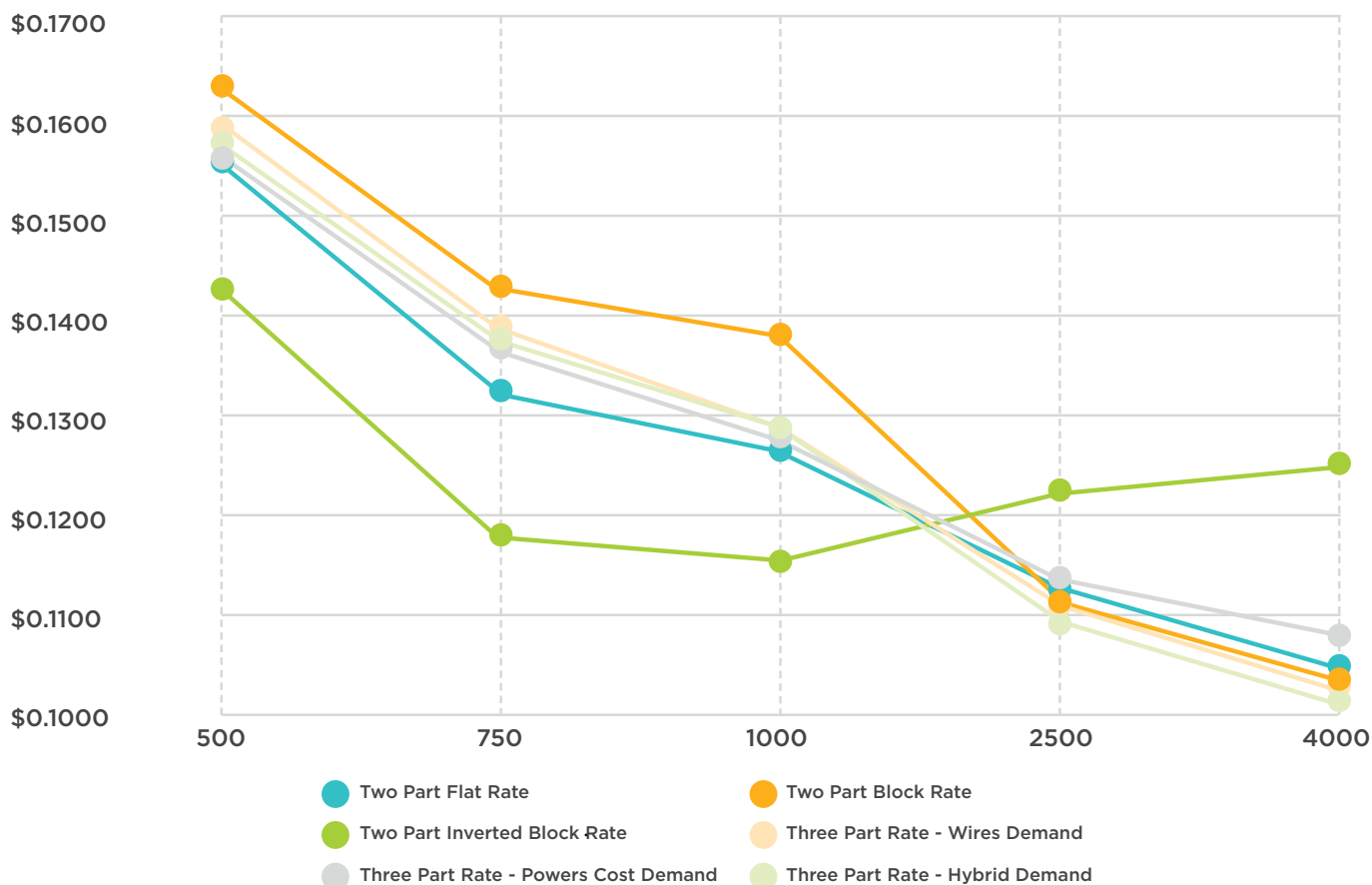
One of the key rate philosophies for the Board to consider is related to providing member-consumers with choices. Many cooperatives have done so for years, offering for example a standard two-part rate, a TOU rate, and a three-part rate. The member-consumer is permitted to select the option they prefer.

The Team must be careful any time it offers multiple rates and allows member-consumer choice. They must assume over time that member-consumers will migrate toward the cheapest and best option. The cooperative might consider calculating billing under each rate option for each member-consumer in order to determine the impact on cooperative revenues as member-consumers ultimately make this choice. Rates may need to be tweaked to ensure the cooperative will receive its revenue requirement once member-consumers have migrated to their best billing option.

The cooperative will also want to ensure that member-consumers understand who is responsible for making the rate choice. Is the cooperative responsible? If so, what happens if at the end of the year, the choice was not the lowest cost option?

The cooperative must also establish how long the customer is obligated to the choice, as well as penalties for changing the choice outside the offered term.

\$ PER KWH



### 3.6.2.5 THERMAL STORAGE RATES

Thermal storage rate offerings are a subset of TOU rates. They are designed to work with member-owned devices that store heat or cold. When coupled with a TOU-type rate, the member-consumer can realize cost savings by storing heat or cold during off-peak periods and using it during peak periods. Cooperative margins are not reduced because the rate passes peak capacity savings to the member-consumer.

This program may be operated with credits provided to member-consumers who participate. However, a highly effective means is to simply offer a TOU rate coupled with the program. This works when wholesale rates provide a demand or energy based on- and off-peak pricing signal and when the cooperative's on-peak windows are narrow enough to permit the member-consumer to have sufficient thermal storage to last through the on-peak periods.

## 3.7

### Large Power and Industrial Rates

The majority of distribution cooperative member-consumers are residential and small commercial. As a result, the majority of this document has been focused on residential rates. For many cooperatives, rates for large power member-consumers have historically been based on three-part rate structures. Other rate design options for unique industrial loads should also be considered.



### 3.7.1

#### COST-BASED INDUSTRIAL RATES

Cooperatives often address large Industrial rates on a case-by-case basis. This is in part because the typical rural distribution cooperative serves few of these member-consumers. Large loads may, however, contribute a disproportionate share of total revenue to the cooperative. Since their service delivery level may be at substation or even transmission level, they also require individual consideration when allocating costs.

During the development of the COSS, the Team should carefully consider each industrial member-consumer to determine that they are accurately identifying all the costs associated with providing service. This is important to ensure the cooperative is correctly allocating costs. In many cases, there might be relatively little in the way of distribution cooperative facilities in place to serve these member-consumers. But the industrial member-consumer may incur a substantial percentage of total purchased power cost for the cooperative. In any case, the particulars of any one industrial member-consumer might be quite different and help explain why the cooperative Team might individually allocate costs, determine a desired margin and design individual retail rates for each such member-consumer. Only when the cooperative is fortunate enough to have multiple industrial member-consumers at different service levels is there a need for the development of traditional tariff-based rates for an industrial rate class.

The Team should consider designing their retail rates in such a way that they are certain to recover the full cost of providing service from the industrial member-consumer. This is generally accomplished by designing a “cost plus” retail rate. Specific costs including any wholesale ratchets, demand roll-ins and facilities costs recovered over time should be included in the rate.

In particular, with new and potential loads, the cooperative Team must consider how much risk it wishes to assume in providing service. Utilities are often looked to by economic development groups to provide incentives when recruiting large industrial entities. Any cost not fully passed on by the cooperative to the industrial member-consumer, such as an incentive or a facilities allowance in excess of what rates will support, should be considered as an investment made by the cooperative and its member-owners in the business. The Team might ask itself if it would make a similar investment in some other venture with similar risks using member-consumer resources should the opportunity arise. In the event of a large industrial member-consumer bankruptcy, the impact on the cooperative could be substantial due to unrecoverable power cost billing alone. The retail rate developed should either include a margin component for risk or be structured in such a way that the cooperative has little risk from the project. Some cooperatives manage risk by requiring deposits, payment by electronic fund transfer, immediate due date, surety bond, or letter of credit.

An alternative for providing new service to a large industrial member-consumer, and in particular one requiring significant investment by either the wholesale supplier or the distribution cooperative, is to require a Contribution in Aid of Construction (“CIAC”). The monthly rate would then consist of a flow through of wholesale power cost, O&M, taxes, allocated A&G, and a margin component. Because there is no investment, the margin component would not be based on ROR, TIER or DSC. An alternative is to mirror the manner in which capital credits are allocated. If a CIAC is not possible, the other alternative is to have a capital cost component on an accrual basis (depreciation + interest) or cash basis (debt service) and to match the amortization of the debt to the contract term. With either approach it will be necessary to make certain there is an agreement on how renewals and replacements will be financed, particularly if there should be a major failure.

Creating rates for these loads can be particularly challenging

### 3.7.2

#### SEASONAL RESIDENTIAL AND SEASONAL AGRICULTURAL

Some cooperatives serve seasonal loads related to the agricultural industry. These loads might include irrigation, dairy facilities, grain dryers or elevators, seasonal agricultural processing, catfish or chicken operations, and cotton gins. For these member-consumers, the Team must consider that the cooperative maintained distribution facilities are in place year round, though the member-consumer may only use the facilities for a portion of the year. Another similar type of load is related to resort homes, hunting cabins or winter homes or other seasonal residences. Again, cooperative facilities are in place for the full year though usage is only intermittent or seasonal.

Creating rates for these loads can be particularly challenging. This is especially true when the period of time in which the load operates is likely to occur when the cooperative establishes a peak demand which the power supplier applies year-round. In these cases, depending on the structure of the wholesale rate, the cooperative may be incurring monthly demand charges all year while the seasonal member-consumer is only purchasing power for a portion of the year.

There are three main areas of consideration for the Team with rate structures of this type:

- Recovering the wires cost of serving the member-consumer.
- Recovering the purchased power capacity cost.
- Recognizing the seasonal benefits of some member-consumers.

For residential member-consumers, the cooperative needs to ensure that its rates and terms and conditions of service do not encourage them to disconnect then reconnect a single service from year-to-year in order to avoid monthly charges. Since the member-consumer has facilities in place all year but is only paying for those facilities for a portion of the year, the cooperative Team may elect to recover its year-round cost of serving the member-consumer in an annual charge based on demand, installed horsepower, installed transformer kVA or another demand-based factor or with a demand ratchet. The customer charge may also be included or converted into an annual charge.

If the cooperative's power supplier includes a demand charge in all months affected by the member-consumer, the cooperative might consider adding to the horsepower or other aforementioned charges a sufficient amount to permit recovery of ratcheted power supply capacity-related costs created by the member-consumer.

Some member-consumers may benefit the cooperative due to their seasonal nature. For example, if the cooperative serves seasonal cotton gin loads whose usage generally occurs outside of the cooperative's power supply capacity window, this might benefit the cooperative. Or, if agricultural processing load occurs following the crop irrigation season and outside of the power supplier's peak window, it would be a complementary load. The cooperative Team must be careful to allocate costs based on an understanding of how this type of load functions in the cooperative's region.

## **3.8**

### **Lighting Rates**

Lighting rates vary by cooperative. Some cooperatives do not offer lighting to member-consumers while others offer metered lighting, non-metered lighting or both. Street lighting, signal lighting, sign lighting, decorative lighting and many, many other lighting types are designed to meet the particular needs of individual cooperative systems. Today, most cooperatives are offering LED lighting of various types and sizes. They may continue to offer legacy mercury vapor, high pressure sodium or metal halide lighting fixtures. Some cooperatives have implemented plans to completely replace legacy lighting with comparable LED lighting.

#### **3.8.1**

##### **RECOVERING POWER COST FROM LIGHTING**

The cooperative Team should consider both the wholesale energy and capacity costs when allocating power cost to lighting equipment. Energy for lighting can either be metered or estimated based on average lighting consumption for unmetered fixtures of a given size. Purchased power capacity cost can be determined effectively if the Team identifies the time of the power supplier's peak for each month of the year to determine if the peak period occurs during daylight or night hours.

It is crucially important to understand the structure of the wholesale rate design. If the power supplier has little to no capacity-related component in the wholesale rate design, lighting is no more or less costly to obtain power supply for than any other load. If, on the other hand, the power supplier provides a strong seasonal pricing signal based on peak summer load, and if the summer power supply peak occurs during daylight hours, the lighting power supply cost is mostly wholesale energy with little or no added capacity related costs.

Some cooperatives charge lighting member-consumers for changes in power/fuel cost while others do not. The safest and fairest approach is to charge lighting member-consumers for changes in power/fuel cost in the same manner as all other rate classes.

#### **3.8.2**

##### **DETERMINING THE WIRES COST OF PROVIDING SERVICE FOR LIGHTING**

Cooperative records show the cost of providing service for lighting member-consumers. Many cooperatives have found, however, that their costs may be understated. This is generally due to maintenance and operations costs not separately recorded by service crews. This should be considered by the cooperative Team when evaluating the performance of the lighting rate class as shown in the COSS (see Volume II, Appendix Schedule F-1.0) and in determining an ultimate retail rate.

For new lighting types and sizes, the Team can determine costs based on a number of factors including the initial cost of the equipment, estimated on-going maintenance costs, and average usage compared to other lights producing the same lumens.

#### **3.8.3**

##### **DETERMINING LIGHTING RATES**

The cooperative Team needs to determine an appropriate margin from lighting service. While lighting member-consumers should be treated fairly and equitably as all other member-consumers, it should be noted that outdoor lights are more of an optional service. In the early days of cooperative history, many promoted outdoor lighting to increase electric sales. Today, most lighting service is offered to provide security.

### 3.9

#### Service Charge Revenue and Adjustment Revenue

In this context, the term “Service Charge” refers to charges for services and not the monthly fixed charge sometimes labeled “Service Charge” by some cooperative tariffs.

While the focus of the Rate Guide has been on retail rate design, many cooperatives derive material revenue from service charges such as late fees, collection fees, connect and disconnect fees, meter reading fees, and service call fees. Revenue collected from these and other fees to recover associated costs do not have to be collected through retail rates being charged to member-consumers. There are several items for the Team to consider during the retail rate proceeding.

Even in states where retail rates are not regulated by the state, there may be regulatory requirements related to service charges. For example, the percentage late fee may be limited by law or regulation. Service conditions during which disconnects can occur may also be regulated. The Team should consider these issues during consideration of service charge changes.

AMI systems with remote connect and disconnect capabilities may affect the service charge revenues. The cooperative might consider differences in connect or account initiation fees between member-consumers who may be remotely connected and those who cannot.

Prepaid metering may significantly affect revenues associated with late fees and disconnect/reconnect fees. Collection of fee revenue and security deposits may be mostly eliminated. Of course, costs will be reduced in both cases as well.

#### “OTHER” REVENUE

The focus of much of the rate design is the base rate and base rate revenue. But another portion of the potential charges to member-consumers and the potential revenue for the cooperative is “Other Revenue.” There can be any number of sources of this type of revenue, but the most common are based on two types: Service charges and adjustment revenue.

Service charges are things like returned check charges, collections fees, connection fees, late payment charges, wheeling revenue, etc.

Adjustment revenue is based on revenue from a number of different types of factors the cooperative could employ to maintain its revenue stability. Examples of this would be power cost adjustment, debt cost adjustment, margin stabilization, renewable energy adjustment, etc.

As part of the COSS, the team should consider each of these adjustment factors and determine 1) should the rate “re-set” the factors close to zero, 2) are any of the historical factors no longer meeting needs and 3) should the Team consider adding new factors.

#### 3.9.1

##### ADJUSTMENT REVENUE

In addition to the base tariff charges many cooperatives apply a factor or factors to recover costs that change frequently. For example, a distribution cooperative might obtain its power cost from a wholesale power supplier whose wholesale rate includes fuel cost components which may change monthly. Some cooperatives have factors to recover costs associated with renewable energy or energy efficiency programs. Some have a debt cost adjustment factor, property tax adjustment factor, storm hardening cost recovery factors, or a margin stabilization factor, among many other possible programs.



Most factors recover costs through energy charges. Calculating and implementing demand factors is more complex. While energy factors predominate, they may cause an issue over time.

For example, a power cost recovery factor based on total cost of power recovers changes in both energy and demand charges. Assuming base rates were perfectly aligned with costs at a point in time, as the factor grows, increasing wholesale demand charges will be recovered through the energy adjustment being applied.

The cooperative may consider a maximum level it will allow any factor to reach before revising rate designs. Otherwise, rates will become increasingly less tied to costs over time.

### 3.9.2

#### FUEL AND PURCHASED POWER COST ADJUSTMENTS

The most common type of adjustment factor is intended to recover changes in the cost of purchased power. In some states, this factor is prohibited or not implemented by all cooperatives. In others, cost recovery is limited to either changes in fuel cost or changes in volumetric charges. In others, the factor recovers changes in the total cost of purchased power.

Depending on the cooperative and state, the factor may be called Fuel Cost Adjustment, Purchased Power Cost Recovery, Power Cost Adjustment, Power Cost Recovery Factor, Wholesale Power Cost Recovery, or any number of similar titles. It is typically calculated in one of two ways. The cost of purchased power is divided by the kWh sold, and a base cost of purchased power per kWh sold is subtracted from the resulting cost of power per kWh sold to produce a factor. Or the cost of purchased power is divided by the kWh purchased and a base cost of purchased power per kWh purchased is subtracted from the resulting cost of power per kWh purchased, and the resulting factor is corrected for losses to bring it to the sales level. The Team must be careful to understand how their factor works to avoid over- or under-collection related to incorrectly applying losses to the factor calculation.

#### RE-BASING ADJUSTMENTS

Adjustment factors over time tend to recover costs through energy charges. For this reason, as the factors become larger, stated rates become increasingly distant from total cost the member-consumer pays.

Many cooperatives consider (or are required to do so by regulation) “re-basing” rates. This involves moving the current factor amount into the base rates and “resetting” all factors closer to zero.

At the time of any COSS and rate analysis, the Team and Board should consider this and carefully communicate these changes to members-consumers. Without correct communication, members-consumers may perceive that a given rate change is greater than will be the case. The member-consumer may focus on the amount that the BASE rate changes and not realize there is at the same time an off-setting change in the charges recovered from the factors.

Re-basing adjustments are more and more important as rates move closer and closer to being cost based. Regardless of the changes in cost that a particular factor is intended to recover, most are driven at least in part by capacity-related costs, and yet most factors are entirely recovered through energy charges.

The cooperative should consider a maximum level it will allow any factor to reach before revising rate designs. Otherwise, rates will become increasingly less tied to costs over time.

If industrial rates have direct power cost billing, industrial power cost and kWh sold or purchased, as applicable, are excluded when calculating factors for the remaining member-consumers.

When the cooperative has large industrial member-consumers, with load factors different from the remainder of the system, the Team should consider

calculating the factor for industrial member-consumers separately from the remainder of the system. The system losses contributed by these member-consumers are potentially quite different from the remainder of the system.

When the cooperative has a PCA based on their total cost of power, a situation can even develop with an industrial member-consumer receiving the benefit of load control or management directly from the cooperative, and then because this action lowers the average total cost of purchased power, the cooperative may see the same demand savings passed through a second time to all remaining member-consumers through the power cost adjustment factor.

In fact, this same issue should be considered by the cooperative as part of any load control program initiated by the cooperative. If the program is successful, cooperatives typically pass through to participating member-consumers the benefits of reducing wholesale demand costs, but if the cooperative has a power cost recovery factor, reductions in the average total cost of power are potentially passed through to all member-consumers a second time through their power cost factor. To address this issue, the cooperative could choose to manage their factor through changes in the base cost as the programs become more effective. Where permitted by regulation, the cooperative may consider adding back the load control demand savings they are giving to the DSM member-consumers when calculating the power cost adjustment factor.

Cooperatives offering avoided cost purchases from member-consumers with DER may include power purchased from those member-consumers along with power purchased from other power suppliers in the calculation of the power cost adjustment factor.

The Team will also want to consider means of managing their power cost recovery factor. Some cooperatives adopt a rolling twelve month or annual change where permitted so as to avoid monthly swings in the factor. Many cooperatives track any over or under recovery of power cost on a monthly basis for recovery in future power cost adjustment factors.

### 3.9.3

#### **MARGIN STABILIZATION ADJUSTMENT**

A margin stabilization adjustment is a separate rate rider mechanism whose purpose is to maintain the cooperative's margins at a certain level. The factor is typically calculated based on TIER, Rate of Return or DSC. This type of adjustment, if permitted by regulation, can be an effective tool for cooperatives to provide secure financial cost recovery. It can also help avoid years with high or low margins caused by unseasonal weather or economic impacts. The factor can lower the cooperative margins during periods of high sales as well as raise them during opposite periods.

The Team and Board, however, should consider the added responsibility they take on with this type of margin factor. Any added expenses incurred by the cooperative may well cause automatic increases in rates through increases in the factor. To minimize this process, some cooperatives adopt procedures for the Board to carefully audit and review the factor, to approve any change to the factor, or to cap the size of the factor – changes above that point might trigger a new COSS or detailed Team review.

### 3.9.4

#### **RENEWABLE ENERGY, ENERGY EFFICIENCY AND DSM ADDERS/ADJUSTMENTS**

In some states, particularly where cooperatives have state renewable, energy efficiency or DSM standards, cooperatives may consider a factor to recover the cost of these programs.

Care should be taken when considering multiple factors. For example, when the cooperative is offering both energy efficiency and renewable programs, each analysis will assume average usage per member-consumer and average savings from the program when calculating costs and benefits. For example, if the DER member-consumer is offsetting all or most of his or her usage through renewable net metering, permitting the same member-consumer to participate in a rebate program to purchase high efficiency HVAC equipment is unlikely to produce the savings contemplated by each program.

### 3.9.5

#### **EVALUATING THE RATE IMPACT ON INDIVIDUAL MEMBER-CONSUMERS**

The team must carefully consider the impact of their proposed rate designs on individual member-consumers. Even rate design options that have very small impact on total revenue for an entire rate class can have extreme impact on individual member-consumers, particularly with usage at the margins.

For example, when considering a three part rate, the Team will likely discover that the impact on individual member-consumers with high demand usage is quite different from member-consumers with lower demand usage for the same monthly kWh usage. Or the Team may find that increasing the customer charge results in a greater percentage increase on low use member-consumers than on high usage member-consumers.

Most cooperatives develop comparisons of billing under existing and proposed rate options at representative usage levels. An example of this is shown on Schedule B-5.0 and indicates the percentage increase for usage at different levels and for the class average member-consumers. In addition, the Standard Electric Team has included the number of member-consumers within each of the billing strata so the board can determine the number of member-consumers impacted. In some cases, a review of the member-consumer impacts may result in the Team going back and redesigning the rates to minimize that impact.

Not only is this information important for the Team when designing the rates, it may be even more important when communicating rate impact to member-consumers at the time of implementation.

# 4.0

## Other Considerations in Evaluating Rate Options

*There are other factors that need to be considered in the evaluation of rate options and selection of the proposed rate. Some of them include:*

1. *Using AMI to implement innovative rate structures*
2. *Coordination with Line Extension Investment*
3. *Implications for Net Metering, Renewables and Pre-Paid Metering*

### 4.1

#### Implication of Technology on Rate Design Options

Cooperatives desire to provide member-consumers with rate options that closely relate to how costs are incurred, including three part rates, time differentiated rates, DSM rates, etc. In order to offer rate design options that track cost, every cooperative Team should review IN ADVANCE their existing billing, communications and meter data management systems to ensure that data will be available to implement a rate option the cooperative Team and board may determine is appropriate.

Advanced Metering Infrastructure (AMI) has swept the country in recent years. AMI offers a broad range of configuration capabilities. At one extreme are AMI systems that measure monthly energy usage remotely. At the other extreme are AMI systems that provide two-way communication and control. The cooperative can read demand and energy usage by time interval, remotely connect and reconnect all or some of their meters and remotely manage load, as well as provide usage and other information to member-consumers, record outages and other important functions.

Most cooperatives today have AMI somewhere between these two extremes. Initial AMI installations may reveal unexpected deficiencies which block the effectiveness of the planned rate design. For example, existing back office systems may not be capable of processing, interpreting, and storing the massive amounts of usage data generated by AMI meters. Choke points along the communication pathways may limit data flows through a particular

#### NOT ALL AMI IS EQUAL

AMI capability is an important factor in developing a COSS and innovative rate designs.

At the beginning of a Rate Analysis Study, the Team will want to evaluate the features of their AMI system to determine the potential rate designs their AMI technology can support.



substation serving a high number of meters. Data management packages or billing packages acquired as components of the initial AMI system design may not interface with existing software. In short, the cooperative's system may well not include Interoperability of Multi-Speak® Specification (the ability for different cooperative computer systems to "talk with" one another—an NRECA objective for many years). Such limitations may restrict not only desired operational efficiencies and cost savings but also the ability to offer new rate designs such as real-time pricing.

Examples (not all-inclusive) of the types of cooperative systems that should be reviewed no later than the start of a COSS process are as follows:

- AMI meter system.
  - If the cooperative desires to modify existing on peak and off peak periods, can this be done remotely, or must the meters be reprogrammed manually?
  - Can the meter be programmed to record usage in multiple time periods to permit on peak, off peak and critical peak or similar rate design options?
  - Does the meter include multiple registers to record flow in both directions for net metering or a single register rolling both directions?
  - Does the meter report usage for each meter at each interval? If not, can the cooperative obtain demands that occur on any given interval (CP peak demands) or does the meter only record peak demand for the month (NCP peak demand)?
- Communications system
  - Does the system used to report meter readings back to the office have sufficient capacity to provide daily demand readings or only monthly demand readings?
  - Does the system allow two-way communication so the cooperative can communicate peak periods, manage member-consumer equipment, and/or remotely connect, disconnect and offer prepaid service?
  - Does the communications system interface with the cooperative website so member-consumers may see information about daily, weekly or monthly usage and manage consumption?
- Billing system
  - Does the billing system interface with the meter system to permit the cooperative to adopt more complex rate structures such as three part rates, DSM rates, TOU rates, etc., without crippling increases of staff time?
  - If so, will the cooperative need to activate typically unused portions of the billing system? Will the system incur costs to implement the processes from their IT provider(s)?
  - Does the billing system interface with the cooperative website so member-consumers may see in addition to their daily, weekly and monthly usage, similar information about their billing? Does the interface allow member-consumers to gather information about their rates and cost and receive signals about peaks and DSM to allow them to manage cost?
  - Have the billing staff been trained in the operation of new and potentially complex requirements of their billing system and rates?
  - Are all of these systems secure to help provide that no confidential member-consumer data will be exposed and none of its systems compromised?

The preceding examples are not all inclusive. But they do indicate the problems that many cooperative Teams and boards experience as they prepare to implement new and innovative rate designs structures. They discover only at the very end of the process that, no matter how desirable they feel a given rate structure might be, their existing system will simply not permit it. Cooperatives should consider this carefully when they select, implement and operate their IT systems, particularly with regard to AMI, communications and billing.

AMI systems provide a flood of potential rate data at the cooperative

Retail consumer backlash to AMI has sometimes been a problem. Concerns expressed by consumers include the potential loss of privacy due to two-way communication and negative health impacts caused by AMI meter technology. As a result of this backlash, some member-consumers insist and some regulators require cooperatives to provide consumers the ability to “opt out” of AMI meters. This option dilutes the effectiveness of the AMI system on all levels. As AMI systems continue to develop and expand; however, a point will be reached where the AMI infrastructure is no longer an “extra” feature of the system and becomes the standard offer.

In any case, AMI systems provide a flood of potential rate data at the cooperative. The data helpful in developing engineering analysis and COSS analysis might be used only every three to five years. It is a challenge to invest time and data processing and storage every year for data that is not required monthly for billing member-consumers.

The cooperative can make use of AMI data available in a variety of ways in their COSS analysis and rate designs. For example, AMI may provide for each member-consumer and in total for each rate class the contribution to any peak period the cooperative desires. If that data is available, and used by the Team, the COSS will be far more reflective of actual costs and provide far more accurate data to use in designing rates.

Beyond the cost of service allocations and determination, AMI can expand the rate design options and in some cases, provide communication with member-consumers. For example, if the cooperative has full two-way communications with its meter systems, it is possible to coordinate meter reading, time of use rates and thermostat control. Also, AMI may offer the ability to remotely control irrigation or commercial processing motors. When coordinated with remote connect and disconnect collars, the AMI system can permit prepaid metering – certainly one of the most popular applications of AMI technology through rates.

The Team may consider not only the rates it has in place today but possible future rate structures. If the Team desires to adopt rates that cannot be implemented with current technology, it should begin gathering, processing and storing the data TODAY that will permit it to ultimately move to desired rate designs. The primary purpose of the COSS analysis is to determine the cost to serve each rate class and provide the data necessary to develop rates. The COSS can also provide information to coordinate rates with other cooperative programs.

AMI can expand the rate design options and in some cases, provide communication with member-consumers

## 4.2

### Developing the Allowable Line Extension Investment

The COSS will identify the plant investment associated with providing service to the member-consumer. The rates will include a capital cost and O&M component reflecting the average investment to serve the average member-consumer. The cooperative will have in place a line extension policy that identifies the investment the cooperative will make to provide service to a member-consumer and the additional amounts the member-consumer will be required to pay for service. Clearly the line extension requirements need to be coordinated with investment assumptions reflected in the retail rates charged.

The application of a line extension allowance varies from cooperative to cooperative. Some cooperatives have a policy of providing a predetermined allowance to each new member-consumer in a rate class. Others perform an individual analysis for each connecting load. Some do not provide an allowance at all while others will extend facilities up to a certain distance before requiring the connecting party to pay for additional facilities. The type of load (residential, commercial, industrial, etc.), may also determine the approach taken by each cooperative.

The Team can use the COSS to determine the embedded cost to serve the current member-consumer. The Team then can determine the cost functions that the line extension policy is intended to reflect. Some line extension policies consider only the costs associated with the line extension, transformers, meters, and services required to provide service. Other line extension policies will go further and consider average embedded backbone

#### ALLOWABLE LINE EXTENSION INVESTMENT

Different rate designs will support different levels of line extension. When rates are changed, it is important to evaluate the line extension policy to determine if it needs to be modified to correspond with the new rate and allowable investment.

facilities associated with providing service. For many cooperatives that are competing for new loads in dual certificated areas, the allowable line extension will be defined by what is required to be competitive in the dual service area.

Of importance in the effective design of rates is to ensure that the proper investment is made by the cooperative to serve the load. This is particularly true for large power or industrial member-consumers. The assumption in developing rates for residential or small commercial classes is that the investment made will be used and useful over the life of the investment. This may not be the case with large power or industrial member-consumers with a significantly shorter project life. It is important in these instances that the capital cost required to provide service either be contributed by the member-consumer directly as CIAC or the cost recovery component of the rate be aligned with the contract period for service. Even then the cooperative may also require a letter of credit or some other instrument that will assure the cooperative that it receives payment for the capital component of cost of service.

## 4.3

### Issues Related to Net Metering, Renewables and Pre-paid Metering

#### 4.3.1 NET METERING

Net metering, in general, and solar applications, in particular, are of special interest to many cooperatives.

Net metering has been in place for many years across the country. But the falling cost of renewable energy and the maturity of the solar industry in particular are causing explosive growth in some states. While net metering is beyond the scope of this Guide, because it impacts rates and cost recovery, it will be discussed here as an example of coordinating policies with rates. Of course, as is the case with all rate designs, the Board must weigh multiple equally important criteria when considering rates. Recovering costs from the member-consumers who cause costs to be incurred is important, as is promoting energy efficiency and renewable energy, as is following PURPA guidelines related to decoupling.

*St. Croix Electric Cooperative (SCEC) serves 10,500 meters in rural Wisconsin. In the course of implementing their net metering program, they learned valuable lessons that are important to cooperatives implementing all kinds of rate changes, not just net metering. They were concerned about recovering the fixed cost of providing service more fully from fixed billing units. Once fixed costs were recovered, the cooperative, felt it could provide more flexibility in the design of the remaining elements in their rate. In addition, to mitigate individual impact, they grandfathered member-consumers, only to discover this decision was difficult for their billing system to implement. As a result they found it to be important to carefully establish that the cooperative's systems are able to implement innovative rate structures. Click [here](#) for more information.*

This situation can be a significant issue when there are large numbers of net metering member-consumers and the cooperative bills under a two-part rate

Net metering rules vary throughout the United States. In most states, regulatory commissions have established the rules for net metering, though not all of these rules apply to cooperatives. In states where cooperatives are not under regulated jurisdiction, the practice even among cooperatives may vary.

There is little doubt that opinions vary widely with regard to the correct approach for net metering especially between the utility sector and other parties. Factoring in stakeholder positions and regulatory commission requirements increases the complexity.

The practice of net metering is not universally defined across states. Some cooperatives are moving away from net metering as a means of compensating renewable DER and are instead considering retail member-consumers as partial-requirements member-consumers. There are generally three concepts involved in net metering rates and they are defined differently in different states. The basic concept is that a member-consumer has installed a renewable resource generator of some type behind the retail meter and is now being billed the net of what is consumed less what is generated.

#### **1. Avoiding usage that occurs at the same time as generation**

While some cooperatives do not permit this, requiring instead that the member-consumer send all energy generated onto the grid and purchase all usage required for the load, most permit the member-consumer to offset any usage that happens at the time of generation. This situation can be a significant issue when there are large numbers of net metering member-consumers and the cooperative bills under a two-part rate, particularly if the cooperative has set its customer charge well below its customer-related cost of providing service. The member-consumer may offset all or a portion of the cooperative's ability to recover its own full fixed wires cost of providing service. Historically, the numbers of net metering member-consumers were small and the desire to subsidize the renewable industry great enough that these issues were not considered as material. This is not the case in many places today.

Banking is of particular concern to most distribution utilities because the member-consumer is being compensated at the full retail rate, potentially for the entire output of the generator

## 2. Banking excess generation to be used at another time period by the member-consumer or at another site by the member

If the member-consumer never generates at any time during the month more energy than used, banking is not an issue. But if the member-consumer ever generates in excess of usage, most net metering programs require that the utility “bank” this excess generation and allow the member-consumer to use it to offset load during later periods. Some states only permit the banked excess generation to offset load in the same month, others in the same year, and in others the banked excess generation is evergreen.

In a few states, banking is not permitted and the member-consumer can only “net” energy that is generated at the time of consumption against retail usage. In some states, a net metering member-consumer is permitted to use excess energy generated to offset load both at the location where the generation is installed and at any other site the member-consumer may have.

Banking is of particular concern to most distribution utilities because the member-consumer is being compensated at the full retail rate, potentially for the entire output of the generator. The full retail rate includes a number of costs that would typically not be eliminated by renewable DER, including distribution wires cost and a portion of purchased power demand costs. Banking may also provide an incentive to over size renewable generation. In some states this is addressed by limiting the maximum size requirement for residential and/or commercial generation that can be considered under net metering.

*Washington Electric Cooperative (WEC) is a fully regulated cooperative serving 10,500 meters in Vermont spread over 2,728 square miles. The case study reviews a net metering rate change instituted by the cooperative. Part of the rate developed included a grid access fee to recover fixed cost of providing service from net metering customers through a fixed billing unit. Since the cooperative determined that the value of solar number it developed would not be of general application, perhaps of more general interest were challenges the cooperative experienced in implementing their new rate as part of their own billing system. For a time, net metering member-consumers had to be billed by hand until these issues were resolved. In addition, the cooperative determined education was key and based its program on a message of fairness and equity for all member-consumers. Click [here](#) for more information.*

## 3. Avoided Cost

Generation in excess of banked usage is not purchased by the cooperative in some states. In others, the excess generation is purchased at “avoided cost.” For a distribution cooperative, this is typically either the avoided cost of purchased power or the power supplier’s avoided cost of power.

