RETAIL RATE GUIDE

Volume II

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.

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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.[1] 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.

1 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 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.

The first crucial decision made at the beginning of the process is to select a "test year."

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[2]. 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.

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2 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[3].
- 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.[4]

3 The capital markets will typically reference equity levels when discussing the financial stability of a system.

4 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[5]

The final objective to be defined by the board is the capital credits retirement objective. Generally, cooperatives must allocate capital credits to consumer-members.[6] "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:[7]

- 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:

5 For more information, see NRECA/CFC Capital Credits Task Force Report. Available at https://www.cooperative.com/interest-areas/governance/capitalcredits/Pages/default.aspx

6 Treatment of capital credits allocation is different in some states such as Nebraska.

7 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. [8]

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,"[9] 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.[10] 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.[11] In addition, these capital credits allocations are patronage-sourced.[12] 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."[13] For RUS, operation at cost and other reasons, it is wise for an electric cooperative to make capital credits allocations.[14]

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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.

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.[15]

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.

$$\text{TIER} = \frac{\text{Margin + Interest LTD}}{\text{Interest LTD}}$$

$$\text{DCS} = \frac{\text{Margin + Interest LTD + Depreciation}}{\text{Debt Service}}$$

$$\text{Return = Margin + Interest LTD}$$

With these equations, the margin can be defined in a variety of ways:

Margin = Interest LTD x (TIER - 1)

Margin = DSC x Debt Service – (Interest LTD + Depreciation)

Margin = Return – 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

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15 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 <u>return of</u> 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 fash 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
Power Supply Demand Energy	Power Supply Energy
Power Supply Delivery Transmission Substation Ancillary – Demand Ancillary – Energy	Transmission CP Cooperative CP Cooperative CP Energy
Distribution Demand Sub-Transmission/Substation Backbone Demand Distribution Demand	Cooperative CP Cooperative CP Customer NCP
Distribution Customer Distrubution Customer Customer Services Customer Ancillary	Customers Customers Customers Customers
Margin	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.[16] 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

16 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.[17]

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.

17 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:

$$\text{Load Factor} = \frac{\text{Energy in Power}}{\text{Hours in Period x Peak Demand in Period}}$$

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 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.

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.

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:

$$\text{Coincidence Factor} = \frac{\text{Coincident Peak Demand}}{\text{Non-Coincident Peak Demand}}$$

$$\text{Diversity Factor} = \frac{1}{\text{Coincidence Factor}}$$

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.[18]
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.

18 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.

Appendix

Schedule A-1.0	Components of Revenue Requirement
Schedule B-1.0	Income Statement
Schedule B-2.0	Summary of Adjustments
Schedule C-1.0	Development of Rate Base, Rate of Return, Return
Schedule C-2.0	Determination of Optimum Equity
Schedule D-1.0	Cash Flow Model for Determination of Margin Required
Schedule D-2.0	Modified TIER
Schedule E-1.0	Classification of Expenses
Schedule E-2.0	Classification of Distribution Expenses
Schedule F-1.0	Cost Allocation Summary
Schedule F-2.0	Summary of Components of Expenses
Schedule F-3.0	Components of Expenses with Class Return - Residential

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
Total	**188,589,400**	**4,224,068**	**192,813,468**	**12,937,431**	**205,750,899**
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
Total	**175,788,900**	**5,895,397**	**181,684,297**	**0**	**181,684,297**
Return	**12,800,500**	**(1,671,329)**	**11,129,171**	**12,937,431**	**24,066,602**
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
Total	**9,975,700**	**110,559**	**10,086,259**	**0**	**10,086,259**
Operating Margin	**2,824,800**	**(1,781,888)**	**1,042,912**	**12,937,431**	**13,980,343**
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
Total	**4,506,700**	**(1,267,500)**	**3,239,200**	**0**	**3,239,200**
Net Margins	**7,331,500**	**(3,049,388)**	**4,282,112**	**12,937,431**	**17,219,543**
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%