To the extent that cooperatives can build their own cost of providing distribution wires service into fixed billing rate, any change in kWh sales, whether from renewable net metering or any other cause, is far less of a potential problem. Over time, the issue is often not one between the cooperative and its member-consumers, because lost margins (reductions in revenues that are greater than reductions in costs) ultimately will trigger a rate increase paid by other member-consumers, or decrease the patronage capital allocated to all member-consumers or both. The issue is between member-consumers with renewable generation and other, often lower income, member-consumers.



### 4.3.2

#### **SOLAR PROGRAMS**

Solar programs present a unique challenge for distribution cooperatives. Unlike many other types of renewable DER, solar installations have the real potential to reduce some portion of the purchased power peak demand cost. The amount of savings depends on factors included in the wholesale rate structure, the location of the cooperative, and the orientation of the solar facilities. Individual rooftop solar systems are typically oriented to produce maximum kWh as opposed to maximum wholesale capacity reductions.

For solar in particular, some advocates push for a wide range of additional adders to use in developing the value of solar. The adders are generally related both to potential peak reductions (purchased power peak and even some distribution capacity peak costs) and societal benefits related to environmental improvements. Others would include savings from avoided capacity realized many years in the future, though most regulated cooperatives are limited by commissions in their ability to include future costs in setting their rates.

### 4.3.3

#### **COMMUNITY SOLAR PROGRAMS**

Community solar programs provide an opportunity for member-consumers and the cooperative to participate together in a DER option. Community solar allows member-consumers who are renters or who cannot afford the large up-front capital investment of individual rooftop solar the opportunity to participate in the program. Community solar programs are regulated in many jurisdictions and may also be limited by the provisions for each distribution cooperative's power purchase contracts.

A major advantage to a community solar program is the ability of the cooperative to orient solar DER to maximize capacity production instead of energy production in parts of the country where these two orientations are materially different.

Cooperatives with community solar may offer a variety of approaches:

- Sell a share in the project and allow "virtual net metering" with the member-consumer receiving a prorated share of the generation from the unit.
- Purchase a share in the output with a fixed charge or credit for the member-consumer each month based on investment and operation costs and cost of generation over time
- Value of DER and compensation
- Offer rate design options to retail member-consumers.

Some cooperatives have sought to offer additional rate offerings to member-consumers. In some cases, the motive is simply a desire to provide a choice to member-consumers. In other cases, additional rate options provide an opportunity for member-consumers to save based upon their load characteristics and consumption patterns. In states with laws providing consumer choice, additional rate options are generally intended to appeal to desirable consumers or to simply give options to existing member-consumers.

Regardless of the intent, cooperatives must always make one assumption when considering offering multiple rate options to member-consumers. Cooperatives must assume for ratemaking purposes that over time, member-consumers will migrate to the lowest rate option. This assumption helps with the establishment of rates and the expectation they will produce the intended revenue.

## 4.4

### **Alignment of Proposed Rate Design with Implementation of Pre-Pay Programs**

Many cooperatives throughout all regions of the U.S. offer prepaid programs. In the past, pre-pay rate offerings sometimes included additional charges aimed to recover additional costs associated with specialized metering, remote connect and disconnect equipment, and payment processing such as online and kiosk related fees. Today, most pre-pay rates are indistinguishable from standard rate offerings for other member-consumers with the exception of the application of a daily rate. For rate making purposes, the primary impact of prepaid metering is related to changes in service charge revenue and expenses related to collection of late fees and benefits from the time value of money. As data is gathered, some cooperatives believe that effectively run prepaid programs have the impact of reducing load as member-consumers watch, understand and adjust peak usage.

# 5.0

## Implementation of Proposed Rates

*Few decisions have the immediate impact on cooperative member-consumers as changes in retail rates. Communicating rate changes to member-consumers and providing notice in a prescribed manner is generally required in states where cooperatives are rate regulated. However, notice requirements only address the mechanics of communicating a rate change. There is much more involved in providing meaningful member-consumer communication regarding rates.*

### 5.1

#### Primary Goal in Implementing a Rate Change

Experience shows that some member-consumers will react negatively to rate changes. This may be true even when there is an economic benefit to them as a result of the rate change. A rate implementation plan developed alongside the COSS will help the cooperative achieve member-consumer acceptance of the rate changes and continued satisfaction with the cooperative.

The rate implementation plan ensures that an appropriate message is developed regarding the proposed rate change and is communicated through each of the cooperative's communication channels. At a high level, the plan should reinforce the message to member-consumers that the pending rate change supports the Cooperative's goals and objectives to provide reliable electric service at an affordable cost on a long-term basis.

A rate implementation plan developed alongside the COSS will help the cooperative achieve member-consumer acceptance of the rate changes and continued satisfaction with the cooperative

*Sioux Valley Electric Energy (SV) is a merged cooperative serving 23,000 meters in South Dakota and Minnesota. They had the challenge of unifying rate structures and implementing basic service charges into rates that did not include these fixed billing units previously. The cooperative elected to implement rate changes and fixed charges over a period of years to reduce the impact on member-consumers. At the same time, the educational process of communicating with member-consumers did not end with the initial rate implementation. An on-going process and willingness to reconsider the initial rate change plan maximized member-consumer understanding and minimized member-consumer complaints. Click [here](#) for more information.*



An educated staff person is perhaps the best communication tool for the cooperative

## 5.2

### Developing the Implementation Plan

Developing an effective Implementation Plan requires the input of cooperative management and senior staff and expertise of member services and communications personnel. A cooperative's manager or other senior staff will typically take the lead in talking with member-consumers and the public about rate changes. While member services and communications staff may take this role in some settings, they will certainly be involved in developing the materials used to educate member-consumers about rates and other issues of interest.

A successful implementation plan will include two primary target audiences. They may be considered an internal audience and an external audience. The internal audience includes cooperative staff and directors. The external audience includes member-consumers and may be thought of as individual member-consumers, local organizations such as civic groups or trade organizations who include cooperative member-consumers and the general public.

### 5.2.1 INTERNAL AUDIENCE

It may not be critical for all cooperative staff to understand all aspects of the cost of service and rate analysis. However, at a minimum, all employees should be able to communicate the general process the cooperative undertook to analyze and modify rates. Cooperative staff should be well informed prior to communicating a proposed rate change. Cooperative staff are commonly in contact with member-consumers outside the workplace through business, social, community and school activities. An educated staff person is perhaps the best communication tool for the cooperative.

Beyond a general understanding of the process and outcome, cooperative managers and senior staff should consider how staff interact with member-consumers and the general public and ensure there is an appropriate level of communication and understanding of the cost of service, rate analysis and rate change. Managers, senior staff and any other staff responsible for communicating with member-consumer groups, civic organizations or key accounts should be well versed in all aspects of the cost of service process, rate change and member-consumer impact. Member services and those staff who respond to member-consumer billing questions and concerns should be intimately familiar with the existing and proposed rates and member-consumer impact. Staking engineers should be able to communicate any associated changes in the cooperatives line extension policy which may have changed as a result of the cost of service and rate analysis.

What is important to remember is member-consumers should be informed about an upcoming rate change well in advance so that they may be prepared

Directors should also understand the process undertaken by the cooperative. They should understand the cooperative's regulatory ratemaking requirements and process. In some cases, the cooperative is regulated by a public utility commission. In others, the public utility commission is no longer the cooperative's ratemaking authority. In such cases, communicating with member-consumers that the cooperative's cost of service and rate study was developed in accordance with generally accepted regulatory standards and practices is important.

Many cooperatives provide training sessions conducted by internal staff or a rate consultant to ensure staff and directors are able to communicate the key issues and are able to answer questions from member-consumers in a positive way. They should be able to direct member-consumers to additional resources offered by the cooperative or others to help them manage energy usage. They also should be trained to direct member-consumers of the media or other interested parties to the appropriate cooperative spokesperson.

### 5.2.2 EXTERNAL AUDIENCE

Communicating rate changes to member-consumers may require at a minimum notice requirements stemming from public utility commission regulatory rules. Cooperatives should be familiar with these requirements and the regulatory approved method of fulfilling them. Cooperatives who are no longer jurisdictional to their states public utility commission should consider what was once required of them when providing notice of rate changes. Many cooperatives still follow these notice requirements.

All cooperatives, as part of their implementation plan, should consider the many other communication channels available to them to educate member-consumers on when a rate change will occur and how much their bill will change. The timing for each communication channel message may vary based upon the cooperative's notice requirements and implementation plan. Some cooperatives will begin communication with member-consumers the need for a potential rate change upon commencement of a cost of service and rate study. Others will begin communicating key issues well before rates are scheduled for implementation. What is important to remember is member-consumers should be informed about an upcoming rate change well in advance so that they may be prepared.

COMMUNICATION METHOD	AUDIENCE	TIMELINE
Internal education about rates, costs of doing business	Directors, employees	Directors, employees
Director Training	Directors	Directors
Employee Training	Employees	Employees
Frequently Asked Questions (Talking Points)	All Audience	All Audience
Managers Column	Member-consumers	Member-consumers
Formal Notice of Rate Change	All Audience	All Audience
Website Announcement	All Audience	All Audience
Online Video	All Audience	All Audience
Letter to Member-Consumers	Member-consumers	Member-consumers
Newsletter article(s)	Member-consumers	Member-consumers
Bill Stuffer	Member-consumers	Member-consumers
News Release	Member-consumers	Member-consumers
Presentations	Member-consumers	Member-consumers

**Cost is the bottom line for most cooperative member-consumers**

Generally speaking, member-consumers want to know the answers to these questions:

**Why is a rate change needed?** Many member-consumers understand there are cost pressures which affect the cooperative just like other utility services. They see periodic rate increases in their cable TV, natural gas, telephone, cell phone and other similar services. They may also be aware of industry matters such as climate change and renewable resources, but they may not understand how these issues affect the cooperative's costs. They may not be familiar with complex issues affecting the cooperative's power supply costs. A rate adjustment provides an opportunity to educate member-consumers about the key issues that affect the cooperative's costs and to assure member-consumers the cooperative is working hard to manage costs both in the present and for the future.

**How will rates be adjusted, and how will the change be implemented?** Cost is the bottom line for most cooperative member-consumers. Member-consumers should know which rates will change and how much they will increase (or decrease). If there are important changes in the rate design, member-consumers should have the opportunity to understand them. For example, if establishing a higher customer charge is an important component of the proposed rates, member-consumer communication regarding the recovery of fixed costs might be a focal point.

The cooperative needs to demonstrate in every way it can that it is being prudent with member-consumers' money

Significant structural changes to rates or the introduction of new rate designs requires much more thought, effort and time to communicate as opposed to the routine rate change. The need for thorough communication lies in the fact that many member-consumers may be affected in any number of ways when rates are structurally changed. Even the slightest change in structure can result in one member-consumer seeing no increase, another seeing a large increase, and a third seeing a rate reduction. The cooperative must be clear as to the rate change at different levels and not reference only average values.

**What is the cooperative doing to manage its costs, ensure reliability and provide for the member-consumers' future needs?** Member-consumers need to know the cooperative is actively working on their behalf. The cooperative needs to demonstrate in every way it can that it is being prudent with member-consumers' money. Appearances also are important. For example, one cooperative received a member-consumer complaint about a bucket-truck that had been left running unattended. It turned out that there was a legitimate reason, and in this case, the cooperative had the opportunity to explain this to the concerned member-consumer. This story illustrates that member-consumers do pay attention to a cooperative's actions as well as its words.

**How can member-consumers manage their use of electricity to manage their bills?** Communicating how member-consumer consumption will determine their billing is critical, especially when introducing rates with components such as time-of-use or demand billing. This enables member-consumers to pay careful attention to their consumption patterns in order to take advantage of potential cost saving. The cooperative can provide critical information on how member-consumers can manage their energy costs in order to mitigate the impact of the proposed rate change. Member-consumers need to understand how they can change their usage patterns in response to rate signals to lower their bills. It is important that member-consumers understand the billing determinants by which rates will be calculated and how billing determinants are derived. This is especially true when introducing new concepts such as demand kW and other complex issues.

Most cooperatives have a variety of programs to help member-consumers conserve and use energy more efficiently, but some member-consumers may not be aware of them. Cooperatives also can serve as a clearinghouse for information on other resources, particularly for lower income member-consumers.

Member-consumer meetings may be a regulatory requirement for some cooperatives implementing a rate change. Even if not required, the meetings provide an opportunity to educate member-consumers on the ratemaking process and proposed rate changes and provide a forum for member-consumers to ask questions.

Cooperatives should begin to prepare member-consumers for a rate change as soon as it becomes clear one is needed.

The primary intent of implementing rates in phases is to reduce member-consumer impact

### 5.3

#### When is the best time to implement new rates?

Cooperatives should begin to prepare member-consumers for a rate change as soon as it becomes clear one is needed. If a cooperative foresees a need for annual adjustments or a future large adjustment, it should be discussing this with member-consumers through as many channels as possible.

It is desirable to implement new rates when it will have the least impact on member-consumers' bills and in a way that is revenue neutral, if possible. The optimal timing depends on the nature and level of the change. If the cooperative does not need a significant amount of additional revenue, changes are likely to have a neutral effect on member-consumer bills. For example, for many cooperatives, a shift to cost-based rates will result in higher customer and demand charges and lower energy charges. Implementing that type of change during a high usage period such as a summer or winter month will spread changes in customer and demand costs over the most kilowatt-hours, and member-consumers will benefit most from lower energy charges. Ideally, rates reflecting a large increase in revenue requirements should be implemented in months with lower usage to minimize the impact on member-consumers.

Cooperatives that decide to delay increases to improve timing should analyze the financial impact on the cooperative. Minimizing the impact on cooperative member-consumers also delays the income to the cooperative. It is important to consider whether the income lost is worth the potential gain in goodwill from member-consumers.

For many years, cooperative rate philosophy emphasized stability of rates and infrequent changes. Although stability is important, an overdue rate increase can lead to large or unexpected changes that can have an adverse effect on the member-consumer. It is best for member-consumers to perceive changes in cost as relatively small. More frequent, smaller rate increases protect the cooperative's financial integrity while avoiding rate shock and negative member-consumer reaction. Many cooperative boards and managers have adopted this philosophy and revisit the cost of service and rate study process every three to five years.

### 5.4

#### Should the cooperative consider implementing new rates in stages over a period of time?

Some cooperatives choose to implement rate changes over time. The primary intent of implementing rates in phases is to reduce member-consumer impact. There are instances when a phased approach may be beneficial. If the cooperative's overall rate increase is significant and adversely affects one or more rate classes, a phased implementation will be beneficial by helping mitigate member-consumer impact.

If a proposed rate design represents a significant departure from the existing rate already in place, the cooperative may wish to implement gradual changes over a period of time. Even though the overall rate change may have little or no impact on a rate class, the rate change may have a significant impact on individual member-consumers within that class, both positive and negative. If such circumstances exist, the cooperative can implement the rate in annual increases to minimize member-

consumer impact. Implementing substantial changes in rate levels or differences in rates in stages may help to improve member-consumer acceptance. For example, if a cooperative's customer charge is \$17.50 per month but the actual customer-related costs are \$35 per month, the cooperative might choose to implement a customer charge of \$22.50 per month for a year before further increasing the customer charge. Again, cooperatives should analyze the financial impact that any delay will have on its income.

In rare cases, proposed rate design changes may warrant implementation for certain member-consumers within a rate class but not all of them at the same time. This has historically occurred when there was a significant departure in the retail rate which negatively impacted a group of member-consumers. For example, a cooperative who has experienced growth due to urban sprawl may find it impractical to continue offering a separate irrigation rate. However, the transition for the few remaining irrigation services may result in significant rate increases for those member-consumers. In such cases, the tariff can be closed to new services while existing member-consumers will be transitioned to a new rate over a period of time. Similarly, a cooperative may adopt a similar approach for implementing a new rate for a large group of member-consumers. Implementing a three-part rate for a residential rate class requires a measured approach. A cooperative may choose to transition existing member-consumers to the new three-part rate over a period of time while immediately placing new connects directly on the new rate. In the meantime, the cooperative can use the transition period to provide education, implement parallel billing and offer member-consumers the ability to move to the new rate under their own direction.

It is important to consider a phased approach from the member's perspective. A phased approach mitigates member-consumer impact. However, a phased approach when the cooperative implements a rate change over several phases may appear differently to a member-consumer. If a cooperative sets rates and forecasts the need for additional revenue in year five of its financial forecast, then implements rates over three or more phases only to change rates again, it may appear to member-consumers that the cooperative is perpetually changing rates.

## 5.5

### Monitoring rates is an ongoing process

Cooperatives continually monitor their financial performance. It is also a good practice to continually monitor rates. This is especially important following a rate change. Upon modifying rates, cooperatives staff should sample monthly bill calculations for each affected rate class.

Rates can also be monitored to gauge whether or not the pricing signal(s) is affecting member-consumer behavior. This is especially important for rates such as time-of-use rates. Time based rates may require adjustments to achieve the desired member-consumer response.

Rates should also be revised when the cooperative financial ratios begin to approach board defined thresholds, when there is a significant change in cost of service such as a change in wholesale power costs; or when the rate design is not achieving the desired member-consumer response.





## Schedule A-1.0

## FINANCIAL PROFILE EXAMPLE—KEY OPERATING RATIOS AND STATISTICS

	12-Months Ended	Rate Base	Return	Interest on LT Debt	Net Margins	Rate of Return	Oper. TIER	Net TIER	Mod. Net TIER	DSC	Equity as Percent of		Avg. Debt Cost	Return on Equity	Plant Growth Rate	General Funds Ratio
		\$	\$	\$	\$	%	X	X	X		%	%	%	%	%	%
1	12/31/Year -2	210,565,322	17,502,614	6,862,012	12,495,860	8.31	2.53	2.82	2.71	3.39	42.71	46.83	5.44	11.58	9.47	4.37
2	1/31/Year -1	212,865,187	17,283,177	6,986,821	12,174,117	8.12	2.45	2.74	2.63	3.31	42.66	46.82	5.54	11.05	9.43	4.98
3	2/28/Year -1	213,968,841	17,894,591	7,101,529	12,433,232	8.36	2.50	2.75	2.68	3.32	43.12	47.11	5.64	11.42	9.34	3.86
4	3/31/Year -1	218,074,141	18,482,664	7,197,394	13,159,988	8.48	2.56	2.83	2.72	3.37	42.18	47.42	5.75	11.50	10.05	3.13
5	4/30/Year -1	217,122,747	18,972,641	7,267,113	13,605,291	8.74	2.60	2.87	2.77	3.41	42.14	46.20	5.76	12.21	9.03	3.65
6	5/31/Year -1	218,273,255	19,510,215	7,386,629	13,971,344	8.94	2.64	2.89	2.79	3.38	42.31	46.86	5.84	12.45	8.70	3.23
7	6/30/Year -1	220,893,338	19,896,183	7,606,685	14,129,715	9.01	2.61	2.86	2.76	3.30	41.60	45.97	5.98	12.57	8.85	4.43
8	7/31/Year -1	223,734,093	20,062,793	7,738,219	14,306,525	8.97	2.59	2.85	2.74	3.27	41.28	45.93	6.05	12.40	9.28	4.38
9	8/31/Year -1	226,298,646	19,928,601	7,833,149	14,130,362	8.81	2.54	2.80	2.69	3.18	41.42	46.19	6.11	11.95	9.93	3.09
10	9/30/Year -1	227,649,688	19,885,806	7,908,878	13,752,258	8.74	2.51	2.74	2.63	3.11	40.94	45.57	6.13	11.85	10.11	5.20
11	10/31/Year -1	228,293,597	20,369,232	7,949,809	14,176,909	8.92	2.56	2.78	2.67	3.15	41.16	45.58	6.12	12.27	9.67	5.35
12	11/30/Year -1	229,531,520	19,980,662	8,197,049	13,334,486	8.70	2.43	2.63	2.53	2.99	42.36	46.44	6.27	11.51	9.66	4.91
13	12/31/Year -1	230,727,204	17,643,015	7,883,854	11,375,176	7.65	2.22	2.44	2.32	2.78	42.39	46.36	5.99	9.57	9.58	5.80
14	1/31/Year -0	233,875,396	18,012,785	7,851,841	11,719,424	7.70	2.28	2.49	2.37	2.84	42.73	46.43	5.92	9.76	9.87	6.15
15	2/28/Year -0	235,226,024	17,502,015	7,834,848	10,991,464	7.44	2.22	2.40	2.30	2.75	42.78	46.21	5.85	9.29	9.93	5.51
16	3/31/Year -0	236,802,112	17,686,945	7,743,232	11,142,737	7.47	2.25	2.44	2.35	2.75	42.25	45.98	5.73	9.51	8.59	4.45
17	4/30/Year -0	237,730,555	17,377,682	7,721,626	10,768,045	7.31	2.21	2.39	2.30	2.72	42.59	46.02	5.68	9.22	9.49	3.59
18	5/31/Year -0	238,203,536	17,442,369	7,570,914	10,705,166	7.32	2.26	2.41	2.32	2.78	42.43	45.96	5.53	9.43	9.13	2.62
19	6/30/Year -0	239,467,198	16,831,325	7,348,353	10,341,972	7.03	2.25	2.41	2.30	2.77	42.27	45.94	5.35	9.01	8.41	2.00
20	7/31/Year -0	241,520,952	16,822,967	7,213,323	10,284,049	6.97	2.29	2.43	2.33	2.82	41.36	45.01	5.21	9.11	7.95	3.36
21	8/31/Year -0	243,325,587	16,676,196	7,128,261	10,235,594	6.85	2.29	2.44	2.34	2.83	41.48	45.26	5.11	8.96	7.52	2.55
22	9/30/Year -0	245,390,168	15,528,840	7,043,307	9,173,614	6.33	2.16	2.30	2.20	2.72	40.86	44.74	5.02	7.94	7.79	3.49
23	10/31/Year -0	246,952,628	15,269,137	6,957,989	9,038,201	6.18	2.14	2.30	2.19	2.72	41.17	45.13	4.94	7.69	8.17	3.61
24	11/30/Year -0	249,150,250	13,956,973	6,894,537	7,765,974	5.60	1.97	2.13	2.02	2.61	41.76	45.71	4.87	6.47	8.55	2.87
25	12/31/Year -0	251,567,301	14,579,520	6,979,640	8,376,468	5.80	2.05	2.20	2.09	2.67	41.26	45.01	4.90	6.89	9.03	3.79



## Schedule A-2.0

## FINANCIAL PROFILE EXAMPLE—USAGE STATISTICS

	12-Months Ended	kWh Sold	Office Use	kWh Purchased	Losses	Percent Losses	kWh Sold % Increase		Cons	Consumer % Increase		Total Miles Line	Miles % Increase		Cons. Density
							Period	Annual		Period	Annual		Period	Annual	
						%	%	%		%	%		%	%	
1	12/31/Year -2	1,480,456,720	1,971,818	1,596,566,299	114,137,761	7.15	0.91	8.31	100,593	0.32	1.11	12,647	11.58	1.31	7.95
2	1/31/Year -1	1,496,019,405	1,959,491	1,603,343,465	105,364,569	6.57	1.05	8.36	102,709	2.10	3.48	12,663	0.13	1.71	8.11
3	2/28/Year -1	1,518,023,112	1,968,395	1,641,259,142	121,267,635	7.39	1.47	8.56	102,166	(0.53)	3.34	12,678	0.12	1.77	8.06
4	3/31/Year -1	1,540,026,805	1,986,000	1,681,676,716	139,663,911	8.31	1.45	8.74	102,708	0.53	4.33	12,718	0.32	1.73	8.08
5	4/30/Year -1	1,572,914,958	1,976,567	1,718,513,107	143,621,582	8.36	2.14	9.08	103,276	0.55	4.53	12,729	0.09	1.64	8.11
6	5/31/Year -1	1,585,131,259	1,969,274	1,724,802,867	137,702,334	7.98	0.78	9.10	103,559	0.27	4.47	12,743	0.11	1.63	8.13
7	6/30/Year -1	1,593,495,176	1,937,102	1,728,771,797	133,339,519	7.71	0.53	9.09	103,922	0.35	4.48	12,752	0.07	1.61	8.15
8	7/31/Year -1	1,603,752,568	1,945,410	1,734,448,619	128,750,641	7.42	0.64	9.10	103,764	(0.15)	3.98	12,759	0.05	1.46	8.13
9	8/31/Year -1	1,607,164,627	1,904,179	1,728,858,711	119,789,905	6.93	0.21	9.09	103,369	(0.38)	3.25	12,767	0.06	1.40	8.10
10	9/30/Year -1	1,602,396,445	1,915,662	1,743,968,856	139,656,749	8.01	(0.30)	9.13	103,671	0.29	3.22	12,780	0.10	1.43	8.11
11	10/31/Year -1	1,610,183,603	1,932,912	1,748,407,736	136,291,221	7.80	0.49	9.11	103,967	0.29	3.17	12,796	0.13	1.43	8.12
12	11/30/Year -1	1,635,042,744	1,937,528	1,810,879,376	173,899,104	9.60	1.54	9.20	104,183	0.21	3.06	12,805	0.07	1.31	8.14
13	12/31/Year -1	1,619,685,665	1,887,428	1,787,978,297	166,405,204	9.31	(0.94)	9.40	104,489	0.29	3.87	12,812	0.05	1.30	8.16
14	1/31/Year -0	1,606,632,983	1,864,222	1,789,479,753	180,982,548	10.11	(0.81)	7.39	104,976	0.47	2.21	12,834	0.17	1.35	8.18
15	2/28/Year -0	1,607,457,816	1,895,437	1,769,799,457	160,446,204	9.07	0.05	5.89	106,023	1.00	3.78	12,848	0.11	1.34	8.25
16	3/31/Year -0	1,599,189,670	1,921,664	1,756,707,070	155,595,736	8.86	(0.51)	3.84	106,873	0.80	4.06	12,896	0.37	1.40	8.29
17	4/30/Year -0	1,589,314,331	2,015,039	1,745,976,082	154,646,712	8.86	(0.62)	1.04	107,673	0.75	4.26	12,903	0.05	1.37	8.34
18	5/31/Year -0	1,594,253,086	2,072,393	1,750,474,329	154,148,850	8.81	0.31	0.58	108,116	0.41	4.40	12,913	0.08	1.33	8.37
19	6/30/Year -0	1,600,702,690	2,098,890	1,774,088,339	171,286,759	9.65	0.40	0.45	108,476	0.33	4.38	12,917	0.03	1.29	8.40
20	7/31/Year -0	1,609,559,898	2,114,108	1,789,298,279	177,624,273	9.93	0.55	0.36	108,329	(0.14)	4.40	12,922	0.04	1.28	8.38
21	8/31/Year -0	1,636,226,159	2,159,325	1,814,472,267	176,086,783	9.70	1.66	1.81	108,061	(0.25)	4.54	12,947	0.19	1.41	8.35
22	9/30/Year -0	1,641,380,648	2,151,724	1,818,613,695	175,081,323	9.63	0.32	2.43	108,448	0.36	4.61	12,972	0.19	1.50	8.36
23	10/31/Year -0	1,652,127,323	2,142,938	1,834,129,585	179,859,324	9.81	0.65	2.60	108,873	0.39	4.72	12,987	0.12	1.49	8.38
24	11/30/Year -0	1,652,408,549	2,158,449	1,801,397,665	146,830,667	8.15	0.02	1.06	109,284	0.38	4.90	12,998	0.08	1.51	8.41
25	12/31/Year -0	1,674,108,209	2,198,330	1,824,474,167	148,167,628	8.12	1.31	3.36	109,960	0.62	5.24	13,017	0.15	1.60	8.45

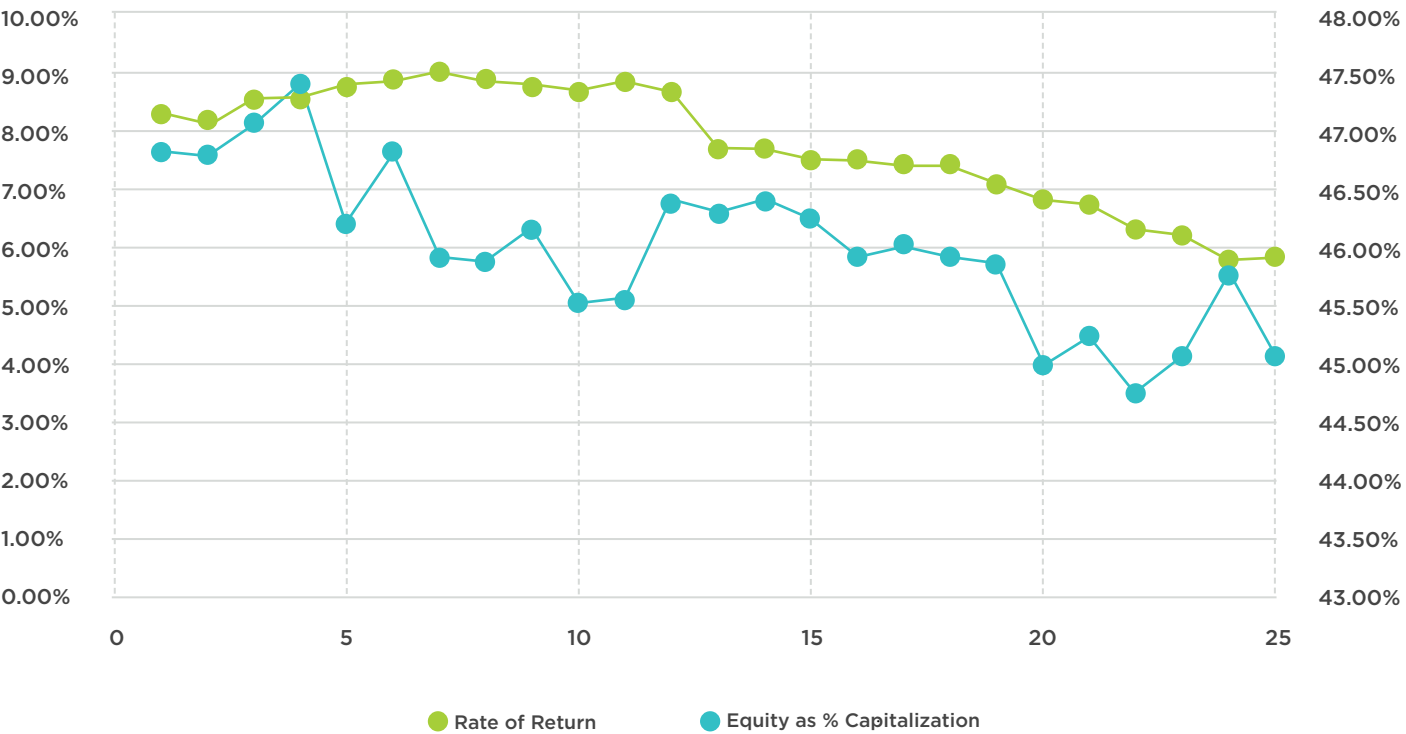
## Schedule A-3.0

## FINANCIAL PROFILE EXAMPLE—STATEMENT OF OPERATIONS

	12-Months Ended	Operating Revenue	Power Cost	Revenue Less Power Cost	Trans. + Distrib. O&M	Cons Acct.	Admin. & General	Deprec.	Taxes	Other Interest & Deduct.	Total Exp. w/o Pur. Pwr.	Interest on LT Debt	Operating Margin
		\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$	\$
1	12/31/Year -2	122,312,752	75,329,067	46,983,685	9,745,756	5,964,730	6,135,296	7,142,599	492,691	173,059	29,654,130	6,862,012	10,467,543
2	1/31/Year -1	124,929,294	77,898,339	47,030,955	9,858,031	6,004,453	6,193,341	7,188,766	503,188	170,459	29,918,237	6,986,821	10,125,896
3	2/28/Year -1	129,277,588	81,250,992	48,026,596	10,122,544	5,962,989	6,306,698	7,237,887	501,887	167,161	30,299,166	7,101,529	10,625,901
4	3/31/Year -1	133,674,086	85,049,405	48,624,681	10,341,281	6,082,819	5,917,005	7,285,721	515,191	84,240	30,226,257	7,197,394	11,201,030
5	4/30/Year -1	137,652,747	88,245,786	49,406,961	10,338,095	6,184,636	6,045,099	7,332,841	533,649	43,894	30,478,214	7,267,113	11,661,633
6	5/31/Year -1	141,786,823	91,576,138	50,210,684	10,571,913	6,200,945	6,005,560	7,381,585	540,467	38,405	30,738,875	7,386,629	12,085,181
7	6/30/Year -1	145,628,052	94,515,146	51,112,906	10,910,750	6,289,646	6,038,319	7,431,358	546,650	40,496	31,257,219	7,606,685	12,249,002
8	7/31/Year -1	148,216,060	96,790,530	51,425,530	10,821,078	6,345,159	6,156,693	7,482,196	557,612	35,090	31,397,827	7,738,219	12,289,485
9	8/31/Year -1	150,824,467	99,055,433	51,769,035	11,150,270	6,401,808	6,206,395	7,533,920	548,041	23,285	31,863,719	7,833,149	12,072,167
10	9/30/Year -1	152,371,220	100,908,587	51,462,633	10,923,432	6,430,640	6,143,402	7,580,522	498,832	52,559	31,629,387	7,908,878	11,924,368
11	10/31/Year -1	154,612,204	102,501,146	52,111,058	10,819,084	6,459,738	6,346,006	7,627,026	489,973	46,037	31,787,863	7,949,809	12,373,386
12	11/30/Year -1	154,783,198	102,901,371	51,881,827	10,867,270	6,521,698	6,362,097	7,668,427	481,673	51,822	31,952,987	8,197,049	11,731,792
13	12/31/Year -1	149,733,071	99,661,330	50,071,741	11,170,329	6,622,985	6,438,854	7,709,758	486,800	125,590	32,554,316	7,883,854	9,633,570
14	1/31/Year -0	146,571,803	95,662,524	50,909,279	11,432,524	6,768,513	6,465,829	7,756,303	473,326	125,001	33,021,496	7,851,841	10,035,942
15	2/28/Year -0	143,587,489	92,467,190	51,120,299	11,787,172	7,110,341	6,461,038	7,800,094	459,637	128,018	33,746,301	7,834,848	9,539,150
16	3/31/Year -0	140,470,316	89,004,903	51,465,413	11,772,841	7,190,882	6,467,270	7,869,476	478,000	269,722	34,048,190	7,743,232	9,673,991
17	4/30/Year -0	137,489,326	86,067,957	51,421,369	11,936,062	7,279,823	6,448,426	7,920,306	459,069	321,430	34,365,117	7,721,626	9,334,626
18	5/31/Year -0	134,452,484	82,538,924	51,913,560	11,911,118	7,390,181	6,764,474	7,964,697	440,722	319,549	34,790,740	7,570,914	9,551,906
19	6/30/Year -0	131,502,243	79,852,923	51,649,320	12,188,884	7,566,486	6,619,388	8,009,089	434,146	325,750	35,143,744	7,348,353	9,157,223
20	7/31/Year -0	129,594,194	77,238,482	52,355,712	12,696,146	7,683,004	6,677,195	8,054,215	422,185	330,867	35,863,612	7,213,323	9,278,777
21	8/31/Year -0	127,132,041	74,394,097	52,737,944	12,913,115	7,990,957	6,633,605	8,100,802	423,269	340,986	36,402,734	7,128,261	9,206,949
22	9/30/Year -0	124,435,913	72,143,413	52,292,500	13,249,022	8,226,470	6,674,211	8,147,128	466,830	342,736	37,106,396	7,043,307	8,142,797
23	10/31/Year -0	122,243,431	69,729,196	52,514,234	13,573,416	8,328,558	6,680,258	8,193,741	469,125	345,947	37,591,045	6,957,989	7,965,201
24	11/30/Year -0	119,836,150	67,898,419	51,937,730	13,806,144	8,725,175	6,745,925	8,239,310	464,202	342,096	38,322,853	6,894,537	6,720,341
25	12/31/Year -0	121,391,407	68,984,238	52,407,169	13,875,526	8,455,102	6,748,321	8,287,869	460,831	270,401	38,098,050	6,979,640	7,329,479
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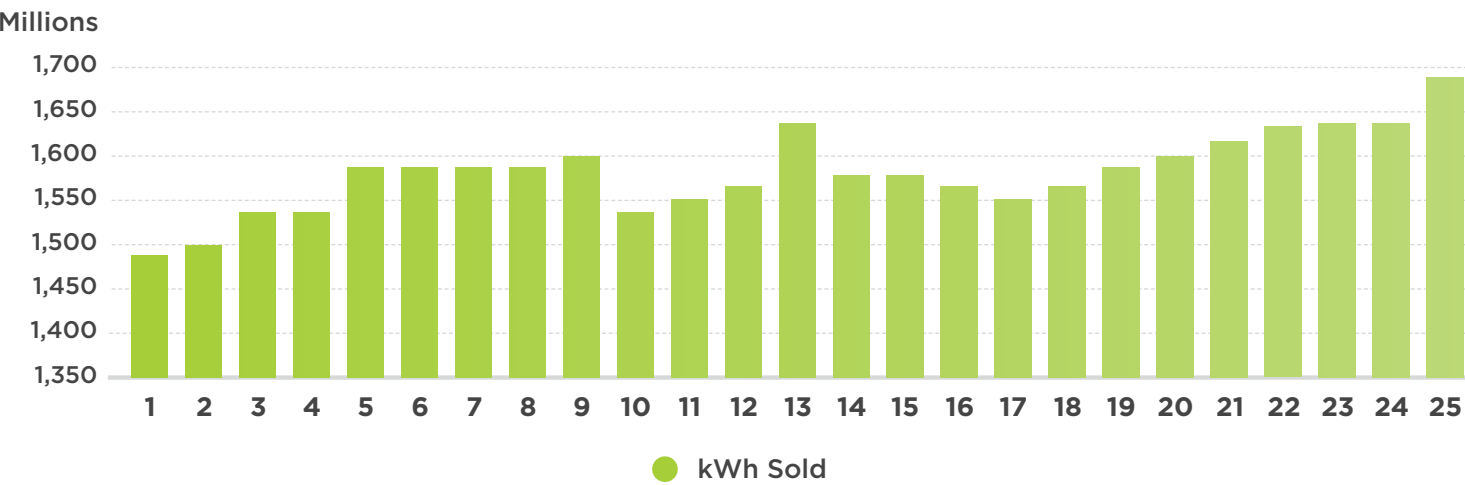
Schedule A-4.0  
FINANCIAL PROFILE EXAMPLE—RATE OF RETURN

Rate of Return



Schedule A-5.0  
FINANCIAL PROFILE EXAMPLE—KWH SOLD

Standard Electric Cooperative, Inc.  
Rolling 12-Month Periods Ended 12/31/Year -2 through 12/31/Year -0



## Schedule B-1.0

### COST ALLOCATION SUMMARY

Account	Total	Residential	COMMERCIAL	IRRIGATION	LARGE POWER	Industrial	Security Lts	Street Lts
Rate Base	303,617,690	238,774,960	19,151,645	13,674,683	17,019,325	3,752,276	9,160,685	2,084,116
Operating Revenue	192,813,464	135,223,989	11,283,884	6,514,689	17,718,979	17,460,065	4,149,868	461,990
Operating Expenses	181,684,293	129,395,245	10,214,652	6,600,828	15,118,981	16,283,710	3,732,473	338,404
Return	11,129,171	5,828,744	1,069,232	(86,139)	2,599,998	1,176,355	417,395	123,586
Rate of Return	3.666%	2.441%	5.583%	-0.630%	15.277%	31.350%	4.556%	5.930%
Relative ROR	1.000	0.666	1.523	(0.172)	4.168	8.553	1.243	1.618
Interest	10,086,256	7,959,881	634,810	448,569	555,281	120,849	298,416	68,450
Operating Margins	1,042,915	(2,131,137)	434,422	(534,708)	2,044,717	1,055,506	118,979	55,136
Margin % Revenue	0.541%	-1.576%	3.850%	-8.208%	11.540%	6.045%	2.867%	11.934%
Operating TIER	1.103	0.732	1.684	(0.192)	4.682	9.734	1.399	1.805
Revenue Deficiencies								
Uniform ROR = 7.927%	12,937,430	13,098,024	448,845	1,170,078	(1,250,942)	(878,927)	308,737	41,614
Deficiency as % of Revenue	6.710%	9.686%	3.978%	17.961%	-7.060%	-5.034%	7.440%	9.008%
Uniform % Margin = 6.795%	12,937,430	12,144,520	356,519	1,048,619	(902,041)	140,410	174,879	(25,476)
Deficiency as % of Revenue	6.710%	8.981%	3.160%	16.096%	-5.091%	0.804%	4.214%	-5.514%

## Schedule B-2.0

## SUMMARY OF COMPONENTS OF EXPENSES

Accounts	Total	Residential	COMMERCIAL	IRRIGATION	LARGE POWER	Industrial	Security Lts	Street Lts
Average Consumers	88,163	81,525	4,827	1,244	565	2	47,504	4,664
kWh Sold	1,830,775,494	1,151,165,422	97,806,128	55,350,845	189,686,899	299,314,241	34,581,451	2,870,508
NCP kW	10,775,573	8,804,700	521,316	285,952	580,553	469,043	105,271	8,738
CP kW	4,225,034	2,980,736	231,492	144,811	400,332	420,159	43,863	3,641
<b>PUR PWR DEMAND</b>	<b>64,248,682</b>	<b>45,701,556</b>	<b>3,517,154</b>	<b>2,302,715</b>	<b>6,020,746</b>	<b>6,054,182</b>	<b>602,464</b>	<b>49,865</b>
Monthly Cost per Cons	60.73	46.72	60.72	154.25	888.02	252,257.58	1.06	0.89
Average Cost per kWh	0.035094	0.039700	0.035960	0.041602	0.031740	0.020227	0.017422	0.017371
Cost per NCP kW	5.96	5.19	6.75	8.05	10.37	12.91	5.72	5.71
Cost per CP kW	15.21	15.33	15.19	15.90	15.04	14.41	13.74	13.70
<b>PUR PWR ENERGY</b>	<b>63,473,630</b>	<b>40,472,271</b>	<b>3,438,634</b>	<b>1,946,006</b>	<b>6,597,534</b>	<b>9,702,462</b>	<b>1,215,803</b>	<b>100,920</b>
Monthly Cost per Cons	60.00	41.37	59.36	130.36	973.09	404,269.25	2.13	1.80
Average Cost per kWh	0.034670	0.035158	0.035158	0.035158	0.034781	0.032416	0.035158	0.035158
Cost per NCP kW	5.89	4.60	6.60	6.81	11.36	20.69	11.55	11.55
Cost per CP kW	15.02	13.58	14.85	13.44	16.48	23.09	27.72	27.72
<b>WIRES DEMAND</b>	<b>41,944,804</b>	<b>33,056,114</b>	<b>2,770,133</b>	<b>1,891,473</b>	<b>3,118,892</b>	<b>744,254</b>	<b>328,699</b>	<b>35,239</b>
Monthly Cost per Cons	39.65	33.79	47.82	126.71	460.01	31,010.58	0.58	0.63
Average Cost per kWh	0.022911	0.028715	0.028323	0.034172	0.016442	0.002487	0.009505	0.012276
Cost per NCP kW	3.89	3.75	5.31	6.61	5.37	1.59	3.12	4.03
Cost per CP kW	9.93	11.09	11.97	13.06	7.79	1.77	7.49	9.68
<b>TOTAL CUSTOMER</b>	<b>36,083,787</b>	<b>29,092,073</b>	<b>2,006,810</b>	<b>1,544,575</b>	<b>730,866</b>	<b>80,242</b>	<b>2,311,641</b>	<b>317,580</b>
Monthly Cost per Cons	34.11	29.74	34.65	103.47	107.80	3,343.42	4.06	5.67
Average Cost per kWh	0.019710	0.025272	0.020518	0.027905	0.003853	0.000268	0.066846	0.110635
Cost per NCP kW	3.35	3.30	3.85	5.40	1.26	0.17	21.96	36.34
Cost per CP kW	8.54	9.76	8.67	10.67	1.83	0.19	52.70	87.22
<b>Total Expenses</b>	<b>205,750,903</b>	<b>148,322,014</b>	<b>11,732,731</b>	<b>7,684,769</b>	<b>16,468,038</b>	<b>16,581,140</b>	<b>4,458,607</b>	<b>503,604</b>
Monthly Cost per Cons	194.48	151.61	202.55	514.79	2,428.91	690,880.83	7.82	9.00
Average Cost per kWh	0.112385	0.128845	0.119959	0.138837	0.086817	0.055397	0.128931	0.175441
Cost per NCP kW	19.09	16.85	22.51	26.87	28.37	35.35	42.35	57.63
Cost per CP kW	48.70	49.76	50.68	53.07	41.14	39.46	101.65	138.31

Schedule B-3.0  
COMPONENTS OF EXPENSE WITH CLASS RETURN - RESIDENTIAL

	Unit Cost				
	Required Revenue	kWh	CP kW	NCP kW	Customer
Components of Expenses - Detailed					
Power Supply-Demand	34,737,661	0.03018	11.65	3.95	35.51
Power Supply-Energy	40,472,271	0.03516	13.58	4.60	41.37
Power Supply-Delivery	10,963,895	0.00952	3.68	1.25	11.21
Sub-Transmission	1,190,070	0.00103	0.40	0.14	1.22
Distribution Substation	3,425,880	0.00298	1.15	0.39	3.50
Distribution Backbone	13,163,611	0.01144	4.42	1.50	13.46
Distribution Demand	12,011,816	0.01043	4.03	1.36	12.28
Distribution Customer	19,339,696	0.01680	6.49	2.20	19.77
Customer Services	1,398,862	0.00122	0.47	0.16	1.43
Customer	6,375,502	0.00554	2.14	0.72	6.52
Total	143,079,264	0.12430	48.01	16.27	146.27
Components of Expenses - Consolidated for Rate Design					
Power Supply Demand	34,737,661	0.03018	11.65	3.95	35.51
Power Supply Energy	40,472,271	0.03516	13.58	4.60	41.37
Power Supply-Delivery	10,963,895	0.00952	3.68	1.25	11.21
Distribution Demand	29,791,377	0.02588	9.99	3.38	30.45
Distribution Customer	27,114,060	0.02355	9.10	3.08	27.72
Total	143,079,264	0.12429	48.00	16.26	146.26
Billing Units					
12-Month Sum		1,151,165,422	2,980,736	8,804,700	978,300

Schedule B-4.0  
SUMMARY OF RATE CHANGE

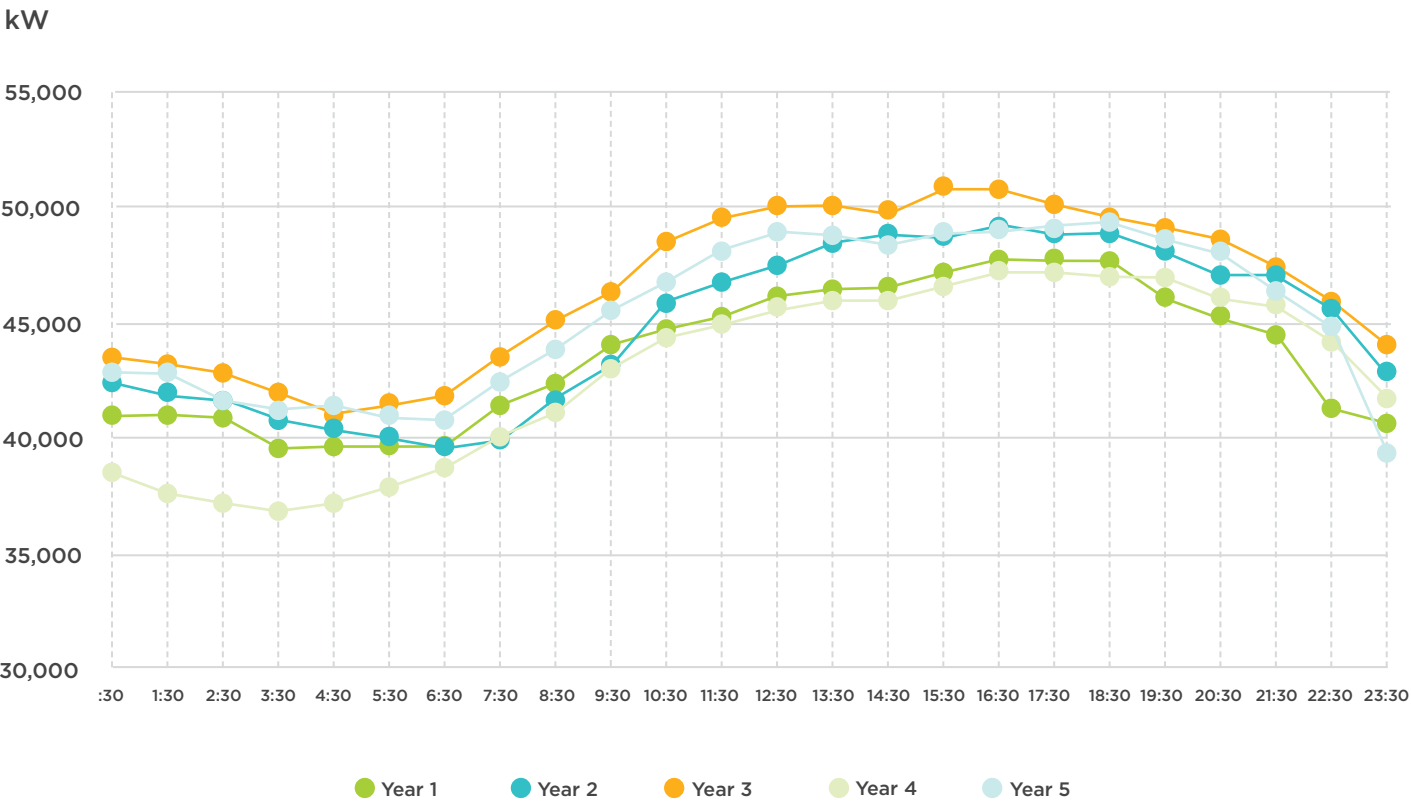
	Consumers	kWh Sold	Adjusted Test Year Revenue	Proposed Revenue	Change	Percent Change
Residential	81,525	1,151,165,422	\$132,083,016	\$143,079,264	\$10,996,248	8.33%
Commercial 1-Phase	3,776	59,350,895	6,754,550	7,284,321	529,771	7.84%
Commercial 3-Phase	1,051	38,455,233	4,330,657	4,584,036	253,379	5.85%
Commercial Total	4,827	97,806,128	11,085,207	11,868,357	783,150	7.06%
Irrigation	722	34,212,927	4,197,549	4,716,824	519,275	12.37%
Irrigation-Load Control	522	21,137,918	2,250,478	2,537,229	286,751	12.74%
Irrigation Total	1,244	55,350,845	6,448,027	7,254,053	806,026	12.50%
Large Power-Secondary	546	125,027,857	12,627,210	12,806,597	179,387	1.42%
Large Power-Primary	19	64,659,042	5,034,489	4,855,079	-179,410	-3.56%
Large Power Total	565	189,686,899	17,661,699	17,661,676	-23	0.00%
Industrial	2	299,314,241	17,460,066	17,460,066	0	0.00%
Security Lights	47,504	34,581,451	4,138,049	4,448,356	310,307	7.50%
Street Lights	73	2,870,508	459,304	501,034	41,730	9.09%
Total Energy Sales	88,236	1,830,775,494	189,335,368	202,272,806	12,937,438	6.83%
Other Revenue			3,478,100	3,478,100	0	0.00%
Total			192,813,468	205,750,906	12,937,438	6.71%



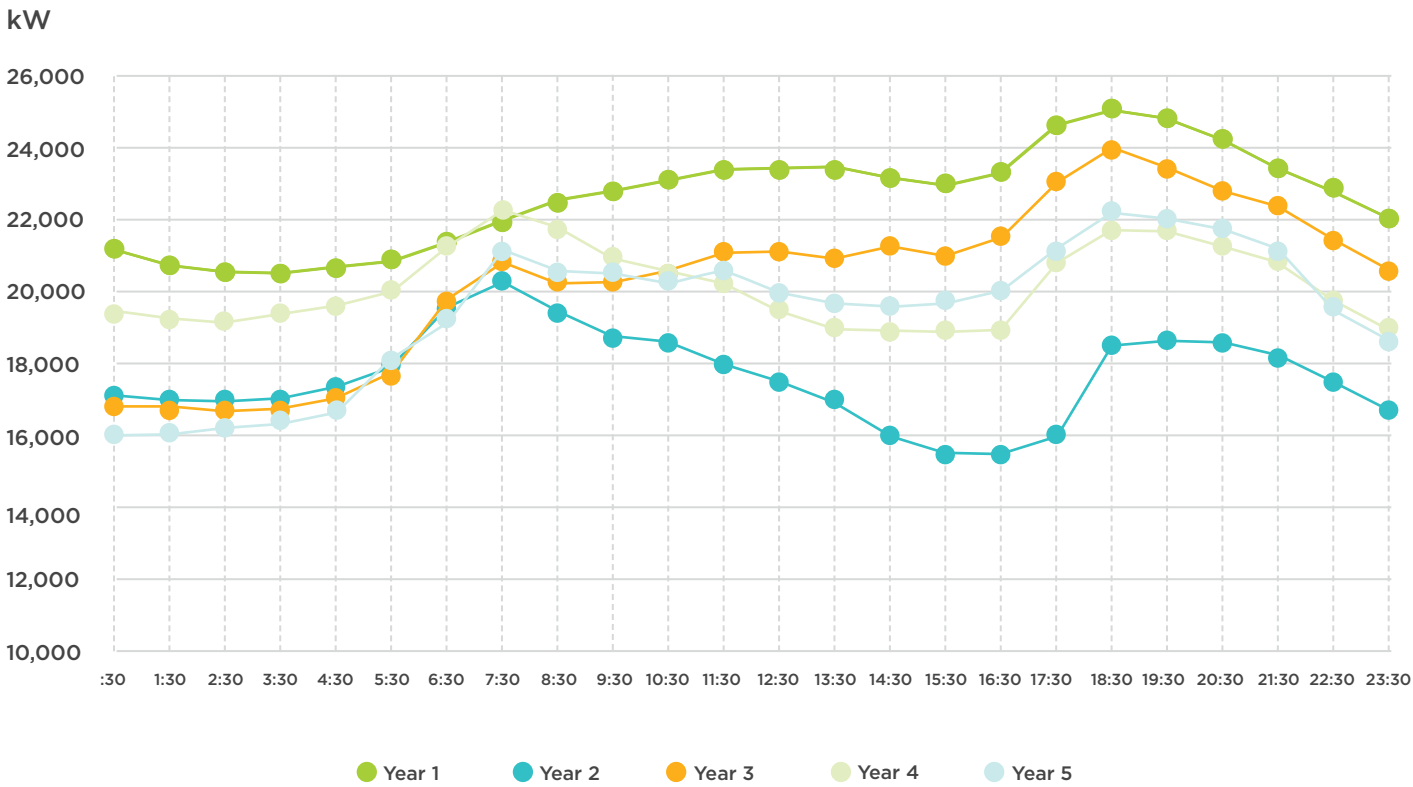
Schedule B-5.0  
COMPARISON OF EXISTING AND PROPOSED RATES - RESIDENTIAL

kWh Usage		Monthly Bills w/ kWh Ending in Block	Exisitng Rate	Proposed Rate	Change	Percent Change
Customer Charge			\$14.50	\$27.72	\$13.22	91.17%
Energy Charge, per kWh			\$0.08950	\$0.10074	\$0.01124	12.56%
PCA Factor, per kWh			\$0.01311	\$0.00000	(\$0.01311)	-100.00%
Total Energy, per kWh			\$0.10261	\$0.10074	(\$0.00187)	-1.82%
	0	1,359	\$14.50	\$27.72	\$13.22	91.17%
	50	4,006	\$19.63	\$32.76	\$13.13	66.89%
	100	2,304	\$24.76	\$37.79	\$13.03	52.63%
	250	6,522	\$40.15	\$52.91	\$12.76	31.78%
	500	7,228	\$65.81	\$78.09	\$12.28	18.66%
	750	13,025	\$91.46	\$103.28	\$11.82	12.92%
	1,000	8,567	\$117.11	\$128.46	\$11.35	9.69%
	3,000	38,167	\$322.33	\$329.94	\$7.61	2.36%
	5,000	2,642	\$527.55	\$531.42	\$3.87	0.73%
	Over 5,000 kWh	229				
1,177	Class Average		\$135.27	\$146.29	\$11.02	8.15%

Schedule C-1.0  
JULY - PEAK DAY



Schedule C-2.0  
JANUARY - PEAK DAY



# APPENDIX

## GLOSSARY OF TERMS

**Annual Growth in Total Utility Plant (KRTA Ratio #116):** Measures the percent change in total utility plant (TUP) from the previous year. Plant Growth Rate = change in TUP from the previous year ÷ TUP balance, previous year.

**Annualized / Annualization:** The process of taking an event (such as an increase in cost) that occurred sometime during an accounting period (such as June of a year) and restating the impact as if the event had been in place for the full accounting period (a total of twelve months).

**Average Debt Cost:** Measures the average cost of borrowed funds. As calculated on Appendix Schedule A-1.0:

$$\text{Average Debt Cost} = \frac{\text{Form 7 Part A, Line 16}}{\text{CFC Form 7 Part B, (Line 38 EOY + Line 38 BOY) } \times 0.5}$$

$$\text{Average Debt Cost} = \frac{\text{Form 7 Part A, Line 16}}{\text{RUS Form 7 Part B, (Line 43 EOY + Line 43 BOY) } \times 0.5}$$

EOY = End of Year

BOY = Beginning of Year

**Billing Units:** Quantities (meter, kWh, demand, etc.) to which rate components are applied to determine the monthly bill.

**Capital Expenditure (CAPEX):** Annual capital requirement for plant additions including general plant less plant financed with contributions in aid of construction.

**Classification of Cost:** Process of defining cost in terms of usage characteristic that drives the cost, i.e., energy, customer, demand.

**Coincidental Demand:** The sum of two or more demands that occur in the same time interval.

**Coincidental Peak Load:** The maximum value in an accounting period of the coincident demand.

**Contribution in Aid of Construction (CIAC):** Payment made by a member-consumer for the facilities to provide service.

**Consumer Density (KRTA Ratio #125, Average Consumers Per Mile of Line):**

Measures the density of the utility system in terms of the number of consumers per mile of line constructed and in service. Consumer density = Average Total Consumers Served (KRTA Ratio #1) ÷ Total Miles of Line (KRTA Ratio #5) The average number of members-consumers per mile of line. As calculated on Appendix Schedule A-2.0:

$$\text{Consumer Density} = \frac{\text{Average Consumers}}{\text{Miles of Line}}$$

Consumers = CFC Form 7, Part R, Line 10 and RUS Form 7, Part O, Line 10

Miles of Line = Form 7, Part B, Line 5

**Debt Service:** The annual principal and interest payments on long-term debt. Note: The annual amount billed as opposed to the amount paid is used in KRTA ratio calculations.

**Distributed Energy Resource (DER):** The DER may be located behind the wholesale meter or behind the retail meter. DER may include renewables such as solar or wind generation or any type of fossil-fired generation.

**Debt Service Coverage Ratio (DSC) (KRTA Ratio #12):** A metric that reflects the ability of the cooperative to pay annual debt service.  $DSC = (\text{Margin} + \text{Depreciation} + \text{Interest LTD}) \div \text{Debt Service}$ . Note: Additional items may be required if the cooperative has capital leases. The long-term lease calculation is intentionally left out to simplify the DSC equation and should be included if long-term leases are large enough to trigger the calculation.

$$DSC = \frac{\text{Part A, Line 29} + \text{Line 16} + \text{Line 13}}{\text{Billed Debt Service}}$$

$$ODSC = \frac{\text{Part A, Line 21} + \text{Line 16} + \text{Line 13} + \text{Line 22} + \text{Cash Patronage Capital Retirements Received}}{\text{Billed Debt Service}}$$

G&T and Lender Cash Patronage Capital Retirements Received reported on CFC Form 7, Part J and on RUS Form 7, Part I.

**Distribution System Operator (DSO):** The entity responsible for developing, operating, and maintaining the electric distribution system including interconnections with other systems.

**Energy Charge:** That portion of the charge for electric service based upon the electric energy (kWh) consumed or billed.

**Equity Level as a Percentage of Assets (KRTA Ratio #16):** Measures the percent of total assets owned by cooperative members.

RUS Form 7, Part C Balance Sheet. Line 36 ÷ Line 29.

CFC Form 7, Part C Balance Sheet. Line 35 ÷ Line 28.

**Equity Level as a Percentage of Total Capitalization (KRTA Ratio #18):** Measures the percent of total capitalization (debt and equity) owned by cooperative members.

RUS Form 7, Part C Balance Sheet. Line 36 ÷ (Line 36 + Line 43).

CFC Form 7, Part C Balance Sheet. Line 35 ÷ (Lines 35 + Line 38).

**Equity Management Plan:** A financial strategy established by the Board of Directors that identifies the key financial objectives for the cooperative. May also be referenced as a Financial Strategy Plan. The plan has four key metrics that can be adjusted to meet particular objectives of the system: equity (either % of assets or % of capitalization), coverage ratios (TIER, DSC, OTIER), liquidity (combination of general fund cash and line of credit) and the capital credit retirement program.

**Financial Forecast:** Ten-year financial forecast for the cooperative.

**Financial Profile:** A summary of operating expenses, margin, coverage ratios, rate of return or usage data on a rolling 12-month basis. The purpose is to identify a rolling 12-month income statement that identifies trends in cost, revenue, usage, and margin.

**Financial Strategy:** See Equity Management Plan above.

**Forecasted Test Year:** Any future 12-month period showing revenue, expenses, usage data and margins for the cooperative.

**Formula Rate Proceeding:** Used in many FERC proceedings. The FERC approves a formula rather than a specific rate. Each year the formula is populated with data consistent with the protocols the FERC approved. The result is an updated rate or revenue requirement.

**Form 7:** Either RUS or CFC statistical report. The analysis reflects RUS Revision Date 2014 and CFC Version 1.05 (1/2016).

**Functionalization:** The assignment of costs associated with a major function such as Production, Transmission, Distribution, Administrative and General Cost.

**General Funds Ratio:** The general fund cash balance divided by total utility plant. As calculated on Appendix Schedule A-1.0:

$$\text{General Funds Ratio} = \frac{\text{Part B, Lines 9 + 12 + 13 + 15 thru 18}}{\text{Line 3}}$$

**Generation and Transmission Cooperative (G&T):** This analysis references two types of G&Ts. The first type provides wholesale service to a member distribution cooperative. The second provides service to a member transmission cooperative, and the transmission cooperative then provides service to a member distribution cooperative.

**Historic Test Year:** Any actual historic 12-month period.

**Interest on Long-Term Debt (LTD):** Reported on RUS/CFC Form 7, Statement of Operations, Part A, Line 16.

**Independent System Operator (ISO):** The entity coordinating, controlling, and monitoring the electrical power system within a state or states.

**Investor-Owned Utility (IOU):** A public utility owned by a corporation or private company.

**Key Ratio Trend Analysis (KRTA):** The KRTA is a set of 145 financial and operating ratios used by staff and board members of distribution systems to better understand how their cooperative has trended over time and compares with other cooperatives nationally and within four other peer groups.

**Line Loss (KRTA Ratio #139):** Measures the difference between electricity sold and accounted for and electricity purchased. As calculated on Appendix Schedule A 2.0:

$$\text{Percent Losses} = \frac{\text{kWh Purchased \& Generated} - (\text{kWh Sold} + \text{Own Use})}{\text{kWh Purchased and Generated}}$$

CFC Form 7, Part R and RUS Form 7, Part O:

kWh Purchased & Generated = Line 16 + Line 17

kWh Sold = Line 11

Own Use = Line 15

**Liquidity:** Consists of general fund cash plus lines of credit available to the cooperative and reflects working capital available to the cooperative to meet operating cash flow requirements.

**Long-Term Debt (LTD):** Loans or financial obligations with a term greater than one year.

**Long-Term Lease Calculation:** Used in KRTA coverage Ratios #6 through #15 when long-term leases are greater than 2% of total margins or equities. Please refer to the KRTA formula guide on the CFC Member Website for the specific calculation.

**Margin for Interest (MFI):** A metric of margin and interest found in some long-term debt indentures.

**Net Margin:** Patronage capital or margins as reported on RUS/CFC Form 7, Statement of Operations, Part A, Line 29.

**Non-Coincidental Peak Load:** The maximum rate of energy usage over a defined period (60 minutes, 30 minutes, 15 minutes, etc.) determined over an accounting period (monthly, seasonal, annual, etc.).

**Normalized / Normalization:** The process of restating usage, revenue, and associated expenses to “normal” weather conditions or to recognize changes in usage for a very large customer or a rate class.

**Operating Margin:** Patronage capital and operating margins as reported on RUS/CFC Form 7, Statement of Operations, Part A, Line 21.

**Operating Times Interest Earned Ratio (OTIER):** See Times Interest Earned Ratio (TIER) below.

**Plant Growth Rate:** The annual percent change in net utility plant. As calculated on Appendix Schedule A-1.0:

$$\text{Plant Growth Rate} = \frac{\text{Form 7 Part B, Line 5}}{\text{Line 5 (12 months ago)}} - 1$$

**Pro-forma Income Statement:** An income statement restated to reflect an accounting period restated for revenue and expense adjustments.

**Public Utility Regulatory Policies Act (PURPA):** The Public Utility Regulatory Policies Act (PURPA, Pub. L. 95–617, 92 Stat. 3117, enacted November 9, 1978) is a United States Act passed as part of the National Energy Act. It was meant to promote energy conservation (reduce demand) and promote greater use of domestic energy and renewable energy (increase supply).

**Purchased Power Adjustment/Power Cost Adjustment (PPA):** A clause in a rate schedule that provides for adjustments to the bill when total power cost billed from the wholesale supplier varies from a specified base amount reflected in the rate design. The adjustment is typically reflected in a \$/kWh adjustment to the member-consumer. However, some adjustors track changes in the demand and energy component separately.

**Qualifying Facility (QF):** A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act (PURPA).

**Rate Base:** The capital investment associated with providing service. For this Rate Guide, estimated as net utility plant × historical ratio of Rate Base to Net Utility Plant.

**Rate of Return (ROR):** A value equal to the Return divided by the Rate Base.

**Return:** Interest and Other Deductions plus Margin. Form 7 Part A, Line 21 + Lines 16 thru 19.



**Return on Equity:** As calculated on Appendix Schedule A-1.0:

$$\text{Return on Equity} = \frac{\text{Rate of Return} - (1 - \text{Equity \% Capitalization}) \times \text{Average Debt}}{\text{CostEquity \% Capitalization}}$$

**Revenue Requirement:** The total revenue that the rates charged to member-consumers must produce in order to pay all of the operating expenses associated with providing service and the capital cost associated with meeting the financial objectives.

**Regional Transmission Organization (RTO):** The entity coordinating, controlling, and monitoring a multi-state electric grid.

**Test Year:** A 12-month period that is used for the determination of the cost components for the cost of service analysis and margin component necessary to meet the cooperative's financial objectives.

**Times Interest Earned Ratio (TIER):** Measures the cooperative's ability to generate sufficient earnings from net margins to pay interest on long-term debt.

$$\text{Net TIER (KRTA Ratio \#6)} = \frac{\text{Part A, Line 29} + \text{Line 16}}{\text{Line 16}}$$

$$\text{Modified TIER} = \frac{\text{Part A, Line 29} - \text{Line 26} - \text{Line 27} + \text{Line 16}}{\text{Line 16}}$$

$$\text{OTIER (KRTA Ratio \#8)} = \frac{\text{Part A, Line 21} + \text{Line 16} + \text{Patronage Cash Received}}{\text{Line 16}}$$

Cash Patronage Capital Retirements Received reported on CFC Form 7, Part J and on RUS Form 7, Part I.

Note: The long-term lease calculation is intentionally left out to simplify the TIER equation and should be included if long-term leases are large enough to trigger the calculation. Please reference the long-term lease calculation in the glossary.

**Unbundling:** The separating of the total process of providing electric power service from generation to metering into its component parts for the purpose of identifying the separate pricing components.

# RETAIL RATE GUIDE

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## Volume II



**National Rural Utilities  
Cooperative Finance Corporation**

*This Rate Guide is jointly owned by the National Rural Electric Cooperative Association (NRECA) and the National Rural Utilities Cooperative Finance Corporation (CFC) with authorship contributions from C.H. Guernsey & Company.*



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## Overview

The Rate Guide is presented in two volumes. Volume I provides an overview of the issues and concerns facing distribution cooperatives in the development of rates and pricing for services that recognize the consumer-member becoming an active agent in the implementation of new technology. Section I provides an outline of a process consisting of seven steps for the development of a rate analysis and describes the board's participation in that process. For those rural utilities that are not necessarily interested in the development of a complete rate analysis and are primarily interested in rate design options, Volume I outlines various possibilities and discusses the advantages and disadvantages of each option. The discussion extends to factors that should be considered in the roll-out and implementation of possible rate adjustments or a new rate structure.

Volume II is applicable for the utility structure that intends to develop a complete rate analysis—implementing all seven steps and resulting in rates that will meet the objectives defined in the cooperative's Equity Management Plan or Financial Strategy Policy, Rate Design Policy and Distribution System Operator Policy. It is not possible to design rates that will meet the policy objectives without first completing all of the steps, in particular Step #3 Develop System Revenue Requirements and Step #4 Develop Cost-of-Service Study. All of the detailed data necessary for the rate design are outlined in these two steps.

The system revenue requirement consists of two components: operating expenses and margins. Volume II Section 1 describes the process for developing the operating expense component, and Section 2 defines the process for the margin component which reflects the Financial Strategy of the cooperative. Section 3 explains the development of the cost-of-service study (COSS), and Section 4 describes how the results of the COSS provide the data necessary to create a rate structure that reflects the Rate Design Policy.

The terms “**return**,” “**rate of return**,” “**earnings**” and **similar terms** are commonly used in utility ratemaking. For convenience and ease of use, Volumes I and II of the Retail Rate Guide use these terms. Using these terms, however, does not suggest that an electric cooperative operates on a for profit or above cost basis. Instead, an electric cooperative operates on a nonprofit and at-cost basis. While an electric cooperative often develops rates based upon projected or desired revenue and margins, it does not earn a “profit” from these rates. Instead, the cooperative annually allocates operating margins from the rates to its consumer-members and patrons.



# 1.0

## Determination of Revenue Requirements

*Volume I, Section 1.2.2 described the various reasons for initiating a Rate Analysis. The most common and also the most important reason is because the current rates charged to consumer-members applied to the billing units in future periods will not produce the desired revenue stream that, given the expected cost of providing service, will not produce margins sufficient to meet the financial objectives. This section describes the development of the cost components of the revenue requirement.*

### 1.1

#### Components of Revenue Requirement

The Form 7 format begins with the total operating revenue, identifies all of the costs associated with providing service and defines the resulting net margin.<sup>1</sup> The format for the determination of the revenue requirement in a Rate Analysis consists of the same components presented in a slightly different format.

The objective is to determine the total revenue requirement, which is the sum of the total cost of providing service in a 12-month period plus the required operating margins. The operating revenue available from miscellaneous fees and rents are subtracted to determine the revenue requirement for the electric rates. Using various allocation factors, the COSS then allocates each component of the total system revenue requirement to each rate classification. Appendix Schedule A-1.0 shows the typical format for the determination of total revenue requirements.