Schedule B-1.0

Standard Electric Cooperative, INC. Summary of Adjustments	
1. Operating Revenue	
Base Revenue	$558,655
PCA Revenue	$3,665,413
Other Revenue	$0
TOTAL	**$4,224,068**
2. Operating Expenses	
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
TOTAL	**$5,895,395**
3. Interest on Long-Term Debt & Other Deductions	
INTEREST ON LONG-TERM DEBT	**$110,559**

Schedule B-2.0

DEVELOPMENT OF RATE BASE, RATE OF RETURN AND RETURN

1. Determine Rate Base

	Adj TY Total $
Plant In Service	429,228,800
CWIP	5,684,600
Total Utility Plant	434,913,400
Accum Depreciation	**(130,764,700)**
Net Plant	**304,148,700**
Working Capital	
Materials & Supplies	227,515
Prepayments	1,002,723
Cash Working Capital	4,644,740
Consumer Deposits	(6,405,985)
Working Capital	(531,007)
Rate Base	303,617,693

2. Determine Capitalization

	$	%	Cost	Return
Debt	191,727,700	58.26%	5.208%	3.03%
Equity	137,385,500	41.74%	11.7200%	4.89%
Total	329,113,200	100.00%		7.93%

3. Determine Cost of Debt

	$
Interest on LTD Expense	9,985,959
Long Term Debt Balance	191,727,700
Cost of Debt	5.21%

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	g
CC Rotation Cycle	n

Growth in Plant	3.00%
Rotation Cycle	10
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

Return = [EC × E% + DC × (1−E%)] × Capitalization

Margin = (TIER × Interest Cost) - Interest Cost

Return = Margin + Interest Cost

Return = TIER × Interest Cost

$$\text{Tier} = \frac{\text{Margin} + \text{Interest Cost}}{\text{Interest Cost}}$$

Return = TIER × DC × (1 - E%) × Capitalziation

$$EC = \frac{(1+g)^{n+1} - (1+g)^{n}}{(1+g)^{n} - 1}$$

Return = [EC × E% + DC × (1 - E%)] × Capitalization

$$\text{Optimum Equity} = \frac{DC \times (TIER - 1)}{EC + DC \times (TIER - 1)}$$

TIER × DC × (1 - E%) = EC × E% + DC × (1 - E%)

Capitalization = (D + E)