### 1.2

#### Selection of Test Year

The objective of the Rate Analysis is to develop rates that will recover the cost of providing service to the consumer-member. The associated revenue requirement is based on costs incurred over a 12-month period, i.e., the “Test Year.” Ideally, when the rates become effective, the billing units for each rate class on the effective date will, when multiplied by the respective rates, produce the revenue necessary to cover the costs incurred by the cooperative on the effective date and generate the desired margins. Given the discussion in Volume I related to the time frame to implement a rate change with an effective date 12 to 24 months in the future, consideration needs to be given to how best define the costs expected in the prospective period.

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<sup>1</sup> The Rate Guide defines margin in terms of operating margin. Reference Section 2.3.1.

**The first crucial decision made at the beginning of the process is to select a “test year.”**

The first crucial decision made at the beginning of the process is to select a “test year.” The test year options include:

1. A historical 12-month period.



The most recent calendar year.



The most recent fiscal year (if not a calendar year).



Any historical 12-month period (often the most recent 12 months).

2. A historical 12-month period with adjustments to reflect expected changes in cost.
3. A projected budget period.
4. A projected budget period with provisions for a true-up.

If rate regulated, the selected test year must comply with the rules of the regulatory authority. The following describes issues that need to be considered.

### 1.2.1 Historic Test Year

A historic test year means using the actual operating expenses and data for a historic period to evaluate existing rates and develop any proposed rate changes. The advantage of the historic test year is that all of the data are available and the Rate Analysis process can be implemented in the shortest time. The disadvantage is that it is not forward looking; therefore only cost and use relationships that existed in the historic test year will be reflected in future periods. Unless the rates include a margin adjustment or some form of reconciliation process, this will not be acceptable.

### 1.2.2 Historic Test Year with Adjustments

The most common test year is a historic period with adjustments to expenses, revenue and use data to make the test year as forward looking as possible. A more detailed discussion of the adjustments that can be made is presented in Section 1.4.

### 1.2.3 Forecast Test Year

Another option is to use a forecast or future test year. The forecast year could be based on a budget or forecast period. The advantage of the forecast test year is that it captures the prospective components related to cost and billing units. The disadvantage of the forecast test year is that most budgets and forecasts do not provide the degree of detail required to develop a complete COSS. Many state regulatory commissions do not allow a forecasted test year for retail rate proceedings because of the concern over the quality and probity of the estimates that would be developed by the utility.

### 1.2.4 Forecast/Budget Test Year with True-Up

One approach is to develop a future test year based on budget estimates with provisions for reconciliation or true-up of the estimated actual expenses. This results in a formula rate that is simply populated each year with forecasted values and true-up provisions. A projected test year clearly has the advantage of being forward looking, and the true-up provision ensures that the consumer-members served pay only actual costs and the margin component is equal to the target value. However, a projected test year is typically not used for retail rate cases.

Another variation of the true-up process involves the application of a monthly rate adjustment (either a charge or credit) to the monthly billing of the consumer-member in an amount necessary to maintain the desired

**Even in a non-regulated jurisdictions it is prudent to follow the same general process as if regulated.**

financial metric. For example, a TIER adjustment would be an adder (or credit) to the rate necessary to maintain a TIER within a desired range.

The benefits of the coverage adjustment (TIER or DSC) are very clear: The cooperative is assured of realizing the desired level of margins needed to meet the financial objectives. The disadvantage is that it opens the cooperative to criticism that with the adjustment there is no incentive for the cooperative to manage costs and seek ways to minimize rates charged to the consumer-member. The discussion of true-up mechanisms or flow-through provisions really goes to the question of providing options to manage risk uncertainty. Clearly, these provisions reduce the potential adverse impact of errors in the forecast of future cost or billing units.

The Rate Guide assumes a test year based on a historic 12-month period with adjustments.

### **1.3 Standards for Making Cost, Revenue and Billing Unit Adjustments**

If the cooperative selects a historic 12-month period for the test year, it is important to review events that occurred in the 12-month period and, if necessary, make adjustments to define a “normal test year” that is as forward looking as possible. The regulatory and industry standard for making pro forma adjustments is that they must be **known, measurable and of a continuing nature.**

If the cooperative is located in a state with regulatory oversight, a utility commission may determine what pro forma adjustments are permitted. Even in non-regulated jurisdictions it is prudent to follow the same general process as if regulated. While some regulatory requirements may seem

burdensome and unnecessary for the rate-making process, most have merit and should be reflected in the undertaking. When explaining the results to a consumer-member it is helpful to be able to say that the process followed normally accepted regulatory requirements – even if the cooperative is not regulated.

#### **Examples of known and measurable adjustments:**

- If the board authorized a rate adjustment sometime during the test year, it would be appropriate to restate revenue with the existing rates annualized over the full 12-month test year.
- If the board authorized a wage adjustment during the test year it would be appropriate to reflect the wage adjustment for a full 12-month period.
- If the cooperative lost (gained) a significant power or industrial load, the test year revenue and expenses should be adjusted to reflect the changed event for a full 12 months. Each cooperative will have its own definition of a change in load that needs to be recognized and is “significant.”
- Each cooperative will have its own definition of an abnormal weather event. If there is an abnormal weather event during the test year it may be appropriate to remove the total cost from the test year and replace it with an amortized amount over a number of years.

- If it is normal for the cooperative to perform tree trimming, pole inspection or meter testing each year, but if for some reason the test year did not have the normal level of activity, an adjustment should be made to reflect this “normal” activity.
- The cost of the Rate Analysis or rate filing should be spread over the number of years until the next likely analysis will be required.
- Non-recurring labor-related costs such as early retirement incentives or workers’ compensation premiums should be adjusted.
- Adjustments may be appropriate to reflect normalized labor cost expensed to operations.

The adjustments to the test year are made to develop the appropriate costs for establishing rates. The adjustments are not necessarily changes to the cooperative’s books and records. The cooperative will follow normal accounting standards in maintaining its accounting records.

## 1.4

### Adjustments to Historic Test Year

One of the first steps in the development of the rate analysis is to identify the events that occurred in the test year, including events that did not occur but should have occurred in a “normal” year. Then, quantify adjustments to costs, revenues and billing units that are appropriate. It is also important to ensure adjustments are aligned between cost and revenue. For example, if a major plant addition is made during the historic period, it would be appropriate to make an adjustment to depreciation, taxes, interest and perhaps O&M expenses to reflect the impact of the additions. Consideration should also be given to adjustments to revenue if the addition is associated with investment made to serve a new consumer-member. The objective is to develop as much as possible a normal 12-month period that is forward looking.

### 1.4.1 Adjustments to Cost

Standard adjustments include the following:

- Cost of power (reflect a rate change)
- Salaries and benefits
- O&M programs
- Insurance
- Taxes
- Depreciation
- Debt cost

Judgment is clearly required in defining the test year adjustments. The applicable qualifying criteria relate to known, measurable and of a continuing nature.

### 1.4.2 Adjustments to Revenue

Adjustments to revenue may also be required. The revenue adjustments may include:

- Application of current retail rates to adjusted test year retail billing units.
- Adjustment to revenue related to any automatic adjustment factors.
- Adjustments to revenue and power costs to “normalize” use for weather or high growth.
- Adjustment to “other operating” revenue, such as late fees or pole attachments. This revenue will be a reduction to the consumer-member revenue requirement and needs to be properly defined.

The potential criticism is that the cooperative is always looking for cost increases but not revenue increases. It is important to talk through each of the proposed cost adjustments and make certain to include revenue adjustments only if they are appropriate.

## 1.5

### The Proof of Revenue

The proof of revenue is a detailed analysis that identifies revenue given a set of rates and billing units. The proof of revenue can and should be used for at least three major tasks:

#### 1. Audit of the test year revenue calculations:

Revenue is defined given test year actual rates and test year actual billing units and compared with actual reported revenue. This provides an indication of any material billing errors that occurred during the test year. Errors can include application of incorrect rates, mistakes in the programming of rate calculations, rates not correctly charged by season correctly, application of incorrect demand billing units were, etc. This audit component is essential since it identifies billing errors, but the real importance is validation of the billing units, which then will be used to define adjusted test year revenue and projected revenue with the new rates.

#### 2. Calculation of the adjusted test year revenue:

The proof of revenue process is then used to determine revenue by applying current rates to adjusted test year billing units. This is a crucial step because it reconciles the test year revenue to the rates.

#### 3. Calculation of the proposed rate revenue:

Revenue for each of the proposed rate options can then be determined based on its application to the adjusted test year billing units.

Many billing systems include test functions that allow cooperatives to determine revenue given alternative rates. It is important that the program uses billing units consistent with the rate definition of the units. Even in such cases, the cooperative should consider developing a proof of revenue process to confirm the revenue from the proposed rates. Nothing is worse than putting in place rates that do not produce the projected revenue.

## 1.6

### Data Needed for COSS and Implications Related to Selection of Test Year

The following identifies the data required for a COSS. The cooperative will likely prepare most of the data as a regular course of business for a calendar year period. Knowing the data required for a COSS may influence the selection of a test year:

- Historical RUS/CFC annual Form 7 reports for the test year and preceding years.
- All rate tariffs in effect during the test year and all tariffs currently in place or to be in place prior to any proposed rate change.
- Financial Forecast.
- Operating Budget.
- General Ledger or trial balance reports for the test year period.
- Continuing Property Records as of test year-end.
- Current work plan and projected plant additions for five to 10 years.
- The Equity Management Plan or board policies related to equity management, including retirement of patronage capital, cash management, etc.
- Cooperative's Rate Design Policy.
- Monthly sales reports from the cooperative billing system.
- Wholesale power tariffs or contracts with definitions of billing units and the wholesale rates effective during the test year and effective after test year-end.
- Test year purchased power bills.



## 1.7

**Development of the Pro Forma Income Statement**

Once the pro forma adjustments have been completed, the test year income statement is restated to show adjustments and the adjusted expense and revenue. Examples are provided for the hypothetical “Standard Electric Cooperative.” Appendix Schedule B-1.0, shows the items typically included in the pro forma income statement (in this case for a historic test year), the adjustments made, and the adjusted test year amounts. Schedule B-2.0 shows a summary of adjustments made, which are then embedded by function. The pro forma income statement on Schedule B-1.0 summarizes by major cost classification:

Column (a): Actual test year revenue and costs.

Column (b): Revenue and expense adjustments.

Column (c): Adjusted test year with revenue based on existing rates and adjusted billing units and costs adjusted to reflect changes that are known, measurable and of a continuing nature.

This is the starting point for the development of the COSS. The margins shown in Column (c) is the margin prior to any change in rates. Section 2.0 will discuss how to determine required margins. The sum of the required margins plus the adjusted operating expenses defines the operating revenue requirement for the cooperative. The revenue from consumer-member rates is then equal to the total operating revenue less other operating revenue. Referring to Schedule B-1.0:

Column (d): Adjustments to revenue necessary to realize the required consumer-member revenue requirement. In some cases there may be revenue-related tax adjustments, which are also shown in Column (d).

Column (e): Reflects the pro forma income statement with proposed rates and adjusted revenue. The resulting margins should be equal to the value developed in Section 2.0.

## 1.8

**Project Team**

Developing adjustments to the test year expenses requires input from individuals with intimate knowledge of the cooperative. It is very important for management to select the proper project team (team) to work on the analysis. The process outlined in this Rate Guide encourages the formation of a team that represents the following cooperative functions:

1. Financial/accounting
2. Billing and customer accounting
3. Engineering and operations
4. Member services
5. Communications
6. Information technology
7. Management

The team may include a third-party specialist such as an accountant, engineer, consultant or other resource. The third party can be a valuable asset to the process, particularly if cooperative staff have not previously been involved in a rate analysis. However, it is essential to avoid a situation in which the entire analysis is assigned to a third party with little or no involvement by the cooperative team. Each cooperative is unique with specific needs and requirements that must be considered in the development of the analysis. No group is better positioned to provide this information than staff.

The typical arguments against establishing a team are:

- My staff does not have the experience or skill sets to develop a rate analysis.
- My staff does not have time given current duties to develop a rate analysis.
- I am comfortable with the third-party because they work with my cooperative and they know the system.

The first point is certainly a valid concern. It is not uncommon for the third party to assume a leadership role, particularly with inexperienced staff. However, establishing a team to work with a third party provides an opportunity for the staff to learn the process and understand how their particular function fits with the whole process and why their contribution is important.

- Engineering and operations staff understand how the CAPEX reflected in their work plans will drive the revenue requirement and rates charged.
- Financial and accounting staff understand what drives the costs they record in each account, including the continuing property records (CPR), and how the data they provide determine the customer charge in the residential rate.
- Member services staff are familiar with questions and complaints about existing rates, and they will be the first to respond to questions on changed rates. They have the best “where the rubber meets the road” insight into consumer-member issues and concerns. Participating in the process will better position them to answer consumer-member questions.
- Billing staff understand how the billing system functions. They will be responsible for providing much of the sales data required to develop the analysis. They also understand the billing system capabilities which may affect the type of rate designs that can be implemented. Advanced rates requiring the integration of advanced metering infrastructure (AMI) and billing systems require the participation of billing staff in the process.
- Communications staff understand how to deliver the rate change message through various media.
- IT staff understand how AMI meters are programmed and read and what data are available with existing or planned AMI and billing systems.
- Management understands how all of the activities are connected and has a better knowledge base to explain the recommendations to the board.

Once they learn the process and understand why certain data are required and how those data are used in the analysis, the staff invariably suggest changes to their internal processes and procedures so that “next time” more comprehensive and meaningful data are available. A very common response from staff is, “Now that I understand why the data are needed, I think I can provide even better information next time.”

The second point really gets to a question of priority. Rate-making activities are critical to the long-term success of the cooperative. Management needs to decide how important it is for their staff to be involved compared with other ongoing activities. This is increasingly important as the distribution system transitions and new technology is implemented.

The third point may be that the third party (consultant for example) has worked with the cooperative for many years and knows the system very well. However, staff, not the consultant, will be working with and applying the results of the Rate Analysis every day. Questions will come up that, if the staff is knowledgeable about the process and the data that went into the analysis, can be easily answered. For example:

- Why is the customer charge set at the particular level and does the charge recover all of the customer-related costs?
- How is the line extension allowance established and how does it relate to costs embedded and recovered in the rates?
- What costs are recovered in the energy charge and what are the ramifications with the expansion of DER on the consumer-member’s side of the meter?
- What are the implications of net metering in terms of cost recovery and cost reallocation?

A good COSS will contain information that is extremely helpful to the staff in dealing with daily issues. To make use of the data, however, the staff will need to have some involvement in the development of the analysis. An important metric in evaluating the value a third party brings to the process is the extent to which they can impart knowledge to the cooperative team participants. Management needs to make certain that a “knowledge transfer” is realized to the maximum extent possible given the staff skills and resources available.

Once the COSS is complete and rates have been adopted by the board, many cooperatives require their entire employee work force, or at a minimum employees with consumer-member contact, are trained on the issues related to the rate changes, particularly where structural changes are involved. For example, in changing from an existing two-part to a proposed three-part rate, it would be extremely important to fully educate employees about the nature of, reason for and impact on consumer-members.

The suggested script for the knowledge transfer will vary. The specific narrative will depend on the individuals involved. The timing for the exchange also may vary. Ideally, the team will discuss the seven-step process and the data required to implement each step before beginning any detailed work. However, for the dialogue to be meaningful, the team members must be familiar with the process. The team members may not have that background. An alternative is to prepare an initial analysis and use that analysis as a reference for discussions with the team. With this approach it is easy for the team participants to understand why certain data are required, how they are used and how their input is used in the Rate Analysis.



# 2.0

## Margin Component of the Revenue Requirements

*Section 1.0 focuses on the development of a historic test year with revenue and expense adjustments. The next step is to determine the level of margins required. Margin is viewed as a cost when developing the revenue requirement. The margin is the cost incurred in meeting the financial objectives identified in the cooperative's strategic financial plan. The methodology presented below is intended to relate the margins requirement to the cooperative's four specific strategic financial objectives.*

### 2.1

#### Identify Cooperative Long-Term Financial Goals

When asked, "...what is driving our revenue requirement?"

The response should never be "that is the value that was recommended to us" or "that is what a consultant or a third party told us" or "that is what my staff said is typically used."

The response should relate directly to the cooperative-stated financial goals given current CAPEX requirements. The following outlines one method to develop the margin component of the revenue requirement that is directly related to strategic financial goals for the cooperative. The methodology relates to the four key elements defining the financial goals for the cooperative in the Financial Strategic Plan or Equity Management Plan and two factors that drive the actual margins requirement to meet the goals. The four key elements are:

1. Coverage objectives
2. Equity objectives
3. Liquidity objectives
4. Capital credits retirement objectives

The two driving factors are:

1. Projected CAPEX
2. Expected interest rate on long-term debt (LTD)

### 2.1.1 Coverage Objectives

The cooperative clearly needs to maintain financial ratios that will ensure access to capital. There are two key ratios for the cooperative one based on an accrual test and the second on a cash test of the adequacy of the cooperative's margins.

Times interest earned ratio (TIER) is a metric to evaluate the margins earned on an accrual basis and reflect margins as a multiple of interest obligations each year. Margin for interest (MFI) is a similar metric found in indentures. Debt service coverage (DSC) is a metric to evaluate the margins earned on a cash basis and reflects a level of cash available before debt service as a multiple of debt service.

Typically the driver will be TIER or DSC depending on the relationship of depreciation to the principal payment of LTD. The driver can change over time so the analysis should continually test both. The values can be defined in terms of operating margins, operating margins with certain cash adjustments, or net margins.

The question is "what is the appropriate coverage target (TIER, DSC, MFI, etc.) for the cooperative?" Before starting the discussion with the board:

- Identify the minimum values defined in the loan documents.
- Understand that bond ratings and access to capital markets are in part related to coverage values earned. Data are available relating coverage ratios to ratings.
- Understand that if regulated, the cooperative may have an indication of coverage values accepted in other proceedings.

No cooperative wants to operate with coverages hovering at the default level. Falling below the loan document minimums will result in undesirable consequences that the cooperative will want to avoid. The board and management know that coverages are only one of many factors considered by rating agencies and lenders. They also know that the coverage ratio accepted for one cooperative in a regulated proceeding may or may not be appropriate for another cooperative.

The Financial Strategic Plan or Equity Management Plan may establish a minimum coverage that is typically defined as a percentage of equity above the loan document minimum. The magnitude of the equity cushion reflects the cooperative's view of risk,

expected margins, erosion over time, and whether or not the cooperative has a coverage adjustment or true-up process in the retail rates.

So the question is whether or not the minimum coverage targets are sufficient to meet the other three financial objectives—equity targets, liquidity targets and capital credits retirement goals—given the projected CAPEX and expected cost of LTD. The minimum coverage values may or may not allow the cooperative to meet the other three objectives. A process needs to be in place that will ensure all four financial objectives are realized.

### 2.1.2 Equity Objectives

The cooperative has three sources to finance capital requirements:

- a. Contributions in aid of construction (CIAC)
- b. Debt
- c. Cash reserves from retained margins (gen. funds)

Plant additions financed with CIAC are recorded as a credit to electric plant in service. The two primary capital funding resources are debt and equity. The total debt plus equity is the capitalization. The amount of equity divided by the capitalization is the equity ratio<sup>2</sup>. A 50 percent equity would indicate the debt and equity component of the capitalization are equal.

So what is the appropriate equity level for the cooperative?

There are some general factors that the board and management should consider in establishing an equity objective for the cooperative. The target equity value reflects a balance of the following factors:

- Maintaining an excessively high equity ratio requires funding a major portion of CAPEX from current margins. The interest component of the revenue requirement will decrease, but the margin component will increase. This means current members are contributing capital to finance assets that will be used by the future rate payers over the life of the asset. This creates inter-generational issues. Rates will typically be higher if this approach is adopted.

<sup>2</sup> Equity can also be defined as a ratio to total assets rather than capitalization. When RUS is referencing equity they typically mean equity as a percent of assets. When the capital markets reference equity they typically mean equity as a percent of capitalization. Either is acceptable so long as the board knows the difference and there is consistency in the application.

- Maintaining a low equity ratio means funding a major portion of the CAPEX with debt. This will increase the debt service used in the calculation of DSC and the interest cost used in the calculation of TIER. The revenue requirement will reflect the impact of the interest or debt service and the associated coverage multiple.

Equity is typically not retained by the cooperative permanently – it is allocated and retired at the board's discretion to the member from whom it came. This is how electric cooperatives achieve operation at cost. The board and management need to define the desired equity level. Some reference points:

- If the cooperative wishes to retire capital credits, the equity must be a minimum level specified by the lenders absent special permission.
- Lenders typically prefer that borrowers maintain higher equity levels<sup>3</sup>.
- Equity is only one metric in the consideration of ratings.

The objective is to define the equity as a percent of capitalization (not assets) that results in the lowest cost considering the factors described above and using these four metrics:

- Plant growth rate
- Capital credits retirement cycle
- Cost of debt
- Desired TIER

Schedule C-2.0 in the Appendix shows the equations and the detailed development of the concept of an optimum equity given the above variables. The table shows the equity results using different assumptions for the four variables. The development is based on:

- Equity cost: based on Goodwin formula considering CAPEX growth rate and capital credits retirement rotation periods. Reference Schedule C-1.0, item #4.
- Debt cost: based on the cost of long-term debt.
- TIER: based on values defined in Section 2.3 process.

The board needs to be aware of the sensitivity of the optimum equity to changes in TIER, plant growth rate and capital credits retirement periods assuming constant debt cost. For example:

1. Assuming a TIER objective of 2.00, and a 15-year rotation cycle, the optimum equity with a 3 percent plant growth is 37.4 percent. If the rotation cycle is reduced to 10 years the optimum equity is approximately 29.9 percent. This occurs because the equity component from retained margins increases.
2. Assuming a growth rate of 3 percent and a 15-year rotation cycle, the optimum equity for a 2.50 TIER changes to 47.2 percent. This is due to the multiplier impact of the TIER calculation on the margins requirement. The impact of the higher TIER can be mitigated by an increase in equity capitalization, which results in a decrease in the debt cost.

Deciding on the appropriate equity level is not a precise process. Care needs to be taken in the application of the optimum equity analysis.

### 2.1.3 Liquidity Objectives

The next requirement relates to maintaining a particular level of liquidity. The liquidity for a cooperative can be provided by two sources. One is the general funds or cash to be maintained. The second involves lines of credit (LOC) that can be used to meet liquidity target objectives. The required cash liquidity (general funds) will be equal to the total desired liquidity less the amount available from an LOC. The general fund component can be expressed in either dollars or a percent of plant. The board needs to define a desired cash liquidity component.<sup>4</sup>

<sup>3</sup> The capital markets will typically reference equity levels when discussing the financial stability of a system.

<sup>4</sup> Some regulatory commissions allow a cash working capital component of rate base equal to 45 days of expenses for cooperatives. The cash working capital needs to reflect conditions specific to the cooperative in terms of meeting operating cash requirements.

### 2.1.4 Capital Credits Retirement Objectives<sup>5</sup>

The final objective to be defined by the board is the capital credits retirement objective. Generally, cooperatives must allocate capital credits to consumer-members.<sup>6</sup> “The board and management must decide on the rotation cycle, method and goal for retiring capital credits. The capital credits are the allocated retained margins (patronage capital) in prior periods. The board needs to consider balancing conflicting interests while complying with applicable law, regulations, and the cooperative’s bylaws and policies.”<sup>7</sup>

- Consumer-members have paid rates that provided revenue in excess of the direct cost of providing service. This contributed capital carries an opportunity cost to the consumer. Is the cooperative in a financial position to retire capital credits to members?
- Should the equity provided by consumer-members in prior periods be replaced with equity from current consumer-members? This will happen naturally when retirement occurs.
- If capital credits are retired, the impact on the balance sheet is a reduction in cash (liquidity) and a decrease in the equity ratio. To prevent the decrease, the margin needs to be increased in an amount equal to the capital credits retirement. If the plant is growing, additional CAPEX funding is required, and sufficient retained margins are needed to maintain the desired equity level. This means higher rates to produce increased margins. The board may ask: If it is necessary to increase rates to retire capital credits and prevent a decrease in liquidity or equity, why make the retirement? Legal, financial, member and policy considerations impact the answer to this question. Margins may not need to be increased beyond the TIER minimum set forth in loan documents; many electric cooperatives do not raise rates to retire capital credits.

The board must decide its position on retiring capital credits to consumer-members and the amount. In addition to the above, they will need to consider:

- Limitations in the loan documents (indenture) related to the equity level required before retirements can be made.
- The importance of the capital credits retirement program and how it distinguishes their cooperative from other energy suppliers in the service area.
- Possible ramifications of sustaining tax status as a cooperative while never retiring the margins earned.

An IOU has a capital cost attributed to the equity component. It is the opportunity cost of funds in a competitive market. It is also the utility’s profit. For a cooperative, the comparable capital cost component is the cost associated with the return of patronage capital.

## 2.2

### CAPEX Implications

The cooperative should routinely prepare engineering studies defining the projected capital additions for the cooperative. Depending on the development of the projections, requirements for general plant (computers, vehicles, trucks, buildings, etc.) may need to be added to the engineering projections. The CAPEX projection identifies the capital requirements. The cooperative should determine the likely financing from CIAC for plant additions and if the contributions are refundable. The remaining amount will need to be financed by a combination of retained margins (equity) and debt.

At the risk of oversimplification, if the CAPEX projections are \$5.0 million per year over the next few years, the board has a 50 percent equity objective and the cooperative is currently at 50 percent equity, then rates will have to be established to produce approximately \$2.5 million for equity financing. If the CAPEX is \$10 million per year, the rates will have to be established to produce \$5.0 million for additional margins. Conversely, if the CAPEX is a very low value, the magnitude of margins necessary to maintain the target equity may not be sufficient to maintain coverage ratios above the minimum levels established by the board. Under these conditions the board has two options:

<sup>5</sup> For more information, see NRECA/CFC Capital Credits Task Force Report. Available at <https://www.cooperative.com/interest-areas/governance/capitalcredits/Pages/default.aspx>

<sup>6</sup> Treatment of capital credits allocation is different in some states such as Nebraska.

<sup>7</sup> Given that equity and capital credits are directly related, many of the factors that should be considered in establishing the appropriate equity are directly related to the capital credits retirement issue.



- Allow the equity and liquidity to increase above the desired value.
- Increase the capital credits retirements if prudent.

Clearly, the projected CAPEX is a very important metric for the board to consider in establishing the revenue requirements for the system.

There are boards that are satisfied with the current equity and liquidity levels and do not wish to alter their capital credits retirement methods. If their cooperative has a low CAPEX requirement, the margins required to meet the equity and liquidity objectives may be less than the targeted minimum coverage values.

## 2.3

### Relationship of Key Financial Ratios

So how does the cooperative determine the margin component of the revenue requirement? The first step is to have an understanding of what is meant by margin an understanding of each of the financial metrics, and an understanding of how the metrics relate to each other.

#### 2.3.1 Margins

There are typically three different margin values that can be reported from the Form 7:

- Operating margins
- Net margins
- Modified margins
- Suggested Margins for the Rate Analysis

#### 2.3.1.1 Operating Margins

Operating margin is the value reported on Form 7, Line 21 and reflects the operating revenue (revenue from energy sales plus other operating revenue) minus the costs directly associated with providing service to the consumer-members.

#### 2.3.1.2 Net Margins

Net margin is the value reported on Form 7, Line 29. It reflects the sum of the operating margin plus the cooperative's non-operating activities. There are typically three major components of the non-operating activities: a) interest income, b) other non-operating margins and c) G&T and other capital credits allocations to the cooperative.<sup>8</sup>

While the RUS "Financial and Operating Report Electric Distribution," formerly known as the RUS Form 7, does not include G&T or other capital credits allocations in a borrower's "operating margins,"<sup>9</sup> an RUS electric borrower must maintain its books of accounts, and all other books and records supporting the entries in its books of account, according to the RUS Uniform System of Accounts.<sup>10</sup> Under the RUS Uniform System of Accounts, an electric borrower's "operating margins," or account 219.1, "shall" include, among other accounts, its G&T and other capital credits allocations.<sup>11</sup> In addition, these capital credits allocations are patronage-sourced.<sup>12</sup> Historically, RUS described G&T capital credits allocations as a "reduction in the cost of power which would increase the amount available as capital credits to the distribution cooperative's consumers."<sup>13</sup> For RUS, operation at cost and other reasons, it is wise for an electric cooperative to make capital credits allocations.<sup>14</sup>

8 A concern if the Net Margin is used is the quality of the components. The objective is to utilize only the cash components that are stable and predictable.

9 U.S.D.A., R.U.S. Financial and Operating Report Electric Distribution pt. A, ll. 26-27 (2010), available at [http://www.rd.usda.gov/files/OpRpt\\_D\\_2010\\_Current.pdf](http://www.rd.usda.gov/files/OpRpt_D_2010_Current.pdf).

10 7 C.F.R. §§ 1767.10, 1767.12(a) (2015).

11 7 C.F.R. §§ 1767.19, 1767.22 (2015) (accounts 423 and 424).

12 See Rev. Rul. 69-576, 1969-2 C.B. 166 and *Farmland Indus., Inc. v. Comm'r*, 78 T.C.M. (CCH) 846, 1999 Tax Ct. Memo LEXIS 443, 77, 103 (1999); See also Capital Credits Task Force Report 25, 27 (2005) (listing "patronage refunds from other cooperatives" as patronage income and stating they "generally constitute patronage-sourced income").

13 Rural. Elec. Admin., Capital Credits – Consumer Benefits, REA Bulletin 102-1 (Electric) 5 (Mar. 1964, reprinted Aug. 1974).

14 See Capital Credits Task Force Report (2005) ("It is prudent for co-ops to allocate capital credits received from affiliated organizations to their own members for tax purposes.") and Rural. Elec. Admin., Capital Credits – Consumer Benefits, REA Bulletin 102-1 (Electric) 5 (Mar. 1964, reprinted Aug. 1974) ("The distribution cooperative should allocate to its patrons the capital credits assigned to it by the G&T cooperative at the same time it allocates other capital.").

### 2.3.1.3 Modified Margins

Another alternative is to use the operating margin but include certain cash components of the non-operating income, such as interest income plus cash payments of capital credits received from third parties (G&T or lender).

### 2.3.1.4 Suggested Margins for the Rate Analysis

The board needs to decide how it wishes to define margins, subject to federal tax law and state cooperative law requirements and definitions. The preferred approach is to use operating margins and to consider non-operating activities as a cushion. If the cooperative is regulated, the regulator will wish to consider “above the line” operating activities with the line drawn at Line 21 of the Form 7. Some boards believe interest income in the current year should be considered. As noted above, the RUS uniform system of accounts differs from Form 7 treatment.

The Rate Guide examples presented in this discussion will use operating margins (“above the line”) and treat non-operating income as a cushion to offset future erosion in margins. References to coverage and return metrics will also be based on operating income.<sup>15</sup>

### 2.3.2 TIER, DSC and Return

The definition of TIER and DSC are generally familiar; however, the relationships between the various metrics may not be as familiar. It is helpful to relate these values to the return referenced in a rate-of-return calculation.

$$\text{TIER} = \frac{\text{Margin} + \text{Interest LTD}}{\text{Interest LTD}}$$

$$\text{DCS} = \frac{\text{Margin} + \text{Interest LTD} + \text{Depreciation}}{\text{Debt Service}}$$

$$\text{Return} = \text{Margin} + \text{Interest LTD}$$

With these equations, the margin can be defined in a variety of ways:

$$\text{Margin} = \text{Interest LTD} \times (\text{TIER} - 1)$$

$$\text{Margin} = \text{DSC} \times \text{Debt Service} - (\text{Interest LTD} + \text{Depreciation})$$

$$\text{Margin} = \text{Return} - \text{Interest LTD}$$

### 2.3.3 Rate Base, Rate of Return and Return

The return is equal to {rate of return} times {rate base}. This is a computation typically used in an IOU regulated proceeding. However, if return on equity is defined as cost of rotating capital credits it can be used by cooperatives as well. The rate base reflects the capital invested by the utility in providing service to the member. The components are typically:

- Gross Utility Plant in Service
- Less: Accumulated Depreciation Reserves
- Equal: Net Plant
- Plus: Materials and Supplies
- Plus: Prepayments
- Plus: Cash Working Capital
- Plus: Some jurisdictions might allow all or a portion of construction work in progress that meet certain criteria
- Less: Contributed capital (typically deposits, refundable construction advances, energy prepayments)

This represents the invested capital. Schedule C-1.0, Item 1, shows the rate base items for Standard Electric Cooperative.

The question is, “What is the cost that should be attributed to the invested capital (the rate base) associated with providing service?”

There are typically three cost components to be recognized:

- a. Cost of debt
- b. Cost of preferred stock (not applicable for a cooperative)
- c. Cost of equity

<sup>15</sup> Many cooperatives use a modified TIER or DSC, which is acceptable assuming there is some certainty and predictability related to the non-operating operating cash components that are included.

**The issue for the cooperative [using] a rate of return approach is how to define the cost of equity.**

The first two components are straightforward to compute. The difficult component is the cost of equity.

For an investor-owned utility, the determination of the appropriate cost of equity necessary to attract equity capital is a subject unto itself and revolves around what return on invested capital an investor in an IOU would expect to receive. The calculation typically involves discounted cash flows for investment in comparable companies.

The issue for the cooperative, if it wants to use a rate of return approach, is how to define the cost of equity. A cooperative is not required to attract equity capital like an IOU. Equity is provided in the form of retained margins by the cooperative member. Hence, there is not a cost of equity in the sense of providing an attractive return to the investor. However, there is a concept of a return of equity as reflected in a cooperative's capital credits retirement.

For a cooperative, the two important factors driving the cost of equity are the CAPEX requirements and desired capital credits to be retired. A number of years ago, NRECA's James Goodwin developed a formula that defined a required return on equity given plant growth and capital credits retirement cycle. If a cooperative chooses to use the ROR approach to determine revenue requirement, it needs to develop the six steps shown on Schedule C-1.0.

1. Determine rate base for the test year.
2. Determine the capitalization for the test year.
3. Determine the average (or weighted) cost of debt for the test year.
4. Determine the cost of equity.
5. Determine the weighted cost of capital, i.e., the rate of return (ROR).
6. Determine the adequacy of the return and possible mismatch with actual debt cost.

Schedule C-1.0 shows each of the six steps with the application of the Goodwin Formula to determine the cost of equity or return on equity (ROE). In the example, the assumption is the cooperative expects a 3 percent growth in plant and desires a 10-year capital credits retirement cycle. The resultant ROE is 11.2 percent and the resultant ROR is 7.92 percent.

If an ROR approach is used, it is important to multiply the weighted cost of debt times the rate base to determine the extent to which the resultant value is sufficient to pay actual interest expense (Schedule C-1.0). Depending on the relationship between the rate base and capitalization, the amount available for the margin component of the return may be less than required. This occurs if the rate base is less than the capitalization.

This is the situation with Standard Electric Cooperative. Schedule C-1.0, Item 6 shows the calculation comparing the computed interest component with the actual interest on long-term debt (LTD). Because of the mismatch, the amount available for the margin is reduced. The point is to make certain margins and interest components are defined properly.

## 2.4

### Recommended Approach to Determine Margin Component

The team needs to develop the margin component of the revenue requirement. The suggested approach is to:




1. Identify the four financial objectives, i.e., coverage ratios, equity, liquidity and capital credits retirements. The coverage ratios should be the minimum target values included in the loan documents. These targeted objectives should have already been identified as part of a Strategic Financial Plan or Equity Management Plan.
2. Determine the projected CAPEX. This information should also have already been developed as part of a work plan by the engineer and approved by the board.
3. The final step is to determine the level of margins and the associated coverage ratios (TIER, MFI, DSC, etc.) required to meet the equity, liquidity and capital credits retirement objectives.
4. The resultant coverage ratios then need to be compared with the minimum values. If the resultant values needed to meet the equity, liquidity and capital credits retirement objectives are greater than the minimum values then the resultant values should be used. If the values are less (this can occur with low-growth CAPEX), then the minimum values should be used.
5. If the minimum values are used, it is likely that the equity and liquidity targets will be exceeded. In this case, the cooperative can accept higher equity ratios and cash or increase the capital credits retirements to maintain the equity and liquidity targets. Either action indicates the need to re-evaluate the Equity Management Plan or Strategic Financial Plan.

The determination of the final revenue requirement is iterative. The team may discover that revenue needed to meet the equity, liquidity and capital credits objectives results in a rate change greater than desired. If so, the cooperative might consider reductions in capital credits retirements, desired equity or deferrals in plant additions. These changes will reduce the margin components of the revenue requirement in the COSS.



There are two analytical tools available for the analysis defining margins in terms of the four financial objectives and a specific CAPEX projection and LTD interest cost. One is the Financial Forecast. The Financial Forecast model should have the ability to define margins given the four objectives, the projected CAPEX and estimated future interest rate for LTD. An alternative is an abbreviated version of the Financial Forecast that models only the balance sheet and the depreciation and interest component of the income statement. The abbreviated version does not require all of the detail associated with a Financial Forecast and may be used to frame the discussion.

Schedule D-1.0 reflects the basic concept of a model that deals with only:



#### 1. Income Statement

-  Margins and associated TIER, DSC, ROR ratios
-  Depreciation
-  Interest LTD

#### 2. Balance Sheet – Assets

-  Plant Investment
-  General Funds – Cash

#### 3. Balance Sheet – Liability

-  Equity
-  Long-term debt

The model is used to determine the level of margins (and associated TIER, DSC and ROR) required to meet equity, liquidity and capital credits objectives given a CAPEX assumption and assumption of LTD interest cost.



Schedule D-2.0 shows examples of different “what if” assumptions for the hypothetical Standard Electric Cooperative. The example shows the required TIER necessary to maintain the current equity and current liquidity under four conditions:

1. Plant Growth 3 percent, maintain current capital credits retirements
2. Plant Growth 6 percent, maintain current capital credits retirements
3. Plant Growth 3 percent, no capital credits retirements
4. Plant Growth 6 percent, no capital credits retirements

The required TIER is in the range of 2.4 assuming 6 percent plant growth and continued capital credits retirements. The other end of the spectrum is a low plant growth of 3 percent and no capital credits retirements, which results in a TIER in the range of 1.40. The latter case may trigger the minimum values. If the CAPEX is at the lower level, the targeted minimum value will require a capital credits

retirement—otherwise, the equity and liquidity will increase. The cooperative should use either the financial forecast model or the cash flow model to evaluate the “what if cases” given the objective of determining margins required to meet the financial targets.

## 2.5

### Revenue Requirement Defined by Competition

The previous discussions in Sections 1.0 and 2.4 provided the step-by-step process to develop a revenue requirement based on the cooperative expense plus margins necessary to meet financial goals. There are situations where, because of competition, the revenue stream available to the cooperative is driven by the need to maintain competitive rates. In this case, the management and staff approach is the opposite of what is described above. The management and staff need to operate the cooperative with a fixed amount of revenue defined by the competitive rates. Expenses must be managed to provide the required margins given the available revenue stream.

# 3.0

## Development of the Cost-of-Service Study (COSS)

**The objective is to define the cost of serving each rate class, define the operating margins given current rates and determine the total revenue requirement based on a criteria in the Rate Policy.**

The process has now determined the revenue requirement consisting of:

- Adjusted test year operating cost
- Plus: Margins necessary to meet cooperative's financial objectives
- Less: Other operating revenue

The next step is to develop a COSS that allocates the total system cost in Column (c) of Schedule B-1.0 to each of the customer classes as appropriate. The objective is to define the cost of serving each rate class, define the operating margins given current rates and determine the total revenue requirement based on a criteria in the Rate Policy. The process consists of the following five steps:

1. Define the rate classification.
2. Define the cost functions (aligned with the unbundled rate components).
3. Classify the cost to fixed (demand), variable (energy), customer and any applicable direct assignments for each cost function.
4. Develop allocation factors based on rate class use profiles.
5. Allocate each cost component to define the individual class revenue requirement (operating margins).

Sometimes the COSS is viewed as a black box that requires special skills and knowledge base to implement. The COSS should not be viewed in that way. It is really a process defined by a series of steps, which the team needs to understand and then implement recognizing some general criteria applicable to all COSS and unique criteria specific to a particular cooperative. The difficult task is defining the cost drivers for the cooperative and allocating the cost to the rate classes.

### 3.1

#### Development of Retail Rate Classes

The COSS allocates plant investment, operating cost and margins responsibility to the consumer-member served in a manner that reflects the cost of providing service. The allocation is based on the use characteristics of the member. To have a manageable number of applicable rate schedules, consumer-members with similar use characteristics taking service at the same level are grouped together into a class. The use characteristics are defined in terms of customer, demand and energy use profiles.

**The difficult task is defining the cost drivers for the cooperative and allocating the cost to the rate classes.**

For the COSS, a rate class is defined by each individual rate schedule—NOT the RUS Form 7 rate classifications. As a result, rather than a single residential class, the COSS for a particular cooperative may have classes for residential, residential with water heater, residential with space heating, residential time-of-use, etc. The large power may be divided into LP with secondary service, LP with primary service and LP with transmission service. Lighting may have separate classifications for security lights and public street lighting. Agriculture services will be reflected as service to irrigation, cotton gins, etc. Consumer-members are grouped based on end use applications with the assumption that load profiles will likely be similar. The team needs to begin by making a list of all the possible combinations and permutations of possible rates for their system; the rate codes in the billing system are a good place to start.

To accurately track use characteristics, it is important to have both demand and energy data to define the use profile. One of the reasons for the “grouping” of consumer-members into a class is because a traditional two-part rate (customer and energy) uses the energy rate to recover both the energy- and demand-related cost. If all of the consumer-members in the class have similar demand/energy use profiles, the recovery of demand costs based on energy is a reasonable compromise given the high cost of demand metering at that time. The recovery of demand cost in an energy charge works if the demand/energy use profile is predictable for the consumer-members in the class. However, if the demand/energy profile is not similar for all consumer-members or if it changes because of actions taken by the consumer, then there is the potential for under recovery of cost and/or the shifting of cost responsibility to other consumer-members.

This is exactly what is currently happening with the installation of distributed energy resources (DER)

on the consumer-member side of the retail meter and application of net metering. The retail consumer-member with a rooftop solar will have a different demand/energy profile than a consumer-member without the solar installation. Therefore, it is not surprising that a retail rate designed assuming no DER, when applied to a consumer-member who adds DER does not properly track cost incurred in providing services. The problem will be further compounded as other applications such as vehicle charging and energy storage are expanded on the consumer-member side of the retail meter. Maintaining a predictable demand/energy profile is fundamental to maintaining a rate class.

The team discussion of applicable rate classifications needs to occur during the initial phases of the COSS. In fact, if the cooperative is considering an entirely new rate class, it is helpful to have this discussion well in advance of the development of the COSS to allow sufficient time to gather the use data associated with the proposed class. The member service staff need to identify any changes to existing rate classes and possible new classes. The engineering/operations staff need to discuss the implications of the cost of providing service to the class and the extent to which the new/changed class use profile drives a different cost profile. The accounting and billing staff need to identify the consumer-members who would be reassigned or placed on the proposed tariff. The IT staff involved in AMI applications and billing staff need to determine if use data are available to define the use profiles. Ideally there are 12 months of use data available to describe the new rate class.

The majority of the time when new rate classifications are introduced, the cooperative does not have the actual historic data to properly define the use profile. The alternative is to establish a new classification, include it in the COSS using the limited data (or assumptions) available and develop a rate that is

intended to achieve the cooperative's objective. Because of the high level of uncertainty given the limited data available, the application of the rate is limited to minimize risk to the cooperative. There may also be conditions in the application to the consumer-member that limit his/her exposure to adverse impacts by offering billing under multiple schedules.

## 3.2

### Define Cost Functions

The next step in the COSS process is to identify the applicable cost functions. The cost functions can be grouped in a variety of ways with differing levels of detail. At a minimum, the cost functions mirror the desired unbundled cost components. Typically, the COSS will develop cost functions in greater detail than only the unbundled components. The objective of the functionalization process is to identify a revenue requirement for the applicable function. For a distribution cooperative the functions include:

#### Power Supply

Power Supply Generation – Fixed

Power Supply Generation – Variable

#### Power Supply Delivery

Transmission Wires - Fixed

Distribution Substation – Fixed

Ancillary – Fixed

Ancillary - Variable

#### Distribution Delivery Demand

Subtransmission - Fixed

Substation - Fixed

Distribution backbone wires delivery – Fixed

#### Distribution Customer

Distribution delivery – Customer

Distribution service – Metering, billing, customer service – Customer

#### Other services

Ancillary Services

Margins Requirement

If transmission and distribution substations are owned by the wholesale power supplier, the wholesale investment and associated cost are reflected in the wholesale rates or delivery billing. If the wholesale supplier is not providing service at a primary voltage, the distribution substation investment and associated cost will be reflected on the distribution cooperative's books. The cooperative may also own and operate transmission assets. The cooperative will want to reflect the transmission and substation costs as a separate function in the COSS, but may not show it as an unbundled component in the rates.

The uniform system of accounts provides the basic cost accounting necessary for the functionalization process for plant investment and operating expenses.

### 3.2.1 Power Supply and Transmission Functions

The distribution cooperative may be purchasing from a G&T, an IOU, a federal marketing agency, the market or a combination of all of the above. No matter the structure, the major component of the distribution cooperative's cost of service will be wholesale power cost. The wholesale power cost reflects the recovery of cost associated with the power supply capacity and energy, transmission wires delivery, transmission ancillary services and, depending on the service level, the substation function.

The focus of the Rate Guide is on distribution service to retail consumer-members. In developing the retail rates, however, consideration must be given to various wholesale rate designs and how those designs can impact the retail rate design. The distribution cooperative must deal with two (sometimes three) tiers of rate design in developing the pricing signal to the ultimate retail consumer. The team's discussion needs to focus on the structure of the wholesale power supply, the rates charged and the cost drivers for the wholesale power supply costs.

No matter the structure, the major component of the distribution cooperative's cost of service will be wholesale power cost.

**The use/billing data that drive the wholesale power supply cost are specific to each supplier.**

The important point is that the team understands what drives the wholesale power cost. Each component of the wholesale supplier's rate needs to be identified and billing units (cost driver) identified. The costs incurred for the total cooperative system need to be allocated to each rate class. This means it will be necessary to develop allocation factors for each rate class that mirror how billing units are defined at the wholesale level.

Ideally, use values applied in the development of the wholesale supplier's COSS should be the same as used in the cost recovery, i.e., the rate design. However, this is not always the case. In a FERC proceeding, FERC will determine the demand allocation factor to be used in assigning cost responsibility to the wholesale customer class; however, the rate used to allocate cost to individual consumer-members within the wholesale class may be based on different demand use values. This usually does not occur with a G&T because the G&T will primarily be serving only the member distribution cooperatives.

Another benefit of the team discussions related to wholesale power supply and delivery is that they allow staff to better understand the costs that can be avoided and the costs that will not be avoided assuming implementation of DER on the distribution cooperative side of the wholesale meter. Ideally, both the G&T staff and cooperative staff work together in the development of a wholesale rate that can be reflected in the distribution cooperative's retail rate that sends the proper pricing signal to the ultimate retail consumer. Everyone needs to keep in mind that the distribution cooperative is not the ultimate load the G&T is serving and is not the load that will be reacting to pricing signals in the rate—it is the retail consumer-member of the distribution cooperative.

The use/billing data that drives the wholesale power supply cost are specific

to each supplier. Typical examples are:

**1. Production Demand:** Typically coincident peak (CP) at the time of the supplier's peak. If the load profile is not seasonal, a 12-month CP allocation will be used. If the load profile has high seasonal differentials, the allocation may be based on the four summer CP average or the winter three CP average demand.

- a. The cooperative CP is another option used by some wholesale suppliers.
- b. Because the supplier's generation assets are driven by coincident peak demand of total consumer-member load served, NCP of delivery points is typically not a consideration for the power supply component.
- c. The billing demand may include ratchet provisions on an annual basis or seasonal basis depending on the load profile served. If so, the ratchet responsibility needs to be assigned in the allocation process to the cooperative's retail rate classes.

## **2. Production Energy**

- d. Billing based on energy use at the wholesale meter. Will include loss adjustments to state energy use at the same level.
- e. May include time-of-use differentials.



### 3. Transmission Demand

- f. Typically billed CP at time of transmission peak.
- g. Applications can include either monthly CP demand or rolling 12-month demand.

### 4. Distribution Substation

- h. Typically billed non-coincident peak (NCP) of the delivery point.
- i. Other options include billing based on investment of substation.

The team needs to review the wholesale power supply agreement and the current rates. They need to identify the use metric that drives each component of the wholesale power supply, transmission and distribution substation rate. They need to then decide how to determine each rate class contribution to that specific billing metric. The objective is to take each component of the wholesale power supply and transmission delivery cost and assign the cost to a rate class.

#### 3.2.2 Distribution Function

The primary function for the distribution cooperative is distribution wires delivery and member services. The functions for delivery can be defined by:

- Voltage level for delivery: The voltage level will impact not only the assets that are assigned to the service but also the energy losses. The possible voltage levels can be:
  - Secondary service.
  - Primary service from a distribution line.
  - Primary service from a substation bus.
  - Transmission service.
- Overhead or underground service.
- Direct assignment: Made to large power and industrial consumer-members for facilities associated with providing service to the load.
- A retail consumer-member taking service at a secondary voltage utilizes the entire system in taking service. A consumer-member taking service at a primary voltage, however, should not be assigned any cost associated with assets such as Account 368 Line Transformers and Account 369 Services. If service is primary

at a substation bus, an argument could be made that the consumer-member has no responsibility for distribution line (Accounts 364 Poles, Towers and Fixtures; 365 Overhead Conductor and Devices; 366 Underground Conduit; and 367 Underground Conductor and Devices). However, before making the assumption consider if the distribution system is interconnected so that if a substation fails, the consumer-member could be served from another substation and distribution feeder. If so, then distribution line assets should be allocated to the member-consumer.

- A consumer-member taking service at a transmission voltage would not be assigned any of the cost associated with distribution line, poles, transformers and services related cost. If a consumer-member takes service overhead it may not be appropriate to assign an underground asset cost to the member. However, it depends on the nature of the underground assets. If the assets are primarily feeders out of substations as opposed to underground service to residential developments or irrigation wells, it would be appropriate to assign the cost to the backbone function. If investment is made to serve a single large power or industrial member-consumer, the associated costs should be directly assigned to that member-consumer. Certain consumer-member classifications may have AMI installed; others may require meter reading by the cooperative, which should be considered when allocating Account 370 Meters and Account 902 Meter Reading Expenses.

The comments above are representative of the discussion that the team needs to have. The team must know how the consumer-members are served and how the facilities are used to provide the service. The objective is to allocate facility investment and associated cost to those consumer-members who use the assets and incur the cost in taking service. This is not a precise process, but it is at the heart of the COSS process and requires the input of the staff.

#### 3.2.3 Common Facilities

The uniform system of accounts provides the basis for the functionalization of most cooperative costs. The accounting system provides a listing of accounts for the production, transmission and distribution functions. However, there are also common functions such as general plant and administrative and General

expenses that serve all functions. One of the tasks is to allocate the common costs to each of the functions that will eventually be reflected in the unbundled rates. The most common approach for allocation of the common expense is based on labor.

### 3.3

#### Classification of Cost

After the investment and related costs have been functionalized, the next step is to classify the cost. The concept is that investment capital costs and operating costs are incurred to connect the consumer-member to the system, to serve the maximum load possible and to provide energy for all 8,760 hours of the year. Therefore, costs are allocated to a rate class based on the applicable use allocation factors. There are typically four general classifications:

- Demand or fixed cost
- Energy or variable cost
- Customer cost
- Direct assignment cost

With regard to fixed cost, the perspective for the COSS is short term, i.e., the 12-month test year. An argument can be made that over the long term all costs are variable. However, in dealing with an allocation of test year cost, the fixed costs are those costs that do not vary as a function of energy use. The customer costs are those costs that vary as a function of the consumer-member being connected to the system. The fixed or demand costs are associated with serving the maximum load of the member.

##### 3.3.1 Power Supply Classification

For the wholesale supplier the major issue is the determination of the demand- and energy-related costs. Schedule E-1.0 shows the production cost classification suggested by FERC in the development of wholesale rates and NARUC for generation costs. The table shows the operating cost component. The taxes, depreciation and interest plus margins or return are considered fixed unless a portion of the plant investment is related to fuel handling.

#### Cost Allocation and Rate Recovery

The billing unit for recovery of costs in the retail rates may differ from the cost allocation unit basis.

The development of the wholesale COSS focuses on the classification of costs to demand and energy. In a FERC proceeding the classification will most likely follow the Schedule E-1.0 classification. In developing a wholesale COSS for a G&T, there will likely be a discussion if any of the fixed costs should be assigned to the energy component. This is referred to as “tilting” the costs. FERC has approved formula rates for jurisdictional G&Ts that include some tilt. Typically, the tilt is based on a capital substitution or peaker equivalent methodology and is not arbitrary. The tilt can also be used by the G&T to control the banding in the wholesale rate, i.e., the ratio of the average cost for a consumer-member relative to the average cost for all consumer-members.

While it is helpful for the team to understand how the wholesale supplier (and particularly the G&T) classifies cost, the important question for the team is how costs are allocated as part of the wholesale rate design for the cooperative. This is determinative as to how the distribution cooperative allocates wholesale power supply and transmission delivery cost to the retail rate classes served by the cooperative. Unless the wholesale rate is based on a single energy charge, costs should never be allocated to rate classes on a uniform \$/MWh basis.

Transmission revenue requirements are almost always classified to demand. Substation costs associated with service to a delivery point are also classified as fixed or demand related.

The wholesale billing may include ancillary charges and they should be allocated on the basis they are incurred (demand or energy).

##### 3.3.2 Distribution Classification

For the distribution cooperative the major issue is the proper classification of demand- and customer-related cost. The only major energy cost component is the energy component of the wholesale rate. The allocation of the distribution wires investment and costs (excluding purchase power) typically do not involve an energy allocation factor. Schedule E-2.0 shows the cost classification suggested by NARUC.

What is apparent from Schedule E-2.0 are the number of cost accounts that are classified to both the demand and customer components. This reflects the concept that the distribution system is first designed to connect every consumer-member to the distribution wires system and second to provide facilities necessary to serve the maximum load the consumer-member will impose on the system. The

task is to develop the plant investment and related costs for first connecting the consumer-member to the system (customer component) and second to serve the maximum consumer-member load (demand component).

### 3.3.2.1 Minimum System

The Minimum System methodology or the Minimum Size methodology can be used to classify distribution cost to demand and customer classifications. The concept involves:

1. Defining a system to connect every consumer. The system consists of the minimum size components of all assets, and the cost would be the cost of the minimum component times the number of units. This minimum system provides the connectivity for the consumer-member but is not large enough to serve more than a minimum load. The cost associated with the minimum system is the customer component.
2. Defining the remainder of the system, which is equal to the total cost of a particular asset less the amount assigned to the minimum system. The cost associated with this is the demand component.

The implementation of the minimum system methodology requires detailed information from the continuing property records (CPR) showing the number of units, description of unit and cost of unit. To determine the minimum system associated with Account 364 Poles, Towers and Fixtures, the computation involves:

1. Determining the total number of poles on the system.
2. Determining the minimum size pole for the system.
3. Determining the average book cost for the minimum size pole.
4. Multiplying the total number of poles times the average cost of the minimum size pole. This amount is the customer component of plant investment.

5. Calculating the total Account 364 plant investment less the Customer Component, which equals the Demand Component of the investment.

The same process is used for each of the distribution plant accounts.

1. Account 365: Unit cost of minimum size wire x total circuit miles = Customer Component.
2. Account 368: Unit cost of minimum transformer size x total number of transformers in Account 368 = Customer Component.

### 3.3.2.2 Zero Intercept

The development of the zero intercept methodology is more involved and requires more data than the minimum system methodology. The calculation involves:

1. Using the CPR to determine the number, investment and average cost for the particular property unit.
2. Developing a regression equation that relates the unit cost.

For example, in dealing with Account 368, typically only single-phase transformers are considered. An investment cost in \$/consumer is determined as a function of transformer size in kVA. A regression equation is developed relating investment per consumer vs. transformer kVA. The investment \$/consumer is defined at the zero intercept, i.e., at the zero kVA. This average cost per consumer is then multiplied by the number of consumers to determine the customer component. The remaining amount in Account 368 is attributed to the demand component.

### 3.3.2.3 Functions of Plant

Another approach in dealing with overhead line, conductor and devices is to determine line miles of three-phase backbone, single-phase line and three-phase extension. A ratio is developed based on present-day cost of constructing three-phase backbone facilities, single-phase and three-phase extension. Knowing the miles of line and the number of consumer-members served by single-phase and three-phase lines, the ratios are applied to determine the estimated investment in three-phase backbone facilities and the single- and three-phase extensions. The three phase backbone is assigned to the demand component and the single- and three-phase extension investment is assigned to the respective customer component.



### 3.3.3 Common Facilities

Cost Components	Allocation Factor
<b>Power Supply</b> Demand Energy	Power Supply Energy
<b>Power Supply Delivery</b> Transmission Substation Ancillary – Demand Ancillary – Energy	Transmission CP Cooperative CP Cooperative CP Energy
<b>Distribution Demand</b> Sub-Transmission/Substation Backbone Demand Distribution Demand	Cooperative CP Cooperative CP Customer NCP
<b>Distribution Customer</b> Distribution Customer Customer Services Customer Ancillary	Customers Customers Customers Customers
<b>Margin</b>	Distribution Components

Schedules E-1.0 and E-2.0 show the classifications of expense accounts specific to the power supply and distribution functions. The common costs also need to be classified. The most common approach is to classify the common costs based on a labor ratio.

## 3.4

### Development of Allocation Factors

The individual components of expense have been functionalized. At a minimum, the functionalization mirrors the proposed unbundled rate components. The costs have then been classified into three use classifications, i.e., customer, energy and demand, and if applicable a direct assignment. The next task is to develop factors to allocate cost to the rate class. The underlying concept is that the electric system was designed and constructed to serve the retail consumer-member load and this load is defined by three use classifications. In some cases the cooperative will put in place facilities to serve only one consumer-member or one group of consumer-members, and the related costs are directly assigned.

#### 3.4.1 Energy Allocation Factor

Energy is the easiest allocation factor to develop. All consumer-members will have meters that identify the energy use for the consumer-member or energy

use can be estimated for the load.<sup>16</sup> However, the service and meters may be located at different service levels. The majority of the consumer-members will be metered at the secondary level; there may also be service at primary voltages and even transmission voltage levels. The team must determine the appropriate loss factor to apply to define energy use responsibility at the wholesale meter. The engineering/operations staff need to establish loss factors for each of the different service levels. The team knows the total energy that must be accounted for, which is the energy purchased at the wholesale level. Loss differentials need to be established for each service level. The energy allocation factors reflect energy use for each rate class as a percentage of total with all metered energy adjusted to the wholesale power supply level with the appropriate loss factors.

#### 3.4.2 Customer Allocation Factor

The customer allocation factor is the ratio of consumer-members in the rate class to the total consumer-members served. Depending on the cost classification being considered, not all consumer-members are equal. For example, in dealing with meter-reading expense, weighting factors may need to be applied to reflect the differing level of cost incurred in reading meters for different rate classes. The cooperative may have some self-read meters, some meters read by cooperative staff, some prepaid services and classes with AMI in place. The same issues will exist with customer accounting expense. The team needs to discuss each of the costs that have been classified as customer and determine the activities that are driving the cost, establish weighting factors and then develop allocation factors. The accounting/IT staff can provide appropriate weighting factor to differentiate customer accounting, meter reading and customer service by rate class. There most likely will be multiple customer allocation factors used in the COSS.

#### 3.4.3 Demand Allocation Factor

The development of the demand allocation factors is the most involved. The basic question is what is the demand value that drives the fixed cost for the particular function? It is important to make certain there is a clear understanding of how the demand value is developed, the different types of demand

<sup>16</sup> Not all rate classes may have meters. For example security lights may not be separately metered. However, in these instances a monthly usage can be attributed to the security light service.

values that are used and how the different values are related. It is very important for the team to discuss exactly what drives fixed costs and, when discussing an allocation based on demand, to be precise in the terms that are used.

### 3.4.4 How Is Demand Determined?

The demand value is the energy use integrated over some period of time. The time period may be 60 minutes, 30 minutes, 15 minutes or any period of time. When a rate includes a demand charge it is important to define the integration period for determining the demand. A 60-minute demand interval is typically defined as a clock hour period and means energy use is integrated over each 60-minute interval in the billing period. Therefore, in a 31-day month there are 744 demand values. A 60-minute integration period is the most common, so the following will assume a 60-minute clock hour period.<sup>17</sup>

### 3.4.5 What Demand Value Is Used?

For example, assuming 744 hours in a billing period, which values are important? For the allocation of wholesale power cost, transmission cost and substation cost, the demand will be defined in the tariff and the distribution COSS should use the same definition for the wholesale cost components. For the distribution demand costs, the team need to discuss this while the engineering/operations staff need to explain what they consider in making decisions with regard to adding substations and in expanding the three-phase backbone facilities. The objective will be to determine the contribution of the individual class to the driving metric.

There are a number of different demand values that need to be considered:

- **NCP Demand:** The non-coincident peak is the maximum of the 744 possible values in a 31-day billing period. This defines the maximum rate of energy delivered to the load over some period of time – usually a billing month or a year. Clearly, the services to the load must be sized to accommodate the peak use whenever it occurs. If a separate transformer is used to serve the load, that transformer must be sized to serve the maximum or the NCP load level. If multiple consumer-members are served from the same transformer the important metric is the maximum load on the transformer.

1. **NCP – Retail Load:** This would be the NCP for service to a retail load.

2. **NCP – Delivery Point:** This would be the NCP for the wholesale delivery point. The delivery point is providing service to many individual retail loads. Unless all of the individual retail loads peak in the same interval, the delivery point NCP will be less than the sum of the individual loads served.

- **CP Demand:** The coincident peak demand is used extensively in defining cost causation in a COSS. The critical question is the timeline, i.e., which 60-minute period is determinative of the asset requirements selected and what is the class load at that time. Therefore, any reference to CP Demand must also reference the timeline for which of the 744 intervals is being considered. There are potentially four different timelines to consider:

1. **CP – Power Supply:** This is the 60-minute period the wholesale supplier uses to define the billing demand for power supply fixed costs. This is typically the 60 minutes with the maximum demand during the accounting period.

2. **CP – Transmission:** If the wholesale supplier unbundles the rate there will be a separate charge for the transmission fixed cost and perhaps a different time for the maximum load on the transmission system. This occurs if the load on the transmission facilities is different than the load served from the production facilities. The cooperative needs to determine the time line for the transmission charge.

3. **CP- Cooperative:** This is the 60-minute period of maximum use for the cooperative. This value is determined by stacking all of the delivery point hourly demands for all 744 hours to determine the time of the maximum use.

<sup>17</sup> Some wholesale markets deal with intervals as small as five minutes.

4. CP- Delivery Point: This is the 60-minute period of maximum use for a particular feeder or substation. For the allocation of substation cost, the CP-Substation is important. Whereas feeder loads are important for engineering and operations and feeder demand data are available, it is generally more detailed than required for a COSS. From the wholesale supplier’s perspective the load served is the delivery point load. Therefore, the NCP of the substation will be the same timeline as the CP delivery point.

The team needs to determine the contribution that each rate class makes to the relevant billing demand or cost driver. This means there could be the following demand allocation factors with each showing the class contribution to:

- Power Supply CP Demand
- Transmission CP Demand
- Cooperative CP Demand

3.4.6 How Are Demand Values Related?

Load factor is a metric used to define energy and demand relationships. The load factor is:

Load Factor=

Energy in Power

Hours in Period x Peak Demand in Period

In defining the load factor for a consumer-member or a class consumer-members, the key elements to define are a) the period involved and hours in the period, b) total energy in the period and c) the demand value. The period can be a month, a season or an annual value. The type of demand can be any of the values described above.

The load factor can be a valuable tool in translating data from a sample set of metered values to an entire class. For example, a common metric in a COSS is the rate class demand contribution to the cooperative’s purchased power demand cost responsibility. If a substation or distribution feeder serves predominately residential consumer-members, knowing the substation demand at the time of the power supply peak and the energy delivered at the substation, it is possible to define the load factor. Knowing the load factor for the residential load served from the substation and assuming the

With AMI data it is much easier to develop the use profile and the rate class contributions to the various timelines. The AMI data are first grouped by rate class. The timelines are defined by the wholesale billing data. The load factor relationships can be used to attribute demand profile data for the entire class. Depending on the cooperative’s ability to handle large data sets, the AMI data for each consumer-member in a class can be used to define the class profile and demand contributions to different timelines or load factor data can be based on a selected subset and then applied to the total class.

load characteristics are representative of the entire residential class, the class CP contribution can be defined based on class metered energy use and the sample CP power supply load factor. Remember to account for losses from the retail meter to the wholesale point of delivery. With this approach load factor values can be determined for the class, each identifying the residential demand contribution to the applicable timeline.

Another important metric is the coincidence factor. This is the relationship between CP and NCP. The most basic demand is the retail consumer-member NCP load at the retail meter. A substation delivery point will be serving a large number of retail consumer-members. However, the sum of the individual NCP demands will be greater than the substation peak demand. This is because of the diversity of the times the individual NCP values occur. There is diversity in the time of the peak loads. For the G&T, the sum of all the delivery point peaks will be greater than the G&T production peak demand. Again there is diversity in the times of the substation delivery point peaks.

The coincidence factor is equal to the CP demand of the load served by the facility divided by the sum of the NCP demands served from the facility. The lower the coincidence factor the greater the diversity of the load. The diversity factor is another metric used and is equal to the reciprocal of the coincidence factor:

Coincidence Factor=

Coincident Peak Demand

Non-Coincident Peak Demand

Diversity Factor =

1

Coincidence Factor

The concept of the rate class is that all of the consumer-members in the class have similar use profiles. This means consumer-members have a similar load factor defined in terms of the demand contribution. For example the power supply CP

load factor, i.e., the contribution to wholesale power supply demand based on energy is similar. If a consumer-member puts in place technology that changes the load profile and the resultant load factors, there can be distortions in the alignment of rate components intended to recover costs incurred in providing service. For cooperatives with detailed AMI data, it is helpful to consider the development of data showing customer load factors based on different cost drivers such as production CP demand, transmission CP demand and consumer-member NCP demand.

### 3.5

#### **COSS Demand Allocation Factors vs. Rate Design Demand Billing Units**

A significant issue in a Rate Analysis is the appropriate demand allocation factor for assigning cost and demand billing units for the recovery of cost. Conceptually, the demand factor used to recover costs should be the same one used to allocate costs. However, this is not always the case. The fixed costs may be allocated to a class based on the class contribution to the production CP demand on an average 12-month basis while the billing unit recovers the cost on a different basis. At the wholesale level it is important to identify how costs are assigned and how they are recovered. If a cooperative is purchasing from a G&T this discussion is more likely to occur.

At the retail level it may be difficult to accurately mirror cost allocation with cost recovery because of meter limitations. The continued expansion of AMI is expected to reduce this problem. Still, limitations will likely continue in terms of consumer acceptance, particularly for demand-related rates at the residential level.

### 3.6

#### **Other Allocation Factors**

The previous discussion focused on allocation factors based on use, such as number of consumer-members and demand. However, the typical COSS will include many allocation factors that are internally generated by the COSS model. For example, many cost-of-service studies will allocate expenses as a function of investment. Therefore, the COSS will develop subtotals of investment of different assets, develop ratios and then use the ratios to allocate expenses. If certain taxes are related to revenue, the COSS model will develop the subtotal of revenue by rate class to allocate expenses. The important point for the team is to discuss what drives a cost and then establish an allocation factor to assign that cost to the respective rate class.

### 3.7

#### **Allocation of Operating Margin Component of Revenue Requirement**

Operating margins are not a cost, but, for ratemaking purposes, should be treated as a cost and allocated to each rate class. The question is how should it be allocated to the rate classes?

An important consideration is how the cooperative allocates operating margins as part of its capital credits program. The revenue requirement reflects a level of operating margins necessary to meet the financial and operational objectives. Rates will be designed that include the operating margins component. The rates are applied to the actual billing units to produce the desired operating margins. The operating margin actually received is then allocated back to the consumer-members in the form of capital credits. It would be desirable if the operating margins allocated to the consumer-member are equal to the operating margins realized from the rate charged to the member.

So what are the options? The typical approach in a regulated proceeding is to allocate return (return = interest + margin) to each rate class based on the allocation of rate base. If a cooperative develops an operating margin requirement based on TIER or DSC, both of those metrics reflect capital cost/debt cost, and an argument could be made that debt follows rate base, which primarily follows net plant. Therefore, a net plant or rate base allocation should be used.

The key question is how the cooperative allocates

operating margins, i.e., patronage capital. If the concept is that operating margins are allocated back in a manner that mirrors how they are produced, then the margin allocation in the capital credits program should be consistent with the margin allocation in the COSS. Doing anything other than this would put the cooperative in harms way of not operating on a cooperative basis for tax purposes.

If a cooperative allocates its distribution system patronage capital in an amount equal to revenue less power cost, then the proper allocation of operating margins in the COSS should produce a uniform margin as a percent of cost to serve excluding purchase power cost. The cooperative would allocate any G&T patronage to the cooperative based on power cost for the rate classes. Many distribution cooperatives only retire G&T capital credits when they receive payment – thus they are

on a separate retirement cycle from the retirement of the patronage capital provided by the distribution cooperative's consumer-members. If a cooperative allocates patronage capital based on energy sales in kWh, then the operating margins component in the COSS should be allocated in the same manner. The important point is to make certain there is an alignment of COS margins and patronage capital margin allocations. The typical options are:

- Uniform relative margins
- Uniform coverage target (TIER, OTIER, DSC)
- Uniform margins as percent of revenue
- Uniform margins as percent of revenue less power cost
- Uniform margins per kWh sold



# 4.0

## Interpretation of COSS Results

### 4.1

#### Determination of Rate Class Revenue and Margins

Sections 1 and 2 discussed the process for determining the total revenue requirement for the cooperative, and Section 3 discussed the development of the COSS. The results of the COSS provide:

- The plant investment and operating costs allocated to each rate class.
- The margin earned from each rate class under the current rates.
- The margin earned from the rate class relative to the system average value.
- The magnitude of rate change required for each rate class to realize the margin objective.
- The unbundled cost components of providing service to each rate class and required for rate design.

Schedule F-1.0 is a typical summary output of the COSS. A review of the return and margin for each rate class on the COSS Summary identifies differences in relative revenue for each rate class. The metrics most often used to evaluate interclass differentials in margins are the rate of return (ROR) and the relative rate of return (RROR). The ROR is the return (margin + interest expense) divided by the rate base. The RROR is the class ROR divided by the total system ROR.

A rate class producing a ROR equal to the system average ROR has a RROR of 1.00. The RROR is less than 1.0 when the class ROR is less than the system ROR, and is greater than 1.0 when the class ROR is greater than the system ROR. In most instances, a rate class reflecting a RROR less than 1.00 has revenue and margins that are lower in comparison to the other rate classes. In the Schedule F-1.0 example, the Residential and Irrigation classes have RROR less than 1.00 while the highest RROR is provided by the Industrial and Large Power classes.