$$\text{Equity \%} = \frac{E}{D + E}$$

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

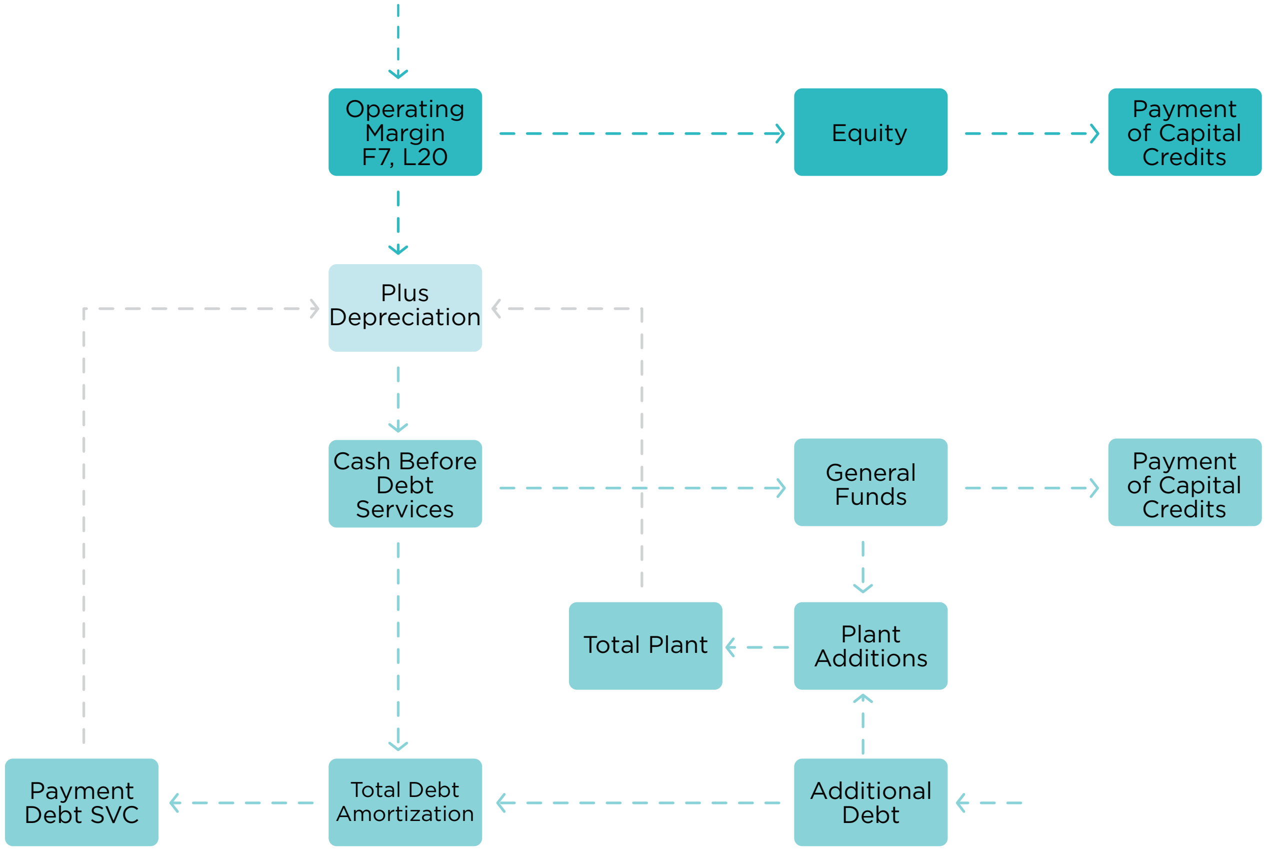
General Funds Sufficient To:
Pay capital credits | Fund plant additions