The cooperative's board and the team should be aware of the operating margin differential of each rate class. If a rate class that is producing a significant share of the cooperative's revenue or margins shuts down or reduces load, the cooperative's margins would be adversely affected. Similarly, consider the negative impact on the cooperative's margins of a rate class that is not covering its cost of service, which begins to grow quickly. The team should be concerned with any rate class providing a margin that is too low or high.

RROR, TIER and DSC are all metrics that reflect plant investment required to provide service that has been allocated to each rate class. A rate class or consumer-member may take service directly from a wholesale delivery point or may have paid CIAC for facilities required to provide service. Under these situations, the relative ROR, TIER or DSC measure for the class will be higher than the system average. Although power supply and transmission investment to serve the consumer-member may be significant, it resides on the G&T's books and not the distribution cooperative. Because the rate base associated with providing service is small even using the system ROR, the return and embedded margin are minimal.

Instead of a plant-based metric a cooperative may use a metric that mirrors the capital credits retirement policy. To mirror the capital credits allocation methodology, the cooperative may have an objective that the margin component as a percent of total revenue be the same for each rate class. This ensures that every class is contributing the same (as measured by revenue not rate base) ratio of revenue to margin. With this objective, the cooperative does need to coordinate the margin in rate design with the allocation methodology in the capital credits program.

It is difficult to find a metric that can be used to evaluate the “fairness” of a rate charged under all conditions for a distribution cooperative. The RROR works best for a vertically integrated utility where the total plant investment required to provide service is on the same balance sheet. This is not the case with distribution cooperatives. The RROR approach works for many of the rate classes but not all. Even if a cooperative is serving a consumer-member with zero direct investment there needs to be some recognition of the fact that the consumer-member is able to receive service because the cooperative is in place and that for decades other cooperative consumer-members have been paying rates that included a margin component that created the equity and the ability for the cooperative to be a sustaining entity. If the cooperative is retiring patronage capital it is appropriate that current consumer-members pay rates that include a margin component necessary to fund the capital credits retirement while at the same time maintaining the cooperative’s equity objectives. Therefore, all consumer-members have a margin component in the revenue requirement.

## 4.2

### Class Revenue Requirement Reflected in Proposed Rates

The results of the COSS will indicate the rate change for each rate class necessary to realize the desired margin objective. For example, Schedule F-1.0 identifies the rate adjustment for each rate class based on two criteria:

1. The required increase or decrease necessary to realize a uniform ROR.
2. The required increase or decrease necessary to realize a uniform percent margin.

Depending on the Rate Design Policy, additional metrics could be added to show the change necessary to produce a uniform TIER, uniform DSC or uniform revenue less power cost.

It is not necessary for each class to have a margin level equal to the system average although having a significant differential can be a problem. A detailed Rate Design Policy will need to address the following criteria:

1. The relevant margins metric for the analysis.<sup>18</sup>
2. The maximum interclass differential in the margins metric that will be allowed.
3. The maximum allowable increase acceptable for a rate class. For example the criteria might be that no single class total rate increase will be more than 1.5 or 2.0 times the average system increase.
4. Previous commitments made by the cooperative. Previous rate analysis may have shown that a rate class required significant adjustments to correct a relative margins metric that was out of line. If the cooperative committed to move the class to an acceptable margins level over a series of rate adjustments, the commitment should be honored. Communicating any proposed plan to the consumer-members is important because they may need the information for planning purposes. The prior representation may be determinative of what is allowed in the current rate analysis.
5. Any competitive considerations with neighboring systems that would limit the amount of rate adjustment to a class.

The team then needs to determine the rate adjustments by class that will satisfy all of the criteria. The team may find that it is not possible to meet the Financial Policy and Rate Design Policy requirements. When that occurs the team will need to revisit the determination of the cooperative margin target and repeat the process in Sections 1.0 and 2.0.

<sup>18</sup> Representative criteria include ROR, percent margin, TIER, DSC.

### 4.3

#### COSS Data

At this point the team has now defined the total revenue requirement, which includes the margin that will allow the cooperative to meet its financial objectives. The revenue requirement has been allocated to each rate class in a manner that satisfies the Rate Design Policy criteria. The next step is to allocate the class revenue requirements to the individual consumer-members of the rate class. The rate design is the mechanism for allocating class revenue requirements to individual consumer-members in the class. The COSS should provide the detailed data necessary to design the rates. For each rate classification the COSS should provide the following:

1. The revenue requirement by function. The degree of detail reflects the likely unbundled components. A minimum functionalization would include Power Supply and Distribution Wires. More detail would involve the functions defined in Section 3.0.
2. For each function, the COSS should show the costs associated with each of the three basic use classifications, i.e., demand, energy and customer. Keep in mind that the manner in which demand is defined will likely vary. For example the relevant demand value in defining power supply cost responsibility may be rate class contribution to the power supply CP, while transmission cost responsibility may be the rate class contribution to the transmission CP. The important point is to mirror the demand metric by which the cost are incurred. The Distribution wires is likely an NCP value. In some cases there may be a direct assignment of cost to the class.
3. Electric use data that were used to determine the allocation factors should be shown. The use data for the determination of the cost responsibility are adjusted for losses to reflect responsibility at the source level. The customer data will likely have a number of different values with each weighted to properly reflect the cost function being allocated.
4. Billing units should be provided. The billing units should correspond with use data used to develop the COSS allocation factors; however, there will be some differences.
  - a. The consumer-member data used for allocation factors may reflect weighting factors.
  - b. The metered energy data will typically not reflect loss factors. Energy costs are allocated based on responsibility at the wholesale meter, whereas rates will be defined based on energy use at the retail meter.
  - c. For rate classes with demand billing, ideally, the rate design billing units should track the cost allocation use. There will be differences in that use data are adjusted for losses, and the loss ratio may not be the same for all classes, whereas the billing data are typically at the meter without loss adjustments. There can be other differences between the use and billing demand values depending on how the billing demand is defined. For example the rate design may reflect a ratchet.
  - d. The starting point is for the rate class demand allocation values and billing demand values to reflect how the costs are incurred and allocated. This means a minimum of two demand values for each rate class; i.e., CP to reflect power supply responsibility (if applicable) and NCP to reflect responsibility for distribution wires. This assumes that the transmission demand component is bundled with the power supply demand component.
  - e. If energy cost varies by time-of-use, the energy cost components in the COSS will need to reflect the energy cost for the different time periods. The time periods may be seasonal such as summer vs. other months. It may be appropriate to consider winter, summer and shoulder months in defining cost differentials. Another consideration would be cost differential during a day. The hourly energy differentials are a way to capture CP demand cost responsibility for non-demand metered customers.



With this data the cooperative is able to implement a wide variety of rate designs ranging from the traditional two-part rate to a four-part rate that tracks:

- Customer cost
- Power supply demand
- Power supply energy
- Distribution wires demand

There are always two basic factors that the team must discuss:

- What is the structure of the rate; i.e., two-part, three-part or four-part rate? The balancing involves wanting to track costs as accurately as possible vs. a structure that the consumer-member understands and is willing to accept.
- The extent to which the individual rate components are set at a level to capture the cost associated with that component. For example, should the customer charge recover all of the customer cost. If not fully recovered, which rate component recovers the remaining cost.

Schedule F-2.0 shows an example of how costs and billing units might be summarized. Given the class revenue objectives and the COSS data, the team is now in a position to begin the rate design process.

In the discussion of COSS allocation of total revenue to a class, it is likely that certain adjustments defined in the COSS are not adopted. The same discussion occurs in the allocation of the class revenue requirements to consumer-members of the class; i.e., the rate design. In the example provided in the Appendix for the Standard Electric Cooperative COSS, the final rate design components for the residential class as reflected on Schedule F-3.0 differ slightly from the COSS results presented on Schedule F-2.0.

The important point is that the COSS provides the basic data used to evaluate rate options and develop final rates.



Components									
	A	B	C	D	E	F	G	H	I
			TY ADJ		Rate Classes Served				
			Total	Allocation	Res	Sm Com	C&I	Lighting	Etc.
			\$	Factor	\$	\$	\$	\$	\$
1	Purchased Power	Form 7-A, L3							
2	Transmission O&M	Form 7-A, L4							
3	Regional Marketing	Form 7-A, L5							
4	Distribution O&M	Form 7-A, L6+L7							
5	Consumer Accounting	Form 7-A, L8							
6	Customer Service	Form 7-A, L9							
7	Sales	Form 7-A, L10							
8	Administrative & General	Form 7-A, L11							
9	Depreciation	Form 7-A, L13							
10	Tax	Form 7-A, L14+L15							
11	Interest	Form 7-A, L16+L17+L18							
12	Other	Form 7-A, L19							
13	Operating Margin	Form 7-A, L21							
14	Total Cost	SUM(L1:L13)							
15	Less: Other Operating Revenues	Form 7-O/R, L13+L14							
16	Revenue Requirement	L14-L15							

Schedule A-1.0

STANDARD ELECTRIC COOPERATIVE, INC.					
INCOME STATEMENT					
	Test Year 12/32/YYYY	Adjustments	Adjusted Test Year	Rate Change	Adjusted Test Year w/ Rate Change
Operating Revenue	(a)	(b)	(c)	(d)	(e)
Base Revenue	168,698,800	558,655	169,257,455	33,015,344	202,272,799
PCA	16,412,500	3,665,413	20,077,913	(20,077,913)	0
Other	3,478,100	0	3,478,100		3,478,100
<b>Total</b>	<b>188,589,400</b>	<b>4,224,068</b>	<b>192,813,468</b>	<b>12,937,431</b>	<b>205,750,899</b>
Operating Expenses					
Purchased Power	123,502,900	4,219,410	127,722,310		127,722,310
Transmission O&M	402,600	(103,619)	298,981		298,981
Distribution-Operations	9,660,700	(1,997,337)	7,663,363		7,663,363
Distribution-Maintenance	16,441,900	372,285	16,814,185		16,814,185
Consumer Accounting	5,178,200	179,612	5,357,812		5,357,812
Customer Service	980,600	29,339	1,009,939		1,009,939
Sales	173,000	5,186	178,186		178,186
Administrative & General	5,805,400	30,056	5,835,456		5,835,456
Depreciation	13,468,300	476,952	13,945,252		13,945,252
Tax	175,300	2,683,513	2,858,813		2,858,813
<b>Total</b>	<b>175,788,900</b>	<b>5,895,397</b>	<b>181,684,297</b>	<b>0</b>	<b>181,684,297</b>
<b>Return</b>	<b>12,800,500</b>	<b>(1,671,329)</b>	<b>11,129,171</b>	<b>12,937,431</b>	<b>24,066,602</b>
Interest & Other Deductions					
Interest L-T Debt	9,875,400	110,559	9,985,959		9,985,959
Interest-Other	89,700		89,700		89,700
Other Deductions	10,600		10,600		10,600
<b>Total</b>	<b>9,975,700</b>	<b>110,559</b>	<b>10,086,259</b>	<b>0</b>	<b>10,086,259</b>
<b>Operating Margin</b>	<b>2,824,800</b>	<b>(1,781,888)</b>	<b>1,042,912</b>	<b>12,937,431</b>	<b>13,980,343</b>
Non-Operating Margins					
Interest Income	2,417,500	(1,267,500)	1,150,000		1,150,000
Other Margins	295,600		295,600		295,600
G&T Capital Credits	945,400		945,400		945,400
Other Capital Credits	848,200		848,200		848,200
<b>Total</b>	<b>4,506,700</b>	<b>(1,267,500)</b>	<b>3,239,200</b>	<b>0</b>	<b>3,239,200</b>
<b>Net Margins</b>	<b>7,331,500</b>	<b>(3,049,388)</b>	<b>4,282,112</b>	<b>12,937,431</b>	<b>17,219,543</b>
Operating TIER	1.29		1.10		2.40
Net TIER	1.74		1.43		2.72
Net TIER Excl Capital Credits	1.56		1.25		2.54
DSC	2.26		1.90		2.77
DSC Modified	2.16		1.81		2.68
Rate of Return	4.21%		3.67%		7.93%
Rate Base	303,803,253	(185,560)	303,617,693	0	303,617,693
Principal Payments	3,679,700	1,174,619	4,854,319		4,854,319
Cash G&T & Other Capital Cr Pmts	402,400		402,400		402,400
Percent Change					6.71%

Standard Electric Cooperative, INC. Summary of Adjustments	
<b>1. Operating Revenue</b>	
Base Revenue	\$558,655
PCA Revenue	\$3,665,413
Other Revenue	\$0
<b>TOTAL</b>	<b>\$4,224,068</b>
<b>2. Operating Expenses</b>	
Purchased Power	\$4,219,410
Payroll	\$470,223
Benefits	\$526,800
Payroll Tax	\$94,139
Liability Insurance	\$58,440
Bad Debts	\$(14,338)
Regulatory Commission	\$4,055
Rate Case	\$10,000
Depreciation	\$476,952
Property Tax	\$45,875
Franchise Tax	\$3,838
<b>TOTAL</b>	<b>\$5,895,395</b>
<b>3. Interest on Long-Term Debt &amp; Other Deductions</b>	
INTEREST ON LONG-TERM DEBT	\$110,559

Schedule B-2.0

## DEVELOPMENT OF RATE BASE, RATE OF RETURN AND RETURN

1. Determine Rate Base		2. Determine Capitalization					
	Adj TY Total \$		\$	%	Cost	Return	
Plant In Service	429,228,800						
CWIP	5,684,600	Debt	191,727,700	58.26%	5.208%	3.03%	
Total Utility Plant	434,913,400	Equity	137,385,500	41.74%	11.7200%	4.89%	
Accum Depreciation	(130,764,700)	Total	329,113,200	100.00%		7.93%	
Net Plant	304,148,700						
Working Capital		3. Determine Cost of Debt					
Materials & Supplies	227,515					\$	
Prepayments	1,002,723						
Cash Working Capital	4,644,740	Interest on LTD Expense				9,985,959	
Consumer Deposits	(6,405,985)	Long Term Debt Balance				191,727,700	
Working Capital	(531,007)	Cost of Debt				5.21%	
Rate Base	303,617,693						
4. Determine Cost of Equity - Using Goodwin Formula							
$RE = \frac{(1 + g)^{n+1} - (1 + g)^n}{(1 + g)^n - 1}$	Growth Rate	Rotation Cycle years					
		5	10	15	20	25	
		1.00%	20.60%	10.56%	7.21%	5.54%	4.54%
		2.00%	21.22%	11.13%	7.78%	6.12%	5.12%
		3.00%	21.84%	11.72%	8.38%	6.72%	5.74%
		4.00%	22.46%	12.33%	8.99%	7.36%	6.40%
	5.00%	23.10%	12.95%	9.63%	8.02%	7.10%	
Return on Equity	RE	Growth in Plant			3.00%		
Growth in Plant	g	Rotation Cycle			10		
CC Rotation Cycle	n	ROE			11.72%		
5. Determine Rate of Return							
			\$	%	Cost	Return	
Debt			191,727,700	58.26%	5.208%	3.034%	
Equity			137,385,500	41.74%	11.720%	4.892%	
Total			329,113,200	100.00%		7.927%	
6. Determine Adequacy of ROR							
		Rate Base	Weighted Cost	Computed Cost	Actual Cost	Difference	
Interest		303,617,693	3.034%	9,212,374	9,985,959	773,585	
Margin		303,617,693	4.892%	14,854,186			
Return		303,617,693	7.927%	24,066,560			

Schedule C-1.0

## Determination of Optimum Equity

## Terms

Growth Rate	g	3.00%	3.00%
Rotation Cycle years	n	15	10
TIER	TIER	2.00	2.00
Equity Cost	EC	8.38%	11.72%
Interest Rate	DC	5.00%	5.00%
Equity % Capitalization	E%	37.38%	29.90%
Interest Cost \$	I		
Long Term Debt \$	D		
Equity \$	E		

## Equations

$$\text{Return} = [\text{EC} \times \text{E}\% + \text{DC} \times (1 - \text{E}\%)] \times \text{Capitalization}$$

$$\text{Margin} = (\text{TIER} \times \text{Interest Cost}) - \text{Interest Cost}$$

$$\text{Return} = \text{Margin} + \text{Interest Cost}$$

$$\text{Return} = \text{TIER} \times \text{Interest Cost}$$

$$\text{Tier} = \frac{\text{Margin} + \text{Interest Cost}}{\text{Interest Cost}}$$

$$\text{Return} = \text{TIER} \times \text{DC} \times (1 - \text{E}\%) \times \text{Capitalization}$$

$$\text{EC} = \frac{(1 + g)^{n+1} - (1 + g)^n}{(1 + g)^n - 1}$$

$$\text{Return} = [\text{EC} \times \text{E}\% + \text{DC} \times (1 - \text{E}\%)] \times \text{Capitalization}$$

$$\text{Optimum Equity} = \frac{\text{DC} \times (\text{TIER} - 1)}{\text{EC} + \text{DC} \times (\text{TIER} - 1)}$$

$$\text{TIER} \times \text{DC} \times (1 - \text{E}\%) = \text{EC} \times \text{E}\% + \text{DC} \times (1 - \text{E}\%)$$

$$\text{Capitalization} = (\text{D} + \text{E})$$

$$\text{Equity \%} = \frac{\text{E}}{\text{D} + \text{E}}$$

Equity % of Capitalization									
TIER =	g	EC	1.50	1.75	2.00	2.25	2.50	2.75	3.00
	0.50%	6.94%	26.49%	35.09%	41.89%	47.40%	51.95%	55.78%	59.04%
	1.00%	7.21%	25.74%	34.21%	40.94%	46.43%	50.98%	54.82%	58.10%
	1.50%	7.49%	25.01%	33.35%	40.02%	45.47%	50.02%	53.86%	57.16%
	2.00%	7.78%	24.31%	32.52%	39.12%	44.54%	49.08%	52.93%	56.23%
	2.50%	8.08%	23.64%	31.71%	38.24%	43.63%	48.15%	52.00%	55.32%
	3.00%	8.38%	22.99%	30.92%	37.38%	42.73%	47.24%	51.09%	54.42%
	3.50%	8.68%	22.36%	30.16%	36.54%	41.85%	46.35%	50.19%	53.53%
	4.00%	8.99%	21.75%	29.43%	35.73%	41.00%	45.47%	49.31%	52.65%
	4.50%	9.31%	21.17%	28.71%	34.94%	40.16%	44.61%	48.45%	51.78%
	5.00%	9.63%	20.60%	28.02%	34.17%	39.35%	43.77%	47.60%	50.93%

Equity % of Capitalization								
TIER =								
g	EC	1.50	1.75	2.00	2.25	2.50	2.75	3.00
0.50%	10.28%	19.57%	26.73%	32.73%	37.82%	42.19%	45.99%	49.32%
1.00%	10.56%	19.15%	26.21%	32.14%	37.18%	41.53%	45.32%	48.64%
1.50%	10.84%	18.74%	25.70%	31.56%	36.56%	40.89%	44.66%	47.98%
2.00%	11.13%	18.34%	25.20%	30.99%	35.96%	40.25%	44.01%	47.32%
2.50%	11.43%	17.95%	24.71%	30.44%	35.36%	39.63%	43.37%	46.67%
3.00%	11.72%	17.58%	24.24%	29.90%	34.77%	39.02%	42.74%	46.03%
3.50%	12.02%	17.21%	23.77%	29.37%	34.20%	38.41%	42.12%	45.40%
4.00%	12.33%	16.86%	23.32%	28.85%	33.64%	37.82%	41.51%	44.78%
4.50%	12.64%	16.51%	22.88%	28.35%	33.09%	37.24%	40.91%	44.17%
5.00%	12.95%	16.18%	22.45%	27.85%	32.55%	36.67%	40.32%	43.57%

Schedule C-2.0

# Cash Flow Model for Determination of Margin Required

## Margin Sufficient To:

Meet coverage | TIER, MFI, DSC | Provide sufficient cash

## Cash Sufficient To:

Pay debt service | Contribute to General Funds

## General Funds Sufficient To:

Pay capital credits | Fund plant additions

## Balance Sheet Ratios:

Equity as % of capitalization | Liquidity as % of plant

## Payment of Capital Credits:

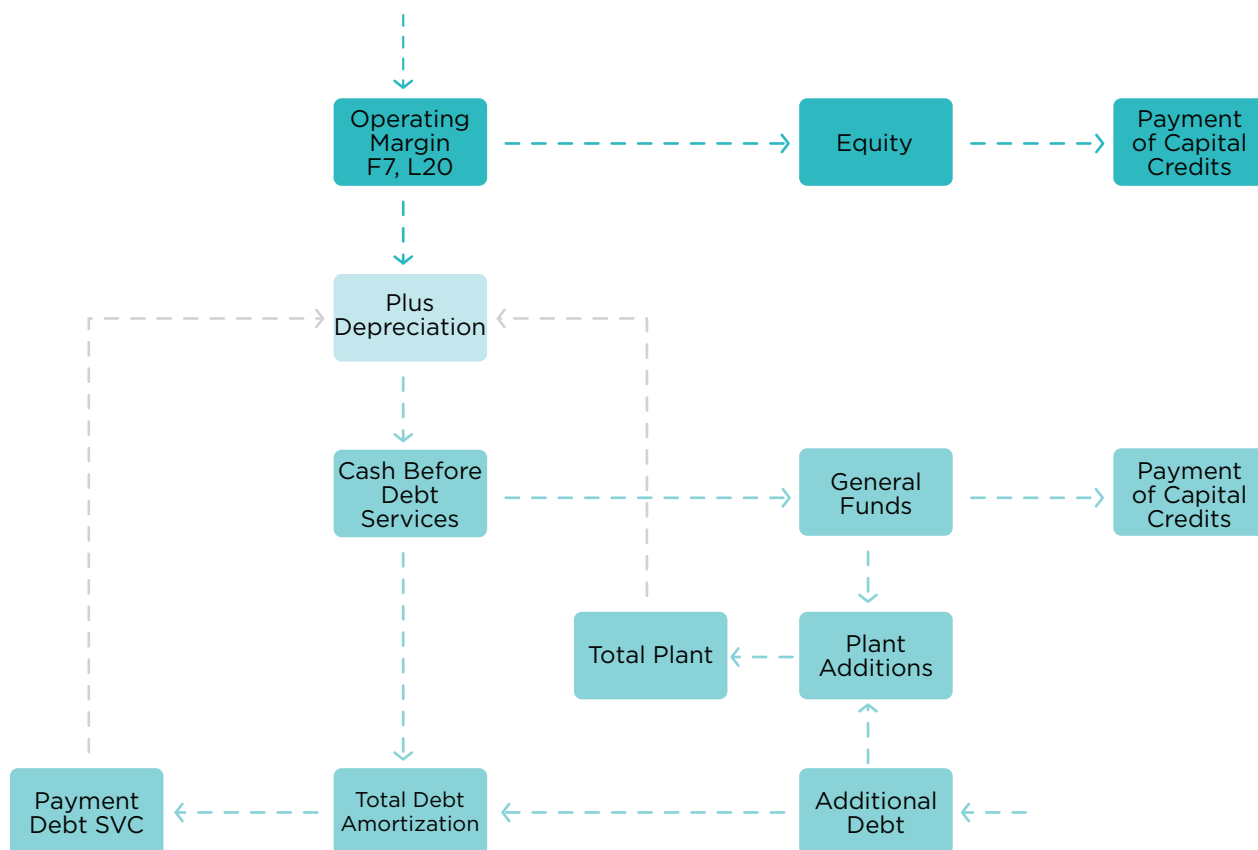
Reduce equity and associated equity as % of capitalization | Reduces general funds and liquidity

## Source of Funds to Finance Plant Investment (net CIAC):

Retained earnings (i.e., cash from operations) | Debt

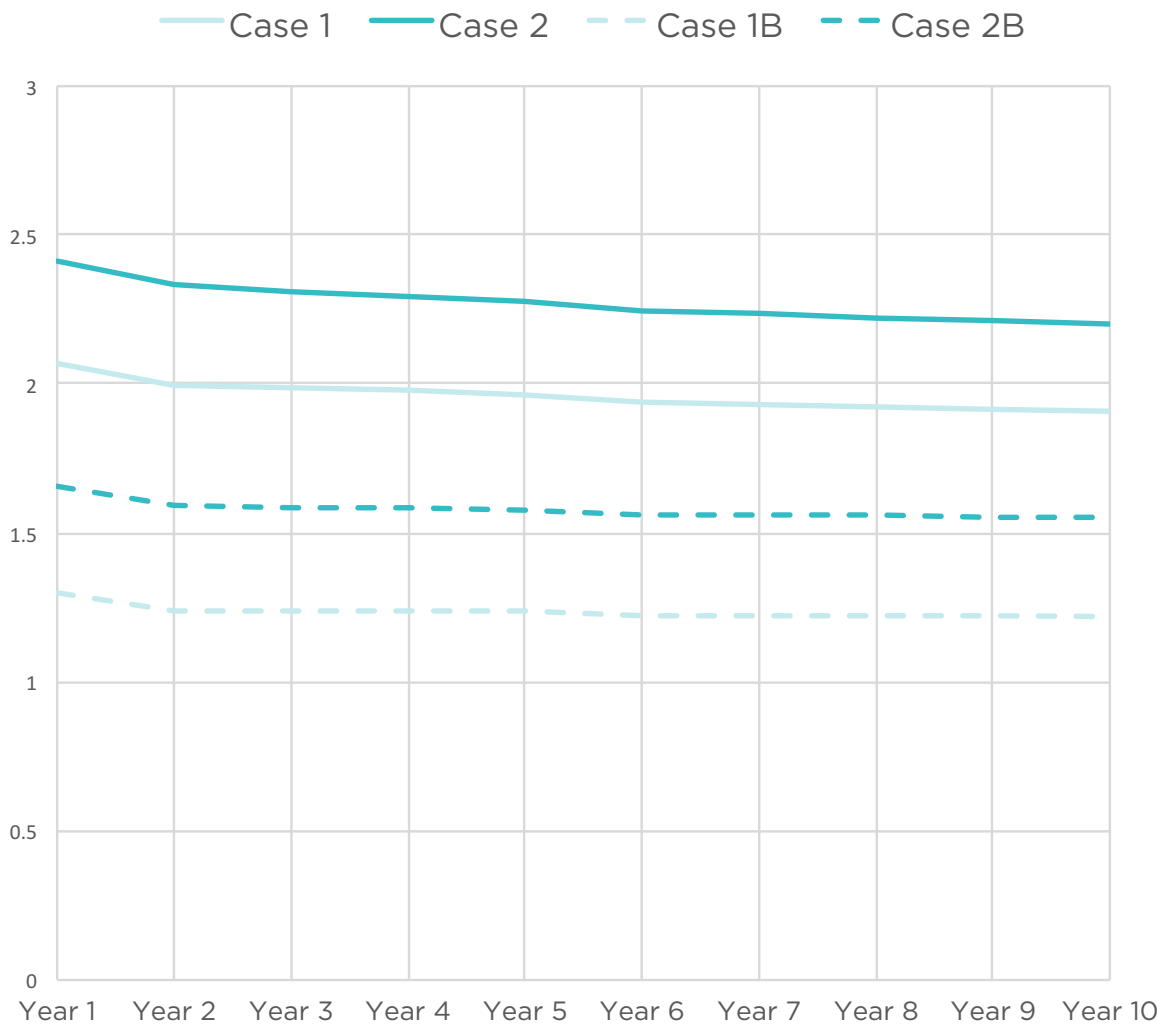
## Equity Ratio:

Equity/(Equity + Debt)





### Modified TIER



**Assumptions (All Cases Maintain Equity Ratio of 37.61% of Total Assets):**

- Case 1: 3% Net Plant Growth Rate, Capital Credits Retired 5.4% of Prior Year's Equity
- Case 2: 6% Net Plant Growth Rate, Capital Credits Retired 5.4% of Prior Year's Equity
- Case 1B: 3% Net Plant Growth Rate, \$0 Capital Credits Retired
- Case 2B: 6% Net Plant Growth Rate, \$0 Capital Credits Retired

Classification of Expenses					
		FERC		NARUC	
ACCT#	Description	Demand Related	Energy Related	Demand Related	Energy Related
Steam Power Generation					
	OPERATION				
500	Operation, Supervision & Engineering	X		X	X
501	Fuel		X		X
502	Steam Expense	X		X	X
505	Electric Expense	X		X	X
506	Misc Steam Pw Engineering	X		X	
507	Rents	X		X	
	MAINTENANCE				
510	Supervision & Engineering		X	X	X
511	Structures	X		X	
512	Boiler Plant		X		X
513	Electric Plant		X		X
514	Misc Steam Plant	X			X
Other Power Generation					
	OPERATION				
546	Operation, Supervision & Engineering	X		X	
547	Fuel		X		X
548	Generation Expense	X		X	
549	Electric Expense	X		X	
550	Misc Other Power Generation Expense	X		X	
	Rents	X		X	
	MAINTENANCE				
551	Supervision & Engineering	X		X	
552	Structures	X		X	
553	Generation and Electrical Equipment	X		X	
554	Misc Other Power Generation Plant	X		X	
Other Power Supply Expenses					
555	Purchased Power	AS BILLED	AS BILLED	AS BILLED	AS BILLED
556	System Control & Dispatching	X		X	
557	Other Expense	X		X	

Classification of Distribution Expenses				
ACCT#	Description	Demand Related	Energy Related	Direct
<b>Distribution Operations</b>				
580	Operation Supervision & Engineering	X	X	
581	Load Dispatch	X		
582	Station Expenses	X		
583	Overhead Line Expenses	X	X	
584	Underground Line Expenses	X	X	
585	Street Lighting & Signal Systems			X
586	Meter Expenses		X	
587	Customer Installation Expenses		X	
588	Miscellaneous Distribution Expenses	X	X	
589	Rents	X	X	
<b>Distribution Maintenance</b>				
590	Supervision & Engineering	X	X	
591	Structures	X	X	
592	Station Equipment	X		
593	Overhead Lines	X	X	
594	Undergrounds Lines	X	X	
595	Line Transformers	X	X	
596	Street Lighting & Signal Systems			X
597	Meters		X	
598	Miscellaneous Distribution Expenses	X	X	

Schedule E-2.0

**STANDARD ELECTRIC COOPERATIVE, INC.**  
**EXISTING RATES ADJUSTED TEST YEAR ENDING 12/31/YYYY**  
 Cost Allocation Summary

Account	Total	Residential	Commercial	Irrigation	Large Power	Industrial	Security Lts	Street Lts
<b>Rate Base</b>	303,617,690	238,774,960	19,151,645	13,674,683	17,019,325	3,752,276	9,160,685	2,084,116
<b>Operating Revenue</b>	192,813,464	135,223,989	11,283,884	6,514,689	17,718,979	17,460,065	4,149,868	461,990
<b>Operating Expenses</b>	181,684,293	129,395,245	10,214,652	6,600,828	15,118,981	16,283,710	3,732,473	338,404
<b>Return</b>	11,129,171	5,828,744	1,069,232	(86,139)	2,599,998	1,176,355	417,395	123,586
Rate of Return	3.666%	2.441%	5.583%	-0.630%	15.277%	31.350%	4.556%	5.930%
Relative ROR	1.000	0.666	1.523	(0.172)	4.168	8.553	1.243	1.618
<b>Interest</b>	10,086,256	7,959,881	634,810	448,569	555,281	120,849	298,416	68,450
<b>Operating Margins</b>	1,042,915	(2,131,137)	434,422	(534,708)	2,044,717	1,055,506	118,979	55,136
Margin % Revenue	0.541%	-1.576%	3.850%	-8.208%	11.540%	6.045%	2.867%	11.934%
Operating TIER	1.103	0.732	1.684	(0.192)	4.682	9.734	1.399	1.805
<b>Revenue Deficiencies</b>								
<b>Uniform ROR = 7.927%</b>	12,937,430	13,098,024	448,845	1,170,078	(1,250,942)	(878,927)	308,737	41,614
Deficiency as % of Revenue	6.710%	9.686%	3.978%	17.961%	-7.060%	-5.034%	7.440%	9.008%
<b>Uniform % Margin = 6.795%</b>	12,937,430	12,144,520	356,519	1,048,619	(902,041)	140,410	174,879	(25,476)
Deficiency as % of Revenue	6.710%	8.981%	3.160%	16.096%	-5.091%	0.804%	4.214%	-5.514%

CoOPTIONS: <sup>2</sup> Cost of Service

*Schedule F-1.0*

**STANDARD ELECTRIC COOPERATIVE, INC.**  
**UNBUNDLED COSTS W/ UNIFORM ROR ON RATE BASE**  
 ADJUSTED TEST YEAR ENDING 12/31/YYYY  
 SUMMARY OF COMPONENTS OF EXPENSES

Accounts	Total	Residential	Commercial	Irrigation	Large Power	Industrial	Security Lts	Street Lts
Average Consumers	88,163	81,525	4,827	1,244	565	2	47,504	4,664
kWh Sold	1,830,775,494	1,151,165,422	97,806,128	55,350,845	189,686,899	299,314,241	34,581,451	2,870,508
NCP kW	10,775,573	8,804,700	521,316	285,952	580,553	469,043	105,271	8,738
CP kW	4,225,034	2,980,736	231,492	144,811	400,332	420,159	43,863	3,641
<b>PUR PWR DEMAND</b>	<b>64,248,682</b>	<b>45,701,556</b>	<b>3,517,154</b>	<b>2,302,715</b>	<b>6,020,746</b>	<b>6,054,182</b>	<b>602,464</b>	<b>49,865</b>
Monthly Cost per Cons	60.73	46.72	60.72	154.25	888.02	252,257.58	1.06	0.89
Average Cost per kWh	0.035094	0.039700	0.035960	0.041602	0.031740	0.020227	0.017422	0.017371
Cost per NCP kW	5.96	5.19	6.75	8.05	10.37	12.91	5.72	5.71
Cost per CP kW	15.21	15.33	15.19	15.90	15.04	14.41	13.74	13.70
<b>PUR PWR ENERGY</b>	<b>63,473,630</b>	<b>40,472,271</b>	<b>3,438,634</b>	<b>1,946,006</b>	<b>6,597,534</b>	<b>9,702,462</b>	<b>1,215,803</b>	<b>100,920</b>
Monthly Cost per Cons	60.00	41.37	59.36	130.36	973.09	404,269.25	2.13	1.80
Average Cost per kWh	0.034670	0.035158	0.035158	0.035158	0.034781	0.032416	0.035158	0.035158
Cost per NCP kW	5.89	4.60	6.60	6.81	11.36	20.69	11.55	11.55
Cost per CP kW	15.02	13.58	14.85	13.44	16.48	23.09	27.72	27.72
<b>WIRES DEMAND</b>	<b>41,944,804</b>	<b>33,056,114</b>	<b>2,770,133</b>	<b>1,891,473</b>	<b>3,118,892</b>	<b>744,254</b>	<b>328,699</b>	<b>35,239</b>
Monthly Cost per Cons	39.65	33.79	47.82	126.71	460.01	31,010.58	0.58	0.63
Average Cost per kWh	0.022911	0.028715	0.028323	0.034172	0.016442	0.002487	0.009505	0.012276
Cost per NCP kW	3.89	3.75	5.31	6.61	5.37	1.59	3.12	4.03
Cost per CP kW	9.93	11.09	11.97	13.06	7.79	1.77	7.49	9.68
<b>TOTAL CUSTOMER</b>	<b>36,083,787</b>	<b>29,092,073</b>	<b>2,006,810</b>	<b>1,544,575</b>	<b>730,866</b>	<b>80,242</b>	<b>2,311,641</b>	<b>317,580</b>
Monthly Cost per Cons	34.11	29.74	34.65	103.47	107.80	3,343.42	4.06	5.67
Average Cost per kWh	0.019710	0.025272	0.020518	0.027905	0.003853	0.000268	0.066846	0.110635
Cost per NCP kW	3.35	3.30	3.85	5.40	1.26	0.17	21.96	36.34
Cost per CP kW	8.54	9.76	8.67	10.67	1.83	0.19	52.70	87.22
<b>Total Expenses</b>	<b>205,750,903</b>	<b>148,322,014</b>	<b>11,732,731</b>	<b>7,684,769</b>	<b>16,468,038</b>	<b>16,581,140</b>	<b>4,458,607</b>	<b>503,604</b>
Monthly Cost per Cons	194.48	151.61	202.55	514.79	2,428.91	690,880.83	7.82	9.00
Average Cost per kWh	0.112385	0.128845	0.119959	0.138837	0.086817	0.055397	0.128931	0.175441
Cost per NCP kW	19.09	16.85	22.51	26.87	28.37	35.35	42.35	57.63
Cost per CP kW	48.70	49.76	50.68	53.07	41.14	39.46	101.65	138.31

CoOPTIONS: Cost of Service

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Schedule F-2.0

**STANDARD ELECTRIC COOPERATIVE, INC.**  
**COMPONENTS OF EXPENSES WITH CLASS RETURN - RESIDENTIAL**

Required Revenue		Unit Cost			
		kWh	CP kW	NCP kW	Consumer
<b>Components of Expenses - Detailed</b>					
Power Supply-Demand	34,737,661	0.03018	11.65	3.95	35.51
Power Supply-Energy	40,472,271	0.03516	13.58	4.60	41.37
Power Supply-Delivery	10,963,895	0.00952	3.68	1.25	11.21
Sub-Transmission	1,190,070	0.00103	0.40	0.14	1.22
Distribution Substation	3,425,880	0.00298	1.15	0.39	3.50
Distribution Backbone	13,163,611	0.01144	4.42	1.50	13.46
Distribution Demand	12,011,816	0.01043	4.03	1.36	12.28
Distribution Consumer	19,339,696	0.01680	6.49	2.20	19.77
Consumer Services	1,398,862	0.00122	0.47	0.16	1.43
Consumer	6,375,502	0.00554	2.14	0.72	6.52
<b>Total</b>	<b>143,079,264</b>	<b>0.12430</b>	<b>48.01</b>	<b>16.27</b>	<b>146.27</b>
<b>Components of Expenses - Consolidated for Rate Design</b>					
Power Supply-Demand	34,737,661	0.03018	11.65	3.95	35.51
Power Supply-Energy	40,472,271	0.03516	13.58	4.60	41.37
Power Supply-Delivery	10,963,895	0.00952	3.68	1.25	11.21
Distribution Demand	29,791,377	0.02588	9.99	3.38	30.45
Distribution Consumer	27,114,060	0.02355	9.10	3.08	27.72
<b>Total</b>	<b>143,079,264</b>	<b>0.12429</b>	<b>48.00</b>	<b>16.26</b>	<b>146.26</b>
<b>Billing Units</b>					
<b>12-Month Sum</b>		<b>1,151,165,422</b>	<b>2,980,736</b>	<b>8,804,700</b>	<b>978,300</b>

Schedule F-3.0

## Glossary of Terms

**Annualized/Annualization:** *The process of taking an event (such as an increase in cost) that occurred sometime during an accounting period (such as June of a year) and restating the impact as if the event had been in place for the full accounting period (for a full 12-months).*

**Billing Units:** *Quantities (meter, kWh, demand, etc.) to which rate components are applied to determine the monthly bill.*

**Capital Expenditure (CAPEX):** *Annual capital requirement for plant additions including general plant less plant financed with contributions in aid of construction.*

**Classification of Cost:** *Process of defining cost in terms of use characteristic that drives the cost, i.e., energy, customer, demand.*

**Coincident Demand:** *The sum of two or more demands that occur in the same time interval.*

**Coincident Peak Load:** *The maximum value in an accounting period of the coincident demand.*

**Contribution in Aid of Construction (CIAC):** *Payment made by a consumer-member for the facilities to provide service.*

**Debt Service:** *The annual principal and interest payments on long-term debt.*

**Distributed Energy Resource (DER):** *The DER may be located behind the wholesale meter or behind the retail meter. DER may include renewables such as solar or wind generation or any type of fossil-fired generation.*

**Debt Service Coverage Ratio (DSC):** *A metric that reflects the ability of the cooperative to pay annual debt service.  $DSC = (\text{Margin} + \text{Depreciation} + \text{Interest LTD}) \div \text{Debt Service}$ .*

**Distribution System Operator (DSO):** *The entity responsible for developing, operating and maintaining the electric distribution system including interconnections with other systems.*

**Energy Charge:** *That portion of the charge for electric service based upon the electric energy (kWh) consumed or billed.*

### **Equity as Percentage of Assets:**

*RUS Form 7, Part C Balance Sheet. Line 36 ÷ Line 29.*

*CFC Form 7, Part C Balance Sheet. Line 35 ÷ Line 28.*

### **Equity as Percentage of Capitalization:**

*RUS Form 7, Part C Balance Sheet. Line 36 ÷ (Line 36 + Line 43).*

*CFC Form 7, Part C Balance Sheet. Line 35 ÷ (Lines 35 + Line 38).*

**Equity Management Plan:** *A plan established by the board that identifies the key financial objectives for the cooperative. May also be referenced as a Financial Strategy Plan. This analysis suggests four objectives—equity (percentage of assets or percentage of capitalization), coverage ratios (TIER, DSC, OTIER), liquidity (combination of general fund cash and line of credit) and capital credits retirement program as the key metrics.*

**Financial Forecast:** *Ten-year financial forecast for the cooperative.*

**Financial Profile:** *A summary of operating expenses, margins, coverage ratios, rate of return or use data on a rolling 12-month basis. The purpose is to identify a rolling 12-month income statement that identifies trends in cost, revenue, use and margins.*

**Financial Strategy:** *Reference Equity Management Plan.*

**Forecasted Test Year:** *Any future 12-month period showing revenue, expenses, use data and margins for the cooperative.*

**Formula Rate Proceeding:** *Used in many FERC proceedings. The FERC approves a formula rather than a specific rate. Each year the formula is populated with data consistent with the protocols the FERC approved. The result is an updated rate or revenue requirement.*

**Form 7:** *Either RUS or CFC statistical report. The analysis reflects RUS Revision Date 2014 and CFC Version 1.05 (1/2016).*

**Functionalization:** *The assignment of costs associated with a major function such as Production, Transmission, Distribution, Administrative and General Cost.*

**Generation and Transmission Cooperative (G&T):** *This analysis references two types. One in which the G&T provides wholesale service to a member distribution cooperative. Second is a G&T providing service to a member Transmission cooperative and the Transmission cooperative then providing service to a member distribution cooperative.*

**Historic Test Year:** *Any actual historic 12-month period.*

**Investor-Owned Utility (IOU):** *A public utility owned by a corporation or private company.*

**Independent System Operator (ISO):** *The entity coordinating, controlling and monitoring the electrical power system within a state or states.*

**Liquidity:** *Consists of general fund cash plus lines of credit available to the cooperative and reflects working capital available to the cooperative to meet operating cash flow requirements.*

**Long-Term Debt (LTD):** *Loans or financial obligations with a term greater than one year.*

**Margin for Interest (MFI):** *A metric of margins and interest found in some long-term debt indentures.*

**Net Margin:** *Margins as reported on RUS/CFC Form 7, Line 29.*

**Non-coincident Peak Load:** *The maximum rate of energy use over a defined period (60 minutes, 30 minutes, 15 minutes, etc.) determined over an accounting period (monthly, seasonal, annual, etc.).*

**Normalized/Normalization:** *The process of restating use, revenue and associated expenses to “normal” weather conditions or to recognize changes in use for a very large customer or a rate class.*

**Operating Margin:** *Margin as reported on RUS/CFC Form 7, Line 21.*

**Operating Times Interest Earned Ratio (OTIER):** *A variation of the TIER calculations that includes interest income and certain cash receipts in the numerator of the calculation.*

**Pro Forma Income Statement:** *An income statement restated to reflect an accounting period restated for revenue and expense adjustments.*

**Public Utility Regulatory Policies Act (PURPA):** *The Public Utility Regulatory Policies Act (PURPA, Pub. L. 95-617, 92 Stat. 3117, enacted November 9, 1978) is a United States Act passed as part of the National Energy Act. It was meant to promote energy conservation (reduce demand) and promote greater use of domestic energy and renewable energy (increase supply).*

**Purchased Power Adjustment/Power Cost Adjustment (PPA):** *A clause in a rate schedule that provides for adjustments to the bill when total power cost billed from the wholesale supplier varies from a specified base amount reflected in the rate design. The adjustment is typically reflected in a \$/kWh adjustment to the consumer. However, some adjustors track changes in the demand and energy component separately.*

**Qualifying Facility (QF):** *A cogeneration or small power production facility that meets certain ownership, operating and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act (PURPA).*

**Rate Base:** *The capital investment associated with providing service.*

**Rate of Return (ROR):** *A value equal to the return divided by the rate base.*

**Return:** *Interest plus margins.*



**Revenue Requirement:** *The total revenue that the rates charged to consumer-members must produce to pay all of the operating expenses associated with providing service and the capital cost associated with meeting the financial objectives.*

**Regional Transmission Operator (RTO):** *The entity coordinating, controlling and monitoring a multi-state electric grid.*

**Test Year:** *A 12-month period that is used for the determination of the cost components for the cost of service analysis and margins component necessary to meet the cooperative's financial objectives.*

**Times Interest Earned Ratio (TIER):** *A metric that reflects the ability to pay interest expense on an accrual basis.  $TIER = (Margins + Interest LTD) \div Interest LTD$ .*

**Unbundling:** *The separating of the total process of providing electric power service from generation to metering into its component parts for the purpose of identifying the separate pricing components.*

## Exhibit D

Exhibit D, Comparison of monthly DG fees and cost caps under MREA methodology and a CCOSS (including all distribution costs)

<b>Comparison of DEA's monthly DG fees under the MREA's methodology and DEA's CCOSS</b>				
<b>Line</b>	<b>Monthly DG Fee</b>	<b>MREA methodology</b>	<b>DEA's CCOSS</b>	<b>Formula</b>
1	Distribution cost (\$/customer-mo)	\$37.39	\$31.74	
2	Customers	97,041	97,041	
3	Fixed charge revenue (\$/customer-mo)	\$9.00	\$9.00	
4	Annual Class Distribution Fixed Costs	\$43,545,671	\$36,964,729	Line 1 x Line 2 x 12
5	Annual Class Consumer Charge Revenue	\$10,480,428	\$10,480,428	Line 2 x Line 3 x 12
6	Distribution Fixed Costs Recovered in Energy Rate	\$33,065,243	\$26,484,301	Line 4 - Line 5
7	Annual sales (kWh)	898,634,906	898,634,906	
8	Distribution Fixed Costs Recovered in Energy Rate (\$/kWh)	\$0.037	\$0.029	Line 6 ÷ Line 7
9	Estimated Solar DG Capacity Factor	15%	15%	
10	Estimated Monthly Solar Production (kWh/kW-mo)	109.5	109.5	(Line 9 x 365 x 24) ÷ 12
11	<b>Monthly DG Fee (\$/kW-mo)</b>	<b>\$4.03</b>	<b>\$3.23</b>	Line 8 x Line 10
	<b>Difference (\$/kW-mo)</b>		<b>\$0.80</b>	
	<b>Difference (%)</b>		<b>25%</b>	
<b>Monthly Charge Cap</b>				
12	Distribution cost (\$/customer-mo)	\$37.39	\$31.74	
13	Fixed charge revenue (\$/customer-mo)	\$9.00	\$9.00	
14	Monthly Charge Cap (\$/customer-mo)	\$28.39	\$22.74	Line 12 - Line 13
15	<b>Monthly Charge Cap - Rounded</b>	<b>\$28.00</b>	<b>\$23.00</b>	Line 14 (rounded)
	<b>Difference (\$/kW-mo)</b>		<b>\$5.00</b>	
	<b>Difference (%)</b>		<b>22%</b>	

Exhibit D, Comparison of monthly DG fees and cost caps under MREA methodology and a CCOSS (including all distribution costs)

Sources:

- 1) DEA's CCOSS: Larson Direct, Exhibit 3 COSS at 18, Filed 7/2/2014 in Docket 14-482 ([link](#))

Summary of Allocation of Revenue Requirements to Rate Classes

Line No.	Cost Classification	Alloc. Factor	Total	Resid. & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
36	<b>Distribution</b>								
37	Power Supply	-Energy E1							
38	Dist. Sub.	-Capacity D9	6,662,134	3,299,353	198,137	51,965	1,656,002	1,414,231	42,445
39	Dist. Sub.	-Consumer C2							
40	Primary Line	-Capacity D9	10,110,517	5,007,129	300,695	78,863	2,513,164	2,146,250	64,415
41	Primary Line	-Consumer C2	14,973,690	13,527,331	788,863	74,464	484,959	52,488	45,586
42	Line Transf.	-Capacity D1	1,862,177	1,272,929	67,338	38,930	293,640	184,668	4,671
43	Line Transf.	-Consumer C3	778,834	702,219	41,565	3,981	25,892	2,810	2,366
44	Sec. & Serv.	-Consumer C4	172,985	156,963	8,849	807	5,271	566	529
45	Meter	-Consumer C5	5,048,674	4,032,128	326,781	59,141	459,761	157,275	13,588
46	Acct. & Serv.	-Consumer C6	10,550,960	8,426,534	682,922	123,596	960,830	328,682	28,397
47	Revenue Related	-Revenue R2							
48	Direct Assigned	Direct	1,062,930						1,062,930
49	Subtotal - Distribution		51,222,901	36,424,587	2,415,151	431,747	6,399,518	4,286,972	1,264,926
50	<b>Total</b>		<b>200,728,492</b>	<b>115,576,812</b>	<b>7,171,338</b>	<b>997,009</b>	<b>47,749,413</b>	<b>27,212,425</b>	<b>2,021,495</b>

DEA Exhibit 3 COS 2014 v4 FINAL.xlsm

SumReqByCl

Exhibit (DEA-3)  
Page 18 of 42

- 2) MREA methodology: DEA's 2016 RUS Form 7, Filed 6/30/2017 in Docket 17-11 ([link](#))

<b>Comparison of MN Valley's monthly DG fees under the MREA's methodology and MN Valley's CCOSS</b>				
<b>Line</b>	<b>Monthly DG Fee</b>	<b>MREA methodology</b>	<b>MN V's CCOSS</b>	<b>Formula</b>
1	Distribution cost (\$/customer-mo)	\$104.96	\$81.44	
2	Customers	4,956	4,956	
3	Fixed charge revenue (\$/customer-mo)	\$20.00	\$20.00	
4	Annual Class Distribution Fixed Costs	\$6,242,021	\$4,843,129	Line 1 x Line 2 x 12
5	Annual Class Consumer Charge Revenue	\$1,189,440	\$1,189,440	Line 2 x Line 3 x 12
6	Distribution Fixed Costs Recovered in Energy Rate	\$5,052,581	\$3,653,689	Line 4 - Line 5
7	Annual sales (kWh)	126,112,214	126,112,214	
8	Distribution Fixed Costs Recovered in Energy Rate (\$/kWh)	\$0.040	\$0.029	Line 6 ÷ Line 7
9	Estimated Solar DG Capacity Factor	15%	15%	
10	Estimated Monthly Solar Production (kWh/kW-mo)	109.5	109.5	(Line 9 x 365 x 24) ÷ 12
11	<b>Monthly DG Fee (\$/kW-mo)</b>	<b>\$4.39</b>	<b>\$3.17</b>	Line 8 x Line 10
	<b>Difference (\$/kW-mo)</b>		<b>\$1.21</b>	
	<b>Difference (%)</b>		<b>38%</b>	
<b>Monthly Charge Cap</b>				
12	Distribution cost (\$/customer-mo)	\$104.96	\$81.44	
13	Fixed charge revenue (\$/customer-mo)	\$20.00	\$20.00	
14	Monthly Charge Cap (\$/customer-mo)	\$84.96	\$61.44	Line 12 - Line 13
15	<b>Monthly Charge Cap - Rounded</b>	<b>\$85.00</b>	<b>\$61.00</b>	Line 14 (rounded)
	<b>Difference (\$/kW-mo)</b>		<b>\$24.00</b>	
	<b>Difference (%)</b>		<b>39%</b>	

Exhibit D, Comparison of monthly DG fees and cost caps under MREA methodology and a CCOSS (including all distribution costs)

Sources:

1)MN Valley's CCOSS: Response to Department of Commerce IR #2, Filed 7/15/2016 in Docket 16-241 ([link](#))

- 2 | Please provide cost support or other documentation demonstrating the amount of fixed costs recovered through the usage charge. At what usage level are all fixed costs being recovered?

Response: For purposes of answering this question the term "fixed costs" is interpreted as relating to non-power supply costs that do not vary with the volume of electricity used or delivered.

According to the Class Cost of Service Study for the Single Phase rate class it is determined that there are three types of fixed costs being recovered through the usage charge: 1) transmission capacity-related, 2) distribution capacity-related and 3) distribution consumer-related costs. To the extent that the Monthly Customer Charge is not collecting all of the consumer-related fixed costs, these costs are being recovered in the Energy Charge(s). Also, for the Single Phase rate, there is not a Demand Charge, so the capacity-related transmission and distribution fixed costs are also being recovered in the Energy Charge(s). The table below demonstrates the amount of fixed costs being recovered through the usage charge.

Response by: Robert Walsh- Minnesota Valley Coop

List sources of information:

Line No.	Single Phase	2012	Reference
1			
2	Transmission Cost of Service - Capacity-Related	\$ 648,530	Exhibit 4, Page 3, Line 55
3	Distribution Fixed Cost of Service - Consumer-Related	\$ 2,842,161	Exhibit 4, Page 3, Line 58
4	Distribution Fixed Cost of Service - Capacity-Related	\$ 1,882,724	Exhibit 4, Page 3, Line 59
5	Distribution Fixed Costs - Total	\$ 5,373,415	Sum
6			
7			
8	Average No. Single Phase Customers	4,835	Exhibit 4, Page 29
9	Monthly Customer Charge	\$ 20.00	
10	Monthly Customer Charge Revenue	\$ 96,700	Line 8 x Line 9
11	Annual Customer Charge Revenue	\$ 1,160,400	Line 10 x 12
12			
13	<b>Distribution Fixed Costs Recovered in Energy Rate</b>	<b>\$4,213,015</b>	Line 5 - Line 11.
14	Annual Energy Sales	89,983,000	Exhibit 4, Page 29
15	<b>Distribution Fixed Costs Recovered in Energy Rate</b>	<b>\$ 0.0468</b>	Line 13 ÷ Line 14

$\$2,842,161 + \$1,882,724$  divided by 4,835 divided by 12 = \$81.44

Exhibit D, Comparison of monthly DG fees and cost caps under MREA methodology and a CCOS (including all distribution costs)

2) MREA Methodology: MN Valley's 2016 RUS Form 7, Filed 7/7/2017 in Docket 16-512 ([link](#))

Exhibit D, Comparison of monthly DG fees and cost caps under MREA methodology and a CCOS (including all distribution costs)

# Exhibit E

Exhibit E, Comparison of monthly DG fees and cost caps under MREA methodology and a CCOSS (including only fixed costs)

<b>Comparison of DEA's monthly DG fees under the MREA's methodology and DEA's CCOSS</b>				
<b>Line</b>	<b>Monthly DG Fee</b>	<b>MREA methodology</b>	<b>DEA's CCOSS</b>	<b>Formula</b>
1	Distribution cost (\$/customer-mo)	\$37.39	\$23.39	
2	Customers	97,041	97,041	
3	Fixed charge revenue (\$/customer-mo)	\$9.00	\$9.00	
4	Annual Class Distribution Fixed Costs	\$43,545,671	\$27,243,264	Line 1 x Line 2 x 12
5	Annual Class Consumer Charge Revenue	\$10,480,428	\$10,480,428	Line 2 x Line 3 x 12
6	Distribution Fixed Costs Recovered in Energy Rate	\$33,065,243	\$16,762,836	Line 4 - Line 5
7	Annual sales (kWh)	898,634,906	898,634,906	
8	Distribution Fixed Costs Recovered in Energy Rate (\$/kWh)	\$0.037	\$0.019	Line 6 ÷ Line 7
9	Estimated Solar DG Capacity Factor	15%	15%	
10	Estimated Monthly Solar Production (kWh/kW-mo)	109.5	109.5	(Line 9 x 365 x 24) ÷ 12
11	<b>Monthly DG Fee (\$/kW-mo)</b>	<b>\$4.03</b>	<b>\$2.04</b>	Line 8 x Line 10
	<b>Difference (\$/kW-mo)</b>		<b>\$1.99</b>	
	<b>Difference (%)</b>		<b>97%</b>	
<b>Monthly Charge Cap</b>				
12	Distribution cost (\$/customer-mo)	\$37.39	\$23.39	
13	Fixed charge revenue (\$/customer-mo)	\$9.00	\$9.00	
14	Monthly Charge Cap (\$/customer-mo)	\$28.39	\$14.39	Line 12 - Line 13
15	<b>Monthly Charge Cap - Rounded</b>	<b>\$28.00</b>	<b>\$14.00</b>	Line 14 (rounded)
	<b>Difference (\$/kW-mo)</b>		<b>\$14.00</b>	
	<b>Difference (%)</b>		<b>100%</b>	



Exhibit E, Comparison of monthly DG fees and cost caps under MREA methodology and a CCOSS (including only fixed costs)

Sources:

DEA's CCOSS: Larson Direct (at p. 32), Filed 7/2/2014 in Docket 14-482 ([link](#))

Testimony of D.R. Larson, page 32

Table 8 provides total costs by class expressed in terms of \$ per customer per month (consumer component) and ¢ per kWh (capacity and energy components).

<b>Table 8</b>			
<b>Unit Cost Summary</b>			
<b>Rate Class</b>	<b>Consumer Unit Cost</b>	<b>Demand Unit Cost</b>	<b>Energy Unit Cost</b>
	(\$/cust.mo.)	(¢/kWh)	(¢/kWh)
Residential & Farm (31,32,53)	23.39	5.03	5.05
Small General Service (41)	33.28	4.90	5.05
Irrigation (36)	62.56	1.87	5.05
General Service (46,54)	69.45	5.09	5.05
Interruptible Service (70,71)	188.92	1.08	5.05
Street and Security Lighting	0.47	3.64	4.73

MREA methodology: DEA's 2016 RUS Form 7, Filed 6/30/2017 in Docket 17-11 ([link](#))

<b>Comparison of MN Valley's monthly DG fees under the MREA's methodology and MN Valley's CCOSS</b>				
<b>Line</b>	<b>Monthly DG Fee</b>	<b>MREA methodology</b>	<b>MN V's CCOSS</b>	<b>Formula</b>
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7	Annual sales (kWh)	126,112,214	126,112,214	
8	Distribution Fixed Costs Recovered in Energy Rate (\$/kWh)	\$0.040	\$0.014	Line 6 ÷ Line 7
9	Estimated Solar DG Capacity Factor	15%	15%	
10	Estimated Monthly Solar Production (kWh/kW-mo)	109.5	109.5	(Line 9 x 365 x 24) ÷ 12
11	<b>Monthly DG Fee (\$/kW-mo)</b>	<b>\$4.39</b>	<b>\$1.50</b>	Line 8 x Line 10
	<b>Difference (\$/kW-mo)</b>		<b>\$2.89</b>	
	<b>Difference (%)</b>		<b>193%</b>	
<b>Monthly Charge Cap</b>				
12	Distribution cost (\$/customer-mo)	\$104.96	\$48.99	
13	Fixed charge revenue (\$/customer-mo)	\$20.00	\$20.00	
14	Monthly Charge Cap (\$/customer-mo)	\$84.96	\$28.99	Line 12 - Line 13
15	<b>Monthly Charge Cap - Rounded</b>	<b>\$85.00</b>	<b>\$29.00</b>	Line 14 (rounded)
	<b>Difference (\$/kW-mo)</b>		<b>\$56.00</b>	
	<b>Difference (%)</b>		<b>193%</b>	

Exhibit E, Comparison of monthly DG fees and cost caps under MREA methodology and a CCOS (including only fixed costs)

Sources:

- 1) MN Valley's CCOS: Response to Department of Commerce IR #2, Filed 7/15/2016 in Docket 16-241 ([link](#))

*See following page*

# Exhibit E, Comparison of monthly DG fees and cost caps under MREA methodology and a CCOSS (including only fixed costs)

Request No.	
2	Please provide cost support or other documentation demonstrating the amount of fixed costs recovered through the usage charge. At what usage level are all fixed costs being recovered?

Response: For purposes of answering this question the term "fixed costs" is interpreted as relating to non-power supply costs that do not vary with the volume of electricity used or delivered.

According to the Class Cost of Service Study for the Single Phase rate class it is determined that there are three types of fixed costs being recovered through the usage charge: 1) transmission capacity-related, 2) distribution capacity-related and 3) distribution consumer-related costs. To the extent that the Monthly Customer Charge is not collecting all of the consumer-related fixed costs, these costs are being recovered in the Energy Charge(s). Also, for the Single Phase rate, there is not a Demand Charge, so the capacity-related transmission and distribution fixed costs are also being recovered in the Energy Charge(s). The table below demonstrates the amount of fixed costs being recovered through the usage charge.

Response by: Robert Walsh- Minnesota Valley Coop List sources of information:

Title: Member Services Manager

Department: Member Services

Telephone: 320-269-2318

Line No.	Single Phase	2012	Reference
1			
2	Transmission Cost of Service - Capacity-Related	\$ 648,530	Exhibit 4, Page 3, Line 55
3	Distribution Fixed Cost of Service - Consumer-Related	\$ 2,842,161	Exhibit 4, Page 3, Line 58
4	Distribution Fixed Cost of Service - Capacity-Related	\$ 1,882,724	Exhibit 4, Page 3, Line 59
5	Distribution Fixed Costs - Total	\$ 5,373,415	Sum
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7			
8	Average No. Single Phase Customers	4,835	Exhibit 4, Page 29
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Exhibit E, Comparison of monthly DG fees and cost caps under MREA methodology and a CCOS (including only fixed costs)

\$2,842,161 divided by 4,835 divided by 12 months = \$48.99

2) MREA Methodology: MN Valley's 2016 RUS Form 7, Filed 7/7/2017 in Docket 16-512 ([link](#))

Exhibit E, Comparison of monthly DG fees and cost caps under MREA methodology and a CCOS (including only fixed costs)



October 7, 2015

# Cost Analysis and Rate Design for Net Energy Metering



# Purpose

- ✦ Our member-cooperatives requested a coordinated common approach to the newly authorized net metering cost recovery fee.
- ✦ The purpose of today's webinar is to offer the recommendations of the Net Metering Cost Recovery Fee Working Group for feedback from the MREA Member Cooperatives.





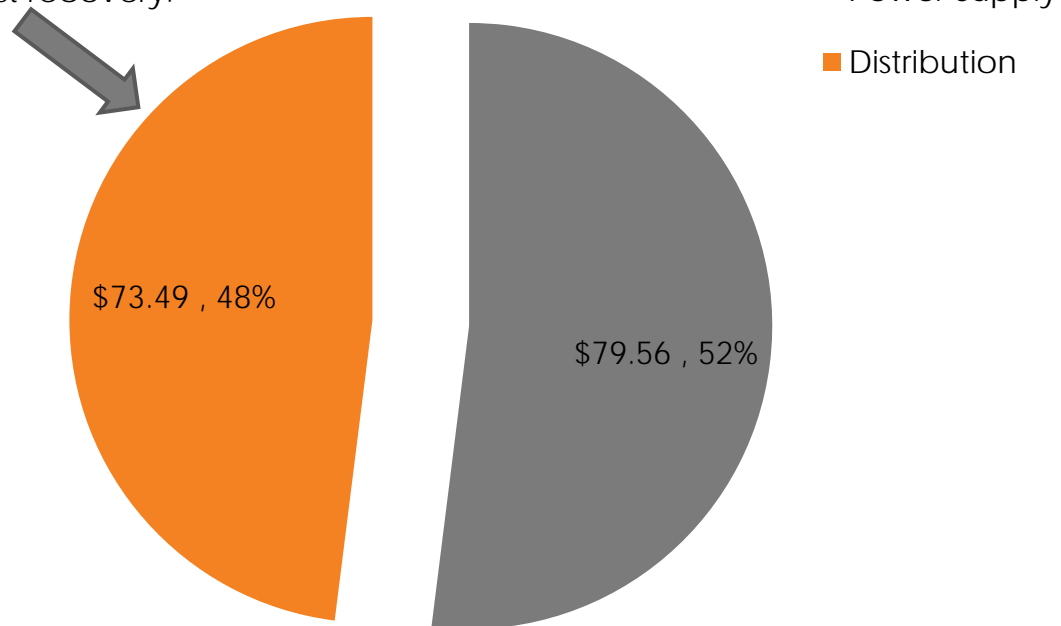
# Topics

- ✦ Cost Structure & Scope
- ✦ Statutory Background
- ✦ Solar Production
- ✦ Cost Analysis & Approach to Rate Design
- ✦ Recovery of Distribution Costs
- ✦ Bill and Revenue Checks

# Cost Structure

Residential Monthly Bill components

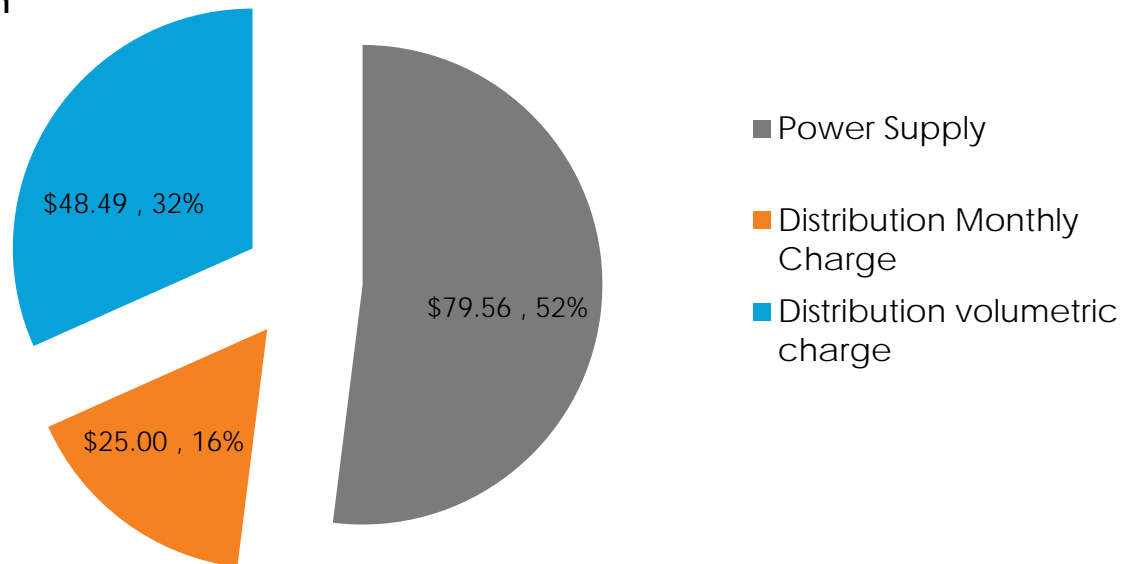
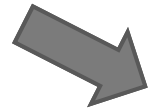
Scope is  
Distribution  
cost recovery.



# Scope of Study

## Residential Distribution Costs Broken Out

Main area of focus – portion of distribution recovered in Energy rate.



# Statutory Background

- ✦ 2015 Legislative Session
- ✦ Minnesota Statute 216B.164, Subd. 3:

## **Purchases; small facilities.**

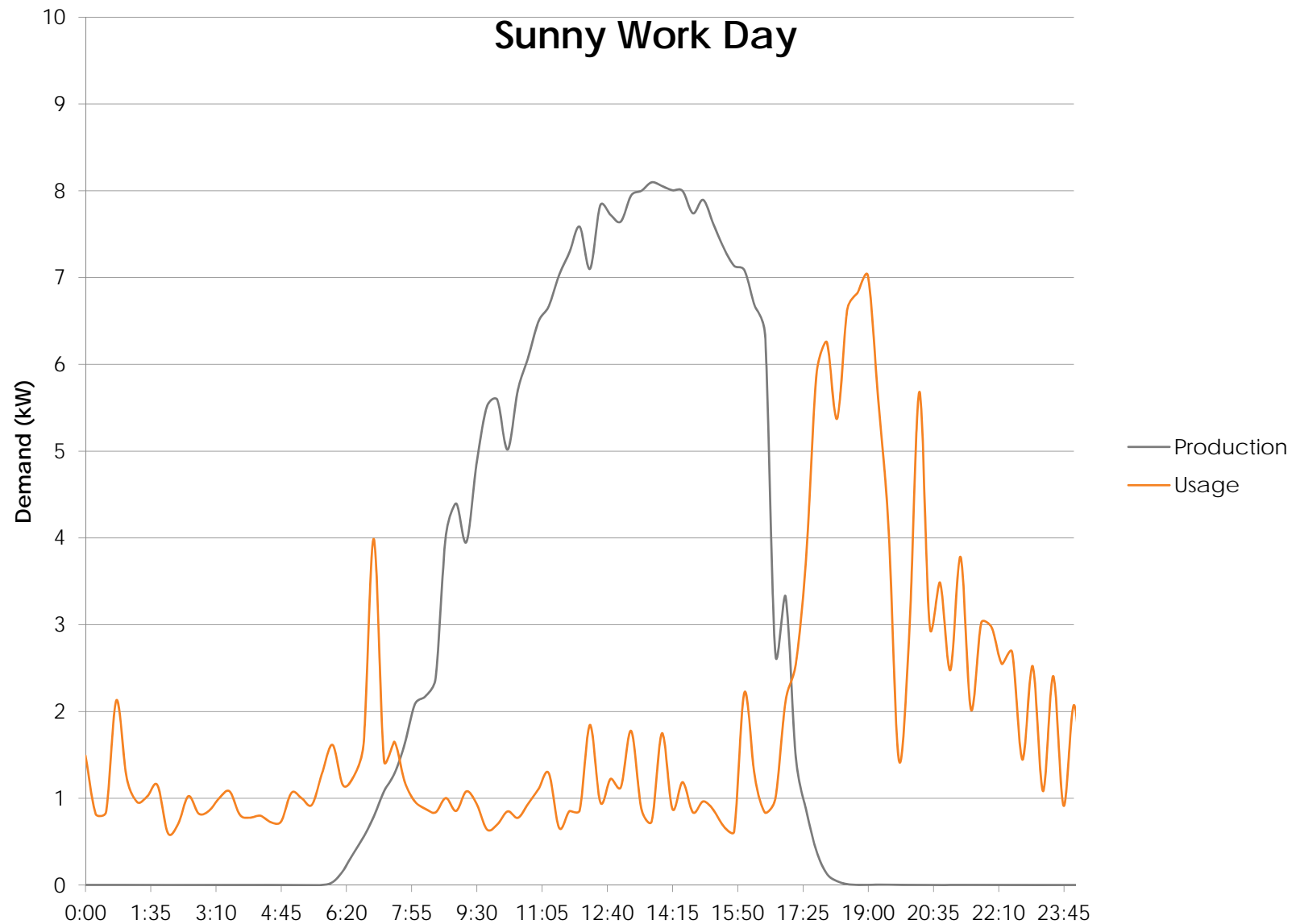
(a) This paragraph applies to cooperative electric associations and municipal utilities. For a qualifying facility having less than 40-kilowatt capacity, the customer shall be billed for the net energy supplied by the utility according to the applicable rate schedule for sales to that class of customer. A cooperative electric association or municipal utility may charge an additional fee to recover the fixed costs not already paid for by the customer through the customer's existing billing arrangement. Any additional charge by the utility must be reasonable and appropriate for that class of customer based on the most recent cost of service study. The cost of service study must be made available for review by a customer of the utility upon request. In the case of net input into the utility system by a qualifying facility having less than 40-kilowatt capacity, compensation to the customer shall be at a per kilowatt-hour rate determined under paragraph (c) ~~or~~, (d), or (f).