Balance Sheet Ratios:
Equity as % of capitalization | Liquidity as % of plant

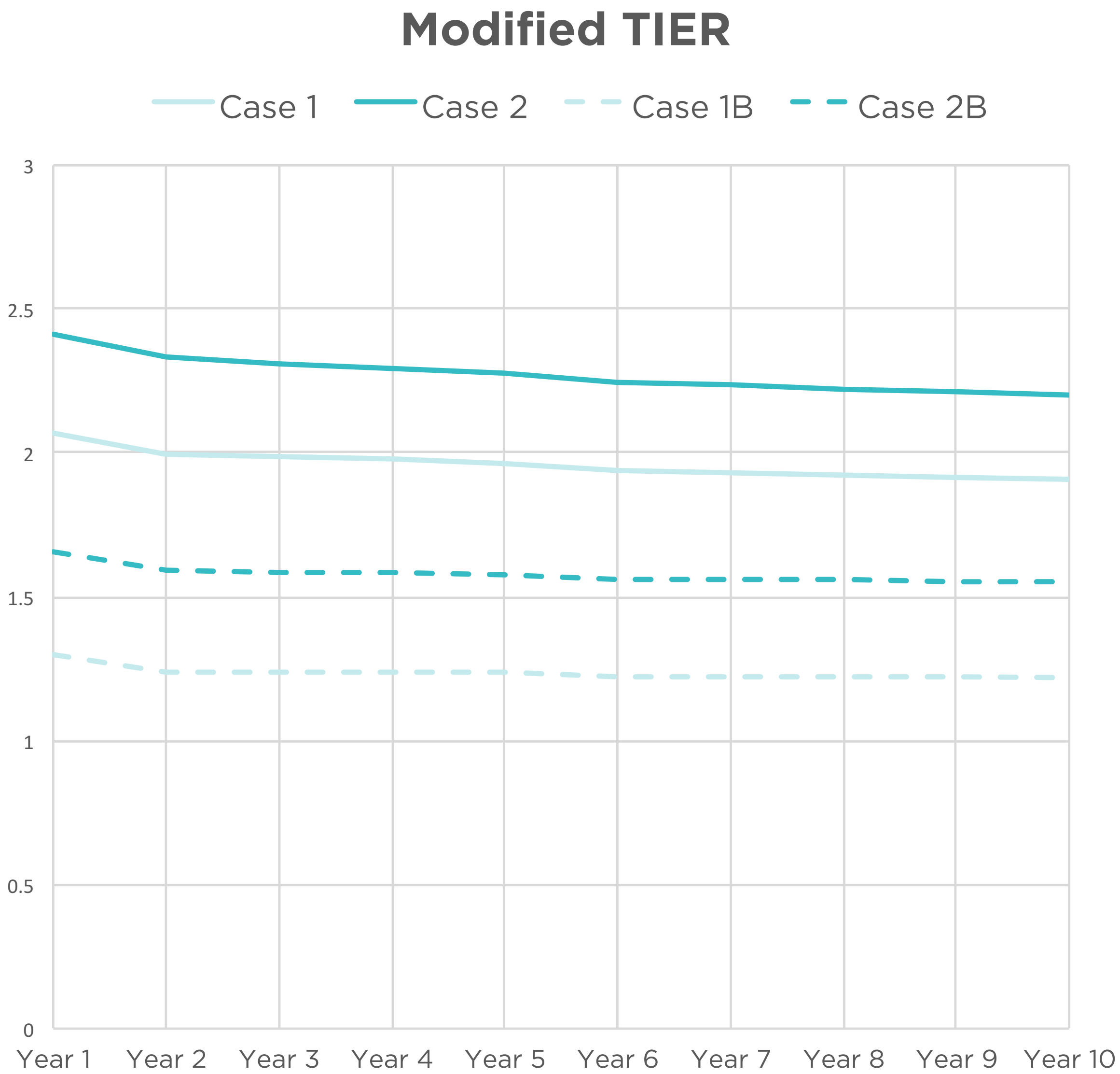
Payment of Capital Credits:
Reduce equity and associated equity as % of capitalization | Reduces general funds and liquidity

Source of Funds to Finance Plant Investment (net CIAC):
Retained earnings (i.e., cash from operations) | Debt

Equity Ratio:
Equity/(Equity + Debt)



Schedule D-1.0



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

Schedule D-2.0

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	

Schedule E-1.0

Classification of Distribution Expenses				
ACCT#	Description	Demand Related	Energy Related	Direct
Distribution Operations				
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	
Distribution Maintenance				
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**
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%

CoOPTIONS:® 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
PUR PWR DEMAND	**64,248,682**	**45,701,556**	**3,517,154**	**2,302,715**	**6,020,746**	**6,054,182**	**602,464**	**49,865**
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
PUR PWR ENERGY	**63,473,630**	**40,472,271**	**3,438,634**	**1,946,006**	**6,597,534**	**9,702,462**	**1,215,803**	**100,920**
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
WIRES DEMAND	**41,944,804**	**33,056,114**	**2,770,133**	**1,891,473**	**3,118,892**	**744,254**	**328,699**	**35,239**
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
TOTAL CUSTOMER	**36,083,787**	**29,092,073**	**2,006,810**	**1,544,575**	**730,866**	**80,242**	**2,311,641**	**317,580**
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
Total Expenses	**205,750,903**	**148,322,014**	**11,732,731**	**7,684,769**	**16,468,038**	**16,581,140**	**4,458,607**	**503,604**
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

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
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 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
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 Consumer	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 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 = (Margin + Depreciation + Interest LTD) ÷ 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) ÷ 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.*