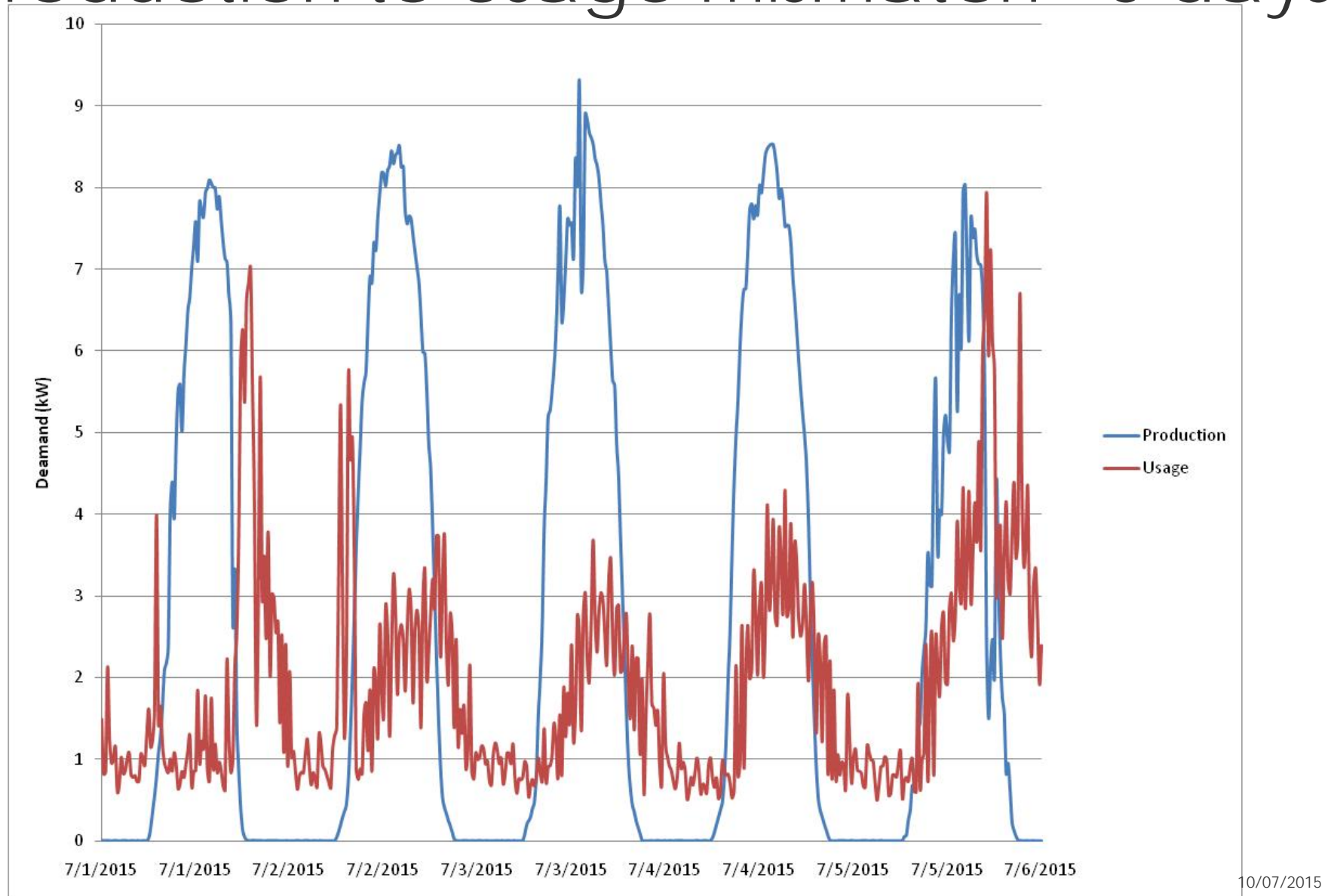
# Solar Production

- ✦ Concerns:
  - ✦ Production does not correlate to distribution peaks
  - ✦ Production is intermittent

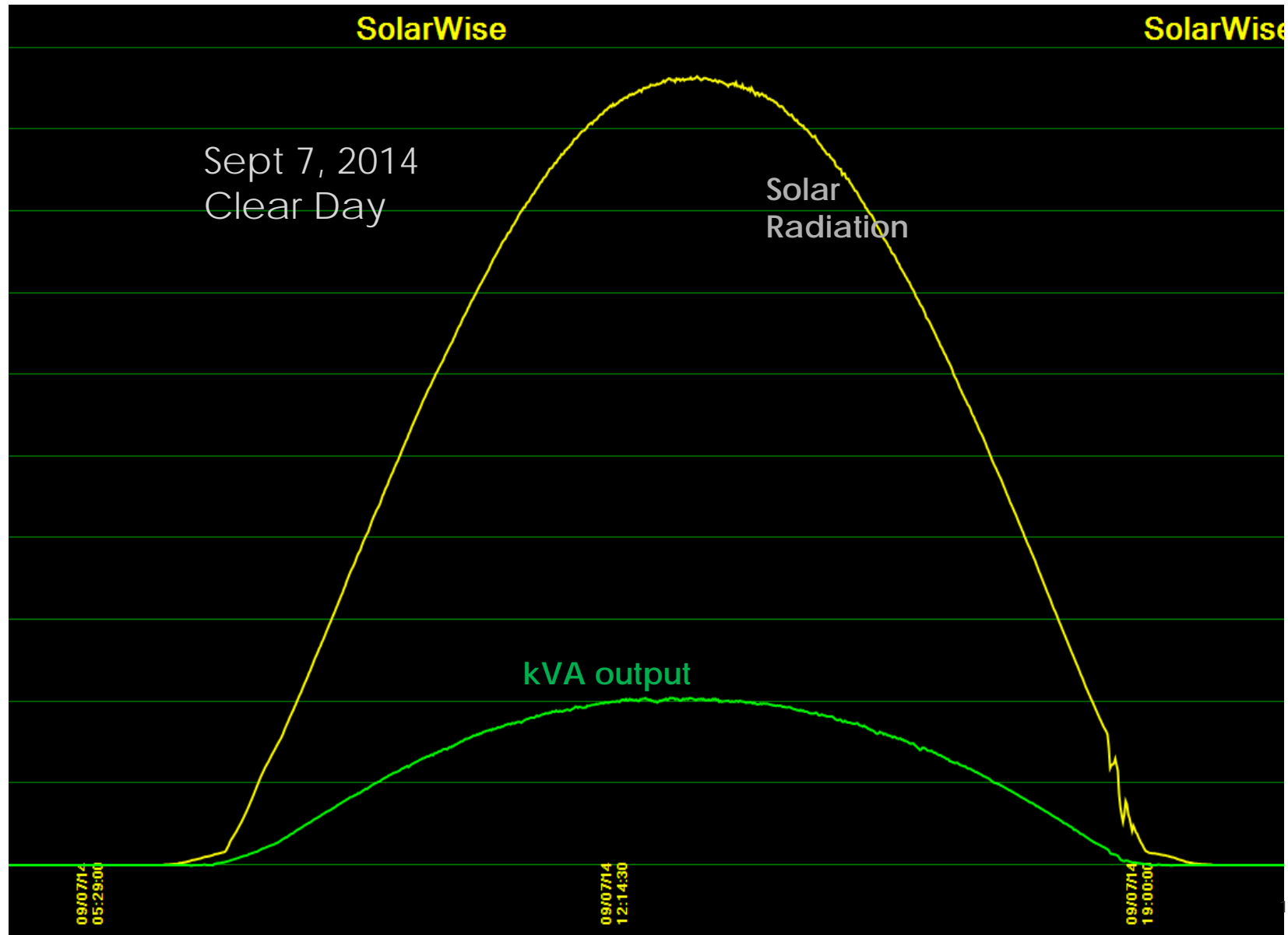
# Production to Usage mismatch – one day



# Production to Usage mismatch - 5 days

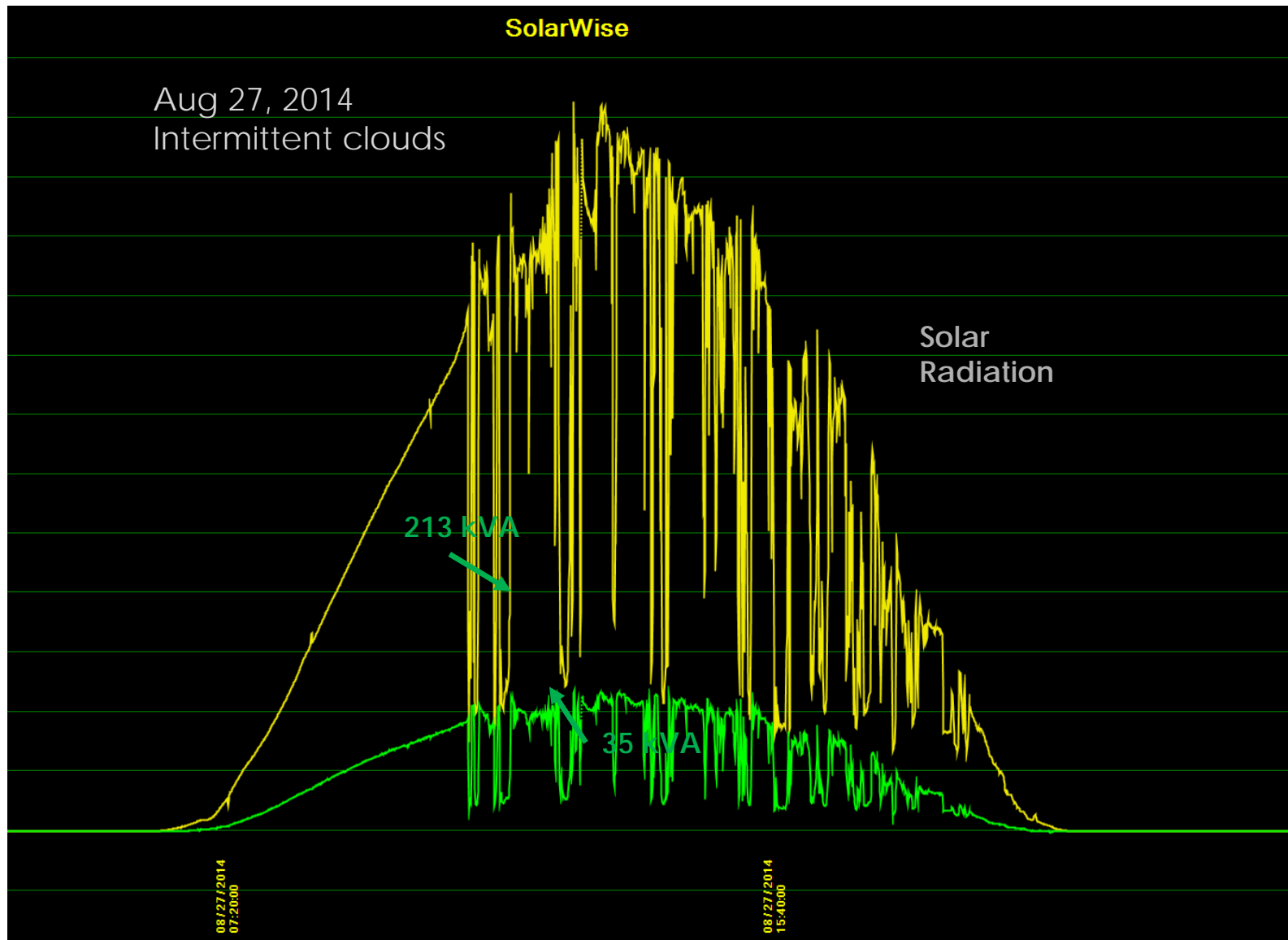


# Intermittency – Sunny day





# Intermittency – Partly Cloudy day





# Solar Production – Rate Impact

- ✦ Demand no longer correlated to energy use.
- ✦ DG customer with low or zero usage will continue to need distribution system.
- ✦ Use of energy as a proxy for charging for use of distribution system no longer works.
- ✦ Result is within residential rate class, DG customers under pay for use of dist system.



# Cost Analysis

- ✦ Cost of Service Approach
  - ✦ Standard distribution financial report (Form 7)
  - ✦ Consistent platform for all cooperatives
- ✦ Cost shifting correction
  - ✦ Limited to distribution
  - ✦ Transmission and Generation not included
    - ✦ The focus of legislative discussion was on distribution costs

# Cost Analysis

## Net Metering Demand Charge

### I. Cost Study: Fixed Costs Not Recovered

	Residential
Annual Residential Revenue	\$ 14,891,437
Annual Total System Purchased Power	\$ 19,188,426
Annual Total System Energy Sales (kWh)	264,222,161
Purchased Power Expense per kWh	\$ 0.0726
Annual Resid. Energy Sales (kWh)	106,595,586
Annual Resid. Purchased Power Exp.	\$ 7,741,219
Distribution Fixed Costs	\$ 7,150,218
Annual Consumer Charge Revenue	- \$ 2,432,400
Fixed Costs in Energy Charges	= \$ 4,717,818
Annual Resid. Energy Sales (kWh)	÷ 106,595,586
Portion of Distribution Recovered in Energy Rate (\$/kWh)	= \$ 0.0443

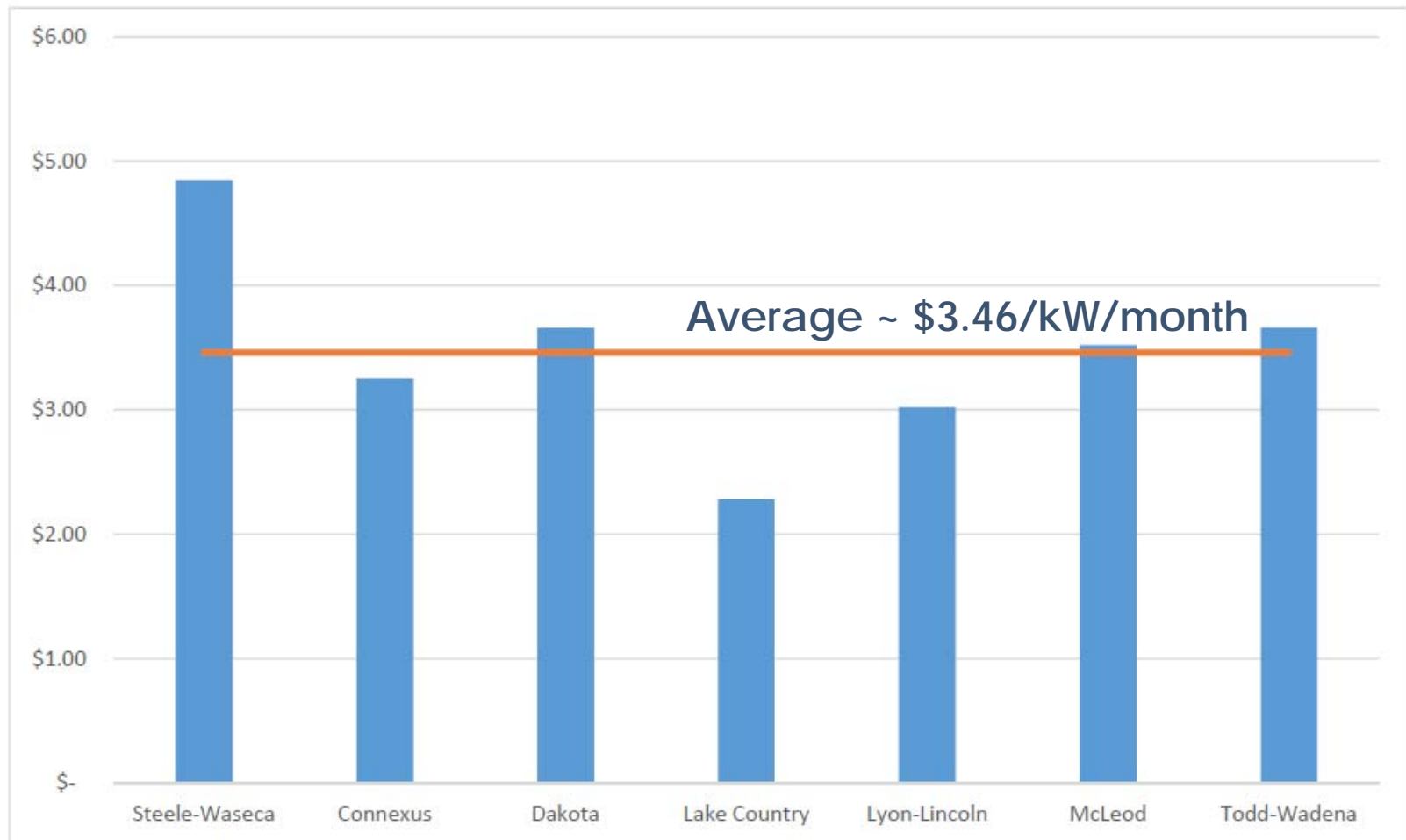
2. Calculation of NEM Demand Charge	Residential
DG Capacity Factor	15%
Monthly Hours	730
Monthly kWh for 1 KW DG	110
Portion of Distribution recovered in energy rate (\$/kWh)	\$ 0.0443
Monthly Charge per kW-mo.	\$ 4.85

**Key Point:** DG is charged \$4.85/kW times the generator size.

**Cooperative perspective:** No distribution cost shifting.

## Example Net Metering Charges for Various Cooperatives

\$/kW/month





# Cost Analysis

## Minimum Size Allowance

### 3. Proposed Nameplate Rating Allowance (No Charge)

	<u>Residential</u>
Mean Annual kWh Consumption	10,185
1st Standard Deviation	4,555
DG Capacity Factor	15%
Annual Hours	8,760
Potential kW Allowance	3.47
Proposed kW Allowance	<b>3.50</b>

**Key Point:** Demand charge waived for generator production under 3.5 kW. Recommend all Cooperatives use the 3.5 kW as the allowance.

**Cooperative perspective:** Recognizes some level of normal variation in consumption. Shows we are willing to accommodate small DG. Cost impact is modest, see following graphs.

# Cost Analysis

## Cap on Distribution Charge

### 4. Proposed Monthly Charge Limit per NEM DG Custom

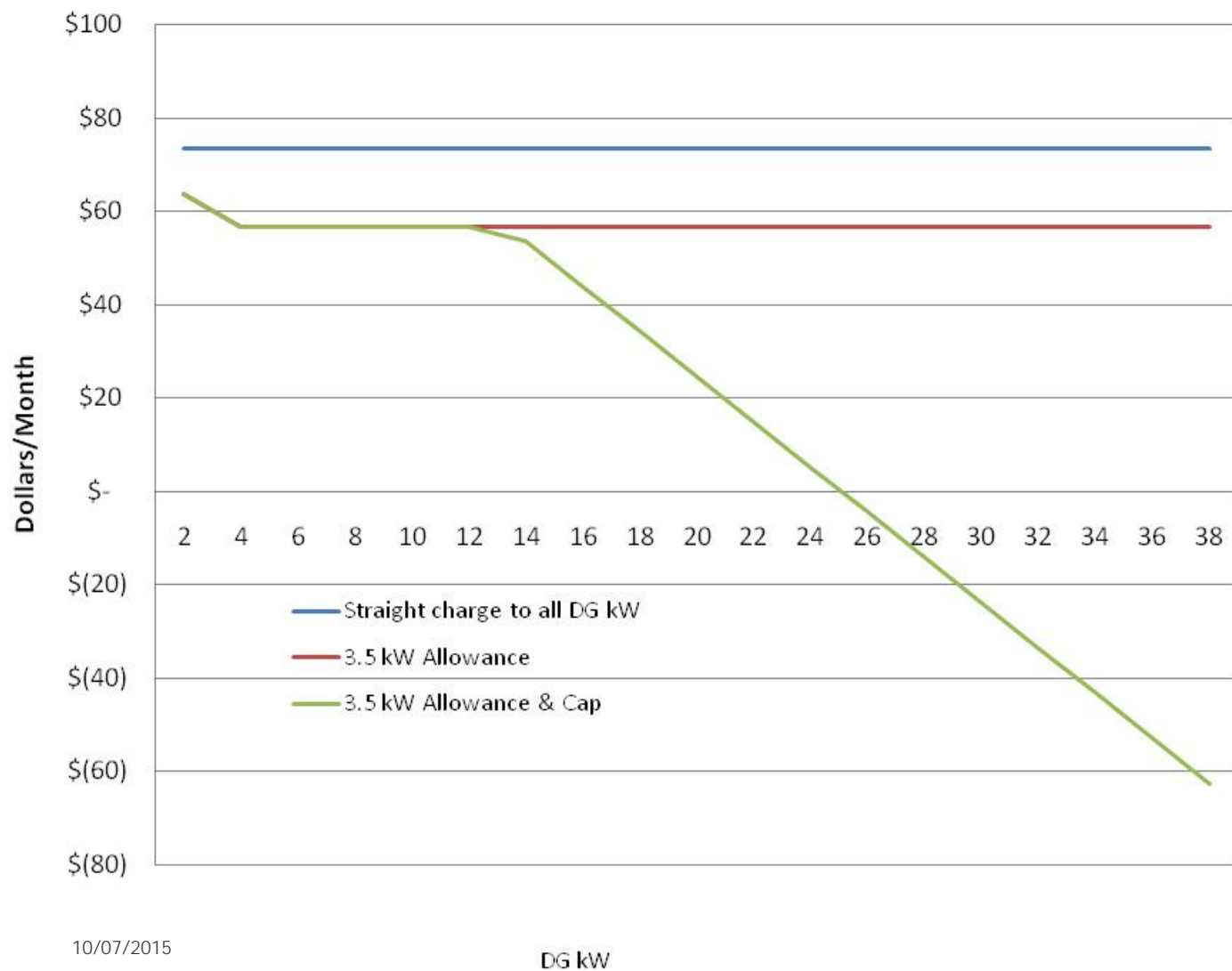
	Residential
Distribution Fixed Costs	\$ 7,150,218
No. of Residential Customers	8,108
Distribution Fixed Costs per Cust.	\$ 73.49
Current Customer Charge	\$ 25.00
Net Charge Limit	\$ 48.49
Proposed Grid Charge Limit	\$ 48.00

**Key Points:** Cap what a DG customer would pay at no higher than the fully allocated distribution cost for an average non-DG customer. The Cap would be calculated for each Cooperative.

**Cooperative perspective:** Can result in significant cost shifting if DG is not sized to load. Need size to load legislation if we are to adopt the cap. See following graphs.

## \$ Recovery of Distribution Cost

Includes all Distribution Revenue impacts including monthly charge, variations in KWH sales



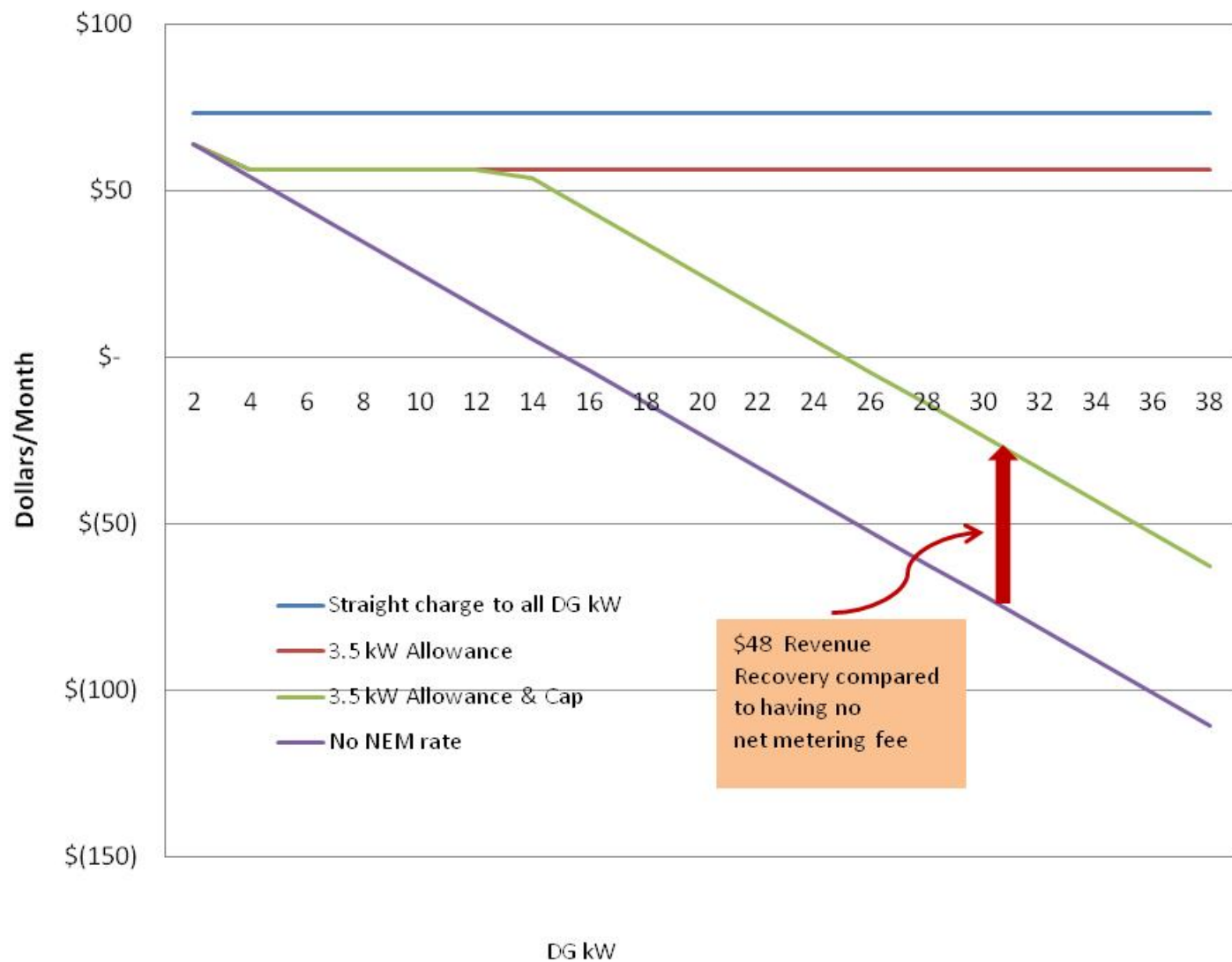
10/07/2015

DG kW



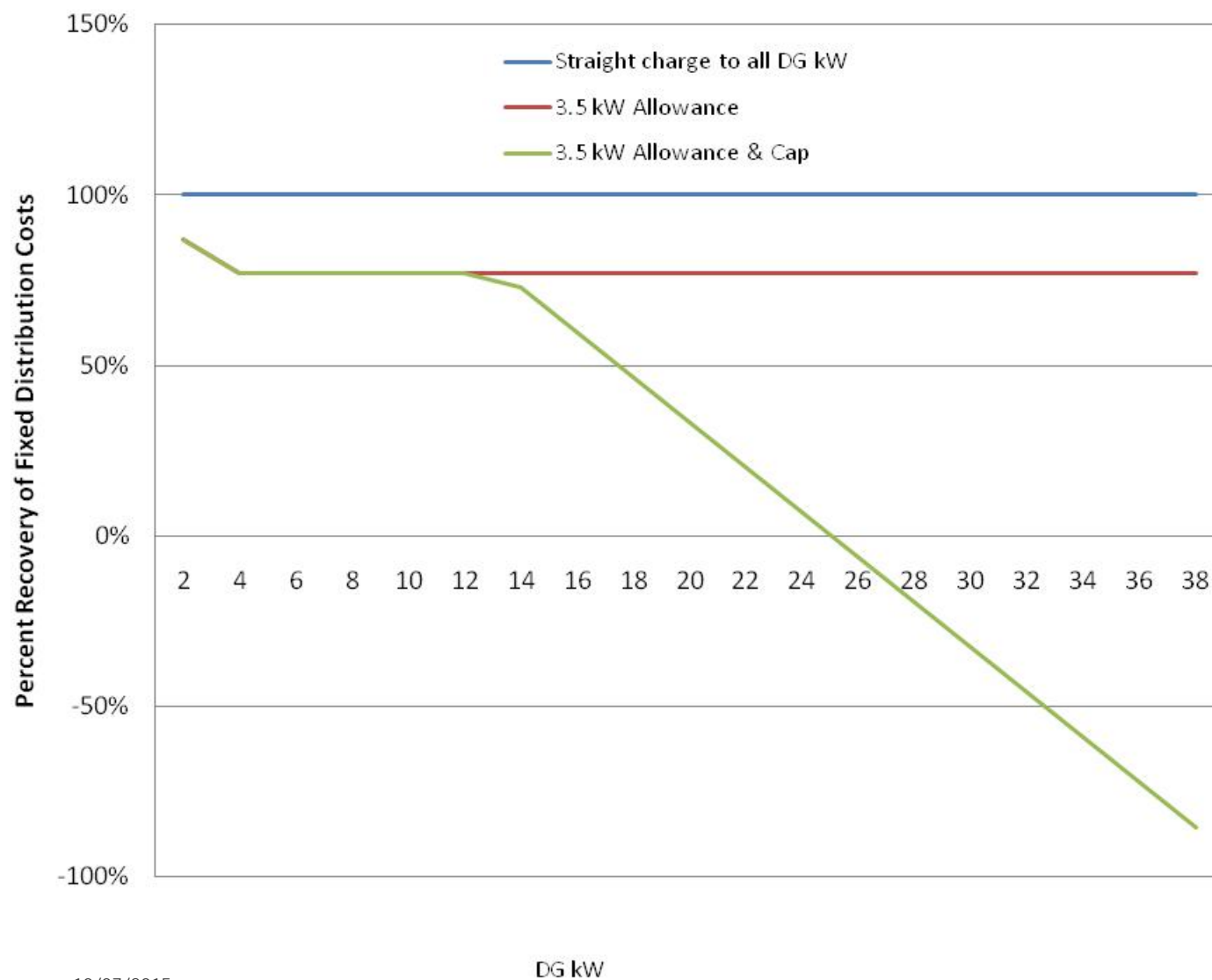
## \$ Recovery of Distribution Cost

Includes all Distribution Revenue impacts including monthly charge, variations in KWH sales



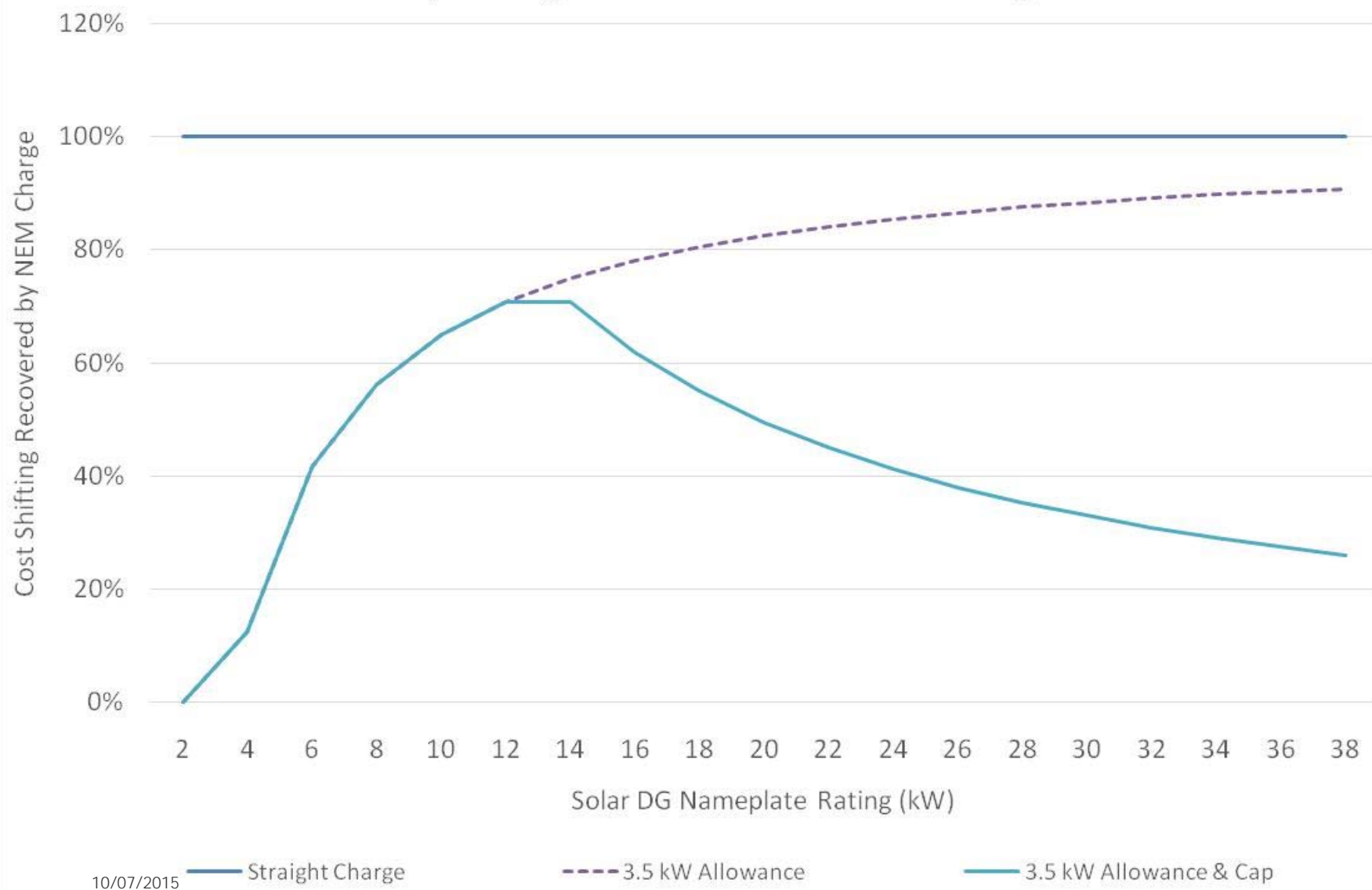
## % Recovery of Distribution Cost

Includes all Distribution Revenue impacts including monthly charge, variations in KWH sales



10/07/2015

### Distribution Cost Shift Recovered by NEM Charge Only looking at Volumetric Portion of Charge



# New DG rate impact in \$/month

	Case 1: DG demand charge		Case 2: DG demand applied > 3.5 KW		Case 3: same as Case 2 with Cap	
	DG demand charge	Total distribution	DG demand charge	Total distribution	DG demand charge	Total distribution
No DG	\$ -	\$ 73	\$ -	\$ 73	\$ -	\$ 73
2 kW	\$ 10	\$ 73	\$ -	\$ 64	\$ -	\$ 64
8 kW	\$ 39	\$ 73	\$ 22	\$ 57	\$ 22	\$ 57
20 kW	\$ 97	\$ 73	\$ 80	\$ 57	\$ 48	\$ 25



# Recap

- ✦ A reasonable Net Metering Rate can be developed from use of Form 7 data.
- ✦ Consistent approach for Cooperatives to use.
- ✦ Rate includes
  - ✦ Demand Charge applied to generator size
  - ✦ Allowance of 3.5 kW
  - ✦ A Cap on the charges



# An Option

- ✦ There is nothing in statute that says you have to adopt a cost recovery fee at this time.
- ✦ You may elect to revisit the option of a cost recovery fee annually.